Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry

Docket No. UG-940778

Reference Volume 1: First Phase Written Comments

STATE OF WASHINGTON
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
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Docket No. UG-940778

Reference Volume 1: First Phase Written Comments

On August 2, 1995 the Washington Utilities and Transportation Commission issued a Notice of Inquiry entitled Examining Regulation of Gas Utilities in the Face of Change in the Gas Industry (Docket No. UG-940778). The Inquiry posed a number of questions on which the Commission invited comment and requested that written comments be received by September 30, 1995. This round of comments constitutes the first phase of the Commission's Inquiry.

This volume contains the text of the Notice of Inquiry, the Commission's rules governing least-cost planning and competitive bidding, and an alphabetically ordered collection of the comments received in the first phase of the Inquiry. The Commission intends that this volume will serve as a basic information resource from which subsequent comment and workshop phases of the Inquiry can draw.

For your convenience, the written responses have been arranged alphabetically and are separated by a yellow title page.

The analysis and opinions included in this volume are the responsibility of commentors and do not necessarily represent the opinions, position, policy, or analysis of the Commission or its staff.

Questions concerning the Inquiry should be directed to Jeffrey Showman (360/586-1159) of the Commission's policy and planning section.

Steve McLellan
Secretary

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Docket No. UG-940778

SERVICE DATE
AUG - 2 1995

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1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 • Olympia, Washington 98504-7250
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NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies

In the Face of Change in the Natural Gas Industry

Docket No. UG-940778

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", <u>Energy Law Journal</u>, 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 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. <u>Supply-side issues</u>

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. <u>Least cost planning</u>

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. <u>Demand side management and conservation</u>

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. Missed questions

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 2d day of August, 1995.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Sharon L. Nelson

SHARON L. NELSON, Chairman

Richard Hemstad

RICHARD HEMSTAD, Commissioner

Wm. R. Gillis

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 . . . .

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)).

PREPROPOSAL STATEMENT OF INQUIRY
(RCW 34.05.310)

SERVICE DATE
SEP - 8 1995

CR-101 (7/23/95)
Do NOT use for expedited repeal

Agency: Washington Utilities and Transportation Commission

Subject of possible rule making: A review of rules relating to economic regulation of natural gas.

The Commission invites comments about structural changes in the natural gas industry; the implications of those changes for regulation; and recommendations concerning specific Commission rules applied to the industry. 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 mechanisms, demand side management incentives and financing, and other regulatory issues which may be articulated as a part of this process. WUTC Docket No. UG-940778.

(a) Statutes authorizing the agency to adopt rules on this subject: RCW 80.01.040

(b) Reasons why rules on this subject may be needed and what they might accomplish:

Following the Federal Energy Regulatory Commission's Order 636 and other industry structural changes, natural gas local distribution companies now operate in a more competitive environment. The Commission is undertaking this inquiry to consider how it may regulate gas companies so as to balance competitive market realities with state and regional policy goals which include securing the benefits of competition for both companies and the customers they serve, while protecting customers who do not have competitive options. As a result of this inquiry, the Commission may propose changes in regulatory practice, including amending or adopting rules which reduce unnecessary reporting and procedural requirements on regulated companies; rely to a greater degree on market forces than existing regulatory practices; and, capture the benefits of competition for all customer classes.

(c) Identify other federal and state agencies that regulate this subject and the process coordinating the rule with these agencies: None

(d) Process for developing new rule (check all that apply):

- ☐ Negotiated rule making
- ☐ Pilot rule making
- X Agency study
- X Other (describe)

SEE PAGE 2

(e) How interested parties can participate in the decision to adopt the new rule and formulation of the proposed rule before publication:
(List names, addresses, telephone, fax numbers of persons to contact; describe meetings, other exchanges of information, etc.)

SEE PAGE 2

NAME (TYPE OR PRINT)
STEVE MCLELLAN

SIGNATURE
S McLellan

TITLE
SECRETARY

DATE
AUGUST 22, 1995

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AUG 23 1995

TIME: 1:10

WSR 95-17-123

(d) Agency study through the Notice of Inquiry: Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry (NOI), Docket No. UG-940778, will permit exploration of the effects of federal regulatory and structural changes in the natural gas industry and their effects upon local distribution companies and their customers in the state. The Commission contemplates use of workshops with regulated utility companies, consumer groups, environmental advocates, and other interested parties in which information and views are exchanged in an effort to reach consensus on changes in Commission rules and regulations governing the natural gas industry.

(e) Interested persons may contact Jeffrey Showman, Washington Utilities and Transportation Commission, Office of Policy Planning and Research, PO Box 47250, Olympia, Washington, 98504-7250; 360-586-1196 (fax: 360-586-1150). Written comments addressed to Commission Secretary, and bearing the above NOI caption and docket number, may be filed with the Commission not later than September 30, 1995. All commentors are asked to file an original and ten copies of written comments. We also ask that comments be provided on a 3 1/2 inch, high density "floppy" diskette, for IBM-compatible systems. Please number and organize responses to questions according to the outline in the NOI. To make comments easier to post to electronic bulletin boards and the Commission's Internet FTP site, please use end notes rather than footnotes. Interested persons also may file additional written comments and attend and participate in workshops, to be announced by written notice to all commentors specifically asking to receive such notice in this docket. Copies of the NOI are available upon request by contacting Steve McLellan, Commission Secretary, at the above address. Copies of the Notice of Inquiry may be accessed on the Internet via anonymous FTP: connect to the host at FTP.GOVT.WASHINGTON.EDU, cd to the directory: /wutc/noi/gas; get the file: GAS.NOI.TXT. **Please note -- the WUTC is not taking formal comments via the Internet.**

Attorney General: Public Counsel

Christine O. Gregoire
ATTORNEY GENERAL OF WASHINGTON
900 Fourth Avenue #2000 • Seattle WA 98164-1012

September 29, 1995

Steve McLellan, Secretary
Washington Utilities and
Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98054-7250

Re: Natural Gas Industry NOI
Docket No. UG-940778

Dear Mr. McLellan:

Enclosed are the Initial Comments of Public Counsel in the above referenced docket. We have enclosed ten copies and a diskette formatted in Wordperfect 5.1.

Very truly yours,

Donald T. Trotter
Assistant Attorney General
Public Counsel

DTT/ljb
Enclosures

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original

Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry	)))))	DOCKET NO. UG-940778

INITIAL COMMENTS OF PUBLIC COUNSEL

CHRISTINE O. GREGOIRE
ATTORNEY GENERAL

Donald T. Trotter
Assistant Attorney General
Public Counsel Section

September 29, 1995

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INITIAL COMMENTS OF PUBLIC COUNSEL

The Commission has requested comment on issues relating to the regulation of local natural gas distribution companies. Public Counsel is responding in two parts to this request. First, we set forth some guiding principles and concepts which we submit should govern the regulation of gas utilities into the future. Second, we respond to the specific questions posed by the Commission. Finally, as requested, we have added some questions which the Commission did not pose which are important, and should be specifically addressed by the Commission in this docket.

We look forward to reviewing the comments submitted by other parties, and anticipate the opportunity to respond to those comments in a subsequent phase of this Inquiry.

I. GUIDING PRINCIPLES AND CONCEPTS FOR THE FUTURE REGULATION OF THE GAS INDUSTRY

A. Background

A primary purpose of utility regulation is to prevent the abuse of monopoly power. For this and other reasons, the focus of the Commission should be to continue to assure that core market consumers are charged no more than is necessary to provide them with safe, economical, adequate, and reliable service.

Where the conditions exist that are necessary for competition to produce efficient results, markets can work for the benefit of all consumers. The textbook economic definition of an efficient market is:

1) Goods are perfectly substitutable;

2) There are multiple producers and consumers, and no one producer or consumer is large enough to influence the market price;

3) All producers and consumers have perfect information about the market;

4) Capital is fungible, and will find the use with the highest return;

5) There is free entry and exit from the marketplace.

This is the economic definition of an efficient market. As a practical matter, reasonably efficient markets would satisfy each of these elements to some significant degree.

But at best, only the first of these elements exists in the natural gas industry: One molecule of methane is interchangeable with another. (But even so, the reliability of service between gas suppliers may not be perfect substitutes). As to the other elements, large consumers do appear to have market power, as they can entice the pipeline to offer a bypass, or persuade the utility to offer a special rate. Small consumers, certainly, do not have perfect information about the market for gas. Capital in the gas industry is virtually all "sunk" in the ground, and is anything but fungible. Gas LDCs retain an obligation to serve under state law, and are granted exclusive territories. Their ability to "exit" is probably as limited as another LDC's ability to "enter."

Absent the preconditions for efficiency under competition, we caution the Commission not to assume that "stimulating competition" will result in benefits for all consumers.

Larger customers have a strong economic self-interest, pay close attention to the cost structure of the industry, and exercise market power when possible. This perspective must not be permitted to dominate the discussion of industry restructuring. The transaction costs associated with small customers taking advantage of market opportunities are considerable, and one should not assume that merely making market opportunities available to core market customers will result in market efficiencies being achieved. The perspective of all customers must be considered.

Many of the changes in the gas industry are driven by increased competitiveness between gas suppliers, gas pipelines, and alternative fuel industries. To date, we believe that the vast majority of the benefits of competition have accrued to large gas consumers, with cost shifts to small consumers being implemented in order to assure that distribution utilities have a reasonable opportunity to earn a fair rate of return on their "used and useful" utility plant investment.

The current situation should be compared to the origin of regulation, which comes from an era a century ago, when customers with competitive options (large grain shippers in cities served by multiple railroads) received very competitive prices, while small customers in areas served by a single railroad suffered the burdens of monopoly power. Large customers with access to competitive options never asked for regulation, and were never the intended beneficiaries of regulation. The same situation is recurring in Washington State in the natural gas industry, with large industrial and electrical generation customers (with bypass and alternative fuel options) receiving special prices, while an increasing share of the regulated utility revenue requirement is being imposed on core market customers who lack competitive options.

This origin of regulation is very evident in the Washington State Constitution, which, among other things, provides with respect to transportation service, that:

> The legislature may pass laws establishing reasonable rates of charges for the transportation of passengers and freight, and to correct abuses and prevent discrimination and extortion in the rates of freight and passenger tariffs on the different railroads and other common carriers in the state, and shall enforce such laws by adequate penalties. A railroad and transportation commission may be established and its power and duties fully defined by law. [Art. XII, Section 18]

A prohibition against discrimination was also included in the Constitution:

> ... Persons and property transported over any railroad, or by any other transportation company, or individual, shall be delivered at any station, landing or port, at charges not exceeding the charges for the transportation of persons and property of the same class, in the same direction, to any more distant station, port or landing.... [Article XII, Section 15]

Natural gas was not an article of commerce at the time the state Constitution was drafted, and natural gas transportation (as opposed to a regulated utility service) is very new to the state of Washington. Nonetheless, gas "transportation" as it exists today and may evolve tomorrow is becoming more akin to common carrier transportation service than to integrated utility service. The Commission may want to give consideration to fundamental changes in the manner in which this service is regulated.

The rationale for regulating the natural gas industry today is that a) gas service is important to the economy of the state; b) there are critical infrastructure issues which need to be addressed; and c) small consumers are unable to efficiently and economically evaluate alternatives, cannot exert market power, and therefore are subject to the exercise of monopoly power.

Regulation was not created to protect large customers from the ravages of cut-throat competition; it was created to protect small consumers from the abuse of monopoly power. With this perspective in mind, below Public Counsel offers some guiding principles and concepts for future regulation of the gas industry.

B. Recommended principles and concepts

1) **Markets should work for the benefit of all consumers.** All customers should share in the benefits of competition.

2) **There is no forgiveness in a truly competitive marketplace; if there are changes in the regulatory scheme to "promote competition," this fact should be recognized.** If competitive forces are to be utilized in the gas industry, the Commission needs to re-evaluate the premise that utilities will be

allowed to recover a fair rate of return on plant or the cost of resources which, while perhaps prudently acquired, may no longer be needed or optimal to provide the service now being demanded of them. An airline which buys too many airplanes cannot charge customers a higher price for its product, and a company which manufactures "square hula hoops" cannot command any price for its product..

This is a fundamental shift from the standard of prudence which has been applied to regulated utilities in the past. Investments in distribution plant or commitments for gas supply left stranded by competitive forces should not be redistributed among remaining customers. "Take or Pay" and excess capacity costs should be equally borne by all customers equally, or else absorbed by utility shareholders.

3) **No discrimination should be permitted which allows any customer to pay less or forces any customer to pay more than other customers for substantially similar products as a result of competitive forces.** If a special rate must be offered to one customer to attract or retain that load (for example, excluding reservation charges from gas supply rates), the same "special rate" should be applied to rates paid by all other customers.

4) **All customers must share in the cost of the system.** Gas utilities are characterized by high fixed costs and very low variable operating costs. The allocation of these costs among customers and customer classes is a critical role for the Commission.

5) **A fair allocation of embedded costs, which make up the utility revenue requirement, should be the guide to pricing equity for natural gas.** If markets do not permit the recovery of embedded costs equitably from all customers, then these costs should not be recovered from any customers.

6) **Long-run marginal costs, not short-run market conditions, should be the guide to pricing efficiency for natural gas.** A utility system designed to operate with one-day in 10-years reliability (some gas utilities have asserted a 1-day in 50-years reliability criterion is appropriate) will have unused capacity 99.97% of the time. A system with unused capacity has very small short-run marginal costs which, if used to set rates for competitive-sector customers, will result in 99.97% reliability with virtually no economic contribution to the costs of providing that reliability. Pricing based upon short-run marginal cost is fundamentally inappropriate.

The term "subsidy" and "subsidize" tend to be pejorative terms. The Commission should define them as a part of this Inquiry. "Subsidy" should be defined by the Commission to mean a price which is lower than long-run marginal cost. The term "subsidize" should be defined by the Commission to mean pricing a service higher than the stand-alone cost associated with serving a customer in the absence of a shared utility "system" or "grid" while another service is priced lower than the stand alone cost of provision. There may be a wide range of costs between long-run marginal cost of utility service from a shared system and stand-alone cost which represent a continuum of non-subsidized prices in which the Commission should use its judgment to set fair, just, and reasonable rates.

7) **There are efficiency benefits to having a utility system.** It is the combination of customers that permits economies of scale in service and peak demand diversity. These characteristics should render the total cost of serving a group of customers to be lower than the total cost to each and every customer or group of customers to build a stand-alone system. If the utility does not achieve this, it is inefficient, and should not be allowed to recover any system costs which exceed the costs which its various customer groups would incur to secure service in the absence of a shared utility system.

8) **The benefits of utility operations in competitive markets should be used to reduce prices for "full-service" customers of regulated utilities.** Customers who choose to purchase only a portion of their energy service from a regulated utility, and the balance from competing suppliers, should expect to pay market-based or value-based prices for unbundled products and services, rather than cost-based prices.

9) **New customers should contribute at least as much to revenue as they do to long run marginal cost.** Line extension policies should be designed to address this principle. Line extension policies and rate design should also ensure that natural gas consumers choose gas where it is the cost-effective energy choice from a societal (i.e., long-run marginal cost) perspective.

10) **Utilities should enable consumers to choose the least costly means of meeting their energy needs, including demand-side management alternatives.** It may be appropriate to separate DSM incentives from the utility in order to avoid conflicts of interest where utilities encourage uneconomic choices to gain margins, or discourage DSM activity to retain margins. Creation of a statewide "Conservco," charged with funding conservation activity and funded through a levy on all utility energy sales, may be a reasonable alternative to utility-funded DSM programs.

11) **Large customers that exercise competitive options should only be allowed to do so in a way that does not jeopardize utility planning efforts for core customers.** Large customers must give reasonable notice to utilities to increase or decrease service from a utility to avoid stranded or inadequate facilities investment, and to avoid shortages and surpluses of gas supply. The term of notice should be based upon the impact that the customer decision will have on the utility and its other customers.

II. RESPONSES TO COMMISSION 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?

PUBLIC COUNSEL RESPONSE

1. The PGA permits an automatic or near-automatic pass-through of purchased gas costs. The PGA itself provides no incentive for a utility to minimize gas supply costs. The PGA should be modified to provide utilities appropriate financial incentives.

At the time the PGA mechanism was adopted, all gas purchases were at FERC-approved rates, and both the utilities and the Commission had limited discretion in the cost. The need for review of these costs was limited. Today, by contrast, the LDCs have great flexibility and ability to control gas costs, and the Commission needs a mechanism to efficiently determine if those costs are reasonable.

2. We propose that the cost of gas or a gas cost index be established in a general rate proceeding or other special proceeding, and that variations from that established cost be permitted on a percentage pass-through basis. It will be critical to establish a gas cost "starting point" that neither unduly penalizes nor favors management.

One manner in which this could be implemented, for example, would be to set a specific rate for gas in a general rate case. For example, the Commission could set the cost of gas at a starting point of, say, $.20/therm, and then variations could be passed through on a 90/10 basis. If the cost of gas increased to $.25/therm, rates would be increased to $.245/therm, and the utility would absorb the balance. Conversely, if gas costs declined to $.15/therm, rates would be decreased to $.155/therm, and the utility would reap the balance.

Another approach would be for the Commission to establish an index for gas prices; for example, a utility could be allowed 95% or 105% of the average spot market price of gas in rates. If they engaged in successful market operations, and held costs below the index, the savings could be shared on some equitable basis.

3. Questions of prudence of supply and pipeline commitments should be examined in general rate proceedings or other proceedings in which sufficient time is set aside to examine detailed transactions. If an ex-ante process (i.e. pre-approval process) is developed, an adjustment to the rate of return and capital structure must be made to reflect the shift of risk to ratepayers.

No wholesale change in line extension policies is required, as they are currently margin-driven. A change in the term of commitment for large customers may be required, and that is addressed below.

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?

PUBLIC COUNSEL RESPONSE

1. Markets can and should work, and if they work, they should benefit all customers and customer classes. Market options which favor only large users are inconsistent with the intent of regulation and the theory of markets.

We are concerned that the availability of gas transportation service has adversely affected sales customers. We recommend that the Commission examine whether gas transportation service should be continued, or should be eliminated. The converse may also be appropriate to examine: should distribution utilities cease offering gas supply services, and leave that business to others, in much the way that long distance telephone service was separated from local telephone service a decade ago?

Large volume customers impose special risks on utilities. All large volume customers should be required to execute long-term contracts with evergreen (automatic renewal) clauses. An exit fee policy would then be required only for customers for whom specific facilities were constructed, and only to recover the cost of customer-specific facilities.

2. The obligation to serve should be modified so that customers choosing transportation service must give 3 years advance notice before they may request sales service of any type. This would avoid a situation where a large customer, unable to "beat the market" during a period of supply constraints, suddenly resumes utility sales service to the detriment of those sales customers who have been supporting the core market gas resources.

An important issue is whether LDCs should not offer portfolios of gas to transportation customers on their own system; i.e. should an LDC compete with its own sales service? Washington has already experienced the failure of an LDC which offered one portfolio of gas to its captive core-market customers, and a separate portfolio of lower-priced gas to its large volume customers (so-called "pool" gas). The Commission questioned this practice, and directed the Company to address whether this service should be subject to a tariff or eliminated. (Re: Washington Natural Gas Co., Docket No. UG-900210, 2nd. Supp. Order, P. 8). The service was discontinued.

If a form of this service should be re-proposed, it should be carefully analyzed. At a minimum, it must not provide additional incentives for customers to flee from sales services, and material, plain, quantifiable benefits to core customers must exist.

3. One alternative to special contracts and banded rates which should be considered is distance-based rates. Large customers close to the pipeline are more likely bypass candidates, and may bypass if they are faced with average cost rates. If they are offered special (below-average-cost) contracts, however, and other customers who cannot reasonably bypass are charged average-cost rates, then the total revenue collected from the two groups will be less than the actual cost of service. Only by charging customers without realistic bypass options (i.e., those who are more expensive than average to serve because of their physical location) more than average can the LDC offset the below-average rates charged to customers with bypass options.

4. Bypass is a difficult situation, essentially arising from the pre-emption of state (certificate of convenience and necessity) regulation by the federal government. If an LDC is bypassed, and customer-specific facilities are no longer used, or joint facilities are no longer economically justified, the stranded costs should not be reassigned to the remaining customers. To do so would place an appropriate level of responsibility upon the utility to take the strongest possible position to prevent bypass.

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?

PUBLIC COUNSEL RESPONSE

1.-4. Gas markets are growing, and certain large volume customers are undertaking to secure their own gas supplies. If a particular customer owns its own gas reserves, it may reasonably need certain unbundled services from a utility or other supplier.

If there is a market for unbundled services such as storage, balancing, or standby, LDCs should be permitted to provide that service on a value-of-service basis (not a cost-of-service) basis, so long as the value of service exceeds the long-run marginal cost to the utility of providing that service. Whether it should provide unbundled services which compete with its own gas sales service is a separate issue that should be addressed. We take no issue with an LDC offering unbundled services outside the boundaries of its service territory, so long as there is economic benefit to core customers, and service quality is maintained.

"Unbundled" pricing is common in the commercial world. A Ford dealer will sell a customer a "bundled" Taurus for $17,000 ready to drive, or the same vehicle "unbundled" for $170,000, piece-by-piece, across the parts counter. That is how "unbundled" service works in competitive markets, particularly when a vendor of bundled service (a whole Taurus) is also a monopoly vendor of certain unbundled components (a replacement door latch, for example).

Unbundling in the gas industry should be available to all customers if it is to be encouraged for some. Few customers need "all" of the services included in bundled gas service. In warm years, no customers need the peaking resources, such as LNG, and a customer located close to the city gate does not "need" the entire distribution system. Residential customers could be offered a service whereby they can choose the gas supply portion of service to be based on spot prices, for example.

If customers with competitive options are allowed to pick and choose the services they need at cost of service-based prices, the customers without competitive options will be forced to pay for not only the services they need, but also those which they may not need, at full embedded price. This can be addressed by recovering market-based prices from users of unbundled services. The sum of unbundled gas services needed for customers to meet their needs (supply, storage, balancing, standby, and transportation) should generally be greater than the cost of bundled sales service, as an incentive to encourage such customers to remain as system sales customers, and share in the burden of all system costs, including those supplies and facilities which no customers may actually need at any given point in time, such as LNG supplies during a warm winter.

Core aggregation should be permitted only within the area served by a single pipeline gate station, and only among customers with joint ownership. The first restriction ensures that the utility does not have unpredictable swings in demand for individual transportation customers affect the reliability of operations for core market customers without compensation. The second restriction ensures that only customers with sufficient potential savings from gas transportation to justify the investment in personnel to fully understand the nature of the gas market will take these risks. Examples may include school districts, federal facilities, and municipal facilities. Core aggregation by marketers of unrelated entities should not be permitted.

As discussed, transportation customers must waive their rights to sales service as a condition of electing transportation service, subject to the 3-year notice requirement proposed in response to (B) above.

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?

PUBLIC COUNSEL RESPONSE

1. Generally, the Commission least cost planning rule is sound. There is not currently any sort of incentive mechanism for LDCs which meets their customers needs in the lowest cost manner, through a combination of supply and demand-side measures. Incentive mechanisms should be considered to align these goals, but care must be given that perverse or overly generous incentives do not result.

2. We generally reject the notion that there is "commercially sensitive" information which must be protected; in an efficient market, all buyers and sellers have access to the same "perfect" information about the market. The protection of confidential information inhibits the operation of an efficient market. The Commission should encourage utilities to

release all relevant information it has to others, and other participants in the regulatory process (including producers, pipelines, marketers, and consumers) should be prepared to share their information. The Commission and the public can only make efficient decisions when they have access to adequate information about the market.

3. At current and projected levels of investment, gas utility DSM will continue to be de minimis, and should have no significant impact on the utility's ability to compete. For WNG and Cascade, current investment in DSM measures amounts to less than 2% of their respective rate bases, compared with up to 10% for the electric utilities. WWP's "Tariff Rider" completely insulates it from a stranded cost problem related to DSM, though such a "problem" would be extremely minute, regardless of the form of recovery.

Apart from bypass considerations applicable to large customers, the state's territorial assignment statute (RCW 80.28.190) protects gas utilities from gas-on-gas competition, and the recovery of gas DSM costs should not be impaired by any foreseeable market or regulatory conditions.

4. The major change which should be considered to the least cost planning rule is to direct LDCs to consider limited-term interruptible service, voluntary curtailment, and firm curtailment to be resources for planning purposes, and to utilize probabilistic and economic planning criteria (e.g. probability of unserved load, cost of unserved load), rather than deterministic planning criteria (i.e. 100% service to firm load under hypothetical one-day in fifty-years "design day" weather conditions). The Department of Transportation does not build 20 lane freeways for rush hour, the state motor pool does not always have vehicles available, and Safeway sometimes runs out of lettuce.

The standard of reliability which gas LDCs seem to assert as a planning criteria (without any analytical foundation), has no equal in the competitive world. Reliable service is important, but analysis is necessary to determine the economically efficient level of reliability. We do not profess to "know" that the economic level of reliability is different than the rigid standard asserted by the LDCs, but we do believe that the LDCs and the Commission need to study this issue objectively, and soon.

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?

PUBLIC COUNSEL RESPONSE

1. We question whether utilities are the best possible entity to provide and operate DSM programs, due to the obvious internal conflict between the desire to provide the best service at the lowest possible cost (which would include DSM) and the desire to secure sales margins which contribute to profits (which would exclude many cost-effective DSM programs.) The extremely modest DSM programs offered by LDCs may be cogent testimony to this fact.

One alternative is to modify the regulatory system to provide direct financial incentives to utilities to provide cost-effective DSM programs. An alternative we believe should be explored is the "Conservco" approach, where a separate entity is established for the sole mission of achieving cost-effective DSM. In the Conservco model, the utility provides consumption information, local distribution capacity needs, and a funding base for Conservco, but otherwise is not involved in the operation of DSM programs. Conservco could be a statewide entity, and provide efficiency programs for customers using fuels other than natural gas. A summary of a Conservco model is included as "Attachment A" to these comments. This approach would require legislative change. A more detailed presentation of this option was presented recently to the B.C. Utilities Commission in Canada.

2. All customers benefit from DSM efforts, and the costs should be shared with all customers. One reason that gas prices are lower today than they were in 1980 is that gas demand has been constrained, and therefore the supply/demand balance is favorable to gas consumers. As gas demand is held down by utility DSM efforts for the core market, gas demand is held down, and the wholesale market for gas is softened. Since the gas itself is sold into an unregulated market, DSM efforts by regulated utilities help to hold down the price of gas to transportation customers.

3.-4. The appropriate benefit-cost test for DSM programs is and should remain the Total Resource Cost test; this should include quantifiable environmental costs. The appropriate avoided cost measurement is and should remain long run marginal cost. Non-energy benefits should be included in DSM cost-effectiveness. The approach accepted by the Commission in Puget's 1993 program amendments is a reasonable approach to incorporating non-energy benefits.

5. DSM plant can become a threat to future competitiveness if and only if DSM becomes a material financial commitment; to date, it has not been. If DSM investment becomes a material financial issue, the Commission could consider whether more conventional rate base treatment, rapid amortization, or expense treatment is appropriate. None of these

mechanisms is required under current, or reasonable anticipated conditions. If DSM is funded through a "Conservco" mechanism, such as a statewide tax on the consumption of energy, rather than as an addition to the rates of specific utilities, the competitiveness issue can be resolved. In any event, at current levels, DSM expenditures pose no "stranded investment" issues for Washington LDCs.

F. EPACT issues

1. Should the Commission adopt the integrated resource planning standard proposed and defined in EPACT Section 115?
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?

PUBLIC COUNSEL RESPONSE

1.-3. The Commission's existing least cost planning rule effectively addresses much of what is raised in EPACT. The only reasonable concern is that utilities no have an unfair competitive advantage in the installation of energy measures; the Commission should address this by requiring utilities to use unrelated third-party providers to actually install any efficiency measures for which they provide financial assistance (other than research-level projects), and to use competitive mechanisms to select those providers.

G. Additional Questions

The NOI provides an opportunity for commenters to provide additional questions to those posed by the Commission and to highlight other important issues to consider. We welcome this opportunity, and provide some additional important issues that should be addressed in this docket.

PUBLIC COUNSEL RESPONSE

1) Has the experiment with gas transportation service provided benefits for all customers on the utility system?

While we are unsure of the exact answer to this question, we do know that the recent experience has not been positive for core market consumers. Utilities have suffered decreases in their loads, which can easily translate into increases in gas supply costs compared to a non-transportation environment. It may be claimed that "opening up" the market for gas supplies has brought reduced cost of gas to all consumers. Quantitative analysis is required before the Commission should countenance such a claim. While large volume customers may have achieved financial benefits, they have done so only with considerable dedication of management resources to gas acquisition, which is a cost which should be considered. Meanwhile, cost increases to core market customers may have more than offset the benefits which large users have enjoyed.

We believe the Commission should undertake a fundamental re-examination of whether it benefits consumers for utilities to offer two competing services, sales and transportation.

2) If a carbon or energy tax is adopted by the state or federal government, how should it be imposed and collected?

Tariffs should be designed for the utility to recover any tax imposed. Current efforts to balance the federal budget may lead to some form of federal energy tax. A placeholder in rates to accommodate such a tax should be considered in ensuing utility rate proceedings.

3) Should the Commission establish policies on the use of natural gas for electrical generation? Should such uses by or on behalf of regulated utilities be subject to curtailment in order to ensure reliable service to core market gas distribution customers?

The Commission should adopt a policy that use of gas for electrical generation is a secondary use of gas, and that all regulated utilities (electric or gas) and all customers receiving gas via transportation service provided by a regulated utility must release their gas supplies if needed to maintain core market service. This would only be exercised if the firm curtailment provisions of tariffs were at risk of being invoked.

4) What are the key factors affecting core market customers which the Commission should be concerned about as regulation changes over time?

a) Reliability of supply
b) Cost of supply
c) Access for core market to lowest-cost resources
d) Customer service quality
e) "Market Playing" by large volume customers seeking to switch back and forth between sales and transportation service.

5) Should regulated utilities be permitted to offer selected services to non-core customers, such as shaping, balancing, standby, reserves, or portfolio management, and if so, should these services be provided on a regulated (cost of service) or unregulated (value of service) basis?

LDCs should be allowed to offer such services outside the boundaries of their service areas. Service should be priced on a value of service basis provided that the value of service exceeds the long run marginal cost of service. If the value of service is less than the marginal cost of service, they should not offer the service.

Whether such services should be offered by LDCs within their own territory should be carefully considered. At a minimum, this should be allowed if tangible benefits to core customers results, and offering unbundled services does not provide additional incentives for sales customers to leave sales schedules.

6) What contract terms should be required of both core and non-core customers?

Yes. The minimum term for customers up to 100,000 therms/year should be based on the criteria set forth in the individual LDC line extension policy. A minimum 3 year term, with an evergreen clause, should be required for customers larger than 100,000 therms/year.

III. CONCLUSION

The Commission should analyze the issues in this NOI consistent with the recommendations and analysis presented above. We appreciate the opportunity to participate in this docket. We look forward to further opportunities to address the issues presented.

Respectfully submitted,

Christine O. Gregoire
Attorney General

Donald T. Trotter
Assistant Attorney General
Public Counsel Section

September 29, 1995

Attachment A

Re: NOI ISSUE AREA E - DEMAND SIDE MANAGEMENT AND CONSERVATION

CONSERVCO: A DIFFERENT APPROACH TO ACHIEVING CONSERVATION

While some utilities have initiated good and meaningful conservation programs, utilities have not fully embraced a role in energy efficiency. Some utilities have operated "conservation" programs which in fact were directed at load retention, such as "efficient" water heater and heat pump programs. The inevitable conflict between the rate impact of direct costs and lost margins when conservation measures are installed and the desire to maintain competitive rates and sustain growth suggest that it is best to assign conservation

A 2 mills/kwh surcharge on all electricity, and $.40/gj surcharge on all natural gas used in the state will be dedicated to a new non-profit corporation with conservation expertise and responsibility (CONSERVCO). In addition, CONSERVCO may receive funds from generating resource developers to provide environmental mitigation to them.

CONSERVCO has full responsibility for operating DSM programs and securing all DSM which is cost-effective compared with supply resources. Utilities do not have any DSM responsibility, but CONSERVCO may contract with a local utility to provide local DSM program management and oversight if the local utility offers the best proposal for local DSM program operation. Utilities shall provide information and assistance to CONSERVCO on customer usage, load research, and other end-use effects of conservation programs.

CONSERVCO will have a single purpose: to achieve all cost-effective conservation in the state. The corporation shall have the option to fund all or a part of any conservation measure, engage in conservation education, fund conservation research and demonstration programs, and to contract with local entities to implement conservation measures.

Utilities will no longer have any DSM responsibilities. This approach eliminates the difficult problems of utilities being concerned about lost short-run revenues due to DSM program success and experience with utility operation of "DSM" programs which in fact are aimed at load retention (such as heat pump or "efficient" water heater programs).

CONSERVCO may contract with local utilities to actually implement DSM programs where it finds that local utilities offer the best combination of expertise, reputation, and cost. Alternatively, CONSERVCO may contract with other entities to implement DSM programs. CONSERVCO will not directly install DSM products and services except for research, demonstration, and market transformation activities.

CONSERVCO will be directed to provide benefits throughout the state, regardless of the local utility, and across all sectors of energy consumption from street lighting to large industry.

Cascade Natural Gas

CASCADE NATURAL GAS CORPORATION

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September 29, 1995

Mr. Steve McLellan
Secretary
Washington Utilities and Transportation Commission
Post Office Box 47250
Olympia, Washington 98504-7450

Subject: Notice of Inquiry Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry - Docket No. UG-940778

Dear Mr. McLellan:

Cascade Natural Gas Corporation ("Cascade") offers the following initial comments to the NOI. Paragraphs are numbered and organized consistently with the NOI. This letter is filed together with 10 copies and a 3-1/2" diskette.

Procedure

Cascade believes the NOI offers a setting in which mutual gains negotiation techniques can be advantageous to all parties. The NOI is likely to generate many different commentators with different interests. All will likely share a strong interest in an enhanced relationship among the Commission, its Staff, intervenor and the utilities. An added advantage is that many participants in the NOI process are familiar with mutual gains negotiation techniques, and it is likely that many others will have been exposed to these techniques before the NOI is concluded.

Cascade believes that it is important that all interested parties have the opportunity to participate from the outset in the NOI process and have the opportunity to put forth their interests. If consensus is possible the regulatory process which results will be even stronger.

A. <u>Supply-side Issues</u>

1. Although the current PGA system can be improved with some modification, it is important that the basic concept of periodic rate adjustment for gas cost changes be retained. The cost of gas is a variable that changes often. The cost of many of the gas supply items included in the PGAs are influenced by trends in the national marketplace or are set by other regulatory bodies, such as the FERC or the NEB. Therefore, these costs are generally beyond the control of the LDCs. As such, the PGA mechanism reduces administrative burden and transaction costs by minimizing the necessity for rate cases. Cascade's interest is to recognize these annual gas cost changes in rates in a timely manner to minimize regulatory lag with these regularly occurring changes in gas costs which do not impact the return on investment.

2. Cascade's interest is to maintain competitive rates to attract new customers by minimizing gas costs, as well as all other costs, without sacrificing service quality. The risks involved with prudence reviews provide incentives impacting supply side acquisition decisions. These incentives, however, are purely negative. While Cascade does not have a specific suggestion for the creation of positive incentives at this time, it favors the consideration of such mechanisms.

   An LDC's efforts for efficiently managing its resource portfolio on an ongoing basis should not go unrewarded. Off system capacity release and gas supply sales are components of resource portfolio cost management that is mostly within the control of the LDC. To the extent a prudent set of resources is in place, the LDC should have an opportunity to receive monetary recognition for off system sales of capacity and/or gas supply that is in the best interest of ratepayers.

3. Optimizing gas supply and transportation acquisitions can better be accomplished through cooperation rather than litigation and should be addressed both on an ex-post and ex-ante basis. In improving the PGA system, the Commission should establish a procedure where the LDCs and the Commission Staff are working together before major supply-side acquisitions are purchased. As the first change in the PGA system, Cascade recommends that resource acquisition planning can be addressed on an ex-

ante basis by ensuring the generic resource decision making framework outlined in the least cost planning rule have been followed during the decision making process with a reasonable level of detail given the type of resource decision made.

Specifically, each time an incremental resource decision is to be made, Cascade recommends a two-step process. (1.) A resource acquisition strategy which defines the need for additional resources and a plan for acquiring the additional resources such as a request for resource proposal (RFP) parameters could be developed and submitted to the Commission Staff . The LDC and the Staff could review the "prudence" of the assumptions behind determining the resource need as well as the universe of potential resources that might satisfy that need before the LDC issues its RFPs. (2.) Upon receiving responses to RFPs, the LDC would make its resource decision and ask the Commission for deferred accounting treatment approval and to include the incremental resource in the LDC's resource portfolio. At that time, Staff could review the prudence of the LDC's decision process for selecting the resource to fill the need that Staff reviewed in Step 1. The LDC's next PGA would include these prudent costs and "processing" time of PGAs should be greatly reduced.

Cascade's interest is to be able to make resource decisions that optimize gas supply portfolio costs by maintaining flexibility, enabling Cascade to take advantage of gas supply market dynamics. This interest can be achieved if the regulatory prudence review process does not adversely impede Cascade's ability to make timely resource decisions.

These resource decisions can be addressed on an ex-post basis to determine the resources available in the portfolio were the best value for ratepayers. However, this value decision would largely be a confirmation of the resource strategy and accounting order process. Conducting a part of resource prudence reviews prior to actually purchasing resources would allow staff input in time to favorably influence acquisition strategy, expedite the PGA process, keep the Commission better informed on an ongoing basis of the LDC's resource needs and strategies and maintain regulatory consistency by which LDCs can reduce the risks in procuring needed resources. Commission Staff would need to address these resource prudence reviews in a timely manner for this process to achieve desired objectives, otherwise marketplace resource opportunities and decisions would be, at best, jeopardized. However, the process should be cooperative, informative and proactive between Cascade and the Staff to achieve common interests.

4. As market conditions vary between LDCs, changes in the line extension policy should be based on each LDC's needs to respond to market dynamics rather than being constrained by a generic policy that could compromise an LDC's ability to compete for new customers. Cascade's interest is to have the ability to tailor its line extension policy to its

own market needs by determining the best way to acquire new customers without burdening existing customers.

B. Customer choice and competitive bypass issues

1. The WUTC should not adopt an exit fee policy to pay for distribution investments for customers that wish to change from sales to transportation service. Since the customer is still purchasing distribution services from the LDC, there is no stranded investment and therefore, other ratepayers are not harmed. However, the Commission should allow LDCs the flexibility to charge an exit fee to newly transferred non-core customers for any stranded costs that otherwise would be borne by core customers. This would include the newly transferred non-core customer's responsibility for core gas costs that cannot be marketed to the remaining core market or other non-core customers, or in the "off-system" market.

The cost impact of a customer that by-passes the LDC's system can be controlled by the contract that customer had with the LDC when it was on the LDC distribution system. Although Cascade is not aware of the basis of contracts other LDCs have with their customers, Cascade has attempted to recover its investment in distribution facilities over the primary term of the Contracts with its customers. If the customer bypasses after the expiration of the primary term, the customer would leave stranded investment, only because booked depreciation rates are generally based upon the expected life of the facilities, rather than the contract primary term. The rest of the ratepayers are the beneficiaries of the lower booked depreciation rates, through rates that were lower than they would have been had depreciation rates based upon the contract primary term had been the basis for setting rates. A customer that wishes to bypass before the expiration of the primary term would be held to its contractual obligations, so no other exit fee is needed.

2. Cascade does not recommend that the WUTC adopt an entry fee policy for customers who have previously bypassed or are attempting to return to sales service from transportation service. Returning customers should, however, be responsible for any costs their return imposes on the LDC's system. The obligation to serve a customer who desires to return to sales service is a fundamental issue that needs to be reviewed. Cascade's current transport customers understand that when they leave bundled sales service, they give up the right to automatically return to sales service at their option. Cascade's transport customers also understand contractually, that if they choose to return to sales service, they must pay the incremental costs of doing so, thereby holding existing sales service customers harmless. This system has worked well for Cascade without the necessity for formalized entry fees. The obligation to serve returning bypass customers

should be no greater.

3. Special contracts and banded rates help to address bypass of LDC's by providing mechanism for being competitive. They may not be the only mechanisms available to address bypass.

4. If an LDC is bypassed after the primary term of the customer's contract, lost revenues and stranded investments should be shared by all ratepayers. As indicated above, shareholders should not be penalized because the plant depreciation period is longer than the primary contract. Ratepayers, in general, have enjoyed the rate impact of revenues from the non-bypassing customer while only having to pay rates based upon booked depreciation rather than depreciation based upon primary term. Ratepayers should also pay for the lost revenues as represented by the rate impact of an unchanged revenue requirement spread over less billing units.

<u>C. Unbundling</u>

1. The WUTC should not direct LDCs to unbundle services. Rather, the WUTC should allow for LDCs to direct their own bundled or unbundled rate structure and let the competitive marketplace decide the level of satisfaction customers enjoy and the resulting success of LDCs to attract and retain customers.

In 1989, the Company unbundled gas supply, pipeline transmission and storage services out of its non-core tariff. Unbundling these gas supply related functions from the traditional sales rate schedules results in non-core distribution tariffs that reflect only the cost of service on Cascade's distribution system. Those customers that select those unbundled services have had to elect the level and duration of services they wish the Company to procure on their behalf. Cascade does not limit which customers can become non-core based upon size or customer classification. The Company does require, however, that the customer be able to forecast their daily gas requirement, to nominate such requirements to the Company's Gas Load Dispatching Department and to be able to control their consumption in response to a supply allocation order from the Company. Cascade also requires that the gas use is telemetered, so that such use can be monitored or curtailed or limited, if necessary.

The Company designed its tariff to allow for the formal offering of a firm pipeline capacity service to the non-core market and for the commitment of such customers to pay the costs associated with such service. (The provision of such service to core customers remains automatic as a part of the bundled firm sales rate schedules.) The Optional Firm Pipeline Capacity Service Schedule is designed to be a supplement to the optional gas supplies rate schedules. Under the optional supply schedules, customers may choose to be served with various supply portfolios other than the normal system supplies used to serve core customers, including customer owned gas that is merely transported through Cascade's system. The Optional Firm Pipeline Capacity Service Schedule provides a further option regarding whether these supplies are transported through the upstream facilities of Northwest Pipeline on a firm or interruptible basis.

For customers contracting for the optional firm capacity service, Cascade will maintain sufficient firm capacity with Northwest Pipeline to provide for firm transportation of the customer's supplies on the Pipeline's system. The customer can select any desirable level of firm pipeline peak day capacity, as well as any level of annual firm pipeline capacity up to 365 times the selected peak day capacity, subject only to availability of capacity to Cascade. The Pipeline's demand and commodity rates are simply flowed through to customers. Conversely, optional supply customers who do not desire service on this schedule will not be assured of firm pipeline transportation of their supplies, and will be charged the interruptible pipeline transportation rates.

Cascade's unbundled tariffs do not currently allow "customer aggregation" or "core aggregation." There are several gas transportation control issues that concern

Cascade, such as the ability to control the takes of customers in an aggregated group when there is a supply limitation or a sudden increase in daily demand (such as a cold weather event), that is not covered with the matching amount of increased supply. Core aggregation should not be allowed until it is clear it will not create a situation where system integrity is compromised or undue expense is incurred to accommodate it. Cascade is also concerned with its obligation to serve core customers.

2. LDCs should have the flexibility to offer both bundled and unbundled services for all customers so customers have the maximum amount of choices available.

3. The Commission should provide enough flexibility for the LDCs to establish competitive rates for all of the unbundled services it offers.

4. If LDCs offer unbundled services, the obligation to serve is dictated by the types of services customers ultimately purchase. The LDC's obligation to serve should involve providing those services the LDC can control on its own distribution system.

D. Least Cost Planning

1. The least cost planning process already involves many business planning functions such as system expansion and refurbishment, supply and demand side resource acquisition without

definitive rules outlining such resources. Utility regulators must be vigilant to avoid overly inclusive regulation which might blanket all aspects of a utility's business planning. Regulation should be balanced to permit the benefits of proper oversight.

2. The WUTC should consider changes to the least-cost planning rule to allow LDCs to protect commercially sensitive information in the planning process. LDCs should not be required to publish any data regarding the costs and related financial terms of any individual resource. However average costs of resources over the planning horizon can and should be published to provide the public an adequate opportunity to evaluate the overall plan.

3. Assuming all demand-side resource costs are recovered in rates, and demand-side resource acquisition is implemented within an integrated resource planning environment, cost effective demand-side resource acquisition should be replacing more costly supply-side resources. This resource acquisition strategy should be maximizing ratepayer value for energy services provided.

4. Cascade believes the suggestions it advanced in response to question A-3 are within the scope of existing rules; however, if this is not the case, appropriate rule changes should be discussed. The WUTC should consider replacing the term "least cost planning" with

"integrated resource planning" in the rule. The term "least cost planning" implies the LDC should search for the least cost set of resource alternatives at the expense of resource portfolio reliability and flexibility to potential future outcomes. The term "integrated resource plan" implies the LDC should plan for the resource portfolio that best fits the LDC's energy needs at the lowest cost while maintaining a desired level of reliability and flexibility.

E. Demand side management and conservation

Cascade believes the WUTC should recognize and encourage LDC's purchases of demand side resources through a cost recovery mechanism that mirrors as closely as possible the cost recovery and rate of return mechanisms that currently result in demand growth. That is, LDCs should be rewarded for the demand side resource investments made by realizing the allowed rate of return on those investments as is realized for supply side investments. LDCs should also be allowed to recover the lost margins through the energy savings for the life of the DSM measures installed.

The consideration of these two premises will provide LDCs virtually an indifference regarding the preference of generating demand for demand side resources or supply side resources. This incentive indifference will allow LDCs to fully consider demand side and supply side resources on an equal and comparable basis and thus plan for the most efficient set of integrated resources over a long term planning horizon.

The WUTC should set guidelines regarding the consideration non-energy benefits. Non-energy benefits should only be considered if they are reasonably quantifiable and if they have a direct impact on the cost of LDC utility services.

When LDCs are truly indifferent regarding demand side and supply side resource acquisition, inclusion of demand side and supply side resources in resource optimization analysis will determine avoided costs of all resources. That is, avoided costs should not be used as a benchmark to make resource decision. Rather, avoided costs should be the by- product of resource optimization analysis on a specific portfolio of resources under specific economic and operating conditions.

F. EPACT issues

1. The current least cost planning rule appears to already incorporate the integrated resource planning standard as proposed and defined in EPACT Section 115.

2. The WUTC should adopt the standard pertaining to utility investment in conservation and demand-side management proposed in EPACT Section 115. If cost effective demand side resource acquisition is a benefit for society, then LDC shareholders should not be harmed by making those demand side resource investments only to earn less than on supply side resource investments.

3. Cascade does not install any of the demand side measures. Cascade provides a list of dealers and installers to the potential DSM customers. Further, Cascade does not use internal staff to perform energy audits. Cascade utilizes engineering and energy audit firms for this function. Most of these dealers, installers, engineers and energy audit firms are classified as "small business".

Sincerely,

Jon T. Stoltz
Senior Vice President
Planning & Rates

JTS:dlp

Enron Capital & Trade Resources

ENRON CAPITAL & TRADE RESOURCES
WORLDWIDE ENERGY SOLUTIONS

September 27, 1995

VIA UPS OVERNIGHT

Mr. Steve McLellan
Commission Secretary
Washington Utilities and
Transportation Commission
1300 S. Evergreen Park Dr. S.W.
Olympia, WA 98504-7250

RE: NATURAL GAS NOI
DOCKET NO. UG-940778

Dear Mr. McLellan:

These are the comments of Enron Capital & Trade Resources ("Enron") in the referenced docket. All communications concerning these comments should be directed to:

Kathleen E. Magruder
Director, State Regulatory Affairs
Enron Capital & Trade Resources
400 Metro Place North
Dublin, Ohio 43017
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Enron is a subsidiary of Enron Corp. which is a provider of energy products and services worldwide. Enron, in its North American gas business, is a marketer of natural gas. Enron provides gas and a variety of financial and risk management services to a host of customers which includes residential, commercial, industrial, and local distribution company ("LDC") accounts across the country, including the state of Washington. Enron buys and sells more than 7 Bcf daily. Its customers have realized savings of over $50 million in the last five years, both from reduced gas costs as well as from reduced transportation costs as a result of unbundling LDC services. Enron does not own, lease, operate, or control any plant, property, or facility for the manufacture, distribution, sales, or furnishing of natural gas to or for the public. Enron Corp. does, however, own interests in several interstate and intrastate pipelines. As such, Enron is an "affiliated marketer." Enron is vitally interested in this proceeding and its outcome and its interests cannot be served by any other party.

Summary of Position

Enron has been an active participant in proceedings in a number of states where the issue of "life after Order No. 636" has been discussed. Enron firmly believes that competition will bring the highest level of service at the best possible price to all natural gas customers and that the Washington Utilities and Transportation Commission ("Commission") should act quickly to permit that competition to develop. Enron suggests that after considering the comments filed in this docket, the Commission should issue an order establishing guidelines for the unbundling of LDC services, mandating roundtable discussions for each LDC by all interested parties for the development of tariffs responsive to those guidelines, and establishing a date certain by which those tariffs must be filed.

Public utility regulation grew from a need to regulate the monopoly supplier of natural gas. Today, the way gas is sold is different from the scenario which was intended to be regulated. Consequently, regulations should change to fit the emerging market. Regulation of the monopoly distribution function and gas sales by the monopoly distributor can be supported, but regulation of sales by non-utility merchants cannot. Hundreds of marketers of natural gas exist, and it is their existence which gives rise to the need for changed regulation.

Enron believes that in an ideal world, all gas consumers, even residential customers, should be permitted to choose their gas supplier. After the customer chooses a gas supplier, the gas would be delivered by the LDC under a transportation agreement between the LDC and the end user after the gas is delivered to the city gate by the supplier. Under such an arrangement, there would be no bypass. Rather, the LDC would maintain all its customers but would serve them as transportation customers rather than as sales customers. The supplier could be a producer, a marketer, or a marketing affiliate of the LDC. The "obligation to serve" would be a contractual one between the supplier and the customer and would not be a regulatory one.

Discussion

Unbundling of natural gas services can be likened to peeling an onion. With each layer you peel, you may shed a few tears, but the result is so tasty that you persist. Through the efforts of the FERC, the interstate pipeline system has been reformed such that the pipelines are now common carriers of natural gas and a variety of players has stepped up to provide peripheral services. Storage, gathering, capacity on the interstate pipeline, and the gas commodity are all now available from market participants other than the pipeline. The next logical step is for the unbundling process to continue to the state level.

California, Illinois, Ohio, New Jersey, and Maryland all have active programs in which small consumers are able to purchase gas from suppliers other than their LDCs. Iowa has a residential pilot underway and several other states are in the process of examining residential pilots. Competitive options are available to all classes of consumers provided the responsible agency permits access to those consumers at a reasonable cost and under reasonable terms and conditions of service, i. e., at costs and terms comparable to those available to utility sales service. Consequently, the Commission need not view this process as breaking new ground. Instead, Enron suggests the Commission can look to the success of these programs in other states and move forward in the same direction without having to plow the same ground again. Those states have found ways to mitigate stranded costs for both pipeline demand charges and gas supply and a robust competitive market has developed in each of them.

Enron believes, and experience in other states shows, that unbundling does not mean deregulation of the gas business. The Commission should continue to regulate monopoly functions such as the actual distribution of the gas. The LDC will have no competition for the delivery of the gas absent a dramatic change in the market as it exists today. It is worthy of note that gas customers who opt to purchase from suppliers other than the regulated utility are not "leaving the system." They continue to take transportation service from the utility, have gas delivered to them by the utility, and receive a bill for those services. Unbundling does not contemplate bypass. Rather, it is a means to provide customer choice while maintaining the customer base of the utility. Exit fees are not appropriate for customers who make such an election.

The situation surrounding the actual sale of the gas is different. There is no lack of competition for the sale of the commodity. There are literally hundreds of marketers of natural gas. They include producers - both large and small; independent marketers; affiliated marketers - of interstate pipelines, producers, and LDCs; banks and other financial institutions. Price discovery is high with the publication of numerous indexes which report gas price, the NYMEX, and the new futures contract available at the Kansas City Board of Trade. Consequently, the need for regulation of the merchant function does not exist except when the merchant function is being provided by a regulated monopoly or by an affiliate of that monopoly which is not separate from its parent and does not adhere to specific standards of conduct.

New Jersey, Wisconsin, and Minnesota are all in the process of considering commission mandated standards of conduct for marketing affiliates of LDCs. The chance for abuse is all too real when an LDC marketing affiliate markets on its parent's system. That chance can be obviated, however, by the requirement of complete separation of the affiliate from its parent and the imposition of standards of conduct similar to those required by FERC Order No. 497. Enron has appended to these comments (Attachment I) which contains suggested standards of conduct which have been offered by Enron in several states this year. They are built from the standards set forth in Order No. 497, but are tailored to the LDC environment. Enron welcomes competition from all players but knows that for competition to succeed all players must play by the same rules. Attachment I establishes rules which permit the LDC marketing affiliate to compete with all other players on the same footing.

Enron recommends that gas customers be permitted to choose from a group of suppliers which is unregulated, except as set forth above. The Commission should refrain from inserting itself into the regulation and certification of gas marketers. One of the goals of this process should be to minimize regulatory bureaucracy and not to create more. The open market will provide discipline and qualification of gas suppliers, although initially, the Commission may wish to establish certain minimum financial requirements for marketers, as discussed below.

Equal footing in the area of obligation to serve is provided by the function of the free market. Customers who are able to choose their gas suppliers are in a far better position than those who are able to be served only by the utility. They have options. A contract with a gas supplier provides consumers a contractual obligation to serve. If they are unhappy with their gas supplier, they can refuse to renew their contracts upon expiration. Currently, if a consumer is unhappy with its utility, all it can do is complain.

We should remember that a regulatory obligation to serve has not guaranteed service in the past. In fact, the biggest shortfall of gas supplies occurred when the gas industry was the most regulated - from the wellhead to the burnertip. Propane and heating fuel users have obtained their fuel for years without a regulatory obligation to serve on the part of their suppliers. Why should gas customers be in a different position?

The Commission has asked what treatment should be afforded customers who switch to an alternate supplier and then wish to return to utility service. Because they have continued to take distribution service, no new facilities will be needed to serve them.

Gas supply would be the only issue to be addressed in terms of "new" service. With an appropriate notice period, the utility should be able to take them on with minimal expense or difficulty.

Enron recommends that the Commission commence a FERC Order No. 636-type restructuring of gas services which would result in unbundled rates and services by the LDC and an unregulated merchant function for the gas commodity. Appended hereto as Attachment II is a proposal for unbundled service. Briefly, it recommends that there be no minimum volume threshold for transportation; any customer should be able to choose to buy gas from any provider. Gas suppliers should be permitted to aggregate their customers into a pool which will be used for nominating, scheduling, balancing, etc. - just as the LDC currently aggregates its customers. Automatic meter reading devices would not be required of transportation customers if they were not required of comparably sized sales customers. Certain minimum financial requirements should be established for marketers of gas in order to provide some assurance of performance and some financial support for backup supply should the supplier default. Rates for the services rendered by the LDC should be unbundled. Customers should be able to choose the services they want and pay for their transportation service and should bear none of the cost of the gas supply function. In the final analysis, all rates should be cost based.

Ultimately, all customers should be able to choose from the same menu of services, taking full responsibility for their choices. Initially, however, the Commission may wish to make some distinction between core and non-core customers giving due respect to the relative sophistication with gas purchasing had by each class. Rather than mandate that the core must be served by the regulated utility, Enron suggests that special back-up requirements be attached to their service. The Commission could require that core customers be dual fueled, or that they have some sort of back-up service available to them, such as no notice service from an interstate pipeline or a specially provided back-up service available from the utility. Fully bundled sales service should not be the only service available to core customers.

Likewise, the Commission may wish to distinguish between types of core customers. Residential customers may want and deserve a higher level of service than some commercial customers. It is conceivable that some small commercial customers may be willing to be interrupted if they could obtain a lower rate for their service. In other words, we should not assume that the "one size fits all" experience of the past will suit all customers in an unbundled world.

Conclusion

Enron thanks the Commission for the opportunity to offer these comments and looks forward to participating in the continuation of this docket. Enron's experience in New Jersey and Maryland with Commission-mandated roundtable negotiations leading to the filing of unbundled tariffs leads us to believe that such an avenue is the most efficient and expeditious way to reach the full benefits of competition for gas consumers.

Enron recommends that the Commission enter an order establishing guidelines for unbundling which include, at a minimum: the establishment of standards of conduct for marketing affiliates of LDCs; the establishment of minimum financial criteria for marketers of gas; no minimum volume threshold for transportation; no automatic meter reading devices for transportation customers; and the ability to aggregate customers into a pool. A date should be established in the order by which these unbundled tariffs must be filed. Ideally, they would be effective April 1, 1996 in order to provide experience with unbundled service before the winter heating season begins.

ENRON CAPITAL & TRADE RESOURCES
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Finally, Enron would observe that unbundling is an iterative process. We will not achieve perfect unbundling or perfect competition with this proceeding. The Commission may wish to provide for a Phase II in its order in this docket in order to assure all parties of the Commission's intent to oversee the process and ensure an orderly transition to a competitive world.

Sincerely,

Kathleen E. Magruder
Director, State Regulatory Affairs

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Attachments

ATTACHMENT I

Natural Gas NOI
Docket No. UG-940778

Standards of Conduct For LDC Marketing Affiliates and Internal Merchant Operations

- LDCs must apply any tariff provision relating to transportation service in the same manner to the same or similarly situated persons if there is discretion in the application of the provision.

- LDCs must strictly enforce a tariff provision for which there is no discretion in the application of the provision.

- LDCs may not, through a tariff provision or otherwise, give their marketing affiliates or customers of affiliates preference over non-affiliated gas suppliers or customers in matters relating to transportation service including, but not limited to, scheduling, balancing, metering, storage, standby service or curtailment policy.

- LDCs must process all similar requests for transportation in the same manner and within the same period of time.

- LDCs shall not disclose to their affiliates any information which an LDC receives from (i) a non-affiliated customer or supplier, (ii) a potential customer or supplier, (iii) any agent of such customer or potential customer, or (iv) a marketer or other entity seeking to supply gas to a customer or potential customer.

- LDCs shall not provide leads to marketing affiliates and shall refrain from giving any appearance that the LDC speaks on behalf of its affiliate. If a customer requests information about marketers, an LDC should provide a list of all marketers operating on the system, including its affiliate, but should not promote its affiliate.

- To the extent an LDC provides a marketing affiliate information related to the transportation, sales or marketing of natural gas, including but not limited to LDC customer lists, it must provide that information contemporaneously to all potential shippers, affiliated and non-affiliated, on its system.

- To the maximum extent practicable, an LDC's operating employees and the operating employees of its marketing affiliate must function independently of each other.

- LDCs shall not disclose, condition, or tie their agreements to release interstate pipeline capacity to any agreement by a gas supplier, customer or other third party relating to any service in which their marketing affiliate are involved.

- LDCs and their marketing affiliates shall keep separate books of accounts and records..

- If an LDC offers its affiliate or a customer of its affiliate a discount, rebate or fee waiver for transportation services, balancing, meters or meter installation, storage, standby service or any other service offered to shippers, it must contemporaneously offer the same discount, rebate or fee waiver to all similarly situated non-affiliated suppliers or customers and must file with the Commission procedures that will enable the Commission to determine how the LDC is complying with this standard.

- Neither LDC nor marketing affiliate personnel shall communicate with any customer, supplier or third parties that any advantage may accrue to such customer, supplier or third party in the use of the LDC's services as a result of that customer, supplier or other third party dealing with the marketing affiliate.

- LDCs shall establish a complaint procedure. All complaints, whether written or verbal, shall be referred to general counsel of the LDC. The general counsel shall verbally acknowledge such complaint within five (5) working days of receipt. The general counsel shall prepare a written statement of the complaint which shall contain the name of the complainant and a detailed factual report of the complaint, including all relevant dates, companies involved, employees involved, and the specific claim. The general counsel shall communicate the results of the preliminary investigation to the complainant in writing within thirty (30) days after the complaint was received including a description of any course of action which was taken.

ATTACHMENT II

Natural Gas NOI
Docket No. UG-940778

Enhancing Small Consumer Transport

Eligible Transporters:

- All commercial and, ultimately, residential accounts, regardless of their size or their designation as "essential human needs" or non-essential human needs customers, would be eligible to transport.

- No minimum usage requirement would be imposed upon any commercial or residental account. If a minimum usage requirement were to be imposed, the same would continue to be able to be met via the aggregation of "buyer group" loads; however, there would be no restriction/limit on the number of customers that could participate in a buyer group.

Aggregation:

- A small consumer transport program would be effected on an aggregated load basis. Specifically, this means that the individual gas loads of numerous small consumers would be aggregated into a pool on the servicing LDC's system. Gas would be sold to this aggregated pool by a marketer/aggregator.

- Individual purchase and sale arrangements would be entered into between the aggregator and each member of the pool.

- The gas provided by the aggregator to the LDC's city gate would be redelivered by the LDC to the individual members of the pool pursuant to a master transportation agreement between the LDC and the aggregator, as agent for the specific pool members. Once such an agreement is in place, updates would be accomplished via a closed computer network.

- The aggregator would indemnify the LDC from any and all liability that might arise as a result of the aggregator's misrepresentation that a specific end user had, in fact, opted to become a member of the pool.

The Effects Of Aggregation:

- The aggregator would place nominations for gas deliveries on behalf of the entire aggregated pool.

- Gas provided by the aggregator to the city gate for the account of the pool members would be allocated by the LDC to each of those members on a pro rata basis, unless the LDC were otherwise directed by the aggregator.

- The LDC's balancing requirements would apply to the entire pool as opposed to any one member of the pool. In effect, the individual imbalances of the pool members would be netted out to determine one overall pool imbalance position, and the LDC's balancing requirements would be applied against that overall position. Imbalance trading among buyer groups would be permitted.

- The aggregated pool would have a single gas bank and/or storage account on the LDC system. Such gas bank and/or storage account would be administered by the aggregator for the account of the pool members. Inputs to, and withdrawals from, the gas bank and/or storage account would be effected on a pro rata basis to all pool members, unless the LDC were otherwise directed by the aggregator.

The Aggregator:

- Any "creditworthy" seller of the gas commodity would be able to serve as an aggregator.

- A "creditworthy" seller is one that (a) demonstrates a net worth, or a parent's net worth (where the ownership interest of the parent is at least 80%), of $100 million or more, or (b) provides to the LDC a performance bond or letter of credit in an amount equal to the following:

  the cumulative MDQ of all members of the aggregator's pool multiplied by the LDC's total delivered per/Mcf cost of system supply sales gas to a "core" sales customer multiplied by 120.

- Having indemnified the LDC, the aggregator would be given broad agency authority to fully represent the members of its aggregated pool in the LDC's program. That authority would (a) include the right to obtain historic usage data, current usage data, billing information, and the like from the LDC, (b) enable the aggregator to execute agreements with the LDC on behalf of the pool members, and (c) permit the aggregator to terminate any pool member's participation in the program.

Billing:

- The LDC could continue to bill pool members, including billing pool members for the commodity supplied by the aggregator.
- Alternatively, the LDC could have the aggregator do all of the billing and pursue collection from each of the members of the aggregator's pool.
- To effect the alternative plan, the aggregator would receive, via electronic data interchange, all pertinent billing information from the LDC. The aggregator would pay to the LDC all amounts due and owing from the pool members to the LDC. The aggregator would bill each member of the pool for reimbursement of the amounts paid over by the aggregator to the LDC.

Supply Reliability:

- The LDC would not take on the burden of, or the potential liability resulting from, reviewing the aggregator's upstream arrangements regarding gas supplies to be provided to the LDC's city gate for the account of the members of the aggregator's pool. The aggregator creditworthiness standard, discussed above, would apply in lieu of any such review process.
- To facilitate the delivery of the aggregator's gas supply to the city gate, the LDC would release to the aggregator (and the aggregator would accept within the context of a FERC Order 636 "prearranged deal"), as agent for the aggregated pool members, the LDC's firm upstream mainline capacity in an amount sufficient to cover the cumulative MDQ of all members of the aggregator's pool. This released mainline capacity would be subject to recall only in the event that a pool member returns to system supply, and in such event the recalled capacity would be equal to the MDQ of that particular pool member. This release of the LDC's upstream mainline capacity would eliminate the need for any "essential human needs" pool member to possess any alternate fuel capability or buy any mandatory backup or standby supply service from the LDC.

- A similar release mechanism would be available with respect to the LDC's upstream (as well as on-system, if any) storage capacity, with one critical difference -- the release of such storage capacity would be made by the LDC only if requested by the aggregator.

Behind the City Gate:

- The LDC would redeliver to the members of the pool all of the transport gas that the aggregator delivers to the LDC's city gate. Such redelivery would be made on a firm basis, except for interruption due to a force majeure occurrence requiring the diversion of the pool's gas to meet essential human needs requirements.

- The LDC would provide an optional backup supply service that is variable in nature, giving the aggregator the ability to choose the level of backup, if any, it wishes to obtain from the LDC for the aggregator's pool.

- The LDC would offer a reasonably-priced balancing service option to the small consumer transport pools. The LDC would also cooperate with the aggregator to accommodate any balancing arrangement that the aggregator might put in place with an upstream pipeline.

- Aggregators would be required to respond to any reasonable operational flow order ("OFO") issued by the LDC. OFOs would be issued by the LDC in a manner that is consistent with the LDC's handling of its own small consumer sales load. If an aggregator failed to respond to a valid OFO issued by the LDC, the proceeds of any performance bond or letter of credit posted by the defaulting aggregator could be called upon and used to purchase gas, at a premium if necessary, in the open market in an amount sufficient to cover the OFO requirement. In effect, the marketplace would be permitted to respond to, and cure, the default situation.

- As long as base load nominations and corresponding city gate deliveries for the account of the pool are reflective of historical usage, and the aggregator has responded on behalf of the pool to all validly-issued OFOs, (a) the members of the pool and the aggregator would not be subject to any daily balancing penalties, although the pool as a whole would have to remain within the LDC's otherwise applicable banking and/or monthly balancing tolerances, and (b) the members of the pool would not be subject to curtailment, unless the same is necessitated by a force majeure occurrence requiring the diversion of the pool's gas to meet essential human needs requirements.

- Consistent with the foregoing and the LDC's treatment of its own small consumer system supply sales load, no daily metering requirement would be imposed upon any of the individual members of the pool.

- No incremental administrative fees or customer charges would be imposed by the LDC upon its small consumer transport program.

- Ultimately, all rates applicable to the LDC's "behind the city gate" monopoly (that is, non-competitive) services would be cost-based.

Mock Resources, Inc.

Mock

Mock Resources, Inc.
Suite 200N
6312 S. Fiddlers Green Circle
Englewood, CO 80111

September 28, 1995

Mr. Steve McLellan, Secretary
Washington Utilities and Transportation Commission
P. O. Box 47250
Olympia, Washington 98504-7250

Re: Notice of Inquiry (NOI)
Examining Regulation of Local Distribution Companies
In the Face of Change in the Natural Gas Industry
Docket No. UG-940778

Dear Mr. McLellan:

Enclosed for filing are an original, ten copies, and one 3-1/2 inch diskette providing the comments of Mock Resources, Inc. pursuant to the above-captioned NOI. We hereby request to be notified of workshops held in this docket. Please notify:

Ann Hendrickson
Mock Resources, Inc.
6312 S. Fiddlers Green Circle, Suite 200-N
Englewood, Colorado 80111-4925
Telephone (303) 689-0060
Facsimile (303) 689-0039

Yours very truly,

Ann Hendrickson

Ann Hendrickson
Senior Marketing Representative

Enclosures

Comments of Mock Resources, Inc.
to Washington Utilities and Transportation Commission
September 28, 1995

Notice of Inquiry (NOI)
Examining Regulation of Local Distribution Companies
In the Face of Change in the Natural Gas Industry
Docket No. UG-940778

Background

Mock Resources, Inc. is an independent marketer of natural gas, and has been serving gas utility, electric utility, and industrial customers in the State of Washington since 1989. Mock Resources, Inc. is privately-owned by Wickland Oil Company.

Overview

Pipeline restructuring under F.E.R.C. Order 636 has produced an efficient marketplace at the citygate. Shippers are aggressively releasing their upstream capacity at rates discounted to the full published tariff. Mock Resources acquires such surplus capacity for resale to industrial customers at the citygate. Mock Resources recognizes that while the regulated gas utilities, as full tariff shippers, are experiencing competition upstream of the citygate, the same utilities do not face competition downstream of the citygate due to their natural monopoly protection. Therefore, Mock Resources believes it is fair to allow the LDCs to compete at the citygate (in fact, the consumer benefits from added competition at the citygate), <u>but</u> such competition should only be conducted by nonregulated companies acting in a free environment. Therefore, Mock Resources recommends that the gas utility industry be restructured into two company types: nonregulated companies to compete at the citygate for industrial loads, and, regulated companies to provide the natural monopoly functions downstream of the citygate (that is, local transportation service and core merchant service). In this manner, competition will thrive and perhaps increase at the citygate, while the core markets will continued to be served by the natural monopoly.

B. **<u>Customer choice and competitive bypass issues</u>**

1. **<u>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 the rates?</u>**
2. **<u>Should the obligation to serve extend to customers who have become transportation customers or have chosen to bypass in the past; ie., 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?</u>**

No, an exit fee is inappropriate in the deregulated environment of customer choice. A customer should have the freedom to elect between sales and transportation fee (and vice versa) without any type of economic penalty (exit or entry fee), <u>but</u> only within a certain timeframe with such timeframe uniformly established by public tariff language. Mock Resources recommends that the service period be for one year, with annual evergreen renewals thereafter, unless the customer provides written notice at least 45 days prior to the expiration of the one-year service period to switch (from sales to transportation, or vice versa).

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?**

Special contracts and banded rates should not be authorized in any circumstance (bypass or not). Special contracts in the form of a confidential bundled rate at the burnertip (that is, one rate which includes the services upstream and downstream of the citygate), are effectively subsidized by captive ratepayers, discriminate against customers paying full tariff rates for local distribution (transportation) service, and impede competition from third-parties. LDCs desiring to serve the segment of the market vulnerable to competition from Order 636 releases, should do so only as nonregulated entities. Their monopoly rights should only extend to the core market merchant, and non-core market transportation functions.

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?**

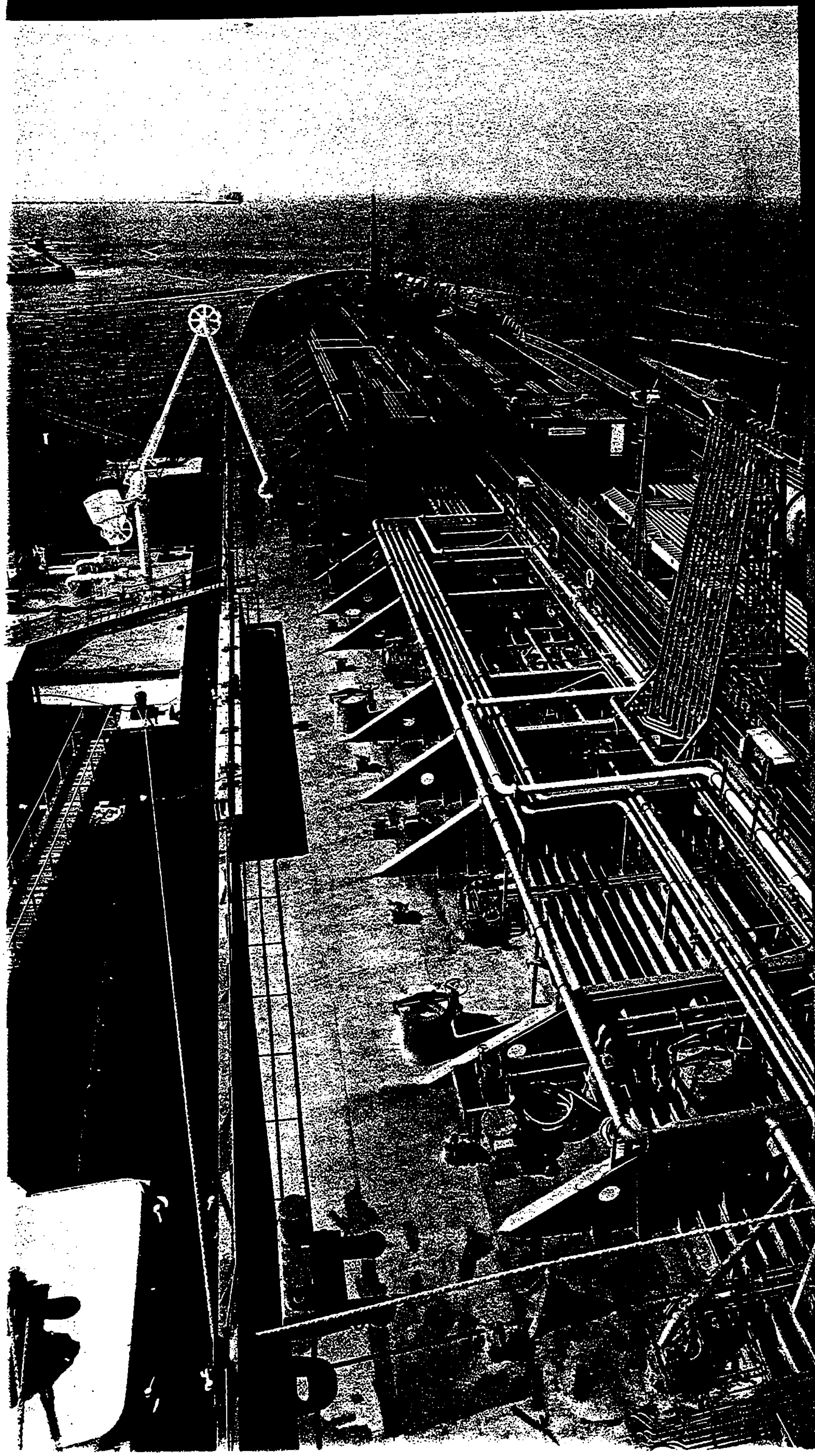
2. **<u>If the Commission should adopt some form of core/non-core unbundling, what specific services should be provided on an unbundled basis, and which services, if any should remain bundled?</u>**

Unbundling is necessary in the deregulated environment of customer choice. While gas service for the industrial customers have been unbundled in the State of Washington, gas service for the residential/commercial customers have not been unbundled presumably due to the theory of natural monopoly. Mock Resources proposes that these customers be given <u>limited</u> unbundled service in the following manner: the residential/commercial customers could buy their own wellhead gas supply and the LDC would continue to render the interstate pipeline and local distribution (transportation) services. Specifically, the residential/commercial customer could elect from a <u>menu</u> of supply funds. These supply funds would be like mutual funds managed by the LDC (fixed price, indexed price, spot market), and the residential/commercial customer could elect such fund within an established timeframe established by public tariff language. The election could be made in person, by mail or electronic online service. After such elections are in (customers not electing a supply fund, default to the WACOG fund), then the LDC formally and publicly buys gas supplies to meet the demand in each fund. In this manner, the residential/commercial customers are given the choice of natural gas supplies, and if the LDC buys supplies to meet the choice of its customers, prudency reviews and PGA filings become unnecessary.

Conclusion

Mock Resources, Inc. is a competitive and reliable supplier of natural gas to customers in the State of Washington. Mock Resources is anxious to participate in restructuring the state's gas industry to foster and increase competition, thereby benefitting consumers to the fullest extent.

WICKLAND CORPORATION



1995

OIL AND GAS DIRECTORY

WICKLAND DIRECTORY

See back cover for office addresses.

CORPORATE

SACRAMENTO

EXECUTIVE	DIRECT TEL:	DIRECT FAX:
J. Al Wickland, Jr. *Chairman of the Board*	(916) 978-2480	(916) 978-2410
John Wickland, *President, Wickland Corporation*	(916) 978-2480	(916) 978-2410
Roy Wickland, *President, Wickland Oil Company*	(916) 978-2450	(916) 978-2410
LEGAL		
Jay Fortun, *General Counsel*	(916) 978-2458	(916) 978-2428
Vincent McLaughlin *Associate Counsel*	(916) 978-2418	(916) 978-2428
GOVERNMENT AFFAIRS		
Dan Hall, *Vice President, Govt./Regulatory Affairs*	(916) 978-2464	(916) 978-2498
John Margowski *Manager, Environmental Affairs*	(916) 978-2485	(916) 978-2498
FINANCE & ADMINISTRATION		
Jack Reho *Chief Financial Officer*	(916) 978-2446	(916) 978-2498
Tony Adrian, *Vice President and Controller*	(916) 978-2443	(916) 978-2498
Tom McCreery *Senior Assistant Treasurer*	(916) 978-2429	(916) 978-2498
Leanne Collett *Assistant Treasurer*	(916) 978-2403	(916) 978-2498
Steven Spanbauer *Supervisor, Cash Management*	(916) 978-2448	(916) 978-2498
Gordon Jones *Manager, Corporate Accounting*	(916) 978-2473	(916) 978-2498
Donna Becker, *Manager, Fuel/Terminal Accounting*	(916) 978-2437	(916) 978-2498
Patrick Martin *Director, Management Information Systems*	(916) 978-2455	(916) 978-2408
Jim Burns, *Director, Personnel & Administration*	(916) 978-2436	(916) 978-2408

IRVINE - MOCK RESOURCES HEADQUARTERS

Brian Mock *President, Mock Resources, Inc.*	(714) 863-0600	(714) 474-6699
Dawn West, *Controller*	(714) 863-0600	(714) 553-9427
John Donovan *Assistant Treasurer*	(714) 863-0600	(714) 553-9427

OIL TRADING

SACRAMENTO	DIRECT TEL:	DIRECT FAX:
Robert L. Sanz, *Vice President, Crude Oil Trading*	(916) 978-2454	(916) 978-2468
Ernie Houtz, *Manager, Crude Supply & Processing*	(916) 978-2447	(916) 978-2468
John Hancock, *Vice President, Products Trading*	(916) 978-2422	(916) 978-2468
Chuck Blaine, *Products Trader*	(916) 978-2484	(916) 978-2468
Michael Callahan *Products Trader*	(916) 978-2469	(916) 978-2468
Mark Oliver, *Manager, Marine Charter/Operations*	(916) 978-2487	(916) 978-2468
Adrienne Montgomery *Operations Coordinator*	(916) 978-2462	(916) 978-2468
IRVINE		
Christopher Kunzi, *Vice President, Heavy Products*	(714) 863-0600	(714) 863-0547

Dennis Bryant, *Manager, Marine Fuels*
Joe King, *Marine Chartering*
Janet Borden, *Operations Supervisor*

SINGAPORE

John Driscoll, *Manager, Fuel Oil, Blendstocks*	(65) 224-2388	(65) 222-7912

William Lo, *Operations Manager/Trader*
Margaret Su, *Operations Coordinator*
Julie Seet, *Operations Administrator*

PRODUCTS MARKETING

IRVINE

Delivered Products: All orders (800) 576-6625

	DIRECT TEL:	DIRECT FAX:
Liz McKinley, *Manager,*	(714) 863-0600	(714) 251-3431

Larry Roberts, *Manager, Supply*
John Frazier, *Contract Manager*
Steve Witkowski, *Transportation Supervisor*

TERMINAL MARKETING & OPERATIONS

SACRAMENTO	DIRECT TEL:	DIRECT FAX:
Richard (Beau) Shore, *Vice President of Terminals*	(916) 978-2404	(916) 978-2410
David Diaz *Manager, Terminal Marketing*	(916) 978-2425	(916) 978-2468
Wally Johnson, *Manager, Environmental, Safety, Health, Training*	(916) 978-2493	(916) 978-2468
MARTINEZ	(510) 228-3227	(510) 228-5617

Jack Blake, *Vice President, International Operations & Projects*

HOUSTON	(713) 359-0042	(713) 359-0051

Jan Olson, *Director, International Terminal Marketing*

TERMINALS

	DIRECT TEL:	DIRECT FAX:
SAN FRANCISCO-MARTINEZ	(510) 228-3227	(510) 228-5617

Larry Hosler, *Terminal Manager*
Dick Brown, *Operations Supervisor*
Mike Allen, *Operations Scheduler*
Bill Johnson, *Maintenance Superintendent*

SAN FRANCISCO-SELBY	(510) 787-1076	(510) 787-1205

Larry Hosler, *Terminal Manager*
John Chicchetti, *Operations Supervisor*
Tom Rogers, *Operations Scheduler*

LOS ANGELES	(310) 834-4495	(310) 834-3627

Rudy De Mara, *Terminal Manager*
Mike Coleman, *Operations Supervisor*

ARUBA	(297-8) 45532	(297-8) 46086

Tony Hoff, *Terminal Manager*
Stanley Miller, *Director, Finance & Administration*
Tomas Figaroa, *Operations Superintendent*
Hubert Ponson, *Quantity & Quality Manager*
Richard Amaya, *Mechanical Supervisor*

NATURAL GAS

IRVINE - MOCK RESOURCES	DIRECT TEL:	DIRECT FAX:
All orders: (800) 576-6625		
RanDe Patterson, *Director,*	(714) 863-0600	(714) 251-3499

Stanley Lyons, *Senior Sales Representative*
Mark Hoppe, *Market Representative*

PLEASANTON	(510) 426-7170	(510) 426-7183

Rand Havens, *Manager, Marketing*
Shelley McClay, *Manager, Operations*
Malcolm Reinhardt, *Senior Sales Representative*
Ann Hendrickson, *Senior Sales Representative*
Don Esse, *Manager, Accounting*

OKLAHOMA CITY	(405) 840-4620	(405) 840-4698

Denette Church, *Manager, Natural Gas Trading*
Steve Harris, *Manager, Transportation & Exchange*
Matt Richards, *Senior Trader - Mid-Continent*
Lee McCravey, *Senior Trader - Rocky Mountains*
Terri Kinnick, *Transportation Representative*
Lorraine Ball, *Transportation Representative*

Table Of Contents

Cover Photo: Vessel at dock, at Wickland's Selby terminal on San Francisco Bay

OUR 41ST YEAR

From left: John A. Wickland, III, President of Wickland Corporation; Roy L. Wickland, President of Wickland Oil Company; J. Al Wickland, Jr., Chairman of the Board of Wickland Corporation

From left: Tom McCreery, Senior Assistant Treasurer; Leanne Collett, Assistant Treasurer; Tony Adrian, Vice President and Controller; Jack Reho, Chief Financial Officer

Wickland's international reputation for excellence in the oil industry began in 1954 when J. Al Wickland, Jr. built and operated his first gasoline station in Orland, California. From that station, Wickland Oil Company evolved, as more stations were added to build a retail gasoline network in Northern California.

John and Roy Wickland joined their father in the company in the early 1970s. By the mid 1970s the three recognized the need to develop a deepwater terminal to import gasoline to support their Regal stations and the wholesale customers they had developed. Wickland bought strategic waterfront acreage at Selby, California on San Francisco Bay and built its first deepwater terminal.

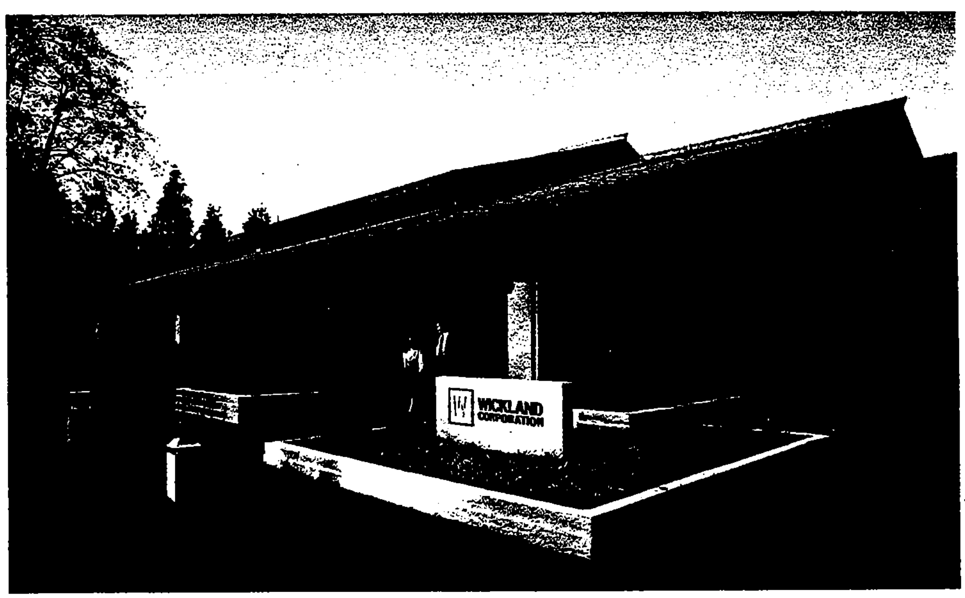
Contracts with U.S. major oil companies and foreign national oil companies provided the gasoline used to supply Wickland's Regal stations and wholesale customers.

In the late 1980s, the Wicklands refocused their business on oil trading and terminalling and sold their 75 Regal stations. They bought two terminals at the Port of Los Angeles, bought the Caribbean crude oil terminal at Aruba, and established an active trading and terminalling presence in the Pacific Rim by opening an operation in Singapore.

In 1993, Wickland acquired Mock Resources, Inc. to add to its oil trading strength and to enter the field of natural gas marketing.

41 years of vision and growth.

Wickland Corporation's Sacramento, California headquarters, the hub of all corporate activity



Caribbean Terminal

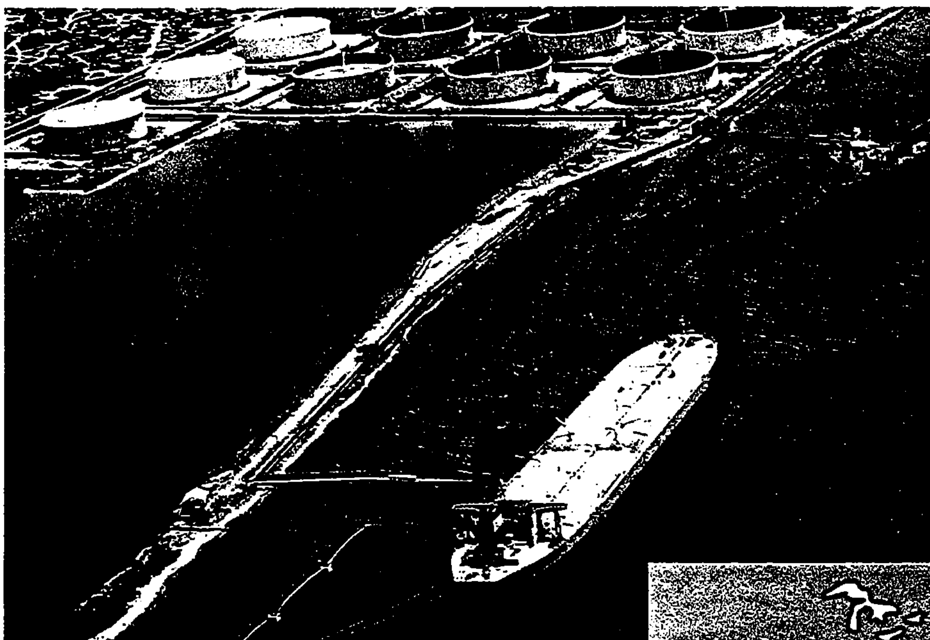
Wickland's large transshipment terminal on the Caribbean Island of Aruba provides storage for crude oil and products from the Middle East, Atlantic Basin and South America for transshipment to the U.S. Gulf and East coasts.

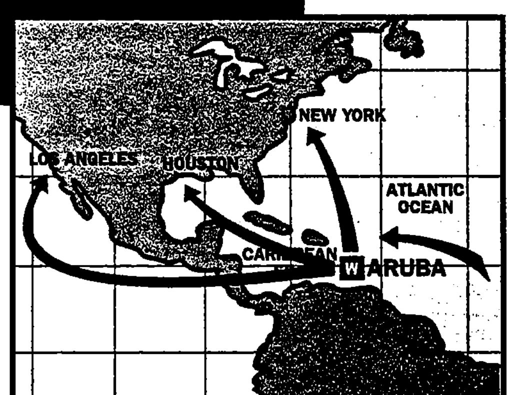
The terminal also offers strategic access to the Panama Canal. Two reef berths accommodate VLCC and ULCC vessels from all international ports.

Aruba, in the southern Caribbean, is an ideal transshipment location because it is out of the path of the annual Atlantic hurricanes.

From left: Jan Olson, Director of International Terminal Marketing, and Robert Sanz, Vice President of Supply and Marketing.

Wickland Oil Aruba terminal





The Aruba terminal's strategic location offers excellent transshipment access to U.S. markets and the Panama Canal.

Aruba Terminal Specifications

Location: San Nicolas, Aruba
Dutch West Indies

Berths: 2 reef berths accept VLCCs and ULCCs
35-500,000 DWT with maximum draft of 100 feet

Draft: Berth 1 - 81 feet, DWT 35,000-400,000
Berth 2 - 100 feet, DWT 35,000-500,000

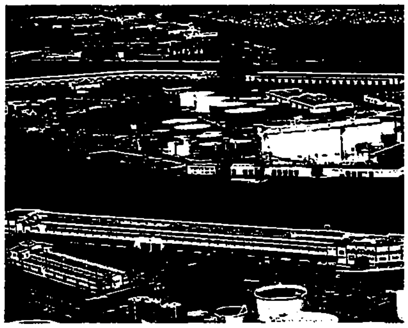
Loading Arms: Four 16-inch diameter arms at each berth connect to shore tanks by a 36-inch and 24-inch diameter pipeline.

Tankage: 5,775,000 barrels. All tanks are 625,000-barrel capacity.

Pumps: Two 2,000-hp pumps, each capable of 27,429 bph
Two 800 hp pumps, each capable of 24,000 bph

Dock-to-dock transfers can be accommodated.

U.S. West Coast Terminals



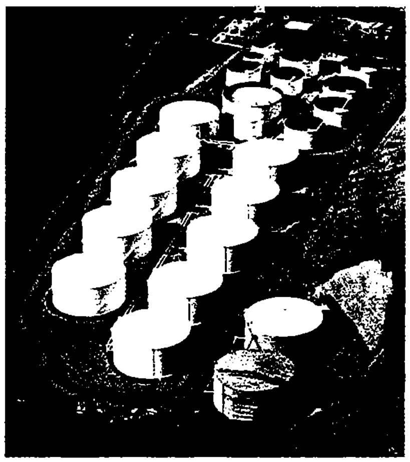
Wickland's two facilities at the Port of Los Angeles accommodate black oil and lube oil products.

Los Angeles

Wickland's terminal facilities at the Port of Los Angeles are ideally located near the Los Angeles/Long Beach refining center for import and export activity. They allow Wickland to trade a full range of products and also offer both long-term and short-term storage and blending services to 3rd parties.

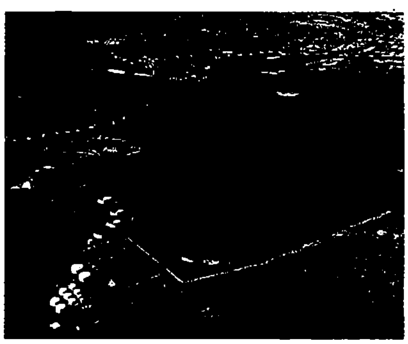
Existing permits allow the handling of crude, gasoline, jet fuel, diesel, heavy fuels and lube stocks.

The terminals offer direct pipeline access to Los Angeles refineries and to major utilities.



San Francisco – Selby

Wickland's Selby terminal near Crockett has more than 3 million barrels of storage for light products. The deepwater terminal offers pipeline connections to various refineries and the Santa Fe Pacific Pipeline. A state-of-the-art truck rack and rail spur tracks provide convenient distribution.



Wickland's two San Francisco Bay terminals have 6 million combined barrels of tankage. The Selby terminal (middle) added 2 million barrels in new tankage during 1992, and the Martinez terminal (bottom) is adding 2 million additional barrels in new tankage during 1995.

San Francisco – Martinez

Wickland acquired the Martinez terminal in 1991 and has upgraded much of the facility. The company has begun a 2-million barrel tank and pipeline expansion project that will be completed this year.

The terminal's current 2.8-million barrels of tankage services crude, gasoline, jet, naphtha, fuel oil and diesel.

Located near a large refining center, the Martinez terminal offers connections to adjacent refining facilities.

From Left: Richard (Beau) Shore, Vice President of Terminals and David Diaz, Manager of Terminal Marketing.

SEL[illegible] TERMINAL SPECIFICATIONS

Location: [illegible]

Berths: [illegible]

Draft: [illegible]

Vessel LOA: 90[illegible]

Tankage: [illegible]

Size: [illegible]

Roofs: [illegible]

Vessel Loading: [illegible]

Vessel Unloading: [illegible]

Services:

Truck: [illegible]

Railcar: [illegible]

Vessel/Barge: [illegible]

Pipeline: [illegible]

MARTINEZ TERMINAL SPECIFICATIONS

Location: [illegible]

Berth: [illegible]

Draft: [illegible]

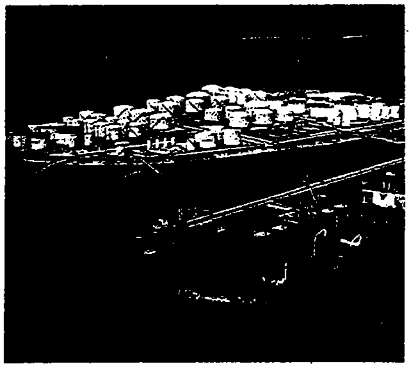
Vessel LOA: [illegible]

Tankage: [illegible]

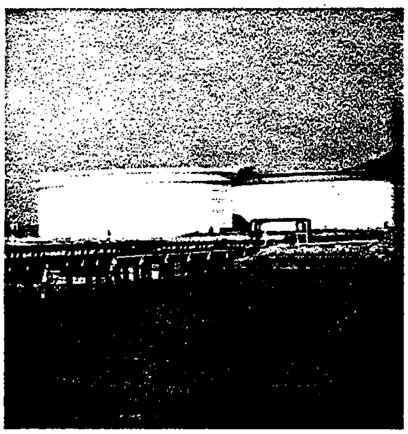
Services: [illegible]

Jack Blake, Vice President, International Operations and Terminal Projects.

Pacific Rim Terminalling



Singapore: Tankstore terminal



China: Zhoushan terminal

Russia: Nakhodka oil port

Singapore

Wickland's Singapore trading office and terminalling operation are the core of the company's busy Pacific Rim petroleum activity. Wickland's experienced and knowledgeable traders are active in the Pacific Basin, storing, blending and marketing products for customers at the ultra-modern Tankstore Pulau Busing complex.

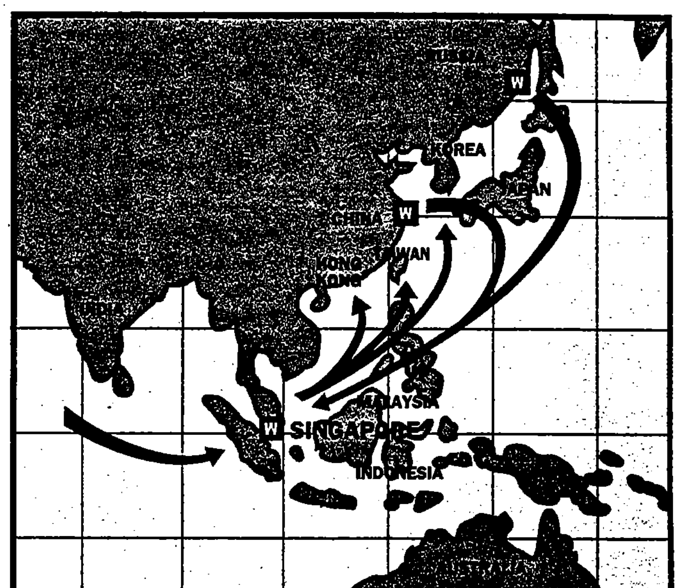
Developing Markets:

China

Wickland, in a joint venture operation with China's Sinochem, will offer storage and cargo trading capability from the modern deepwater port at Zhoushan. One of Sinochem's oldest U.S. customers, Wickland looks forward to serving the growing China market from the well-placed oil port.

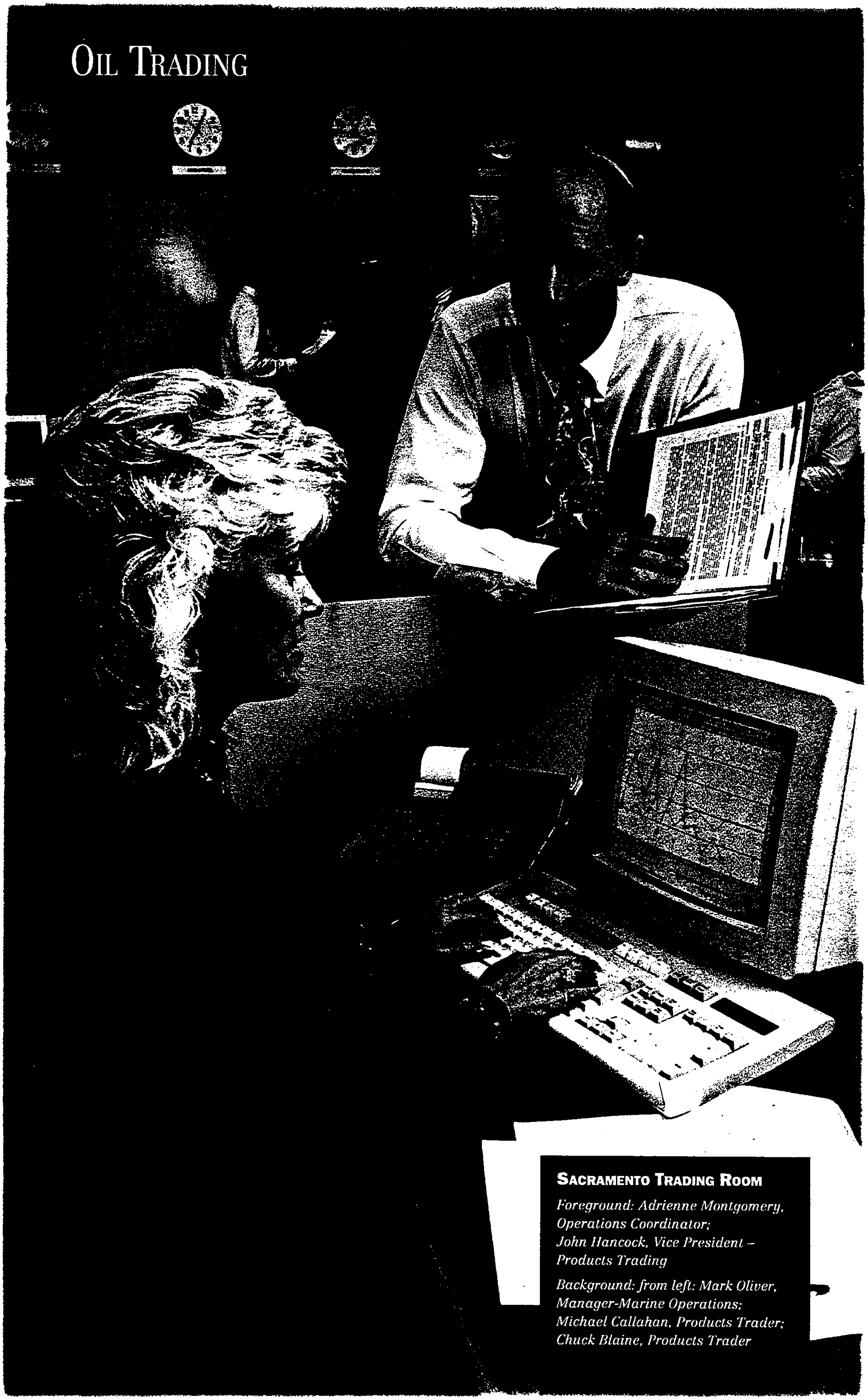
Russia

A joint venture company, Navik Oil Ltd., formed by Wickland with Russian partners, services the light product needs of Pacific Rim customers from the large Nakhodka oil port in Far Eastern Russia.



Wickland is dedicated to providing customers with competitive supply, utilizing its considerable Pacific Basin presence.

Oil Trading



Sacramento Trading Room

Foreground: Adrienne Montgomery, Operations Coordinator; John Hancock, Vice President – Products Trading

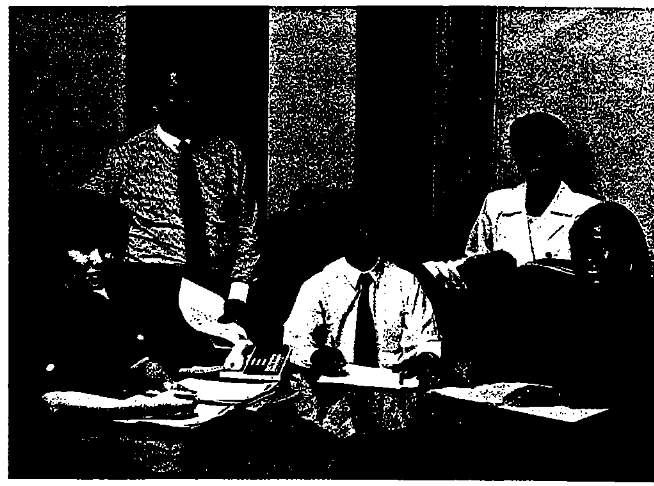
Background: from left: Mark Oliver, Manager-Marine Operations; Michael Callahan, Products Trader; Chuck Blaine, Products Trader

Oil Trading

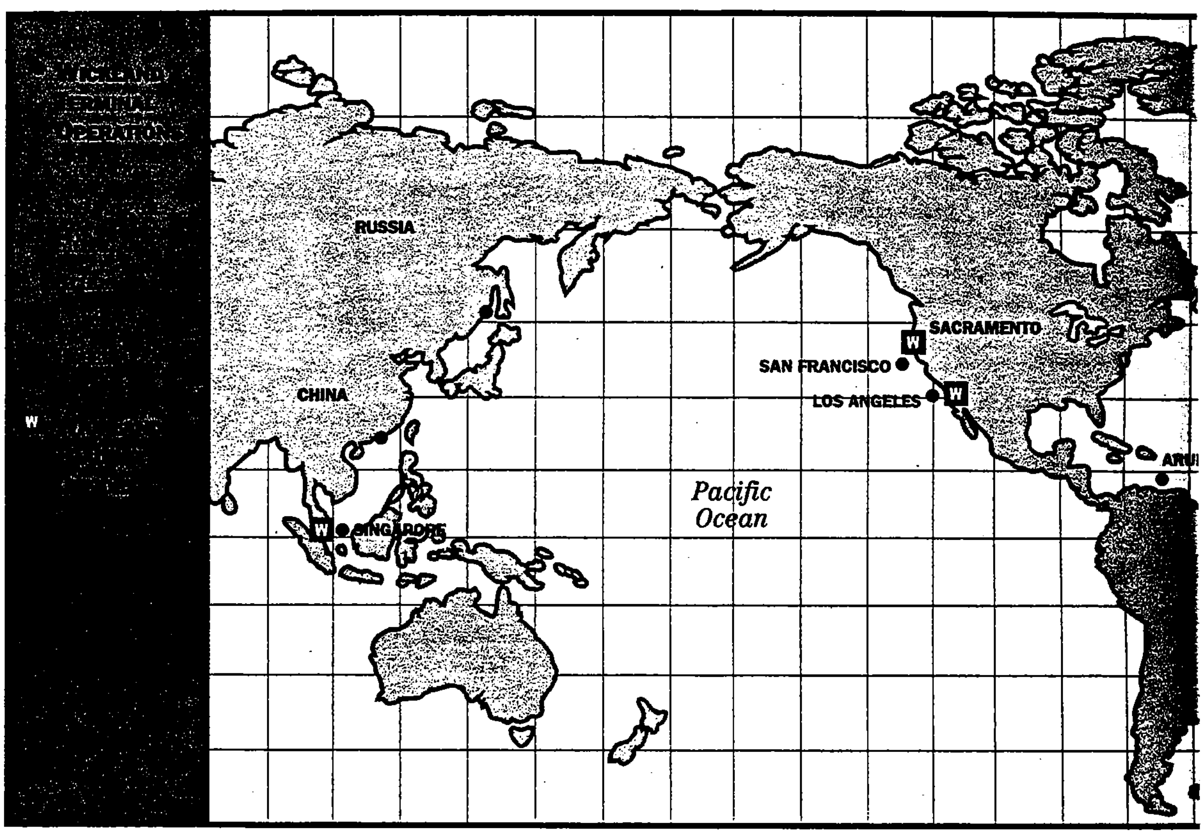
From left: Robert Sanz, Vice President of Crude Oil Trading, and Ernie Houtz, Manager of Crude Supply and Processing.

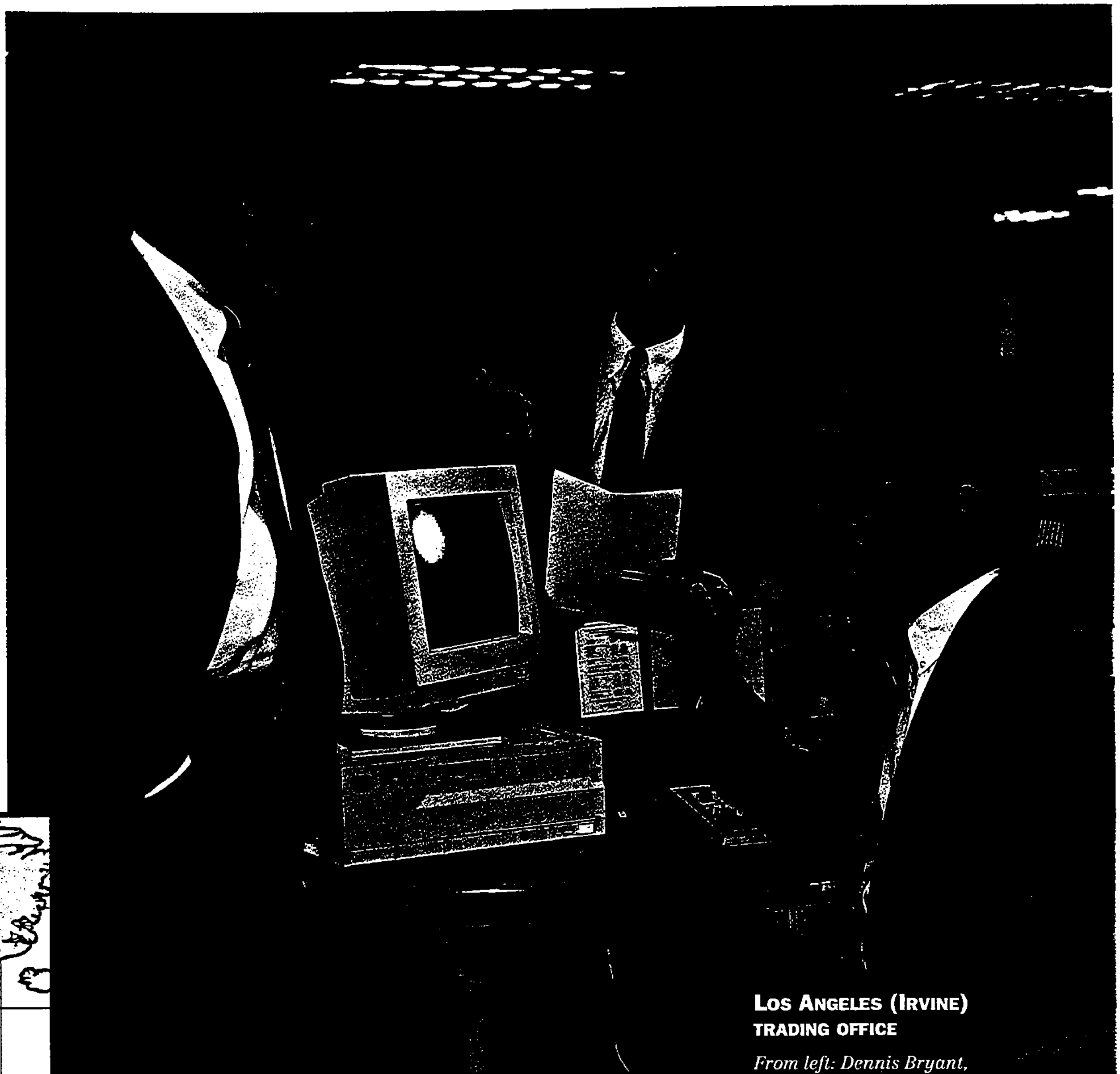
Wickland Oil Company's strong oil trading network provides a steady flow of crude and products to customers all over the world.

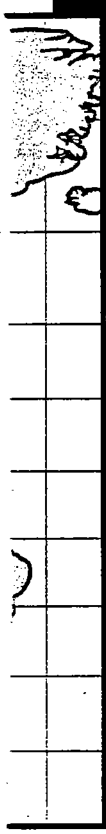
Wickland has a fine international reputation for aggressive, farsighted and fair trading practices and for providing dependable supply sources. Skilled, dedicated traders with many years of industry experience develop a steady flow of marketing opportunities.



Singapore trading office, from left: Julie Seet, Operations Administrator; John Driscoll, Manager, Fuel Oil and Blendstock; William Lo, Operations Manager and Trader; Lilian Lim, Office Administrator; Margaret Su, Operations Coordinator.







Los Angeles (Irvine) Trading Office

From left: Dennis Bryant, Manager of Marine Fuels; Joe King, Marine Chartering; Chris Kunzi, Vice President of Heavy Products.

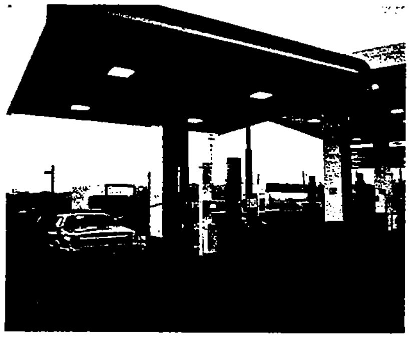
As well as supplying products for its own marketing network, Wickland serves major oil companies, independent refiners, terminal operators, wholesalers and end-users.

Wickland is proud of its long-term trading associations with U.S. and worldwide national oil companies, and its presence in emerging markets such as Russia and China.

The trading activity of Wickland Oil Company is complemented by long-term financial resources and strong international banking relationships.

All these factors combine to underscore Wickland Oil Company's reputation as a reliable and dominant petroleum trader.

Oil Marketing



Mock Resources, Inc., a subsidiary of Wickland Oil Company, has a proven reputation as a customer-oriented supplier of cost-effective, top-quality petroleum products and services.

The marketing group is responsible for buying, marketing and transporting products to a wide range of customers in California and the Western United States.

Drawing upon decades of practical experience and trading acumen, our professionals insure that Mock meets the specific needs of our customers for transportation fuels and industrial fuel oil.

Our customers include:

- Federal, state and municipal government agencies
- Utilities
- Truck fleet and auto rental firms
- Agricultural, industrial and construction firms
- Railroads
- Distributors and retailers

Mock's broadbased supply capabilities and numerous storage and transportation options insure that we know where to find the products our customers need and that they are delivered on time and on specification.

Broadbased supply capabilities combined with numerous storage and transportation options give varied customers access to Mock Resources' excellent combined marketing network.

Irvine Delivered Products, from left: Penny Bibey, Marketing Representative; Kelly Harris, Marketing Representative; Liz McKinley, Manager.

Irvine Delivered Products, from left: Larry Roberts, Supply Manager; John Frazier. Manager of Marketing; Brian Mock, President, Mock Resources.

Top photo, Marketing Representative Penny Bibey confers with a representative of one of Mock's major fuel customers, the Los Angeles Police Department (LAPD). Other major customers include the Los Angeles area Rapid Transit District (lower photo).

Natural Gas

Pleasanton, from left: Brian Bates, Sales Promotion Supervisor, and Rand Havens, Manager of Marketing.

Pleasanton, from left: Shelley McClay, Manager of Operations, and Roberta Crowley, Control Coordinator.

Oklahoma City, from left: Matt Richards, Senior Trader; Steve Harris, Manager of Transportation & Exchange; Denette Church, Manager of Natural Gas Trading; and Lee McCravey, Senior Trader.

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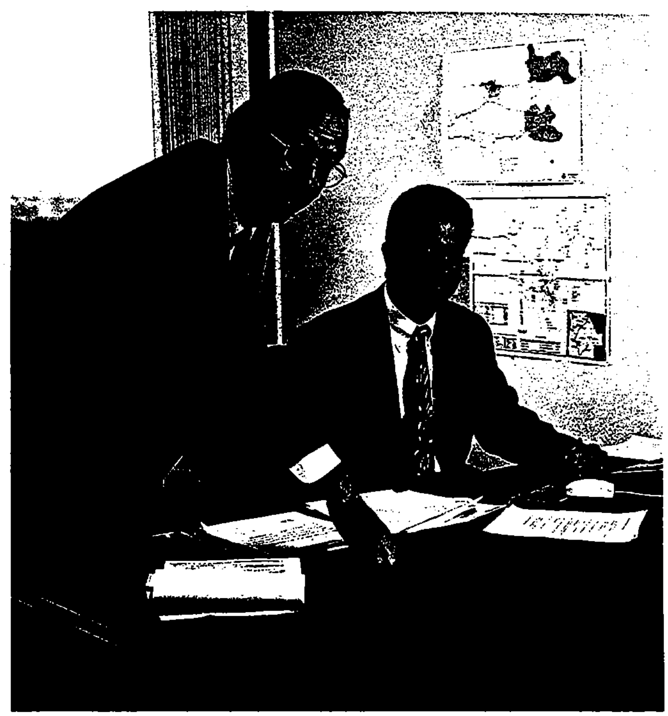
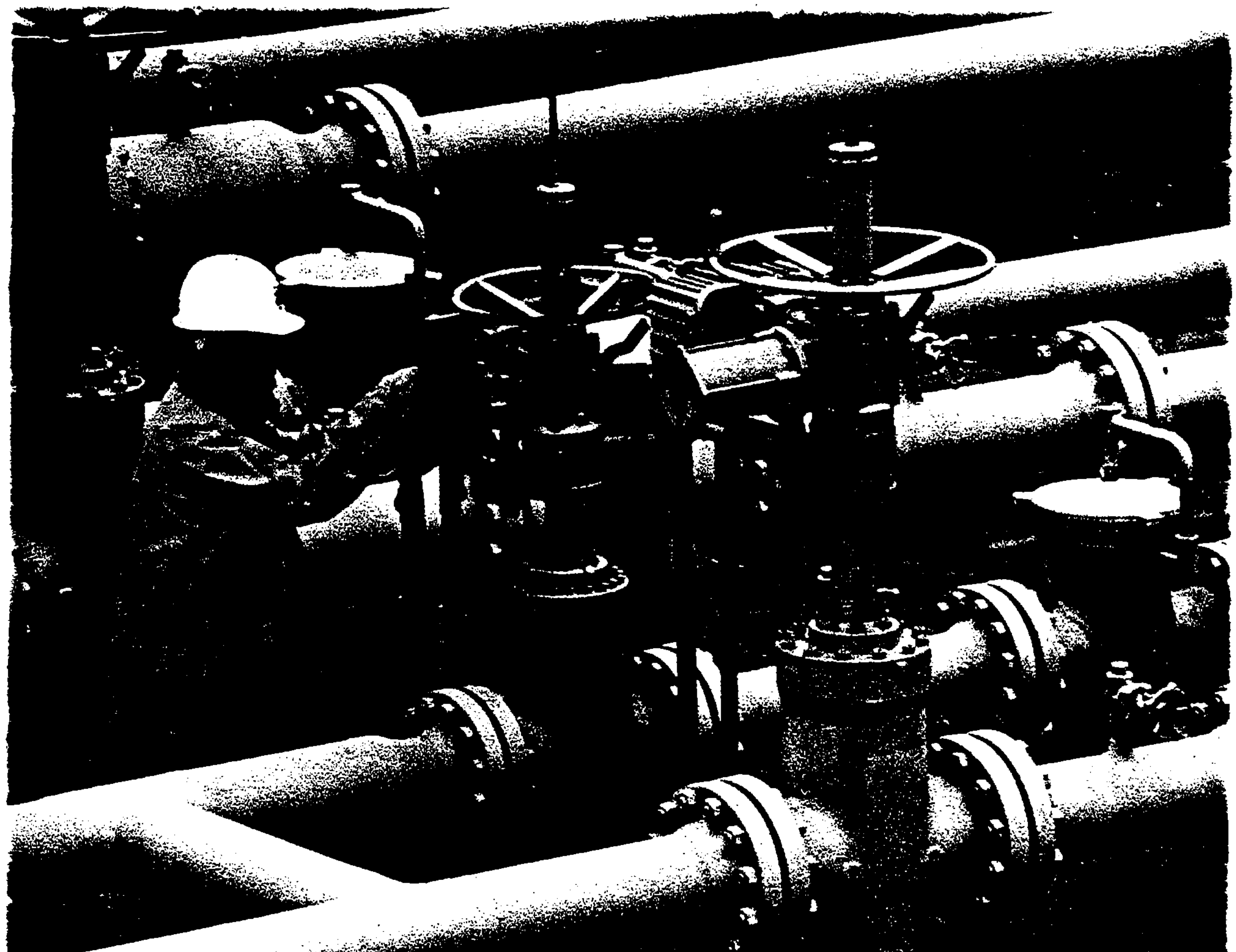


Irvine, from left: Stan Lyons, Senior Sales Representative, and RanDe Patterson, Director of Natural Gas Division.



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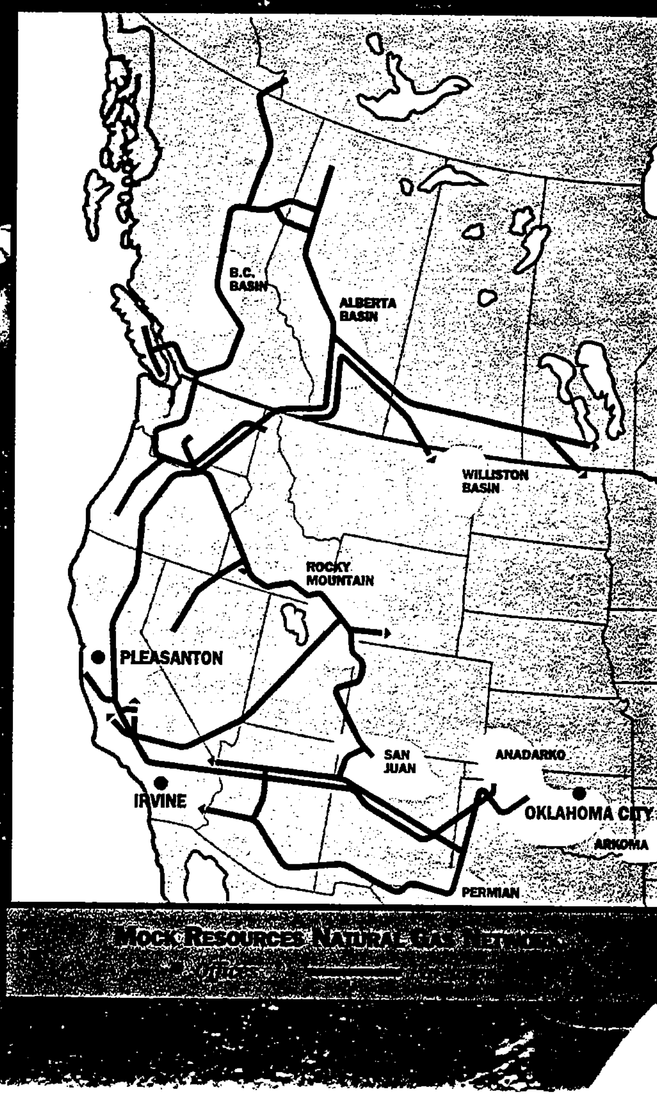

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September 29, 1995

Mr. Steve McLellan
Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive, S.W.
Olympia, WA 98504-7250

RE: Docket No. UG-940778
Regulation of Local Distribution Companies

Dear Secretary McLellan:

Enclosed is a compilation of four gas policy positions prepared by members of the Natural Gas Supply Association (NGSA). NGSA represents companies who produce, process and market approximately 90% of the U.S. gas consumed annually. A 3.5" disk containing the policy papers in WP 5.1 format is also enclosed.

The Natural Gas Supply Association (NGSA) has a strong interest in your Commission's gas policy inquiry, because the lion's share of gas industry capital investment in the mid-1990s continues to be in the exploration and production sector. For this reason, gas producers are very attentive to policy changes in the pipeline and LDC sectors that will enhance competitiveness and increase efficiency from the wellhead to the burner tip.

The four NGSA generic papers on state regulatory policy cover:

- Unbundling of Local Distribution Companies;
- LDC Marketing Affiliates;
- Performance-Based LDC Regulation; and
- Contingency Planning.

In order that we might follow the progress of your inquiry and seek opportunities to make further input, we would appreciate your placing John Paul Johnson of NGSA on your notification list.

We appreciate the opportunity to comment in your important gas policy inquiry.

Sincerely,

L. Harold Milton

L. Harold Milton (Exxon U.S.A. Inc.)
Chair, State Regulatory Affairs Committee

cc: Hon. Sharon L. Nelson
Hon. Richard Hemstad
Hon. William R. Gillis
Mr. Jeffrey Showman
Dr. Patricia A. Hammick,
Vice President, NGSA

STATE GAS POLICY CHANGES IN AN ORDER 636 ENVIRONMENT

COMMENTS IN WASHINGTON UTC DOCKET NO. UG-940778

SEPTEMBER 30, 1995

NATURAL GAS SUPPLY ASSOCIATION
1129 20TH STREET, N.W.
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WASHINGTON, D.C. 20036

POSITION PAPER
ON
UNBUNDLING OF
LOCAL DISTRIBUTION COMPANY
SERVICES

JULY 1995

INTRODUCTION

The Federal Energy Regulatory Commission (FERC), through Order No. 636, set the stage for all natural gas consumers to benefit from competition. Order 636 mandated direct access to gas supplies and provided an entirely new menu of "unbundled" interstate pipeline services. State public utility commissions (PUC's) now have the opportunity of assuring that these benefits are passed on to consumers of natural gas at the retail level. The obvious question becomes, if unbundling of interstate pipeline services benefits the gas industry, would unbundling of local distribution companies (LDCs) also provide an improvement?

POSITION

NGSA fully supports the unbundling of the services of local distribution companies. We believe this step is necessary in order to continue bringing the benefits of competition and economic efficiency to all segments of the natural gas industry and its customers.

BENEFITS OF UNBUNDLING

Below are some of the specific benefits NGSA believes will occur if LDCs are unbundled:

- Unbundling expands consumer choice. Each customer will be allowed to choose from a variety of new services and pay only for specific services that are needed. Customers will be able to select the most economical source of gas supply, and as existing services are unbundled, competitors will strive to develop new services tailored to market needs.

- Competition will assure the best consumer prices. Competition is the best means of assuring adequate supplies of goods and services at the best price to all consumers. When the benefits of competition are extended from the wellhead to the customer, state regulators will be able to rely on the market to ensure that the price of gas and other services will be competitively priced. Of course, certain monopoly services, such as transportation service, will need continued PUC oversight.

- Increased access can lower all consumer costs. Unbundling will make gas available at the burner tip at the best possible price, creating economics that could result in increased gas consumption. If gas use increases, the potential exists to reduce rates to all consumers by spreading fixed costs over increased throughput.

- Increased use of gas will generally provide environmental benefits from an overall emissions perspective. Where specific environmental compliance issues are pertinent, such as mandates for NOX and S02 reduction, decreased costs from access to gas may lower the cost of compliance, where use of gas is part of the compliance strategy.

- "Obligation to serve" concept can be updated. Under unbundling a utility will only have an obligation to provide gas to those who contract and pay for it. The "obligation to serve," for transportation customers, can be redefined under unbundling to be an obligation to redeliver to the end user gas that the customer has purchased and had delivered to the citygate. This redefinition of responsibility could allow the LDC to reduce personnel, planning and administration costs, as well as direct external costs for gas, transportation and storage. Currently, some of these costs are incurred to be prepared to provide a "last resort" sales service that may never be called upon.

- State regulation can streamline its focus. Under unbundling, the regulator can focus on oversight of the monopoly functions of an LDC, leaving the non-monopoly segments of the industry to compete on the basis of price and service quality. This more precise regulatory focus, combined with vigorous competition, should provide the maximum possible benefits to all classes of customers.

- Cross-subsidies will become more apparent. This simplification of regulation under unbundling should increase the ability of PUCs to identify and eliminate cross-subsidies. Actual cost causation and alignment of rates and charges will flow from this new process, whnether the issue is cross-subsidization between services, customer classes, or even between the LDC and its affiliates.

PRACTICAL ISSUES TO BE ADDRESSED IN INDIVIDUAL LDC UNBUNDLING PROCEEDINGS

The PUC and the LDC, with the involvement of other interested parties, should strive to develop rates, tariffs, and operating practices that optimize the number of customers who are able to take advantage of the unbundling of the LDC's system. Experience has shown that there are many issues that will have to be addressed in the process of unbundling each LDC's system. Among the important issues that NGSA has identified are:

- Appropriateness of exit fees and/or transition costs;
- Requirements for installation of additional equipment, such as telemetry on meters;
- Requirements for changing from one service to another;
- Appropriateness of the unbundled rates;
- Appropriateness of alternate fuel requirements;
- Availability and price of ancillary services such as stand-by or backup gas commodity;
- Minimum volume requirements;
- Appropriateness of current curtailment procedures;
- Access to upstream firm transportation capacity;
- Balancing issues such as cashouts and imbalance trading.

CONCLUSION

NGSA believes that LDC services should be unbundled. Recognizing that each state, municipality and utility will have unique circumstances that may require a custom-tailored transition plan, NGSA urges all relevant jurisdictional bodies to hold proceedings as quickly as feasible, to determine what that plan should be. Delays only prevent consumers from realizing the full benefits of competition and choice, and postpone the realization of an efficient gas market.

POSITION PAPER ON LOCAL DISTRIBUTION COMPANY MARKETING AFFILIATES AND STATE PUBLIC UTILITY COMMISSION REGULATORY OVERSIGHT

JULY 1995

OVERVIEW

The Natural Gas Supply Association (NGSA) developed this paper to provide its perspective on the matter of the relationship between local distribution companies (LDC's) and marketing affiliates they might establish after they have unbundled gas sales and transportation services.

As unbundling occurs, state regulatory policy should incorporate standards and safeguards to ensure uniform and fair treatment for all parties that use LDC services. Regulatory policy should guard against LDCs engaging in anticompetitive practices or providing preferences to affiliated companies. Because consumers cannot realize the benefits of gas market competition if any participants are given undue preferences, the regulatory environment needs to ensure that a market exists which is free of such faults.

The following standards are recommended as a minimum framework of regulatory policy applicable to the relationship and conduct of the LDC in dealing with a gas marketing affiliate and nonaffiliated users of LDC services:

- Equal treatment for all users of LDC unbundled services.
- No subsidization of LDC marketing affiliates.
- Confidential handling by the LDC of information gained from nonaffiliated gas marketers.
- Contemporaneous release of any information disclosed to all users of LDC services.
- Independent functioning of the LDC and its marketing affiliates.

BACKGROUND

A similar scenario to unbundling of LDC services existed when interstate pipelines became transporters of gas and largely exited the sales service business during the late 1980s and early 90s. The current discussion of LDC unbundling is the logical extension of the same desire to create market choices for consumers that drove pipeline restructuring actions.

During the transition to the present industry role for interstate pipelines, unregulated pipeline marketing affiliates were formed and began to compete for gas sales. Without rules in place to guide the conduct of pipelines, many believed that anticompetitive practices, which advantaged the pipeline affiliates at the expense of marketing competitors, were creating distortions in the market place.

Perceived and actual abuse motivated the Federal Energy Regulatory Commission to govern the conduct of the pipelines in their dealings with affiliated marketers. The goal was a reasonable set of rules which obligated the regulated pipeline to provide the same services, information, and pricing terms to all customers, regardless of corporate affiliation. NGSA recognizes that the rules have served a valid purpose.

NGSA believes there is a similar potential for conflict of interest between the local distribution company's role as a monopoly provider of services to all parties competing for natural gas sales, and its ownership of one of those competitors.

DISCUSSION

NGSA suggests appropriate rules governing the LDC and affiliate relationship are necessary to ensure a vital and functioning competitive market for merchant sales. Such oversight should include, as a minimum, the five standards previously cited and amplified below:

1. Equal treatment. LDCs must apply and strictly enforce tariff provisions for transportation or distribution services without regard to whether the customer is a utility affiliate, its competitor, or an end-user. Affiliates must not receive preferences on any matter including, but not limited to, scheduling, balancing, transportation, distribution, storage, speed of service, or curtailment of similar services.

2. No subsidies. Tariffed services provided to the affiliate should be charged at the tariff rate or at a discount not less than that available to all users. The cost of other services provided the affiliate should represent the total actual cost of the LDC. The cost must be free of any subsidies and include the actual or imputed cost of staff, facilities, equipment, third party services, corporate overhead, and any other allocated or assigned costs to the LDC for providing the service.

3. Confidentiality. LDCs must not disclose confidential information to marketing affiliates received from non-affiliated users of the LDC's services.

4. Contemporaneous disclosure. LDCs must contemporaneopusly disclose any information provided to their affiliates to all potential users of the LDC's services. Examples include gas transportation or distribution, sales or other service or market information. Such information should be provided through an electronic bulletin board format (where possible) to ensure all market participants obtain the data simulltaneously.

5. Independent functioning. Operating and marketing employees of regulated LDC must be separate from, and function wholly independent of, utility affiliate employees. There should be no common or shared employees that preferentially enhance the ability of the marketing affiliate in competing against third parties.

CONCLUSION

Once a public utility commission has decided to pursue the goal of LDC unbundling, a regulatory code of conduct governing the relationship between LDCs and their marketing affiliates must be implemented and enforced. NGSA believes a utility has the ability and motivation to provide a wide variety of preferences to it affiliate. If unchecked, these preferences are simply too great for non-affiliated marketers to overcome. As a result, competition is stifled and the position of the consumer is damaged.

The potential appearance of impropriety is damaging in and of itself. NGSA believes that state commissions should proactively address this issue at the earliest possible point. Equality of marketing opportunity is the vital element for providing consumers the competitive alternative which is the avowed goal of LDC unbundling and restructuring. Decisive action will serve to provide a level playing field and remove any perception that anti-competitive behavior will be allowed.

POSITION PAPER ON FACTORS TO CONSIDER WHEN EVALUATING PERFORMANCE-BASED NATURAL GAS REGULATION AT THE STATE LEVEL

JANUARY 1995

OVERVIEW

The Natural Gas Supply Association (NGSA) developed this paper to provide its perspective on the implementation of non-traditional regulatory programs. These Performance-Based Regulations (PBRs) are typically aimed at providing local distribution companies (LDCs) with new incentive mechanisms intended to foster greater efficiency.

NGSA's interest in this matter derives from the fact that state public utility rate-making methodologies create price signals that impact all aspects of the natural gas industry, including producers' ability to find and develop natural gas supplies.

The following standards should provide the basis for evaluating performance-based programs:

- Service reliability must always be the highest priority consideration because of the LDC's obligation to serve and attendant human needs implications.
- The overall goal of the program must be system-wide efficiency gains that translate into lower costs (in aggregate) for the customers, without degrading quality of service.
- Incentive mechanisms should not distort market signals nor inhibit competition.
- A portion of the savings should flow to the utility as efficiency gains occur.
- System-wide efficiency gains should be measured in terms of total cost, not individual cost components (for example, a focus on gas supply costs that ignores transportation and storage costs).
- Gas supply, transportation systems, weather and gas consumption patterns may require a different approach for each individual state.
- Each LDC's customer load, service area, and plant investment is unique. There is no cookie-cutter model that will be universally applicable to all gas utilities.
- Performance-based programs that provide documented gains to the customer and enhanced return to the utility shareholder should be allowed to continue for the term originally authorized.

BACKGROUND

Because many state regulators have been involved for several years in modifying telecommunication regulations, it is only natural that public utility commissions are questioning whether cost-of-service based utility regulation should be the only approach to natural gas regulation. The transition to competitive gas supply markets has further intensified the debate over the effectiveness of traditional cost-of-service/rate-of-return regulation for utility distribution systems. Some regulatory changes under discussion include incentives aimed at encouraging LDCs to advise and implement new business practices that ultimately reward both the shareholder and the customer through gains in efficiency of utility operations.

In 1992 the Federal Energy Regulatory Commission adopted a Policy Statement On Incentive Regulation (issued October 30, 1992) which set forth guidelines for interstate natural gas pipelines (as well as oil pipelines and electric utilities). The policy statement listed five regulatory standards upon which any incentive proposals should be judged. Incentive programs must: (1) be prospective, (2) be voluntary, (3) be understandable, (4) result in quantified benefits to consumers without causing higher rates than consumers would pay under traditional regulation, and (5) demonstrate how they will maintain or enhance incentives for quality of service. The NGSA subscribes to these standards and believes that PUCs should also endorse and require these standards when moving forward in the area of incentive regulation. NGSA believes that these standards are sound and applicable to performance-based regulation of state utilities.

DISCUSSION

Underlying any proposed incentive regulatory process should be a standard of reliability established for the utility which recognizes its service obligation to customers. PUCs, in conjunction with the regulated utility, must agree upon the level(s) of service reliability targeted for the various classes of customers. There must be a clear understanding between the regulator and the regulated as to the standard of reliability to be met in operation of the utility system.

Utilities plan service for firm customers by estimating gas usage under various scenarios, including peak-day demand, cold-year demand, and winter-season demand. A reserve margin to cover contingencies (estimation error, delivery system, or gas supply failure) is often added. Once the system gas load has been established for the utility, a reliability standard for service can then be agreed upon. The LDC would then use this standard to develop its mix of gas supply and delivery resources required to meet customers needs.

The natural gas market provides a broad range of available resources to the LDC to meet the reliability standard. Suppliers and transporters offer a wide variety of services to meet specific delivery timing and volume needs. Firm and interruptible pipeline capacity is available, and multiple production areas can be accessed. Gas storage options exist both in the supply and market areas. Peak-shaving facilities and the use of alternative fuels can supplement gas supply. Furthermore, mutual assistance agreements can be negotiated with on-system transporters and off-system entities, as well.

Management must choose the best combination of capital, labor, materials and gas supply resources to optimize efficiency in conducting the buusiness of the utility. It should be remembered, however, that each combination of resources has its own cost structure. For example, storage may be substituted for firm transportation or peaking service. Another trade-off would be to accept less reliability in exchange for a lower price. A focus on any single economic input, to the exclusion of other options, cannot produce the optimal mix of resources for the utility's operation. Optimization of the resource mix and resulting efficiency gains should lead to reduced costs. Even if a portion of the savings is retained by the utility as an incentive, consumers will still realize a cost-benefit.

A significant challenge in designing an incentive program is developing the standard used to evaluate the utility's performance. One method that has been suggested is to compare the performance of one LDC against another or a group of LDCs. The inherent problem in this methodology is that it is extremely unlikely that any two LDCs are sufficiently similar to be compared against each other. Variables include the nature of their customer load profiles, the particular gas supply and delivery options available for their choosing, and the specific cost structures of those options. Therefore, the optimal mix of services assembled and cost achieved by one LDC will likely not be a model suitable for any other.

Unfortunately, much of the discussion and many current proposals focus only on the utility's purchased gas costs. The exclusion of other equally important components of the cost-of-service to consumers may lead to inefficient decisions and investments that actually increase the total cost of providing gas service.

CONCLUSION

To date, the emphbasis in the area of incentive regulation has been on gas costs. Isolating gas supply costs as the sole efficiency target, fails to recognize that utilities' costs are integrated and interdependent. Lower gas costs won't necessarily result in lower total costs to customers. NGSA believes that any performance-based regulatory program should be broad-based, applicable to all utility operations, to avoid the inevitable distortion created by the incentive to reduce only targeted costs.

To assess progress toward the goal of greater efficiency, PUCs must examine the total cost of the service and reliability provided. As efficiencies are achieved by the LDC, customers should benefit even if some slice of the gains realized are offered as incentive to the LDC's shareholders. In the final analysis, the goal is to provide reliable service at lower cost to customers, while providing a reward to the LDC and its stockholders for becoming more efficient.

POSITION PAPER ON NATURAL GAS CONTIGENCY PLANNING

AUGUST 1994

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NATURAL GAS SUPPLY ASSOCIATION

POSITION PAPER ON NATURAL GAS CONTINGENCY PLANNING

EXECUTIVE SUMMARY

The Natural Gas Supply Association ("NGSA") is a trade association of gas producers who believe that natural gas can achieve its optimal role in the economy only if the gas industry effectively and reliably meets high priority needs during unexpected disruptions to gas supply or interruptions of transportation capacity.

Gas plays a critical role in meeting the energy needs of consumers across the country. Experience has shown that the allocation of this resource to those who need and value it the most can best be accomplished through the unfettered operation of competitive market forces, as reflected in freely negotiated contracts tailored to meet customer needs. The interstate gas shortages of the 1970s proved the fallacy of relying on government-mandated allocation plans to meet emergency needs. Government mandates for gas diversion discouraged investment in production, rewarded poor planning, and created a less reliable domestic natural gas system.

Well-executed contingency planning, together with reliable supply and transportation contracts, including appropriate mutual assistance agreements, should prevent the need for government-mandated diversions of gas. The process of contingency contracting will stimulate the growth of a reliable infrastructure.

In today's Order 636 environment, capacity interruptions should be dealt with by a pro rata allocation of available space. Supply disruptions should be resolved by private contracts.

State public utility commissions ("PUCs") should encourage contingency planning by providing guidelines to local distribution companies ("LDCs") that encourage private contracts, including mutual assistance agreements with other LDCs and/or end users. PUCs can ensure that plans are in place prior to an emergency, and that these plans rely on contractual agreements.

BACKGROUND

Capacity Interruption and Supply Disruption

Contingency planning is designed to address the occurrence of unanticipated shortfalls in gas deliveries. These shortfalls must be viewed in two separate contexts: "capacity interruptions" and "supply disruptions". In the former, there is no shortage of gas supplies, but rather the shortfall is due to an outage of pipeline facilities such that all firm transporters can not use 100 percent of their contracted capacity for some period of time. Capacity interruptions typically occur as a result of any number of unplanned operational events on the pipeline. In contrast, a supply disruption occurs when some customers are unable to secure their contracted gas supplies due to an event temporarily restricting gas supplies at or near the points of production, such as a hurricane or severe freeze.

Federal Curtailment Regulation

Historically, interstate pipelines have been the predominant suppliers of natural gas in the marketplace. Pipelines acted as gas merchants, buying gas from producers at or near the wellhead and reselling it to LDCs or end-users. The term "curtailment" in the gas industry implied the allocation of pipeline merchant gas ("system supply") by federal mandate in circumstances where that supply was insufficient to meet the demands of the pipeline's resale customers. Because of the supply/demand distortions caused by federal wellhead price controls, shortages of gas in the interstate market in the 1970s became almost systemic, and curtailment became a long-standing federal regulatory issue.

Prior to the Natural Gas Policy Act ("NGPA"), the Federal Power Commission adopted an "end-use" curtailment policy which categorized the "use" of the gas and assigned curtailment priorities for each gas consumption category. In the hierarchy of end-use curtailment, "essential human needs", primarily hospitals and residential users, were assigned top priority. With the passage of the NGPA in 1978, Congress established a mandated end-use curtailment priority for pipeline system supply generally consistent with prior regulatory policy.

In the years that followed passage of the NGPA, the wellhead price incentives contained in the NGPA worked to eliminate gas shortages in the interstate market. Concurrently, producers, marketers, and customers began to market or purchase their gas directly. As a result, pipelines began to lose their dominant role as merchants of gas and increasingly became transporters. As system supply decreased as a percentage of the total gas in the system, the amount of gas subject to curtailment mandates declined, making the application of the end-use priorities contained in the NGPA largely irrelevant.

While the Federal Energy Regulatory Commission ("FERC") has the authority to mandate the allocation of pipeline capacity in the event of capacity interruptions, it does not have the authority to mandate allocation of transportation gas during a supply disruption. As a result of the implementation of Order 636 and the total deregulation of natural gas at the wellhead, the supply and demand for gas are now driven by market forces. In this environment, market-driven commercial arrangements, including mutual assistance agreements, are best able to deal with the allocation of gas during supply disruptions to provide for human needs. Even though pipelines may have some flexibility to use storage and "line pack" gas to meet emergency needs on a short-term basis, deliveries of transportation gas must ultimately balance receipts into the pipeline system. In such circumstances, market mechanisms have proven themselves superior to regulatory fiat in the allocation of scarce resources.

State Curtailment Regulation

While federal regulation now concerns itself primarily with the allocation of transportation capacity on jurisdictional pipelines, state regulation deals with allocations of gas by public utilities. Even under the curtailment provisions of the NGPA, state regulators are responsible for the allocation of gas delivered by a public utility. Historically, state curtailment policy generally paralleled that which was in place at the federal level.

Today, state PUCs recognize that the gas market has been transformed from one in which the pipelines dominated as merchants to one where pipelines are transporters. And instead of the one pipeline merchant of gas there are now many competing suppliers. As a result of these developments in gas markets, state regulators will have to adjust their policies to correspond to the changes brought about by the restructuring in the industry.

Despite the evolution of the gas market from one determined by regulations to one driven by market forces, the industry is not beyond the influence of short-term events that might disturb the supply/demand balance in a way that would affect human-needs customers. It is in this context that the question of "curtailment" has again arisen. How should the restructured gas industry respond during times of emergency, particularly with regard to human needs?

NGSA POSITION

Capacity Interruptions

In cases of capacity interruptions of firm transportation service, pipelines should implement pro rata allocation.

After discontinuation of interruptible transportation services, pipeline tariffs generally call for a reduction in deliveries to firm shippers served by the pipeline facility subject to an outage. The reduction for each firm shipper is proportional, that is "pro rata", to its "contract demand" or other measure of pipeline capacity reserved. In this paper, this method of allocating pipeline capacity is referred to as "pro rata allocation".

Pro rata allocation enhances the reliability of gas service.

Each customer now has the right and opportunity to contract for firm service with transporting pipelines. This is a key component of reliability in the Order 636 era.[1] Before choosing the amount of capacity to reserve or to acquire through capacity release or other means, an LDC will need to evaluate its "essential human needs" and other "core" requirements in light of its own customer base and alternative gas delivery systems that can be utilized during peak periods. Large industrial firms and electric generators will also need to make a similar study of their essential requirements during peak periods and the appropriate transportation options that are available to satisfy those requirements.

In Order 636, the FERC correctly perceived that firm transportation service derives its value primarily from the assurance of pipeline capacity during periods when capacity is scarce. Indeed, reserved pipeline capacity is a critical element in building a portfolio of services reflective of desired reliability. However, the durability of that element depends on pipeline capacity being reserved by contract for the use of the firm shipper under all operating conditions, including situations when capacity is temporarily reduced due to an outage. Under pro rata allocation, a shipper's contractual reservation is honored to the maximum extent possible -- that is, regardless of the cause of the interruption, the shipper may use its portion of reserved capacity then available on the affected pipeline segment.

[1]For a detailed analysis of reliability in the Order 636 era, the NGSA recommends "Natural Gas Reliability", a 1993 publication of the Natural Gas Reliability Task Force of the Natural Gas Council.

In contrast to pro rata allocation, end-use allocation attempts to identify, track and police the ultimate end-use of the gas flowing through the affected facility and to allocate deliveries among firm shippers based on a ranking of end uses. However, this method does not promote reliability and opens the door to undue discrimination among customers.

End-use allocation requires a consideration of factors extraneous to each customer's firm transportation contract. It also necessarily requires a valuation -- outside of the market -- of end uses. What each firm shipper may properly regard in the contracting process as a valued essential human needs or other core requirement is recognized only to the extent it falls within the FERC-approved definition of a high priority end use. The capacity reserved by contract is largely irrelevant to this process, except to the extent that each shipper's contract demand may serve as a cap on its delivery entitlement. At precisely the time the economic value of reserved capacity is likely to be highest, those who have been paying for that capacity are denied its use. Instead, access to capacity is made a function of extraneous factors beyond the shipper's control and responsibility, including the changing customer base and portfolio composition of other shippers, and the approved hierarchy of end uses.

End-use allocation ultimately undermines delivery system reliability. It undermines individual responsibility for procuring storage, pipeline capacity, and contingency supplies by creating entitlements to gas deliveries even when insufficient service has been contracted. It also blocks market-based price signals on the value of reliability. This in return undervalues pipeline capacity, alternative fuel capability, and storage, resulting in diminished construction of infrastructure and less reliability of the entire delivery system.

Finally, regulators should recognize that end-use allocation creates strong incentives for shippers to engage in unduly discriminatory behavior. These acts could include the submission of inflated or unverifiable claims of end-use. Policing such behavior would be difficult and represents an inefficient use of regulatory resources.

Pro rata allocation can be administered cost effectively by the pipeline under emergency conditions.

Generally, capacity interruptions are short in duration. Long-term interruptions are infrequent because pipelines are generally diligent in their maintenance and repair operations. A loss of capacity can only be remedied by physical action to repair the affected facility. During such emergency periods, the pipeline's focus should be on repairing the damage and restoring service at the earliest feasible time. Pro rata allocation generates a delivery schedule for affected customers that the pipeline can implement under emergency conditions without undue cost or diversion of its resources away from these critical activities.

A database adequate to perform an end-use allocation in light of the changes that have occurred in the restructured gas industry does not currently exist. Due to the proliferation and dynamic nature of individual end users, types of use, alternative fuel capability, and multiple pipeline connections that has occurred, this database would be complex and extremely difficult to develop and administer. Moreover, capacity release compounds this complexity due to shipper identity changes. The benefits, if any, would not justify this costly and burdensome exercise.

Supply Disruptions

All gas users should consider entering into reliable supply contracts and arrangements for alternative sources of supply to be delivered during emergency situations.

In contrast to capacity interruptions, supply disruptions may not result from outages of pipeline facilities. A customer's delivery shortfall may be caused by physical factors such as hurricanes or freezes affecting gas production and capacity-related interruptions on gathering or other upstream facilities. Alternatively, the shortfall can reflect non-physical causes, such as insolvency or contractual default by an individual supplier. In all these cases, supply disruptions are not amenable to interim resolution by the pipeline (through the use of system supply) due to the decline of the pipeline merchant function.

The complete deregulation of gas supplies and Order 636's unbundling of transportation gives customers the opportunity and responsibility to prudently manage these supply risks through contracts. For example, supply source diversification in a customer's portfolio will reduce the risk of interruption due to physical outages, and careful screening of suppliers will minimize interruptions due to non-physical factors. A supply portfolio should be tailored to fit each customer's essential requirements during emergency situations. This mix of supply contracts will vary depending on the characteristics of the individual customer, but should certainly include, but not be confined to, a consideration of the availability and price of the following portfolio elements:

- Firm and interruptible supply contracts,

- Firm and interruptible transportation agreements,
- Storage services,
- No-notice transportation,
- Reliability of supplier(s),
- Geographical location of supply,
- Diversification of pipeline transportation providers,
- Peakshaving supply (e.g. LNG, propane, etc. as backup supply)

Both federal and state regulators should resist calls for mandated supply diversions. While the details differ, all depend on the confiscation of one customer's gas for the satisfaction of another customer's delivery shortfall. Moreover, diversion schemes actually discourage prudent contingency planning by customers. For the same reasons discussed above with respect to end-use allocation, mandatory diversion schemes will impair the reliability infrastructure of the industry. Further, since at least one party will likely be deprived of the benefit of its bargain when gas is diverted, parties are actively and perversely discouraged from responsible contracting. Regulatory or legislative emergency schemes that seize and redirect gas supplies owned by contracting parties discourage tailored supply portfolios that mitigate risk and address contingency planning.

Proponents of diversion schemes defend them on the grounds that such intrusive regulation is necessary to protect essential human-needs consumers from potential losses of supply. While these consumers should be fully protected, this objective can be accomplished under a market-driven (i.e. contract-driven) approach. Such an approach will encourage proper contingency planning by customers while also respecting the ownership rights to gas conferred by contracts.

Mutual Assistance Agreements

All gas users should consider mutual assistance agreements covering supply and capacity among gas owners within a state or within a geographic region to voluntarily redirect gas to high priority users during emergencies.

A gas delivery system should have a means for prioritizing and meeting high priority customer needs in emergency situations. Historically, the pipeline acted as a high-level allocator in which it would direct its system supply gas to high priority users based on surveys previously filed by customers (generally, LDCs). With the pipeline no longer owning substantial amounts of gas, this allocator role now falls upon the current owners of gas and capacity within the market area.

Mutual assistance agreements can allow the industry to do an even better job of meeting the needs of high priority users than was possible in the past. Mutual assistance agreements are voluntary contracts between market participants (usually geographically contiguous parties) involving the transfer of gas and/or capacity to alleviate delivery shortfalls. The success of mutual assistance agreements is predicated on the parties anticipating problems and devising solutions well in advance of actual emergencies.

A model mutual assistance agreement is not being proposed; the circumstances are too diverse, and the range of good approaches too great, to suggest a "best way". However, several topics that should be addressed in the process include:

A. What conditions will constitute an "emergency" and invoke the agreement?

B. Who are appropriate parties to the agreements?

C. If multiple agreements are entered into, which one is triggered first? second?

D. How will the "assisting party" be compensated?

E. What is the appropriate geographic scope? (within state or multi-state?)

The Appendix presents additional details on the above list of topics.

In addition to the factors discussed above, which relate directly to the mutual assistance agreements themselves, other related issues may need to be addressed. For example, pipeline and LDC tariffs may need to be re-examined to ensure compatibility with emergency arrangements. Particularly important is the flexibility to make quick adjustments in emergency situations, such as intraday nomination changes, utilization of "new" delivery points, and de facto "instantaneous" capacity release.

In some localities it may be appropriate to seek adjustments in laws and/or regulations to facilitate emergency assistance for high priority users. For example, an "environmental waiver" may be required to allow fuel switchers to burn "environmentally restricted" fuels for short periods without penalty.

All parties should be alert to the fact that agreements of the type discussed here can, if improperly formulated, stray into areas that might raise antitrust questions. Contingency plans can be implemented consistent with antitrust laws. Consequently, antitrust counsel should be involved in all phases of the process.

Role of the State Public Utility Commissions

Public Utility Commissions should promulgate procedures that encourage and facilitate gas customer contingency planning.

State public utility commissions are key players in the development and implementation of advance planning as the proper response to emergency shortfalls in the delivery of contracted gas to the city-gate. State regulatory action should facilitate the development of contingency planning by encouraging LDCs and high priority end users to pre-plan for emergencies by negotiating mutual assistance agreements, and by developing a portfolio of supply and capacity contracts.

The successful transition from an environment where emergencies are responded to by government mandates to one which employs contract portfolios and mutual assistance agreements will require active support by PUCs. The topics to be addressed in mutual assistance agreements outlined in the preceding section require regulatory guidance. Guidance will be needed with respect to overlapping state jurisdictions, the definition of an emergency, appropriate parties to be involved in agreements, and compensation to assisting parties. These PUC guidelines should provide latitude for LDCs to develop the details of their contingency plans which respond to the unique needs of their systems.

Uncertainty created by the specter of post facto discussions of prudence, eligibility, and recovery of costs with respect to emergency pre-planning will inhibit the process. Contingency guidelines must send clear signals as to the standards and expectations for contingency planning against which LDCs will be judged. PUCs may wish to initiate a review process to monitor the adequacy of emergency plans and to address disallowance concerns of LDCs.

Contingency planning yields a prudent result and enhances the value of service to all LDC customers. If contingency planning is not adopted, the likely result will be a failure to meet core needs and/or the unwarranted diversion of gas. PUCs should therefore recognize and reward those utilities that have acted in advance to meet the gas supply needs of customers during an emergency.

Information Flow

Modern electronic measurement and communication systems should be implemented in order to gather and transmit gas flow information to customers on a timely basis.

Historically, the industry measured gas volumes with mechanical chart recorders. The time lag between recording gas volumes and when those volumes were reported ranged from a few days to as many as 45 days. Access to gas flow information on a real time basis is a key necessity in the restructured gas industry and requirements pursuant to Order 636 have been driving pipelines to substitute electronic measurement for mechanical measurement.

The NGC's booklet, Natural Gas Reliability, recognizes that the availability of accurate and timely information is essential in the new natural gas market. The NGC publication commented that "electronic market information systems enable buyers to locate and purchase gas, plan and order transportation services or storage, track volumes and confirm deliveries. These systems also enable industry to respond more quickly to equipment malfunctions, maintenance procedures and other temporary supply disruptions by rerouting gas."

Also, the National Petroleum Council's ("NPC's") two year study, The Potential for Natural Gas in the United States, found that "today's operational environment reflects the need for a more global approach to automation emphasizing real-time pipeline monitoring, control, and communications to optimize pipeline operations and make it responsible to customer needs." The NPC study further found that the ultimate result of such action is to provide a system where "...a customer can obtain consistent information about transportation options...."

Such broad industry support, and Order 636's equal access requirements, should accelerate pipelines' implementation of real time

electronic measurement devices. Real time data will provide information necessary to manage ordinary transportation arrangements and contracted alternative supply arrangements, including mutual assistance agreements. However, this information is of value to customers (i.e. shippers, gas suppliers, transportation and storage customers - and their agents, marketers, and end users) only when pipelines transfer it to such customers through electronic bulletin boards and through standardized Electronic Data Interchange. Further, LDCs should also share appropriate real time volume flow information with their customers. This movement to real time information will greatly assist in making industry participants better able to cope with short-term emergencies, and thereby materially improve the reliability of natural gas deliveries.

APPENDIX

Topics to Be Addressed in Mutual Assistance Agreements

A. What conditions will constitute an "emergency" and invoke the agreement?
   I. Supply shortfall?
   II. Capacity shortfall?
   III. Distribution system pressure?
   IV. Temperature below a certain point?

B. Who are appropriate parties to the agreements?
   I. LDC to LDC?
   II. LDC to on-system industrial?

C. If multiple agreements are entered into, which one is triggered first? second?

D. How will the "assisting party" be compensated for:
   I. Capacity "used"?
   II. Commodity "used"?
      a. Purchase cost
      b. Market value
      c. Alternative fuel value
   III. Storage related charges?
   IV. Administrative burden?

E. What is the appropriate geographic scope?
   I. Within state?
   II. Multi-state?

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Response of

NORTHWEST INDUSTRIAL GAS USERS

to the

Washington Utilities and Transportation Commission

NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies

In the Face of Change in the Natural Gas Industry

Docket No. UG-940778

September 29, 1995

OVERVIEW

In numerous state and federal proceedings over the last ten-plus years, Northwest Industrial Gas Users has constructively worked to help resolve issues such as those raised in the Washington Utilities and Transportation Commission's Notice of Inquiry. We have addressed these issues in numerous forums ranging from broad policy inquiries to narrow tariff proceedings before the state commissions of Washington, Oregon and Idaho and at the Federal Energy Regulatory Commission.

In all these forums, one of the most difficult challenges has been to ascertain where and to what extent competition can or should control the marketplace, and where and to what extent regulation is still necessary to protect the interests of natural gas consumers. In this ever-changing environment, the Commission must find the appropriate level of regulation that protects the essential interests of all consumers without obstructing the benefits of market competition for those consumers.

Three elements are essential to achieving this balance and providing a consistent policy foundation for addressing new issues as they arise.

First, **utilities must have the regulatory flexibility and incentive to offer a broad array of service levels from which customers may choose**. This flexibility to choose among service levels provides many of the benefits of a competitive market within a regulated environment.

Second, **the rates for each regulated service must not exceed the true cost-of-service of providing that level of service**. In all forums over the past ten-plus years, Northwest Industrial Gas Users has steadfastly advocated broad, nondiscriminatory access to unbundled gas transportation services at rates not exceeding the cost of the services actually being provided. As will be seen in the following comments, adherence to this cost-of-service principle helps resolve many of the ancillary issues that arise in this changing regulatory environment.

Third, **consumer protection can best be assured with workable terms and conditions of service set out in the LDC tariff and/or service contracts**. These specific terms and conditions applicable to each service level effectively define the rights and obligations of the consumer and the utility. They assure that each service option is both workable and does not adversely affect other consumers' interests. This practical approach obviates the need for an abstract policy concerning theoretical "obligation to serve" questions.

These principles will be reflected in Northwest Industrial Gas Users' responses to each of the Commission's specific questions, below.

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?

With the wide range of supply-side resources and cost-mitigation measures now available to local distribution companies (LDCs), including the potential for significant revenue from capacity release activities, the Commission's oversight requires more than an "automatic" pass-through of gas cost changes. On the other hand, it is not appropriate to micro-manage LDCs, expect them all to have the same resource mix or WACOG, nor second-guess decisions after the fact that may have been prudent at the time they were made.

New concepts for incentive mechanisms, prudence reviews and pre-approval processes may be appropriate if they are carefully crafted to provide the right mix of flexibility and consumer protection. Even a combination approach of all three is possible. (For example, the Commission could use an ex ante process to set a benchmark WACOG for the particular LDC, then provide for an ex post sharing of savings or costs between customers and the LDC for an actual WACOG below or above that benchmark level.) Northwest Industrial Gas Users will be interested in reviewing any PGA proposals of the Washington LDCs in response to this Inquiry, and would like the opportunity to respond to such proposals.

If the Commission considers changes to the PGA process, attention should be given to identifying what types of issues the Commission deems appropriate to be addressed in its revised PGA process. In this quickly-changing industry, pressure has sometimes mounted to address limited "rate case" -type issues in PGAs, especially when an LDC has not filed a general rate case for some time which would provide a better forum for such issues. Lacking a ready-made forum to address the issues, the only alternative is to bring a difficult complaint procedure or use the PGAs. If as a result of its review of the PGA process the Commission decides to limit the scope of PGA proceedings, other mechanisms should be considered to provide a forum for resolving issues outside the PGA. For example, the Commission might consider requiring LDCs to file a general rate restatement every three years unless a full rate case was filed within that time frame. A rate restatement requirement would place the burden on the LDC to justify its current margins for all customers, in exchange for continuing to have the ability to track gas costs through the PGA. Such a requirement would also provide a forum for review of issues such as cost allocation and rate design that may arise in the interim period.

Realizing that any significant changes in the PGA process may be some time in coming, following are two more modest observations and suggestions concerning the Commission's current PGA process.

First, public input and participation is very difficult under the current PGA review process. The filings are of necessity voluminous and complex. Increasingly they raise important issues beyond the basic questions of gas acquisition costs. These involve the allocation of costs and revenues from a number of different sources among increasingly diverse customer groups. Since few of these PGAs are suspended, the informal process for reviewing the filings primarily involves discussions between the staff and LDC. While both the staff and LDCs are forthcoming with specific information upon request, it is often difficult to ascertain the full scope of issues being discussed and what changes to the filing may be made in response. When an LDC withdraws and re-files its PGA as a result of the staff's investigation, it is often with an extremely short deadline and waiver of statutory notice (WSN) treatment so that the Commission may act and the new rates can take effect on the particular date upon which the LDC's calculations are based. This sometimes leaves just a couple of days to learn that there has been a replacement filing, to obtain a copy, and review it for changes of concern. It then leaves little recourse but to raise any new issues directly to the Commission and seek a delay to attempt to resolve the issues. To improve this informal review process without burdening or lengthening it, Northwest Industrial Gas Users suggests that the staff and LDC schedule at least one generally-noticed meeting (or conference call meeting) to discuss issues raised in the filing. If only one such meeting is scheduled, it should be far enough along in the process for the staff and interested parties to have identified issues. However, it also should be early enough to allow adequate time for the staff to subsequently prepare its recommendation to the Commission and/or for the LDC to make any changes to the filing. Notice of such meeting could be given to intervenors in the LDC's previous rate case or others who requested to be noticed on an interested party list for such purposes.

Second, aside from changing wellhead gas prices, many of the cost changes passed through to LDCs' customers in PGAs reflect fluctuations in Northwest Pipeline rates. These include permanent rate increases, occasional rate refunds resulting from resolution of rate cases or other proceedings by FERC, and transitional costs such as take-or-pay buydown costs. Behind every pipeline rate adjustment is a FERC proceeding -- most of which are protracted and contentious with numerous parties in addition to the Northwest LDCs and end user interests. Serious efforts have been made to attempt to reach settlement on many Northwest Pipeline rate cases and proceedings, with mixed results. Washington LDCs have taken disparate positions in these pipeline proceedings, which is certainly appropriate given that the outcome of some proceedings may affect each LDC differently based on its load factor, other capacity resource options or storage, potential for mitigation through capacity release, etc. However, LDC concern over recovery of costs at the WUTC should never be an excuse not to settle a pipeline controversy. Of course a negotiated settlement may produce a higher-cost result than advocated in the party's litigation position. However, a settlement also eliminates the very real risk that the litigated outcome of the case may result in even higher costs or have other adverse consequences. Northwest Industrial Gas Users does not believe this

Commission has ever disallowed, nor would disallow, an LDC's recovery of otherwise prudently-incurred pipeline costs simply because the LDC agreed to a multi-party settlement of a case instead of fully litigating it. If so, the inverse must also hold true: An LDC must be at risk for recovering incremental pipeline charges if the LDC refused to accept a settlement and the litigated outcome ultimately produced a higher cost result. If ever an LDC has a scintilla of doubt as to whether a pipeline settlement may be viewed as prudent by this Commission, we would hope and expect that the Commission could be consulted and provide general guidance, outside a PGA or formal proceeding, which would help in making reasoned decisions on such questions.

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

Adherence to embedded cost-of-service pricing will largely prevent situations where an LDC loses more money each time a new customer is connected. Obviously, if the rates set for a class of customers underrecover revenues, adding customers to the class will exacerbate the underrecovery over time. Eventually a rate increase must be made, which can either produce rate shock for the affected class or exacerbate cross-subsidies from other classes of customers. Keeping rates for each class at a level that reflect the class cost-of- service helps avoid these problems and contributes to rate stability. This adherence to cost-of-service pricing need not result in purely incremental pricing for all new extensions. This would not be consistent with the concept of a public utility service. However, reasonable tests and contribution policies to assure adequate revenues over a period of years will avoid imprudent extensions.

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?

Exit fees are discriminatory and they violate the filed rate doctrine and principles of contract law. Exit fees and reentry fees are not only inappropriate, they are unnecessary. Workable, effective mechanisms are readily available to address the potential problems caused by customers switching among service levels. Unquestionably, such switching of service levels -- or the decision to reduce, discontinue or commence service from the LDC for any reason -- affects an LDC's resource acquisition strategies. However, these movements can be accommodated, and any adverse impacts on other customers can be avoided, with adherence to cost-based rates and with fairly simple tariff and/or service contract provisions.

Cost-based rates help assure that other customers are not adversely impacted by the decisions of others. To the extent a customer's rates include cross-subsidies of other customers' costs, the movement of that customer from one service level to another will have magnified consequences for the subsidized customer. If, on the other hand, the customer's rates for a particular level of service reflect just the costs of providing that particular level of service, that customer's choices among service levels will have little if any impact on other customers.

Tariff and/or service contract provisions can assure that a customer's movement among service levels coincides with the LDC's resource acquisition cycles. This eliminates switches that would leave the LDC unprepared or unable to respond with adjustments in acquisition strategies. For example, an LDC may determine that, given its gas purchasing practices, it needs customers to commit to a minimum one-year term of service for either transportation, interruptible sales, or firm sales service, and to give a minimum four-months prior notice for a change in service type prior to the anniversary date. By the election date, the LDC will then know which customers it must accommodate with what level of service and make resource acquisitions accordingly. This length of term of contract and election window may be different for each LDC, depending on their customer mix and resource strategies.

Tariff and contract provisions can also set out the rights, obligations and risks of making service level changes outside the proscribed window for such changes. For example, tariffs may provide that a premature switch from transportation back to sales service will only be accommodated on a "best efforts" basis and that any incremental gas supply or pipeline capacity costs will be borne by the switching customer until the next regular election date. Likewise, minimum bill charges can assure the LDC's recovery of costs if a customer reduces or discontinues service before the current term of service expires.

The same provisions must apply to all customers seeking service from the LDC, whether they are entirely new customers, were former customers who shut down the plant for a period of time, were using a different fuel, or were using a different source of natural gas. If, outside the normal election window, the customer elects a firm sales service that would cause the LDC to alter its resource acquisition portfolio, tariffs may provide for only best-efforts service and/or an incremental price until the regular election date for such service. Of course, such conditions on service should be kept to the minimum necessary to accomplish the goal of protecting all customers' interests. If a one-year term of service provides good protection, it does not mean a two-year term of service would be even better. To the contrary, conditions that are excessive in accomplishing their intended purpose are inappropriate and counter-productive. Customer choice among service options must not be artificially manipulated with unnecessary regulatory hurdles.

Throughout the transition in natural gas regulatory and market structures, a lot of academic discussion has been given to this legal concept of the "obligation to serve". In practice, Northwest Industrial Gas Users has found it to be a non-issue. A number of sensible, workable tariff provisions have been designed for LDC systems in Washington, Oregon and Idaho that clearly spell out the rights and obligations of the customers and LDC under different service schedules and scenarios. Where new situations cause new questions to arise, common-sense provisions can be drafted to cover them as well. This pragmatic approach has proved far more effective in resolving real-life issues than could ever be achieved through a lofty abstract policy on the "obligation to serve".

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?

Although often stereotyped, industrial gas users are actually very diverse: they differ in the amount of natural gas they use, their applications for the gas, their seasonal usage/load factor, their preference for gas relative to other fuels, their ability to use other fuels, their proximity to the pipeline enabling economic bypass, the value they place on reliability versus cost, their desire or ability to manage their own gas purchases, etc. As more opportunities have become available in the natural gas marketplace, industrial gas users have sought out the level of service that best fits their particular needs at each facility. They expect to pay a price for that service that reflects that precise level of service being taken.

At the state level, LDCs can no longer properly serve this market with a one-size-fits-all service. This has created pressure for special contracts to tailor services to a customer's particular needs.

Another way to help satisfy this market -- and avoid some of the special contracts -- is for LDCs to offer a broad array of service levels, all at rates not exceeding the cost of each particular service level. This will enable some customers to take the barest stripped-down, unbundled service if that's what they prefer. Others may choose a higher level of repackaged, value-added, or customized services from the LDC. LDCs must have the creativity and regulatory flexibility to respond to the diverse needs of their customers. The availability of unbundled transportation and related services at rates not exceeding the true cost-of-service for those services will significantly reduce the pressure for bypass and necessity for special contracts.

Finally, the Commission should take note that when a gas user directly connects to an interstate pipeline, it not only bypasses the LDC but also effectively "bypasses" the state utility commission. In considering a direct connection, many customers not only examine the pure economics of the direct connection versus LDC service, but also weigh the uncertainty of future state regulatory policies, the existence or potential of subsidization of other classes with rates higher than cost-of-service, the potential costs of social policy goals implemented through energy rates, the Commission's flexibility in approving creative contractual arrangements with the LDC, etc. Therefore, in looking at ways to help avert bypasses, the Commission must look to the predictability, flexibility, and impact of its own policies and procedures as well.

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?

First of all, losing a customer to bypass should be treated no differently than losing load due to some other cause, such as plant shut down, the use of other fuels, etc.

Second, in the case of a gas user bypass there is likely very little, if any, "stranded investment". There is no large "generating resource" acquired by the utility. Most likely, the bypasser was already taking transportation-only service from the LDC, so there would not even be any pipeline capacity or gas supplies bought to serve the customer. Even if the customer formerly was a sales customer, the term of service and election date procedures discussed in Question B.1 and 2, above, would prevent costs being borne by other customers or the LDC. Revenues from the industrial customer would have long-since paid for the distribution system pipe in the ground. Furthermore, the pipe may continue to serve other customers. Even the LDC-owned meter can be removed. If the LDC made substantial new investments to serve the customer (e.g. acquired firm pipeline capacity or made distribution system extensions), the LDC should and would have entered into a service contract with the customer that assured recovery of these special investment costs. Thus, the concept of stranded investment really does not apply to LDC bypasses.

Third, cost-of-service pricing will avoid shifting of costs as a result of any loss of load, whether from bypass, plant shut down, or use of other fuels. If the rates of one class of customers subsidize other classes, any revenue loss -- including loss of the subsidy -- will be an added problem for the subsidized class. This can be avoided with adherence to cost-of-service pricing.

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 service should be provided on an unbundled basis, and which services, if any, should remain bundled?

Many issues relating to unbundling were addressed in the recent proceeding concerning Washington Natural Gas transportation tariffs and rates (UG-940814). It is appropriate for the Commission to direct LDCs to provide unbundled services at cost-based rates. Unbundled services provide the flexibility for customers to choose among various levels of service to fit their particular needs, which is essential in today's energy environment. Unbundled, cost-based services also helps retain customers without as much need to resort to a special contract to meet individual customer's needs.

A sharp distinction between "core" and "non-core" customers does not reflect the profile of natural gas users, which span a wide range of characteristics. These range from very small, firm sales residential customers, through moderate sized commercial and industrial firm sales and interruptible sales customers, to the very largest interruptible transportation-only customers. Northwest Industrial Gas Users has always supported broad, nondiscriminatory access to gas transportation service and has eschewed a strict "core/non-core" distinction. However, it may be problematic to design unbundled services that are truly cost-based (with no inter-class subsidies) for the entire range of potential customers and to make such services workable for all levels of service. The solutions, if any, to these problems will be different depending on the size and type of customer involved and the nature of the LDC services being proposed. Thus, the questions are best addressed in individual proceedings based on the facts of each case in which such services are proposed.

In such proceedings in the past, the Commission has addressed the appropriate rates, terms and conditions for unbundled services made available to larger volume users. The same type of questions, but perhaps different conclusions, would be applicable to other types of customers if a demand for such service developed. For instance, if a service is being considered for aggregation of residential gas users, the Commission would need to address the cost-of-service for firm distribution system delivery, meter reading, billing changes, etc. The Commission would need to address the ability to move between LDC sales service and unbundled aggregator service, including restrictions and cost implications of new customers coming on and current customers leaving the system. The Commission would also need to address the proper extent of aggregator services such as meter reading, billing, and balancing. Contingencies in the event of supply failure or other nonperformance by the aggregator/marketer must also be addressed. (Just as an alternate fuel facilities are routinely required as a condition of interruptible sales or transportation service for industrial users, the question might be whether the aggregated residential customers can demonstrate an adequate source of alternate energy and/or a back-up or standby service provided by the LDC or other natural gas supplier. The cost of those services would also be an important factor, as well as the cost and risk to other customers on the system without such mandatory backup.) After the Commission determines all the necessary requirements for consumer protection and the true cost-basis for such services, they may or may not prove workable or cost-competitive. However, this would seem to be a fact-based determination best made at the time such services are proposed in response to a market demand.

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

As discussed above, it is essential that rates for each of the services be set based on embedded cost-of-service. This is the only way to ensure there is no cross-subsidization among customers.

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

As discussed in Question B.1 and 2, the LDC's obligation to serve can be largely defined in tariffs providing for the unbundled service. Provisions can set out the ability to switch among levels of service, the consequences for demanding new service, different levels of service or discontinuing service outside the election window, etc. Since the unbundled services are voluntary, a customer choosing the unbundled option does so upon acceptance of the conditions of the tariff. Fully bundled or packaged service would still be available from the LDC for those customers who do not want these conditions that qualify the LDC's obligation to serve.

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?

The least cost planning process consumes considerable time and resources of the LDCs, public agencies, and other participants. Now that LDCs have gone through a couple of rounds of least cost planning, perhaps it is time for the Commission to evaluate what the process is accomplishing and at what cost. Are LDCs making different decisions as a result of least cost planning than they would without it? Why? How else might the same results be obtained? Is the two-year frequency of the current process appropriate or could a longer time frame be used? Is the growing level of detail, technical analysis, modeling, etc. necessary? What is the total cost of the least cost planning process ultimately paid by the consumer and could it be reduced without sacrificing the most important benefits of the process?

E. Demand side management and conservation

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

The acquisition of Demand Side Management (DSM) should be treated as any other resource available to an LDC to satisfy demand. The need for the resource, suitability to meet that need, and cost should be the determining factors in acquiring any resource, including DSM. No "public policy" preference should be given to one type of resource over another. If social goals are to be pursued in utility resource acquisitions, such public policy objectives should be determined by the state legislature (or Congress) along with appropriate programs and funding mechanisms.

Other mechanisms are also now available to complement LDCs' least cost planning and DSM strategies. With the new competitive market for gas supplies and other resources, LDCs have the opportunity to price their sales gas supplies in a manner that reflects actual cost. The LDCs could now pass through to sales customers the price signals that reflect the true costs of the customer's energy choices. For example, instead of a single weighted average cost of gas (WACOG) applicable to all firm sales customers, an LDC could have different categories of gas supply and design its rate schedules around each. The cost of the different gas supplies (including the costs of other resources such as storage, pipeline capacity, etc.) could reflect differences between high load factor and low load factor usage generally, seasonal variations, and (with suitable metering) even time-of-day usage. In today's market it is not appropriate or necessary to artificially manipulate customer rates to induce or deter a particular behavior. However, those rates now can more accurately reflect the true costs of the customer's gas usage patterns. Allowing those price signals to reach the LDC's sales customers could be a part of the LDC's least cost planning and DSM strategies.

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

When an LDC purchases DSM it does so as part of a resource portfolio to meet the needs of its firm sales customers (as a substitute for gas supplies, pipeline capacity, etc.) The costs of DSM should be paid only by those customers who would otherwise pay for those resource portfolio costs: that is, the firm sales customers for whom the LDC purchases gas supplies and pipeline capacity. The LDCs do not purchase any of these resources for customers taking distribution-system transportation service. The transportation customers do not pay for the supply-side resources the LDC purchases to serve its firm sales customers. Hence, transportation customers should not pay for the costs of DSM resources purchased as a substitute for those supply-side resources.

Likewise, LDCs do not acquire firm pipeline capacity and firm gas supplies for their interruptible sales customers. The interruptible sales customers use whatever resources are not needed at the time to serve firm sales customers. They are curtailed when the contracted-for resources are needed to serve the firm sales customers. Unlike supply-side resources, DSM resources provide no usable fuel energy to the interruptible sales customer. (An interruptible sales customer cannot run a boiler on DSM.) For these reasons, interruptible sales customers also should not pay for DSM resources that do not serve them.

Moreover, transportation customers and interruptible sales customers do not "benefit" from LDC-sponsored DSM in any way that justifies an allocation of costs. Since neither type of customer places a "demand" on the LDC system (since they are already interruptible), there is no additional load to be shed. The "avoided cost" is zero. (In fact, the argument can be made that increasing interruptible loads is a least cost planning strategy to increase system load factor and reduce average costs without incurring additional demand obligations.) Furthermore, as the LDC acquires DSM resources to substitute for supply-side resources for firm sales customers, the LDC reduces its purchase of supply-side resources accordingly. Therefore, there is less seasonal "surplus" of supply and capacity resources available to the interruptible sales and transportation customer, leading to potentially more frequent interruptions. Even more interruption may result if LDC estimates as to the effectiveness of its DSM measures are inaccurate, and firm loads are actually higher than projected at various temperature levels. Thus, since they do not benefit from the effects of DSM, transportation and interruptible sales customers should not be allocated the costs of DSM.

If indeed DSM is acquired as a cost-effective resource, then the costs of DSM should be included in the LDC's total weighted average cost of gas (WACOG) and reflected in periodic adjustments to the WACOG (in PGAs) just like any other resource. However, there is still a question of equity to be resolved. Since DSM is acquired from customers, the customers eligible for the program derive financial benefit (in lower energy bills) not enjoyed by customers not eligible for the program. To fairly account for this extra benefit, the Commission can direct LDCs to design and offer DSM programs for each firm sales customer class in proportion to the revenues contributed by each class. Alternatively, in the PGA the Commission can apportion the costs of each DSM program in a way that takes into account the particular the customer classes that were eligible for each program.

The question of lost revenues as the result of DSM conservation measures should be treated as a rate case issue. The actual and measurable loss of sales attributable to the DSM program will be a factual issue best reviewed in a rate case-type forum.

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?

As discussed under Question E.1., above, the costs and benefits of DSM programs should be evaluated the same as a supply-side resource: the suitability to meet customer needs and the actual cost. This may include related factors such as demonstrable reliability, flexibility to reduce or eliminate the investment should it not be needed, etc. However, it is not appropriate to introduce externality "costs" and "benefits" based on public policy objectives or social goals with highly subjective quantification. If the state wants to establish policies favoring one type of resource over another -- whether it be DSM over hydrocarbons, or gas over electricity, or gas over oil -- it should be up to the legislature to set such policies and provide a proper mechanism for funding the state-wide programs to carry them out.

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?

To avoid DSM acquisitions being a threat to competitiveness or resulting in stranded assets, DSM resources must be evaluated with the same scrutiny and tests applicable to supply-side resources. As described above, these include the reliability and suitability of the resource, flexibility in the resource portfolio (that is, the relative ability to shed the resource if or when it is no longer needed), and the actual investment cost. This should not include arbitrary quantification of externality costs based on changing social goals.

F. EPACT issues

1. Should the Commission adopt the integrated resource planning standard proposed and defined in EPACT Section 115? (The WUTC attached relevant sections.)

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?

Given the development of the Commission's own programs and standards for least cost planning and DSM acquisitions, there appears to be no purpose gained in adopting the EPACT standards.

G. Missed questions

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?

Issues will continue to arise in the evolution of the natural gas regulatory/market environment that raise the same underlying question discussed in our Overview to these comments: Where and to what extent can or should competition control the marketplace, and where and to what extent is regulation still necessary to protect the interests of natural gas consumers. The Commission will be continually challenged to find the minimum level of regulation needed to protect the essential interests of all consumers yet avoid excessive regulation that would obstruct the benefits of market choice and competition for those consumers.

Following is a brief discussion of some of these other emerging issues. They have been grouped into two broad categories for discussion. However, these issues are actually all interrelated aspects of this continued introduction of market forces into a regulated industry.

Upstream services/confidentiality

Increasingly, LDCs will likely offer new unbundled or repackaged services in addition to simple distribution system transportation service. These services might include customer-specific gas supply, interstate pipeline capacity, storage, parking/peaking service, enhanced balancing services, back-up services, etc.. Some may be subject to FERC regulation relating to "capacity release", others may not. Some may fall within the definition of traditional utility services; others may have the characteristics of a competitive market service. The Commission will need determine what types of services it must fully regulate as a distribution utility function and which services it might not as fully regulate or regulate at all (except, of course, as to the treatment of costs and revenues and the like.)

To aid in making these determinations, it is extremely useful to make a distinction between "downstream" services and "upstream" services. Downstream services are those provided on the LDC's own system, physically downstream of the LDC's interconnection with the pipeline. For example, distribution-only transportation service is a downstream service. Upstream services are those that are provided outside the LDC's own system, such as gas supply purchases or pipeline capacity. Oregon law and utility commission rulings provide a model for making this downstream/upstream distinction.

Downstream services, even if unbundled, are still regulated monopoly services. It is appropriate to apply the Commission's traditional regulatory oversight to these services. This includes approval of tariffed rates, approval of special contracts, full disclosure of the rates and essential terms of such tariffs and special contracts, protection against undue discrimination, etc. To assure customer protection for these regulated downstream services, the essential terms of special contracts cannot be kept confidential.

On the other hand, upstream services may be provided in a competitive market where the LDC is competing with marketers and others to provide the same types of services. For such services, traditional regulatory oversight by the Commission may not be necessary. Instead, competitive upstream services might be provided with confidential, self-implementing contracts not requiring Commission approval. However, where arrangements include both downstream and upstream services, the protections for the downstream elements of the arrangement must still apply. For example, this would require disclosure of the terms for the downstream services but may allow confidentiality of the terms of upstream services.

In addition to the question of what upstream LDC services can be exempted from traditional oversight or given more light-handed regulation, the Commission may also need to address questions such as the LDC's interrelationship with its nonregulated affiliates that may provide such services; the appropriateness of providing upstream services to customers outside the

LDC's own service territory or outside the state; the treatment and allocation of utility costs and revenues from such services (such as pipeline capacity costs and the revenues from capacity release, or the accounting of the WACOG for bundled sales service and separate pricing for an unbundled gas supply service); procedures for handling arrangements that combine both downstream and upstream services; etc. Northwest Industrial Gas Users has found that making this underlying distinction between downstream and upstream services greatly helps in guiding these regulatory decisions, including issues of confidentiality.

New cooperative opportunities

Great new opportunities exist to forge new partnership relationships between LDCs and industrial gas users. These symbiotic arrangements will help the LDC cost-effectively meet the needs of its firm sales customers while at the same time tailoring services to meet the individual energy needs of the industrial customer. The most obvious example of this is a capacity-sharing arrangement: An LDC may need gas supply and pipeline capacity to meet its growing peak-day demand. An industrial gas user may have acquired its own firm gas supply and pipeline capacity, yet have some tolerance for using alternate fuels. These needs can mesh beautifully with a contractual arrangement between the LDC and industrial user allowing the LDC to utilize the industry's gas supply and capacity during peak periods up to a specified number of days per year, consecutive days per month, etc. The LDC would receive this service in exchange for some form of pre-negotiated compensation to the industry that is lower than the cost of other peaking resource options available to the LDC to serve its firm sales customers. Conversely, an LDC may make its unneeded pipeline capacity available to an end user through capacity release, with call-back provisions tailored to meet both the LDC's and user's particular needs.

There are countless possible variations on these examples. The terms of each arrangement can be crafted to efficiently and cost-effectively meet the needs of the LDC's firm sales customers for any appropriate length of time. The arrangements provide the flexibility, responsiveness, predictability, and cost-effectiveness so essential in meeting both the LDCs' and the industrial user's energy needs. As a side benefit, the LDC develops a cooperative relationship with the industry and the industry's energy needs are met with a tailor-made level of service at an attractive price. Both these elements will be crucial to help avert bypass and retain industrial customers on the LDC system.

In this evolving natural gas regulatory/market environment, flexibility and customer choice will increasingly supplant the one-size-fits-all services and rigid tariff classifications of the past. This is a positive transition, full of opportunities to better serve all consumers' needs. The Commission should encourage LDCs to seek out these opportunities and forge cooperative arrangements with industrial gas users. Of course, as with any resource acquisition or service contract, the Commission will need to exercise an appropriate level of regulatory oversight of such arrangements and their costs. The extent of that review will depend on the type of arrangement entered into as discussed above concerning upstream/downstream services. However, the Commission should embrace this partnering concept and assure that its review process does not discourage the development of positive arrangements. To realize the benefits of these new opportunities, LDCs and their customers will need regulatory flexibility that encourages and rewards innovation in meeting customer needs in today's changing market.

CONCLUSION

As the natural gas regulatory/market hybrid system continues to evolve, the Commission will continue to face issues in which it must strike a balance between protecting the interests of consumers with appropriate level of regulation while not obstructing the benefits of competition with unnecessary regulation. For over ten years and in numerous forums, Northwest Industrial Gas Users has been helping to constructively resolve these constantly evolving natural gas regulatory issues. Our experience has proven time and again that the best way to achieve this balance is with adherence to three key elements:

-- LDCs must have the regulatory flexibility and incentive to offer a broad choice of service levels to their customers;

-- The rates for each regulated service must not exceed the true cost-of-service for just that level of service; and

-- Each service level must have clear terms and conditions spelling out the rights and obligations of the customer and LDC.

Adherence to these principles will establish a consistent policy foundation that will be applicable in a broad array of situations that will continue to arise in this evolving market.

Northwest Industrial Gas Users is eager to assist the Commission in any way possible to help develop positive and workable solutions to the natural gas regulatory issues still on the horizon. We respectfully request the opportunity to file further comments in response to other parties' initial comments and look forward to participating in any workshops or other proceedings arising from the Commission's Inquiry.

Northwest Natural Gas

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October 2, 1995

Mr. Steve McLellan, Secretary
Washington Utilities & Transportation
Commission
1300 S. Evergreen Park Dr., SW
Olympia, WA 98504

Re: **<u>DOCKET NO. UG-940778/NOI</u>: EXAMINING REGULATION OF LOCAL DISTRIBUTION COMPANIES IN THE FACE OF CHANGE IN THE NATURAL GAS INDUSTRY**

Northwest Natural Gas Company hereby responds to the Commission's Notice of Inquiry dated August 2, 1995 with an original and 10 copies of its comments on the above-referenced matter. A diskette of the company's comments is also enclosed.

The company thanks the Commission for this opportunity to participate in its Notice of Inquiry. If any questions should arise, please feel free to call me.

Sincerely,

Susan Ackerman

Susan K. Ackerman
Manager, Regulatory Affairs
& Associate Counsel

SKA/cmt
enclosures

cc: Jeffrey Showman, WUTC
Bruce Samson
Bruce DeBolt
John Hanson
Randy Friedman
Brian McCabe
[All w/enc. (hard copies)]

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies

In the Face of Change in the Natural Gas Industry

Docket No. UG-940778

Comments of Northwest Natural Gas Company

Northwest Natural Gas Company (Northwest Natural or NNG) submits the following comments responding to the Commission's Notice of Inquiry referenced above.

I. INTRODUCTION.

Northwest Natural believes that this docket is timely, and that the questions posed by the Commission are the correct ones. Generally, NNG does not in these comments suggest any radical departures from the Commission's current regulatory practices, although the company does point out areas where the Commission may want to fine-tune current practices, or consider new ones.

In addition to responding to the Commission's specific questions, Northwest Natural also addresses two issues not specifically raised by the Commission. Briefly, NNG first urges the Commission to consider adopting long-run incremental cost principals for pricing services and products. Second, given the developing nature of our business, Northwest Natural encourages Commission and Commission staff not to place excessive importance on precedent in reaching decisions on new issues facing the utilities and the Commission. Flexibility is increasingly important to customers, and therefore, also to the utilities.

II. NNG'S RESPONSES TO COMMISSION 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?

Response: Washington's PGA mechanism has worked well and is adequate. However, NNG would favor WUTC adoption of the Oregon PGA mechanism. Oregon's PGA adopts a forward-looking cost of gas based on "known and measurable" changes in gas costs. To the extent actual costs vary from the forward-looking costs, the utility shares 20% of the increase or decrease in costs, while 80% of the variance flows back to customers. The Oregon PGA has merit for the following reasons:

1) Oregon utilizes incentive rate making principles which may help drive down utility purchased gas costs;
2) The administrative burden of PGA filings has not unduly increased;
3) Oregon's emphasis on "known and measurable" pricing encourages rate stability and supply security, and;

4) Approvals are not subject to hindsight reviews which second-guess purchase decisions and increase uncertainty and risk to the utility and its suppliers.

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

Response: As mentioned above, NNG believes the Oregon PGA mechanism has incentives which are efficient and effective. NNG is not aware of any other state with a better method for recovering gas costs which also encourages improvements in utility gas purchase programs while not sacrificing long-term security of supply.

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?

Response: *Ex ante* reviews, as done in Oregon, promote good decision-making and facilitate stable and secure gas supply and transportation acquisitions. *Ex post* (hindsight) reviews, by comparison, increase the risks faced by the utility and its suppliers which generally translate to lost business opportunities and higher costs. Hindsight reviews also tend to double the administrative burden since every transaction is, in essence, reviewed twice (first by the utility prior to consummating the deal, then by the utility and the Commission during the prudence review).

Ex ante reviews do suggest that the Commission be willing to set guidelines and communicate expectations regarding utility actions, respond on a timely basis to requests for contract approvals, and then **not** revisit approved transactions.

Exceptions, of course, would be made in the unlikely event that the Commission was deliberately misinformed or misled by the utility, or if the utility itself wanted to reopen a previously approved contract.

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

Response: Changes in main and service line extension policies may be needed, but this is not necessarily a product of the new environment. The impact of line extension policy on retail rates is the most important compass for guidance in this area. Generally, a "ratepayer neutrality" policy goal of line extensions is one means of assuring that new customer growth does not lead to non-competitive retail rates. In both Oregon and Washington, NNG generally seeks a "ratepayer neutrality" line extension policy.

NNG's primary problem with its line extension policy in Washington is that NNG's residential rates are low in comparison to new customers' competitive fuel choices. Conducting main and service line extension policy in a manner to preserve current residential rates results in too much new business being turned away. Thus, for NNG, the long-term solution requires a realignment of rate spread based on incremental cost of service concepts. This is discussed later in NNG's remarks at pages 20-22.

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?**

Response: Northwest Natural does not recommend that the Commission adopt an exit fee for customers changing from sales to transportation service, or alternatively, bypassing the existing distribution system. Rather, the Commission should support LDCs as they attempt to find competitive solutions for these customers. For example, LDCs need sufficient advance notice of a customer's desire to change from sales to transportation service, so that the LDC can take that customer's choice into account when planning for gas supplies and transportation capacity. By way of further example, for customers choosing to physically bypass the LDC, Northwest Natural's policy is to hold the bypassing customer to the terms of its existing contract. In some cases, this might mean that the bypassing customer would have to pay the present value of the remaining contract revenues in order to terminate the contract early. This is not exactly an exit fee, but is more akin to contract damages. Commission support for such an approach would be appreciated.

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?**

Response: Customers seeking to return to utility service should not be charged an entry fee. Usually, these customers are high-volume, high load factor customers. Their presence as LDC customers usually has operational advantages to the LDC such that the LDC would prefer to have them return if they so desire. However, for large customers with competitive options, either transportation service or physical bypass, the LDC's obligation to serve should not be an obligation to serve at any price. A large customer's right to return to LDC service is not unqualified, but would be subject to the LDC's ability to serve them with existing resources. If system improvements or new supplies are required to serve the returning customer, Northwest Natural's preferred policy is to require that customer to pay these costs up front. This is not a re-entry fee. Rather, this is more in the nature of a "contribution-in-aid-of-construction" payment. Northwest Natural's line extension policies consistently apply this principle to all customers entering the system. Consequently, it is a nondiscriminatory way to allow returning customers back onto the system without negatively affecting on-system customers.

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?**

Response: NNG urges the Commission to reconsider and abandon the banded rate concept. While developed as a means of dealing with increased competition in the gas industry, it has at its foundation all of the inappropriate precepts of fully allocated historic embedded costs (FAC) pricing methodology.

The banded rate approach places shareholders at considerable risk when FAC methods are used. After a rate proceeding the FAC-based upper band is treated as current revenues regardless of the negotiated rate the LDC finds necessary to forestall bypass. "Phantom revenues" result. The lower band is something akin to short run marginal cost or variable cost. Some might think that "phantom revenues" inspire due diligence in the negotiation of special contracts. Whether the upper band may be well above or near negotiated prices for discrete service offerings, the LDC has equally strong incentives to bargain for as much margin as possible from customer groups with multiple competitive options. The banded rate concept protects discretionary customers who by their very definition do not require protection. Core market ratepayers are protected by an arbitrary *ex ante* rate disallowance and shareholders absorb the difference.

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?**

Response: Lost revenue resulting from the bypass of existing customers to competitive fuel options should be borne by all ratepayers in a manner that causes efficient departures of price from marginal cost across all rate pools. Lost revenue resulting from bypass is not an appropriate focal point for rate proceedings because it follows from a revenue responsibility assignment perspective rather than an efficient pricing perspective.

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?

Response: The Commission should permit but not direct LDCs to provide further unbundled services. NNG favors unbundling service where competitive markets can be developed to the benefit of participating customers. Currently, only very large volume customers have the ability to seek an alternative gas supply or purchase their own pipeline capacity. The component of gas service which is subject to a competitive market, namely gas supply, is purchased by NNG through ever shorter contracts on a very large-scale basis. Gas supply costs are then passed through to customers without markup. It is unlikely that smaller customers or those who aggregate multiple accounts could achieve either lower cost or higher reliability than is now provided by NNG.

While NNG does not seek the Commission to mandate further unbundling, NNG believes that unbundling eventually may be required in some segments of the market. Further unbundling should be consistent with a long-run incremental cost-based cost of service analysis. It may be more appropriate to review the utilities' current rate structures to evaluate the extent to which bundling of services is creating market inefficiencies or cross-subsidization between various customer groups. Rate offerings should be numerous enough to provide customers with choices that do not require them to purchase unnecessary services.

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?

Response: An unbundling strategy should be accompanied by a thorough analysis of markets, suppliers, customers, costs and benefits. It might be helpful to discuss the desired outcomes of unbundling prior to recommending the components of an unbundled portfolio of LDC services. Nevertheless, unbundling could include commodity gas, capacity, storage, balancing, backup supply, equipment service, billing and other items. Those services that provide for reliability of delivery likely should be included with bundled service for all but the largest of customers.

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

Response: The rules in setting rates for unbundled services must provide for recognition of the challenger's (or competing third party provider's) incremental cost of service for the discrete services offered. The gas utility's rates should reflect the incremental cost of providing the service involved on an ongoing basis. If the demand for a discrete service is highly price elastic, efficient departures from marginal cost pricing require that it be priced very near marginal cost. If inelastic, general revenue requirements can be "loaded" on this billing determinant. Resulting LDC rates are limited by the challenger's own cost. If the LDC's on-going incremental costs are greater than the challenger's cost of providing the unbundled service, then the correct price signal is communicated and the lower-cost challenger should provide the service.

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

Response: As a practical matter, Northwest Natural believes that LDCs will continue to have a service obligation to residential, commercial and other firm customers for which interruption of service is unacceptable. Firm customers are firm because they require service under the most extreme conditions. Assuming unbundling down to the residential and commercial level, it would be politically, economically, and socially unacceptable for an LDC to "valve-off" a residential or commercial customer whose independent gas supplies fail during a cold weather episode. This means that the LDC will need to stand ready to provide supplies in the event the independent supplier fails.

Given that the LDC likely will be required to serve customer loads even if supplies fail, then the real issue is not whether the LDC has an obligation to serve, but (1) who pays for the cost of maintaining the back-up facilities that will provide supplies when independent suppliers fail, and (2) what requirements, if any, should be placed on independent, third-party suppliers who seek to serve uninterruptible core markets? It is for this reason that NNG believes that reliability services should remain bundled with the rates for all but the largest of customers. See response to question C., 2., at page 9.

D. Least-Cost Planning.

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

Response: Institutionalization of rules to align least-cost planning with other LDC planning functions is not necessary. There is a natural tendency for LDCs to synchronize internal and external planning functions. NNG has already integrated its resource planning with its business planning, and thus can live with the current biennial planning cycle. While a two-and-a-half year cycle is attractive, remaining "in sync" with internal planning functions would require moving to a three-year cycle. A three-year cycle is manageable if mid-cycle plan amendments and updates are an available option during periods of rapid change.

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?

Response: Confidentiality in the IRP process is a major concern for NNG. Some of NNG's competitors are publicly-owned utilities with an interest in municipalizing select parts of LDC service areas. Revealing details of gas supply portfolio strategy and producer contracts undermines the LDC's competitive position. Similarly, prospective capacity release and electronic bulletin board strategies must be held in confidence. Of foremost concern, revelation of options for increasing pipeline capacity or a variety of gas storage development protects can be disastrously harmful to multiparty negotiations. The result of full public disclosure is the acquisition of resources at a higher cost and greater burden to core market customers.

WUTC Staff has demonstrated a clear understanding of these concerns regarding commercially-sensitive information. NNG has dealt with this problem by allowing WUTC and WSEO Staff complete access to sensitive information subject to a signed confidentiality agreement. Thus, while we have been able to manage these issues through communication with Staff, an explicit recognition in the LCP rule that some information may be protected by the Commission at the request of the LDC may be useful and would be supported by NNG.

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?**

Response: A negative impact of utility-funded DSM on an LDC's ability to compete is a possibility, but the impact is likely to remain small. However, stranded regulatory investment is a concern if DSM program cost recovery is spread over the long life of DSM investments. Prudent investment in DSM by LDCs is facilitated by allowing short capital recovery periods. Allowing recovery over short periods of time with the possibility of extending amortization periods when necessary is the best outcome because this mitigates the risk of stranded regulatory investment.

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

Response: Housekeeping changes to the rule are timely. WAC 480-90-191(3)(b) requires "An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements." NNG has no problem with this section if it were to apply only to core market firm customers. Large volume interruptible transportation customers, and customers taking service on bypass avoidance service agreements, should be excluded from this requirement.

Beyond low margin contributions and the ability to bypass to other fuels, this customer group is distinguished by its strong interest in sophisticated energy management for its own competitive survival. NNG has conducted studies as called for by the rule, but the basic finding is that there is little untapped potential for energy efficiency improvement in this market.

Section (3)(c)(iv) calls for "an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers." This language predates open access pipeline transportation and did not anticipate the early abandonment of pipeline sales service by the region's LDCs.

Section (5) states: "The Least Cost Plan, considered with other available information, will be used to evaluate the performance of the utility in rate proceedings before the commission." The language included in the Commission's plan acceptance letters gives no comfort that resource acquisition decisions by LDCs acting in accordance with their filed and accepted Plans will be viewed favorably in rate proceedings. NNG would prefer the language of the rule (and plan acceptance letters) to create a stronger rebuttable presumption of prudence when resources are acquired in accordance with the utility's announced course of action.

E. Demand-Side Management and Conservation.

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

Response: LDCs should be encouraged to pursue all cost-effective conservation options under circumstances structured so that shareholders are neither advantaged nor disadvantaged by prudent DSM activity. A credible and completely compensatory lost margin recovery mechanism is a necessary element for utility DSM acquisition incentives. A companion condition is that LDCs should have the ability to act quickly to abandon or modify DSM programs that prove to be non-cost effective from a Total Resource Cost (TRC) perspective.

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

Response: Programs should be structured so that DSM participants (the principal beneficiaries of conservation activity) pay a significant share of DSM costs. Ratepayer supplied funds should be limited to the level necessary for acceptable program penetration.

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

Response: Avoided cost estimates should be used for screening feasible conservation and load management technologies. Technologies found to have economic potential should be included in a fully integrated resource stack to be evaluated by optimization (linear programming) models. The cost of conservation technologies should include the full installed cost of measures or the incremental cost of more efficient conservation devices. Program administrative costs must be recognized. Annual carrying charges applied to the LDC's share of investment cost should include the full revenue requirements associated with utility financing (income and property taxes).

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?

Response: Non-energy benefits of energy efficiency measures should be recognized. Storm windows and storm doors provide a variety of non-energy benefits. Installed measure cost should be adjusted to reflect the participant's implicit valuation of energy benefits based on retail rate savings over the life of the measure. For further discussion, see page E-7 (attached) from NNG's 1995 Draft Integrated Resource Plan Technical Appendix.

On the supply-side, the non-energy benefits of reduced gas use are dominated by environmental externality concerns. Carbon dioxide, nitrous oxides, and methane releases are the primary concern here. LDCs should explore the sensitivity of supply-side and demand-side choices to alternative levels of damage costs associated with these byproducts of natural gas use.

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?

Response: At current activity levels, the impact of DSM program costs on NNG's retail rates is minor. The passage of time and increased DSM acquisitions could introduce price competition problems in some core-market segments. The risk of strandable regulatory assets associated with DSM investments is best mitigated through short amortization schedules with program costs deferred rather than capitalized where feasible. For further discussion, see pages E-37 and E-38 (attached) from NNG's 1995 Draft Integrated Resource Plan Technical Appendix.

F. EPACT Issues.

1. Should the Commission adopt the integrated resource planning standard proposed and defined in EPACT section 115?

Response: The Commission's integrated resource planning rule already meets the integrated resource planning standards proposed in EPACT section 115. Northwest Natural sees little value in adopting the federal standards as current state standards already meet or occasionally exceed federal standards.

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

Response: Wholesale adoption of the standard pertaining to utility investment in conservation and DSM is not necessary. However, the Commission should consider adopting the philosophy that utility investments in DSM should be at least as profitable as supply-side investments. Northwest Natural has supported economically-sound DSM over supply-side resources despite the fact that DSM has raised a considerable number of issues, in particular the question of shareholder impacts. In this regard, a variety of mechanisms are available to regulators to remove the financial disincentives associated with DSM and, thus, put DSM on equal footing with supply-side resources.

Among these mechanisms are decoupling, lost revenue recovery, program cost recovery, shareholder incentives or any combination thereof.

Under the current rate of return regulatory regime, which in recent years has produced few rate cases, NNG actively manages its utility business operations to both control costs and increase economically beneficial sales volumes. In short, NNG supports this traditional type of regulation as it ensures lower rates for customers and fair earnings for shareholders. Implementation of DSM is thus contrary to the two key motivations of Company management. It is necessary then that modifications be made to encourage the utility to actively pursue cost-effective DSM.

As an example, NNG implemented a large-scale high efficiency showerhead program in its Oregon service territory during 1994. The program supplied over 223,000 showerheads for a total cost of $1.7 million and has resulted in a lost margin impact of over $750,000 annually. This type of DSM program implementation would have significant earnings consequences apart from removal of the inherent disincentives.

NNG believes that the preferred mechanism for removing DSM disincentives is one which provides for rapid recovery of program costs and lost margin through a sequence of temporary rate adjustments continuing until the Company's next general rate case. Rapid program cost recovery is preferred as a means to mitigate the risk that these investments could be considered stranded regulatory assets or could become a problem in a more competitive energy environment. Thus, financial disincentives are removed so NNG is indifferent towards DSM implementation. NNG finds positive incentive to develop programs because implementation produces increased customer satisfaction levels and customer loyalty.

NNG dislikes establishing either conservation targets or shareholder incentives. In both cases, gaming can become an unintended and negative consequence of the incentive. For example, short-term shareholder incentives may encourage NNG to spend too much or try to force customers to accept programs and measures they do not want.

Decoupling mechanisms also have too many unintended consequences. For example, decoupling is far more sensitive to the impacts of weather on an annual basis than to the impacts of DSM programs. Consequently, the annual adjustments to rates resulting from weather changes could be dramatic. Decoupling also removes the current incentive to increase sales volumes through the development of gas equipment markets. In Northwest Natural's view, incentives for economically-beneficial growth should continue in order to more rapidly recover investments in service lines and main extensions. Decoupling is inherently inconsistent with this philosophy, and with the developing competitive gas markets.

As a final note, NNG believes DSM program costs should be contained in an effort to minimize future rates. This strategy dictates that market transformation type programs are preferred to those that require continued consumer cash incentives from the utility.

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

Response: Overall, a negative impact can be avoided if the utility partners with small business to achieve DSM. For example, the company's participation in DSM activities should have a positive impact on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other DSM measures. The entirety of residential and commercial DSM programs that the company prefers rely on the active participation of market intermediaries to promote and sell energy efficiency.

This approach to DSM relies on partnerships with small companies engaged in the sale of energy efficient products and energy management services. Where incentives are proposed in the residential equipment markets, equipment distributors and dealers will be encouraged to sell higher efficiency equipment. In NNG's case, dealer incentives and advertising will allow business partners to become more successful. The energy services billing approach also provides for similar synergy between the company and energy conservation suppliers. Overall, NNG's participation in DSM activities will have a positive economic impact on smaller companies involved in providing energy conservation services.

G. Missed Questions.

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?

Response: In addition to NNG's responses to the Commission's specific questions, the company encourages the Commission to consider two other points not directly addressed in the Commission's questions.

1. Long-Run Incremental Cost Pricing is More Compatible with New Competitive Markets.

One of the most important changes to regulation that the Commission should make in the evolving natural gas industry, where most customers have some choices and some customers have many choices, is to adopt policies that improve the efficiency of the price signals sent to natural gas customers. Specifically, the Commission should consider moving away from fully allocated embedded cost of service (FAC) concepts for purposes of rate spread and rate design, and instead should utilize long-run incremental cost (LRIC) approaches to rate spread and developing bypass avoidance rates.

Pricing that relies on FAC principles had merit in the early days of utility regulation, when utilities built capital-intense systems to serve the needs of many customers with diverse service needs. FAC pricing helped all customers gain utility service. But FAC pricing was sustainable only as long as customers lacked competitive options, which they largely did prior to Order No. 436. Order No. 436 and its aftermath, however, introduced competitive options to large customers served by the natural gas distribution industry. In the new environment, pricing based on FAC principles encourages customers with options to leave utility service, to the detriment of remaining customers. Northwest Natural believes that this new environment necessitates considering alternatives to FAC pricing principles.

As a practical matter, FAC studies provide no useful economic information to either the utilities or their customers. Average historical costs play no role in evaluating new service offerings, as the decision to acquire a customer depends on the marginal cost of serving that customer. The investment in an alternative fuel source or energy service is incremental and will not take place unless the incremental cost of the investment and its operation is less than the LDC's price. Thus, a customer (for example, a James River/Camas) which has a choice between various bundles of utility service and some other service option looks at its own cost of acquiring the same level of service, not at the utility's average historical cost. Similarly, Integrated Resource Planning looks at the range of options available to serve incremental load and values supply- and demand-side options at marginal (or incremental) cost. In sum, many of the competitive problems facing LDCs and their smaller customers with more limited choices may be solved if LDC rates are based on efficient pricing concepts.

The Commission correctly recognized the importance of rates which send correct price signals in its recent Order in Washington Natural's case, Docket Nos. UG-940034 and UG-940814, at page 19. Northwest Natural encourages the Commission to continue exploring ways to develop rates which send correct price signals. While

Northwest Natural believes LRIC-based rates are the most appropriate way of sending the right signal, because of the technical nature of this concept, Northwest Natural seeks only that the Commission and Commission Staff provide a future opportunity for the company to explain why now is the right time to transition away from FAC rate making methods to incremental cost-based pricing.

2. Regulatory Flexibility is Important to Gas LDCs Seeking to Meet Customer Requests.

Since Order No. 436, increasing competitive pressures have been brought to bear on the LDCs. NNG's experience in dealing with customers with competitive alternatives has led to one overriding conclusion: each customer is unique; and therefore, each customer's service needs may be unique. Because customers differ from each other, LDC responses may differ. In this environment, some issues may merit generic solutions, but others may not. Northwest Natural urges the Commission to be flexible in its approach to regulating utilities as they respond to the differing competitive pressures experienced in their service territories. Regulatory flexibility may be one of the more important ingredients for a healthy gas industry capable of providing low-cost, reliable service to gas customers.

III. CONCLUSION.

In summary, NNG does not generally believe that radical departure from the Commission's current regulatory structure is called for. Rather, assuring rates that send proper price signals and taking a flexible regulatory approach to developing issues will adequately address most issues.

DATED this 2nd day of October, 1995.

Northwest Natural Gas Company

Susan Ackerman

Susan K. Ackerman
Manager, Regulatory Affairs
& Associate Counsel

(2) Administrative cost is not applied to individual measures as in the past, but is now expressed as an addition to total program cost.

(3) Past reports incorporated a 50 percent realization rate adjustment to engineering estimates of therm savings. Instead, this report shows benefit cost ratios at a 100 percent realization rate and then examines critical values for realization rates. As discussed above, empirically-estimated realization rates range between 16 and 32 percent of engineering estimates.

1. Treatment of Non-Energy Benefits. Building shell measures such as ceiling, floor and wall insulation are generally thought to not involve non-energy benefits. These measures are not visible and have no aesthetic value. Wall insulation does provide some noise abatement benefits, but it is difficult to ascertain the extent to which customers investing in wall insulation value the resulting noise reduction.

Storm windows, window replacements, storm doors and security doors with thermal barrier properties all provide a high degree of non-energy related benefits to the customer. Regarding storm windows and dual pane window replacements, non-energy benefits such as reduced drafts, reduced condensation, increased security, new window screens provided as part of the package, reduced noise levels, reduced maintenance in the case of window replacements, and the perception of enhanced market value on resale, when taken together, dominate pure energy savings considerations. The cost of security doors packaged with energy efficiency door paneling is dominated by the cost of security elements and features.

The choice of representing non-energy benefits as an addition to avoided gas supply cost (conservation energy benefits) or as a reduction to conservation measure cost will undoubtedly receive further discussion. NNG has chosen to represent non-energy benefits as a reduction in installed measure costs. Specifically, based on an approximation of the net present value of customer gas bill savings, the energy component of measure cost is taken as 25 percent for storm windows and 10 percent for storm/security doors.

2. Basic Findings. Using 1994 DSM activity as a frame of reference (Appendix E, pages EE-1 - 3), several noteworthy observations and findings are shown. In column C, an energy savings weighted average measure life of 26

inspection, cleaning, control improvement and adjustment. These "O&M conservation measures" often have very short investment payback periods compared to traditional weatherization measures or equipment improvements because of their issues surrounding persistence of O&M savings and payback periods of less than one year have prevented implementation of this program.

The company sees significant exposure to lost margins in this type of program that must be addressed before going forward in this area.

XII. INDUSTRIAL CONSERVATION AND CONSERVATION COST RECOVERY.

Because of the rate issues associated with DSM cost recovery mechanisms, some discussion of options is necessary. Recovery mechanisms for costs associated with financial incentives intended to increase DSM program participation have not been discussed elsewhere in this plan, as cost-effective DSM programs are expanded over time, concerns over the incidence of these costs in customer class rates will increase.

Parties to rate proceedings across the nation where DSM cost recovery is a major issue have advocated a variety of allocation methods. Beyond participants direct contributions, these range from direct assignment by class at one extreme to general allocations over all classes at the other.

In regulatory jurisdictions such as Oregon, where efficient pricing is sought using marginal cost pricing principles, DSM cost recovery principles are straightforward. That is, total revenue requirements inclusive of DSM costs would be spread so as to achieve equal percentage departures from long-run incremental cost estimates.

Since the company proposes to limit DSM programs to firm core market customers, including all full margin transportation customers, cost recovery would be similarly limited to this same market segment.

Within the electric industry which is facing increased competition encouraged by the FERC and propelled by compliance with the Energy Policy Act of 1992, concerns regarding strandable costs of supply and the strandable benefits of public interest programs has led to intense discussion of cost recovery issues. Public interest programs generally include conservation programs, environmental damage mitigation costs, the cost of low income programs and programs supporting other social objectives. If these programs are to survive for electric utilities with high retail rates and thereby strong competitive pressure, a means of cost recovery that cannot be bypassed draws increasing interest.

The leading candidate in the electric industry for recovery of strandable costs and benefits is a Universal Service Charge for the use of distribution systems' wires. What billing determinant this charge would apply to is not clear. It could apply to access (customer charge), demand (kWh), or be implemented as a volumetric rate per kWh.

The magnitude of NNG's investment in DSM is not large enough to raise strong customer concerns regarding the burden of these costs. The cost of recently initiated programs is recovered through temporary increments to rates that take the form of an equal cents per therm adder to all core market rates. As we move forward in time with proposed new programs, these costs may rise to the point where between-service-class cost recovery issues must be dealt with in a different manner.

The company's integrated resource planning activities are focused on the provision of efficient energy services to the firm core market sales customer. Forecast interruptible loads are included for informational purposes in order to provide indications of the expected reliability of this service. We have no intention of offering DSM programs and incentives to the interruptible sales service class. We have not advocated including pipeline capacity charges or DSM cost recovery in interruptible rates. The company will continue to provide technical assistance on boiler efficiency.

While the company does not contemplate the use of ratepayer funds to finance the installation of conservation measures for large volume interruptible customers, the Technology and Conservation Section of the company's Industrial Business and Development Department administers an ongoing technical assistance program for commercial and industrial customers. The following list highlights accomplishments during the most recent 12-month period:

1) Three one-day boiler operator training classes were held in Portland and Albany. About 60 boiler operators attended these classes which stressed safety and conservation.

Northwest Pipeline Corporation

NORTHWEST PIPELINE CORPORATION
ONE OF THE WILLIAMS COMPANIES

P.O. BOX 58900
SALT LAKE CITY, UTAH 84158-0900
801-583-8800

October 9, 1995

Washington Utilities and Transportation Commission
1300 South Evergreen Parkway Drive SW
P.O.Box 47250
Olympia, Washington 98504

95 OCT 10 AM 9:16
UTIL. AND TRANSP. COMMISSION

Attention: Steve McLellan, Secretary

RE: Notice of Inquiry: Docket No. UG-940778

Northwest Pipeline applauds the Commissioners for issuing this NOI and would like to participate. The questions raised are best answered by the LDC's that you regulate; however, there is one issue that was not included in the NOI that we would ask you to address. That issue is the way that the commission determines the pressure allowed on laterals built from the interstate pipeline to the market area.

A significant amount of growth is taking place outside the Interstate 5 corridor, where Northwest Pipeline has the major portion of it's mainline facilities. This growth will require LDC's to install laterals that will extend further and further from that corridor and the pipeline. As that happens higher pressures on the LDC's laterals will be necessary to serve these new areas.

We would recommend that the regulations in Washington be more reflective of federal regulations regarding pressures and classifications for pipelines. This change could allow the LDC's to serve new markets without installing expensive compressors.

Enclosed are ten copies of this letter. Thank you very much for the opportunity to participate in this docket. Please provide us with copies of other parties comments in this proceeding. We look forward to working with the Commission on these issues.

Sincerely,

Lynn Hemingway

Lynn N. Hemingway
Manager, Governmental Affairs

LNH/caw

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Paine Webber

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Peter H. Kind
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PaineWebber

September 27, 1995

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive, S.W.
P.O. Box 47250
Olympia, Washington 98504-7250
Att: Steve McLellan, Commission Secretary

Re: Response to Notice of Inquiry:
Examining Regulation of Local Distribution Companies
in the Face of Changes in the Natural Gas Industry
Docket No. UG - 940778

PaineWebber Incorporated appreciates the opportunity to provide comments on the notice of inquiry regarding examining regulation in the changing natural gas industry. PaineWebber is a major full-service investment firm, with services including: brokerage services to over 2.5 million investment customers and investment banking services to the utilities industry.

The changing dynamics in the local distribution gas utility business are characterized by competition in several segments of this industry, including demand for customer choice as to services available and providers of service.

Our analysis of changing business and regulatory environments in other industries during the last fifteen years illustrates that increasing competition and/or de-regulation has resulted in a significant increase in financial risk and as a result, adversely impacted financing capacity and security values for companies in these industries.

Utility industry investors have provided significant capital to fund the growth of the gas distribution industry based upon recovery of a return on and return of prudently incurred costs, as supported by the regulatory compact. As changes in regulation of the gas distribution industry are considered, it is essential that the role of the investor and the impact of any regulatory changes on capital formation be assessed.

As an example, the NOI seeks comment on the PGA mechanism. Since almost two-thirds of LDC revenues are associated with gas cost recovery, any significant change to the PGA mechanism would have a major impact on investor risk and/or reward. Such impact could have a substantial impact on capital access and formation for the LDC industry. Our point is that several of the issues raised will have substantial potential investor impacts and thus, require careful study and deliberation. However, many of the issues outlined in the NOI primarily impact operating and industry structure considerations and thus, are more appropriately addressed by the LDC's.

We would like to offer our availability to address views as to investor and capital formation implications of specific issues as the NOI review process develops.

Sincerely,

Peter Kind

Washington Natural Gas

Washington Natural Gas
A Washington Energy Company

October 2, 1995

Advice No. 851

95 OCT -2 PM 4:25
STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

Mr. Steve McLellan, Secretary
Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, Washington 98504-7250

Dear Mr. McLellan:

Washington Natural Gas Company submits herewith an original and ten (10) copies of its written comments in response to the Commission's Notice of Inquiry (NOI) - Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry - Docket No. UG-940778. Washington Natural Gas Company appreciates the opportunity to provide comment to the issues raised in this NOI. These comments include a summary of the company's observations regarding the re-evaluation of regulation of the gas industry as well as specific responses to each of the topics and questions outlined in the NOI.

These comments are also included on the enclosed 3 1/2 inch, high density "floppy" diskette.

Very truly yours,

Ronald J. Amen

Ronald J. Amen
Director, Rates and Tariffs

Enclosure

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NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry

Docket No. UG-940778

October 2, 1995

Washington Natural Gas
A Washington Energy Company

TABLE OF CONTENTS

I. INTRODUCTION

Washington Natural Gas (WNG) is pleased to respond to the Washington Utilities and Transportation Commission's (WUTC or Commission) Notice of Inquiry (NOI) and welcomes the opportunity to participate in the re-evaluation of regulation for the natural gas industry. In preparing these comments, WNG has given careful consideration to how changes in current regulatory practices and industry structuring can benefit our 470,000 customers while providing fair returns to the Company's shareholders. The opportunity now exists to choose a course that can meet both goals. For a successful evolution of the natural gas industry structure and regulate in Washington state both goals must be met.

WNG does not believe that the optimal course is simply one of less regulation. In some instances, existing regulations need to be more responsive and flexible if customers are to benefit from transient market place opportunities. In other cases, new regulation needs to be developed for optimizing benefits to the core market (which consists of customers receiving bundled sales service) and providing competitive services to the non-core market. The following comments are intended to offer recommendations on these two courses of action.

II. OVERVIEW OF INDUSTRY AND ISSUES

The post-Federal Energy Regulatory Commission's (FERC's) Order 636 environment has brought many changes to the gas industry and to Local Distribution Companies (LDCs) in particular. The new regulatory framework has facilitated competition between direct purchase of gas by end users and LDC system supply. There has been vigorous gas on gas competition. Traditional long-term LDC supply has had to compete with short term direct purchase supplies by end users. LDCs now have a greater responsibility in providing for core customers' gas supply needs. Along with these responsibilities come greater risks for all stakeholders.

There have been benefits of a less regulated gas industry. Natural gas is now a tradable commodity. Greater choice for LDCs in selecting resources - coupled with the ability to market both commodity and capacity resources - allows for better optimization of resources to meet customer demands. Unbundling provides clearer price signals to customers. They may now select only services they need in much the same way LDCs meet their core market's requirements. Competition at the city gate brings customers greater choice and flexibility.

These benefits are not without cost, however. Greater choice brings greater risk. LDCs must make more decisions and accept greater price and supply risk to serve the core market at the lowest cost. Uncertainty may make cost-effective capacity resources less attractive from a business risk perspective. Unbundling has reduced non-core customer contributions to the fixed cost portions of gas supply contracts serving the core market. An opportunity exists through the WUTC's NOI to address this condition.

Under the current regulatory paradigm, ratepayers receive all the benefits of competition while the risks associated with these benefits may be borne by LDC shareholders. Increased merchant function and pipeline management responsibilities are requiring LDCs to incur greater costs to achieve these ratepayer benefits. An additional dilemma faces LDC management. There is an emerging understanding that, to optimize a least cost resource cost mix, some mistakes in the marketplace will be made. The current regulatory process of judging prudency on a transactional basis results in utility management seeking to make no errors. This caution leads to missed opportunities to achieve least cost.

The industry-wide change in the risk/reward balance has caused some LDCs to consider abandoning the merchant function. WNG does not believe LDC abandonment of the merchant function to be in the long-term best interest of ratepayers. Through the Commission's NOI and subsequent companion filings by LDCs, these issues can now be successfully addressed.

III. WHAT IS NEEDED

Historically, LDC rate regulation has focused on operating and capital costs. However, the restructuring of the gas industry requires that regulatory procedures be revisited to permit LDCs to operate in an increasingly competitive world.

Regulatory changes can take various forms, from instituting performance or incentive-based ratesetting approaches for core markets, to streamlining existing cost-based ratesetting. Each LDC is unique, and there is no single answer which is right for all. Through collaboration, the Commission and the LDCs can reach solutions that benefit everyone. Regulatory reform goals should include the following:

- Continued commitment to Least Cost Planning (LCP) principles for core customers;
- Take a comprehensive, long-term view of utility operations;
- Encourage long-term productivity improvement v. current "feast or famine" rate case cycles;
- Provide clear standards for judging utility performance;
- Reduce need for and cost of transactional prudence reviews and litigation;
- Re-assess regulatory objectives and acknowledge value trade-offs; and
- Align customer and shareholder interests.

A framework is needed that will:

- Allow LDCs flexibility to meet the varying needs of customers;
- When offering choice is economic, allow customers to choose the types of services they desire (and assume the associated level of risk);
- Minimize unnecessary risk;
- Balance the risks and opportunities of all stakeholders;
- Allow, encourage and incent LDCs to meet their core market needs at the least cost; and
- Recognize that non-core customers will make their own least cost resource choices.

The detailed discussion that follows will provide recommendations specific to developing this new framework.

IV. DETAILED DISCUSSION AND RECOMMENDATIONS

A. SUPPLY-SIDE ISSUES

1. Should the Commission keep the 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?

Response by WNG:

The Commission should consider changes to the PGA process in response to changes in the gas industry. As the number and types of transactions in the gas market have grown, traditional reasonableness reviews have become more complex.

The PGA process should encourage the pursuit of the various new market opportunities available to an LDC for optimally utilizing its supply-related resources. Incentives for releasing idle capacity will encourage LDCs to improve their system load factors and improve overall economic efficiency as they better utilize the existing infrastructure.

At the same time, the Commission has been understandably cautious about second-guessing the capacity management decisions of LDCs. As LDCs continue to gain knowledge through experience, they will be able to skillfully participate in the secondary market, which will significantly benefit core market customers.

Risk management tools available to LDCs should be evaluated in Least Cost Plans. Principles of least cost and reliability are often at odds with one another. Risk management techniques can be useful in balancing competing principles.

The following goals should be addressed when considering changes to the PGA. The structure should:

- *Measure the effectiveness of purchasing strategies and management of upstream capacity resources;*
- *Provide objective standards to augment, if not replace, post-period reasonableness reviews;*

- *Provide clear cost reduction/optimization incentives; and*
- *Recognize increased utility gas supply portfolio risk.*

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

<u>*Response by WNG:*</u>

Yes. A mechanism containing the following concepts would encourage more efficient supply-side acquisitions by LDCs.

- *An objective, identifiable benchmark that the company could use to measure performance as it makes supply-side acquisitions choices;*
- *An incentive to optimize utilization of upstream resources;*
- *Minimize the regulatory burden of reviewing the reasonableness of the multitude of individual gas purchase transactions;*
- *More efficient price signals to potential direct gas supply purchasers; and*
- *Permit the possible use of market-specific mechanisms.*

Mechanisms that, to varying degrees, incorporate these concepts have been tested in other jurisdictions. A review of these mechanisms by those participating in the NOI process would prove useful in determining desirable changes to the Commission's existing mechanism.

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?**

<u>*Response by WNG:*</u>

Given the increasingly large number of gas supply transactions, it will be difficult for the Commission staff to review individual transactions. With the competitive gas supply options available to an LDC, it would be more appropriate for a review to have increased focus on an LDC's overall performance while reviewing certain types of transactions, such as the addition or permanent release of capacity resources, for prudence.

LDC gas commodity purchase decisions must be made rapidly and frequently. Requiring after-the-fact justification for each of these decisions imposes costs that will reduce the ability to make decisions.

The dynamic nature of the gas supply market requires LDCs to be forward-looking and innovative. Regulation should provide incentives to encourage innovation which results in lower costs consistent with reliable supply.

While LDCs have opportunities to participate in transactions that reduce gas supply costs, sufficient incentives are needed to take on added risk including both price risk and credit exposure from off-system transactions. The traditional outcomes of prudence reviews, that is, pass-through or disallowance, are powerful disincentives to accepting incremental business risk.

Establishing a different approach to prudence review may be appropriate in order to disaggregate the long-term commitment to capacity resources from commodity resource decisions. The Commission should consider incorporating some ex-ante review of long-term capacity resource plans with benchmarking or index-based treatment of commodity purchases.

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

<u>Response by WNG:</u>

The company has recently made significant changes in its line extension policy to reflect the economics of growth on its system. We believe that our new policy is a marked improvement over the previous policy and allows the company to grow economically. However, the policy could evolve to allow for extending facilities into undeveloped areas at the time it is least costly to do so. For example, when other infrastructure is being installed, gas facilities should be considered for installation where formal growth plans exist, even if this is in advance of an identified customer's request for service. Alternatively, the policy should accommodate place-holder services (such as propane) in remote areas until they can be economically reached by the distribution system. There are similar opportunities in developed areas not currently served by natural gas when existing infrastructure is disturbed.

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?**

   Response by WNG:

   Exit fees are not appropriate for universal application. It is useful, however, to use an exit fee to eliminate or reduce the risk of future stranded investment, when agreed to by the customer as a condition of service. WNG does not acquire long-term resources for non-core market customers or enter into special contracts for new facilities without some contractual assurance of cost recovery.

   Physical bypass should be dealt with differently than migration to transportation.

   Cost-based rate designs and use of marginal cost pricing techniques in special contracts are currently being effectively employed to eliminate uneconomic physical bypass.

   The loss or migration of a single customer does not represent the same impact on the system as an entire group of migrating customers. In the case of migration to transportation, LDCs should be allowed the flexibility to re-package the otherwise under utilized resources into services that will be valued by non-core customers. These unbundled services will directly contribute to lowering the cost of service to core customers.

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?**

   Response by WNG:

   The traditional categorization of utility customers is changing. LDCs are redefining customer classes as core or non-core, based on distinctions such as whether the *customer has the ability to choose an alternate energy supplier. The traditional customer class distinctions are changing because aggressive marketers and new technologies provide more customers with access to greater choice among energy suppliers. A growing number of weather-sensitive customers, such as schools and hospitals, are buying gas supplies from marketers. If their gas supply is interrupted, this may leave the LDC as the supplier of last resort.*

We believe the obligation to serve non-core customers (including transportation customers) should be contractual, containing specific parameters, including the amount of a particular type of service, price, re-entry fees, recall rights and other trade-offs. Re-entry fees should be structured to protect the core market from incremental costs associated with returning transportation customers. Re-entry fees should not, however, be used as barriers to unbundled services.

WNG's transportation service tariff addresses the issue of customers wishing to return to sales service and includes a mechanism for administering it. The mechanism is a product of our recent rate restructuring case, Docket No. UG-940814.

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?**

<u>Response by WNG:</u>

It is our experience that special contracts are effective tools for addressing bypass, but not the only tools. Cost-based rates and rate designs reflecting marginal cost principles are key to preventing uneconomic bypass. The removal of cross-subsidies between customer classes also contributes to minimizing bypass risk. Ultimately, the cost to the customer must be in line with the customer's valuation of the particular service.

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?**

<u>*Response by WNG:*</u>

The answer to this question should be determined on a case-by-case basis, giving consideration to several factors. The sharing of cost responsibility could depend on the degree to which the rates for the service class at issue were cost based, that is, the degree to which other customer classes were subsidized. Were all avenues of bypass prevention, including the use of special contracts, pursued? Are the stranded resources remarketable? Has the LDC been adequately compensated for the associated bypass risk? The answers to these questions will aid in determining the degree to which remaining customers should be responsible for cost recovery associated with physical bypass.

C. <u>UNBUNDLING</u>

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?**

<u>*Response by WNG:*</u>

The keys to serving the best interests of all customers are flexibility and fairness. The Commission should allow LDCs the flexibility to provide unbundled services that meet their customers' needs. Customers who want a competitive price will shop for it. Likewise, customers who want the convenience of bundled services will pay for it. Rebundling of services to meet the market and derive shared benefits for the core market should be encouraged. LDCs must be able to respond to the needs of both core and non-core customers.

Unbundled services should include both a core/non-core distinction and core aggregation to the extent the LDC's system can economically accommodate these options. The benefits of competition are available to both core and non-core customers.

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?**

Response by WNG:

LDCs may offer services upstream of the city gate (on- and off-system sales, parking, lending, buy/sell and exchange arrangements, capacity release, peaking, storage) as well as downstream (standby sales, transportation, balancing, demand-side management). The services to unbundle should be based on customer demand. However, those services which cannot be economically unbundled should remain bundled.

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

Response by WNG:

Unbundling should allow the rate design for each distinct service to be consistent with the characteristics of that service and the nature of the market being served. Price flexibility will promote the economic efficiency that regulation was designed to ensure.

The WUTC has adopted unbundling for WNG in the form of transportation service without artificial barriers such as minimum annual volumes. This service should continue to be cost-based. (Lack of a competitive market generally requires this.) Commodity services should be offered as well. However, pricing of these services should be marked-based to assure the maximum contribution to core customers' cost of service. The presence of marketers and brokers in providing these services ensures competitive alternatives.

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

Response by WNG:

Yes.

Unbundled services should be structured to ensure that system integrity and service reliability to the core market are not compromised. Protection of the core market's *interest will continue to be the responsibility of the LDC and the regulator. WNG believes non-core customers have chosen to assume the risk for their own supply.*

Nothing should obligate an LDC to assume the role of supplier of last resort for these customers without adequate compensation for itself and the core market.

While the obligation to serve certain groups of customers may require revisiting, practically speaking , an LDC will make every effort to continue service. There are several reasons for this including:

- *Public policy considerations dictate serving residential customers as well as other customer group; e.g., hospitals, schools, etc.;*
- *It is logistically difficult to selectively shut off and reactivate service to large numbers of customers; and*
- *Interruptions reduce the LDC's distribution margins.*

D. LEAST COST PLANNING

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

Response by WNG:

Least cost principles will be critical to an LDC's future success regardless of the rule. Basic fiscal survival in today's environment necessitates rigorous demand and resource analysis. The rule and its implementation should continue to evolve. While flexibility remains very important, some additional guidance would be useful.

For example, clearer guidelines and minimum requirements for facilities planning would aid in ensuring that the presentation of a sound facilities plan and planning process meets with Commission acceptance. WNG also believes the rule should specifically address the issue of long-term least cost facilities planning, as discussed above under line extension policies (A.4.). The least cost opportunity for facilities extensions may often occur in advance of a customer's request for service. Typically these opportunities are prior to or in conjunction with changes in other infrastructure. Examples include road resurfacing and improvement projects and the expansion or replacement of underground electric, water, cable or telecommunication facilities.

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?**

Response by WNG:

Yes.

LDCs should be empowered to manage the level of information that is confidential within the Least Cost Planning (LCP) process. A new section should be added to the LCP rule to enable this latitude and encourage LDCs to strike an appropriate balance between necessary confidentiality and an open process.

As a more structured alternative, the company and Commission staff could meet and decide which information is suitable for confidential treatment. In the event agreement could not be reached on certain items, those items would be referred to the Commission. Confidential information could still be shared among appropriate parties (e.g., Staff, Public Counsel, WSEO, NWIGU etc.) under the protection of confidentiality agreements.

Perhaps even more critical is the issue of access to other regulatory proceedings by third parties. Customers and their advocates are appropriate participants in regulatory proceedings. Parties providing merchant services are not appropriate participants (as customer representatives). Problems will arise from the inability to distinguish between customers and competitors. There may be proceedings from time to time that will examine the competitive aspects of LDC operations. In those instances it would be appropriate for competitors to participate in the process. New regulation on this topic will be required to avoid unnecessary litigation as LDCs attempt to minimize the costs of serving the core market.

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?**

Response by WNG:

The cost of currently available DSM resources will put upward pressure on rates. Under current cost recovery mechanisms, these competitive impacts are mainly an issue in the sales/merchant function.

General issues remain about having different planning standards for different service providers. While it may be impractical to have least cost standards apply to all merchants, the recovery of DSM costs should be accomplished without competitive impacts. Recovering DSM costs from firm sales customers would eliminate any competitive impacts under current industry conditions. If unbundled services become a significant factor in the core market, it may make sense to consider a charge that is independent of service provider choice. A demand-side energy service charge is one mechanism that would effectively mitigate the competitive impacts of DSM cost recovery. Whether or not the marketplace will respond to a DSM energy service charge that will recover 100% of program costs, remains to be seen.

Societal costs are also a similar concern. Bad debt costs, the costs of not being able to shut off customers for non-payment in the winter, pay station costs and utility taxes are other cost elements that need to be collected in ways that do not affect the competitive position of any party.

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

Response by WNG:

The rule should be updated to be more consistent with the realities of the industry today.

WNG believes that the mandate for estimates of DSM potential for interruptible sales customers is unnecessary and should be considered for deletion. The company should be allowed to pursue demand-side and contractual opportunities that are shown to be *sound, but performing a sector-wide assessment of DSM for interruptible customers does not appear to be the best use of ratepayer or shareholder funds.*

The rule should also allow and encourage some of the emerging strategies to mitigate core market costs. For example, an unbundled commodity service for on-system transportation customers could aid in defraying fixed contract costs of commodity purchases to the core market.

E. DEMAND SIDE MANAGEMENT AND CONSERVATION

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

Response by WNG:

The current methods of program delivery and evaluation are working well. Each LDC identifies the DSM opportunities in their customer base and implements programs to address the specific circumstances that they face. High quality process and impact evaluations are the key elements to determining program cost-effectiveness and identifying potential improvements.

The cost-effectiveness tests applied to DSM resources should remain the Utility Cost Test and the Total Resource Cost Test (TRC). The TRC is a valuable policy screen for determining which DSM resources are appropriate for acquisition. The Utility Cost Test identifies the appropriate cost range to be borne by the utility. The cost to the utility is the appropriate cost to be compared with other resource options. The Rate Impact Test will take on a greater role in forming program offerings and determining the size of the annual DSM effort, if the competitive impacts of DSM cost recovery cannot be mitigated. (DSM cost tests are covered in more detail under E.3).

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

<u>Response by WNG:</u>

DSM programs should be paid for by firm sales service ratepayers. Firm sales service demand is the cause and justification for DSM programs. Therefore, the costs for DSM should be borne by this sector. This method would minimize the competitive impacts of DSM cost-recovery.

Cost sharing needs to be balanced between participants and non-participants. However, there would not be any cost-effective DSM resources available in customer facilities if customers were willing to pay 100% of the measure's cost. The market would already have acquired these resources. In the case of new technologies or information barriers, market transformation is one strategy that will help mitigate participant versus non-participant equity issues while providing some level of DSM acquisition.

LDCs should be encouraged to explore creative mechanisms for cost sharing with participants. These could include low-interest loans and energy service charges. Any net costs (costs in excess of those recovered directly from participants) borne by the utility should be recovered through a tracker mechanism with a short amortization period. This will minimize the build-up of regulatory assets and the issues that may go along with such a build-up. Should unbundling come to the core market, either merchants serving that market should be held to least cost standards or LDCs should continue to provide DSM services to all firm customers, with the costs also spread to all firm customers.

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

<u>Response by WNG:</u>

The Total Resource Cost Test remains a useful policy screen for evaluating which DSM resources are appropriate for acquisition. The utility cost perspective determines the cost to be paid by the utility and is the appropriate cost to use in comparing DSM with other resources. The Rate Impact Test is a useful tool to help evaluate cost sharing and overall DSM expenditures. The Participant test is useful in evaluating the benefits program participants realize. These tests should be used to evaluate most full-scale programs.

Low-income programs have many additional aspects that are not easily evaluated by most benefit-cost tests. Low-income programs should be evaluated with a Utility Cost Test. Low-income programs would be an excellent topic for a future workshop.

These standards are inappropriate for pilot programs. These programs are generally less cost-effective because of their lower participation rates and relatively high costs of planning, data collection and evaluation. Pilot programs are necessary tools to assess and develop the DSM resource. They should be used when there is a reasonable expectation that a full-scale program will emerge from the pilot. These programs should be used to test measure cost and performance and to establish technology viability.

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?**

Response by WNG:

Yes.

Non-energy benefits should be considered when evaluating energy efficiency options. This should be done when determining the benefit-to-cost ratio under the TRC. Non-energy benefits should not be internalized. Resources should be selected on the basis of their cost to the utility. Inclusion of environmental adders for the purposes of passing a Total Resource Cost Test is also appropriate. This would effectively turn the TRC into a Societal Cost Test. If environmental adders are included for meeting a TRC, then it would be desirable to have some standard factors that were universally applied (e.g., $/ton of emission avoided).

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?**

Response by WNG:

If DSM plant is allowed to build up, it does pose a threat to future competitiveness and/or a risk of becoming stranded.

A cost recovery mechanism that has a short amortization period will minimize these risks to acceptable levels (see E.2). Also, commercial and industrial customers that may potentially leave the core market can be required to repay the unamortized portion of any DSM assets they have acquired from the company. This would be done through contractual arrangements at the time they participate in the DSM program.

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.)

<u>Response by WNG:</u>

WNG believes the Commission is already in substantial compliance with EPACT Section 115, 1. Integrated Resource Planning.

Items A and B of this subsection are essentially current practice. Item C also is a current practice, however some further clarification of methods would be useful.

Item D may not be a current practice. However, the EPACT language is suggestive of an approval process that may be useful as an alternative to a transactional review for certain capacity resources (new additions and long-term releases). Commodity transactions and short-term capacity release could continue to be handled within the PGA. WNG believes a strong commitment exists that Least Cost Plans will be implemented and that the current practice is in alignment with the spirit of item D.

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

<u>Response by WNG:</u>

WNG believes that EPACT Section 115, 2. Investment in Conservation Resources, has merit and should be adopted. Recovery of lost margins for DSM program implementation has been one of the reoccurring stumbling blocks to all-party solutions of DSM cost recovery. Compensation for the margin lost by virtue of DSM programs should be *granted to the extent those impacts are over and above what would have happened in the program's absence.*

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?**

Response by WNG:

Companies should be encouraged to use outside contractors in implementing DSM programs. Where contractor services are not available, or are too costly to be incorporated in a cost-effective program, LDCs should be encouraged to use internal resources to produce programs that are cost-effective.

G. MISSED QUESTIONS

1. **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?**

Response by WNG:

The following questions may be worthy of consideration:

- *What is the appropriate role of the new market players (agents, brokers, marketers) in the regulatory process?*
- *What guidelines should be adopted regarding the appropriate level of reliability for services in the new competitive environment?*

H. CONCLUDING REMARKS

Washington Natural Gas Company appreciates the opportunity provided by this inquiry. The changing character of the gas industry makes it highly desirable that existing regulations be more responsive and flexible to address new market conditions. Emerging competition is already redefining the LDCs' business. Customers are testing whether the LDCs can meet their needs for new services.

The development of new regulation that encourages creative solutions to market opportunities which balance the interests of customers and LDC shareholders is warranted. Regulatory mechanisms must be developed for LDCs to remain competitive in today's energy market while providing service at least cost.

Washington Water Power

Washington Water Power

September 29, 1995

Washington Utilities & Transportation Commission
Chandler Plaza Building
1300 S. Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Attention: Steve McLellan, Secretary

Re: Docket No. UE-940778 -- Comments of the Washington Water Power Company

Enclosed are the comments of the Washington Water Power Company on the Commission's Notice of Inquiry on "Examining Regulation of Local Distribution Companies in the Face of Change in the Natural Gas Industry". Ten copies are provided as well as the electronic version on a 3.5 inch, high density diskette with the software indicated on the label.

Please provide us with copies of other parties' comments in this proceeding. We look forward to working with the Commission in further examining issues identified in this process.

Sincerely,

Thomas D Dukich

Thomas D. Dukich, Manager
Rates and Tariff Administration

enclosures

The Washington Water Power Company

RESPONSE TO NOTICE OF INQUIRY (NOI)
September 29, 1995

Examining Regulation of Local Distribution Companies
In the Face of Change in the Natural Gas Industry

WUTC Docket No. UG-940778

Introduction

The Washington Water Power Company appreciates the opportunity to provide comments on the changing natural gas industry as it impacts local distribution companies ("LDCs") and our customers. WWP has three general observations which shape our response to this NOI.

First, natural gas is a "fuel of customer choice" because competitive alternatives exist. Open access is present for large customers to arrange their gas supply directly from producers. Even residential customers have choices for their heating fuel needs from among natural gas, oil, electricity, wood, and propane.

Second, natural gas supply has become a tradable commodity which is largely deregulated. LDCs do not generate or produce this commodity. Larger customers of LDCs may purchase natural gas directly from producers, marketers, etc. In addition, many players (producers, pipelines, agents, aggregators, etc.) exist such that the natural gas industry is not vertically integrated.

Third, LDCs are different amongst themselves. Each LDC is unique such that some regulatory mandates may have universal application while others may be utility specific.

These observations lead us to two broad conclusions which are further developed in our comments.

Regulation should be compatible with how LDCs run the business. Currently, gas cost savings are flowed through to customers in the purchased gas adjustment (PGA), but related (non gas supply) cost recovery has a lag between rate cases. Some of these costs are incurred to optimize the gas system for the benefit of the core customers. Examples include administrative costs associated with off-system sales and capacity releases, FERC litigation cost recovery, etc.

Pricing remains an issue of concern to compete on an equal footing with gas supply aggregators and marketers for high load factor customers. Presently, the Company's transportation customers purchase gas directly through marketers. The majority of these customers have high load factors whereby, if the appropriate regulatory vehicles were in place, the Company could be the gas supplier for these customers with the result being lower costs to core customers. Additionally, incremental revenue gain of special contracts may in actuality be less than that imputed by regulatory decisions which offers benefits to customers but not the company.

Flexibility will continue to be important in meeting customer needs. The necessity of the WUTC's efforts to continue flexibility, while assuring rates and conditions which are fair, just, reasonable and sufficient, will be heightened in the future. This should be reflected in pricing, where appropriate, in the least cost planning rule, and in the application of the special contracts rule.

WWP believes that our success in the changing energy industry will be dependent on our ability to understand and effectively respond to customer needs. The primary focus of our gas business is to provide customers with reliable service at a competitive, low cost. New customers will be added through cost-effective gas main extensions into new markets and by switching customers to natural gas from alternative fuels. On the supply side, we are focused on innovative approaches to reducing supply costs while strengthening service reliability across our entire system.

Supply-side issues (Questions A1-A4)

Current PGA Mechanism. WWP believes that the PGA has worked as intended for recovery of those costs over which the LDC has limited control. WWP suggests no changes to this mechanism at this time other than ideas for potential incentive enhancements.

Incentive Mechanisms. WWP recommends that any incentive mechanism be at least partially tailored to the individual utility. Any incentive system should have as a basis a fair allocation of costs and benefits to customers and the Company. WWP would like to see a simple, straightforward approach and suggests that such a mechanism might consist of three phases. The first phase might include a recovery of prudently incurred costs associated with the minimization of gas costs. Some of these incremental administrative expenses, which are currently not recovered through the PGA, are incurred specifically to minimize gas costs to core customers. For example, LDCs typically have underutilized pipeline capacity for some portions of the year. This capacity is being released to third parties to minimize costs for existing customers. But this activity is labor intensive and involves coordination among several departments within the Company. Additionally, off-system gas sales have served to reduce customers' cost of gas significantly. However, the volume of transactions and tracking create the need for additional administrative support. The cost of this additional support goes unrecovered between general rate cases while, presently, all benefits flow to customers.

Another category for potential inclusion in the Phase 1 approach includes FERC litigation costs beyond those included in the Company's rates. Such costs can directly benefit our customers and are incurred primarily on the customers' behalf.

An additional area of cost recovery, which may be utility-specific, include regulatorily imputed margins which are not realized in actuality. For example, special contracts often include rates below those which were imputed in the Company's last general filing. Retention of a special contract customer provides a contribution to fixed costs, resulting in lower rates to other customers as compared to the loss of a customer. Without recognition of actual revenues obtained, core customers receive the same fixed cost contribution as if the special contract customer was on a tariffed rate schedule, yet the Company receives less margin. A more equitable situation, given the benefits received by core customers, would be for a sharing of the benefits and costs of customer retention through special contracts.

The second phase might involve proposals to reward innovation and cost efficiencies in areas such as gas procurement and capacity release.

The third phase would be a longer term approach which could involve performance-based ratemaking in some form. A performance-based mechanism may be as narrow as to relate to purchased gas costs only or as broad as a return on investment system. The latter could include price caps or percentage of sales benchmarks to recognize reduced levels of investment but increased throughput.

<u>Prudence Issues.</u> WWP recommends no change to prudency evaluation at this time. The Commission's *ex-post* analysis has generally been implemented in a reasonable manner. WWP strongly believes that open communication between the WUTC staff and the Company

leads to a reduction of contested issues. The Company believes that pre-approval brings protracted hearings and the temptation for micromangement.

Line Extension Policies. WWP recommends no change in line extension policy. The Company's current policy is simple, flexible and effective.

Customer choice and competitive by-pass issues (Questions B1-B4)

Exit/Entry Fee Policy. WWP does not generally support exit or entry fees, except when instituted on a contractual basis where significant incremental investment is required to provide service, i.e., dedicated pipe and/or upstream pipeline capacity. In those instances, contractual terms by prior agreement can provide for the recovery of such investment directly from the customer.

Special Contracts and Banded Rates. LDCs today operate in a competitive market. Many large commercial and industrial customers have options to arrange for their gas supply and transportation needs through LDCs, marketers, brokers, wholesalers, aggregators, producers, and interstate pipelines. Many of these entities are not subject to regulatory oversight. It is important to LDC core customers that the LDC remain competitive to other customers' alternatives in an expeditious manner. Delays and uncertainty in obtaining regulatory approvals can cause a loss of a customer who can contribute to fixed LDC costs to the benefit of core customers.

The banded rate RCW is intended to allow utilities to offer prices, within an accepted floor and ceiling range, to customers subject to effective competition. Once the parameters are established, the price can be offered without being subject to regulatory approval. The downside of the banded rate approach is the potential for lengthy hearings to establish these parameters for mostly unknown future scenarios.

From a pragmatic perspective, the special contract rule is the preferred approach if affirmed by the Commission to be flexible and expeditious. The uncertain nature of cost recovery and imputed margins remain a concern with both the banded rate and special contract approaches. In terms of addressing "other mechanisms" as requested in the NOI, WWP feels none is necessary at this point if the Commission's preference is known for pricing in a flexible manner to meet the Commission's public interest responsibilities and the Company's needs. The Company's concerns in this area are the ability to respond to customers in an expeditious manner as well as the "lost margin" issue.

<u>Lost Revenue from Stranded Investment.</u> While the Company is not in favor of exit fees, WWP does not wish to understate the issue of load loss and related impacts on customers or the Company. The Company believes the costs associated with load loss should be shared by the utility and its customers on a basis which takes into account factors such as magnitude, the efforts of the utility in preventing the loss, the competitiveness of the utility's rates, etc.

Unbundling (Questions C1-C4)

A certain level of gas unbundling has occurred in order to meet customers' needs and competitive alternatives. Many industrial and commercial customers have direct access to supply and pipeline transportation and often only desire distribution services from LDCs. WWP has provided for distribution-only service for a number of years, even though the cost assignment and rates associated with the service are dated. As additional customer needs develop, further service/rate unbundling will occur.

WWP believes that customer-responsive unbundling should continue to be applied to LDCs. Technological and informational advances make unbundling more feasible to smaller customers. But full unbundling for customers at all levels of service would present the Commission with a host of cost allocation issues. Further, it may not be in the customer's best interest to unbundle all services given a lack of customer expertise in the industry with a limited economic payback. For example, prices for gas supply have decreased in the past few years, but the costs of pipeline transportation for a low load factor customer have doubled. (Demand charges on Northwest Pipeline were at $4.73/month for every MMBtu of contract demand in November, 1992; today's rates are at $8.79 and proposed to be $9.28 in February, 1996.)

WWP encourages a dialogue with staff and other interested parties to explore possible unbundling opportunities. These options must balance the desire for greater choices for some customers, fair cost allocations for all customers, and the continued opportunity for fair and reasonable returns for the LDC. Even without additional unbundling, WWP may find it desirable to provide existing customers with services such as balancing or storage which would require revisions to existing tariffs.

Least cost planning (Questions D1-D4)

WWP believes that a least cost, or more aptly entitled "integrated resource", planning rule has value. An IRP rule allows the Company to dovetail its internal planning process in a manner responsive to regulatory concerns.

WWP suggests that the IRP rule be updated to reflect the natural gas environment which has changed in the intervening time period from when the rule was first established. Specifically, the Company recommends 1) increased flexibility for timing of filings to align multi-state requirements, 2) consideration that fewer technical advisory committee meetings may be a practical way to increase public participation, 3) additional meetings, as necessary, with staff to pursue issues in more detail that may be of a confidential nature, 4) modified terminology to include the acknowledgment of sensitive data and how it is handled and that LDCs are seeing increased competition in the market place from non-regulated marketers, 5) suggested Commission guidelines on distribution analysis, and 6) that least cost planning embodies integrated resource planning to include reliability of supply, transportation and distribution.

Demand Side Management and Conservation (Questions E1-E5)

WWP's DSM mechanism as approved by the WUTC meets several competitive and public policy concerns associated with conservation. The DSM tariff rider provides DSM funding and, as a distribution charge, does not create competitive disadvantages. WWP intends to continue its DSM efforts with the following objectives:

- Maintaining continuity in the promotion and support of energy efficiency;
- Promoting the transformation of consumer markets to energy efficient choices; and
- Providing customer service.

The DSM Tariff Rider (of 0.55%) provides a minimal base of funding to support a viable gas DSM program. The majority of DSM installation costs are borne by participants. Thus, WWP believes its funding mechanism provides a proper balance for supporting DSM programs in an increasingly competitive industry. Additionally, this DSM accounting treatment avoids creation of regulatory assets and stranded investment.

EPACT Issues (Questions F1-F3)

The WUTC appears to currently be in compliance with standards espoused in the National Energy Policy Act Section 115 for integrated resource planning and demand side management with the potential exception of lost margin recovery on DSM.

If the Commission adopts the EPACT standards, WWP 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. This is because WWP currently (and intends to continue to) encourages customers to work with local contractors for provision of DSM services. The majority of WWP's DSM programs steer customers to independent contractors.

Conclusion

In conclusion, the Company believes that the regulation of LDCs must be compatible with the changes occurring in the natural gas industry. As LDCs must become increasingly flexible to meet customer needs, so too must the regulation of the LDCs become more flexible. If the LDC is expected to earn authorized profits and minimize costs, it must have the same opportunity to act in the marketplace as unregulated entities such as marketers and brokers. Lastly, the PGA remains a useful mechanism which could potentially be improved by incorporating a few changes which reflect some of the changes in the marketplace. WWP appreciates the opportunity to provide these comments and hopes these comments assist the Commission as it defines issues for further examination.