NRRI 93-15

PRESENTATIONS AND PAPERS FROM THE NATIONAL SEMINARS ON PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE ENERGY POLICY ACT OF 1992

Sponsored by

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and

The Electric and Gas Division
of
The National Regulatory Research Institute
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PREFACE

Without question, the electric services industry is undergoing its biggest change since the mid-1930s. The Energy Policy Act of 1992 represents the latest in a series of changes that are transforming the industry from regulated monopolies to a more competitive structure. Electric service industry representatives have recently been attempting to anticipate and prepare for these changes in various fora across the country. State and federal regulators will also need to make adjustments to their procedures in order to take full advantage of the opportunities these changing industry conditions present for ratepayers.

In July of 1993, The National Regulatory Research Institute (NRRI), conducted two seminars[1] on the public utility commission issues related to the Energy Policy Act. The seminars were funded by the U.S. Department of Energy's (DOE) Office of Policy, Planning, and Analysis. The objective of the seminars was to assist states in the implementation of the Act. DOE recognized the critical role that state public utility commissions will play in the Act's performance, and were, therefore, interested in facilitating the states' understanding and implementation of the Act's provisions.

This comprehensive and far-reaching Act contains thirty titles that address a variety of issues ranging from water conservation to nuclear waste. The seminars focused on the two sections of the Act of most immediate concern to state commissions, Titles I and VII. The sections of these proceedings correspond with the session outline of the seminars. The first provides an overview covering the general issues of concern to states with respect to the Act; the next two deal with the Title I changes to the Public Utility Regulatory Policies Act of 1978; and the last three sections deal with the changes to the Public Utilities Holding Company Act of 1935 and the Federal Power Act that are amended by Title VII of the Act.

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[1] The first seminar was held in Portland, Oregon on July 15 and 16, 1993 and the second was held in Indianapolis, Indiana on July 19 and 20, 1993.

As reflected in these proceedings, various options were suggested and examined as to how states should implement their responsibilities. While there was no general agreement on the direction that states should take (as might be expected given the diversity of participants), there was an understanding at both seminars that the Act will have a significant effect on the electric services industry for many years to come and that all interested parties should brace for its impact and prepare for its challenges.

Two earlier NRRI reports discuss the requirements and regulatory issues that state commissions face as a result of the Act: *A White Paper on the Energy Policy Act of 1992: An Overview for State Commissions of New PURPA Statutory Standards* (NRRI 93-6, April 1993); and *A Synopsis of The Energy Policy Act of 1992: New Tasks for State Public Utility Commissions* (NRRI 93-7, June 1993). A future NRRI report will address the longer-term implications for the industry's structure and possible regulatory responses from state and federal regulators.

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December 1993

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SESSION I

NEW RESPONSIBILITIES AND OPPORTUNITIES FOR THE STATES, FEDERAL REGULATORS, AND ELECTRIC UTILITIES

NATIONAL REGULATORY RESEARCH INSTITUTE
Public Utility Implementation of the Energy Policy Act of 1992

Comments of
Commissioner Patricia M. Eckert, California PUC

Portland, Oregon
July 15, 1993

Thank you. I am pleased to be here to discuss some of the challenges the entire electric industry faces as fundamental changes unseat a previously secure landscape. California, as you may be aware, is in the midst of a comprehensive review of the "... conditions the electric industry currently confronts, as well as future trends likely to influence the [electric] industry." Our Commission's Division of Strategic Planning, under our direction, undertook a broad study of the past actions and events that produced the regulatory structure that we have in place today in California. From that study, the Division of Strategic Planning produced what has been termed the "yellow paper" entitled "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future." Circulated widely, the yellow paper is provoking interesting debate and discussion, and is receiving general praise.

I would like to discuss the California Commission's thoughts, and my thoughts, on the yellow paper, how our review incorporates changes caused by the National Energy Policy Act of 1992, and what steps the California Commission might take based on our current comprehensive review of the electric industry.

The seed corn that initiated our Commission's concern, and that which still rests at the heart of our dialogue is the issue of **vision.** Under the Commission's daily crush of utility business, with all of the decisions we make to shape prospective energy policy, we found ourselves limited, unknowingly, by shortsightedness. Our biweekly decisions became guided by short-term stimuli and changes in the electric industry without the benefit of a complete, long-term vision for the future of the industry.

Each additional decision we made without such a vision added policy that was perhaps incongruous with long-term goals though they may have made sense at the time. Along the way, however, signposts of change in the industry were all around us, and we were very aware that they existed. Our problem was that we didn't have an effective means to put all of the pieces of change into context. We had no framework within which to evaluate whether the incremental policy changes that we contemplated would bring about all of the good things we generally envisioned. Our only stable principle was that Commission decisions promote least-cost, environmentally sensitive energy services

on a non-discriminatory basis. Well, that's rather broad, and can be fulfilled in a variety of ways. It is certainly not enough of a guide to address all of the changes and pressures facing the industry.

Our frustration was exacerbated, and the vision issue came to a head in mid to late 1992 when our Commission struggled with a petition brought by Southern California Edison Company. In its petition, Edison sought approval of a form of "all-supply source bidding" as an alternative to the QF-only bidding structure the Commission developed in our resource procurement proceeding. We denied Edison's petition because we had not contemplated such a large competitive step forward. Our QF-only competitive framework, we said, was to serve as a transition toward full competition in generation. We also acknowledged the inadequacy of our resource procurement framework to address the many issues surrounding all-source bidding. However, we accepted that expanding the pool of potential bidders was no longer a "remote theoretical construct," and that "The time is ripe to plan and begin the steps leading to all-source bidding."

What we recognized in the process was that once one reviews one aspect of the current electric regulatory construct, here resource procurement, our review must also encompass the whole. We understood that touching procurement on one side of the equation meant fiddling with ratemaking to some extent on the other side. Again, however, without the vision, we were quite hesitant to move expediently.

Our task, then, was to formulate a vision, and for the past six months we have ventured down this path. So, where are we at this point?

The Division of Strategic Planning's Yellow Paper

Released this past February, the Yellow Paper, written by our Division of Strategic Planning, stood as the starting point for an exchange.
It now stands as the centerpiece to guide continuing discussions about the future of California's electric industry. The paper thoroughly chronicles the historical trends, and past conditions that together shaped today's electric regulatory framework. The paper goes on to identify today's economic status, and future trends, and contrasts today's economic reality with regulations currently in place for the state's investor-owned electric utilities.

Quite succinctly, the yellow paper concludes the following:

1. **"California's current regulatory framework, significant portions of which were developed under circumstances which no longer persist, is ill suited to govern today's electric services industry."**

and,

2. **" The state's current regulatory approach is incompatible with the industry structure likely to emerge in the ensuing decades."**

The paper characterizes our current regulatory framework as a hybrid with regulations keyed to cost of service ratemaking principles, and policies tied to market oriented

solutions. Because of this hybrid, the paper cites five problems that our Commission, the industry and consumers face:

1. **The current regulatory regime blunts incentives for efficient utility operations.**

2. **The current regulatory program increases the potential for inefficient investment due to unbalanced incentives governing utility investment options.**

3. **The current regulatory approach requires many complex proceedings, which increase administrative costs and threaten the quality of public participation and Commission decisions.**

4. **The current regulatory approach offers utility management limited incentives and flexibility to respond to competitive pressures.**

5. **The current regulatory approach conflicts with the Commission's policy of encouraging competition in the electric services industry.**

The conclusions and resulting problems are quite an indictment of our current framework. I happen to agree with the report's conclusions and the problems I just enumerated. Our utilities face a myriad of incentives: to build versus to buy power, to invest in energy efficiency or to invest in generation, to keep O&M costs down or up, or to increase productivity or to say "the heck with it." PG&E, for instance, has the simultaneous incentives to run is nuclear units at Diablo Canyon as high as possible, and to invest as much as it can in demand-side management. For these two operations, PG&E can reap large rewards. Conversely, PG&E gains nothing, and arguably loses when it must buy QF power, or other purchased power in the market. The behavioral response to these divergent incentives are further muddled by the Energy Policy Act, which allows additional low cost competitors into the generation business, and allows the FERC to mandate wholesale transmission access.

The Commission's Full Panel Hearings

To continue our dialogue, the Commission held three Full Panel Hearings that we constructed to roughly mirror the yellow paper's final chapters. Our first hearing's goal was to explore whether today's regulatory framework is compatible with the current industry structure, and whether it is well equipped to adapt to future trends in the industry. The second hearing focused on the role of the utility in a changing industry structure. In the last hearing, we allowed the utilities to make detailed presentations, describing each company's vision, proposed corporate strategy, and recommended regulatory reform.

My impression of the hearings was that everyone was anxious to get to an answer despite our best attempts to first identify the problems, and generate options for a vision.

Most participants in our review process accept most of the conclusions drawn by the yellow paper. To the question "Is reform warranted?" posed in the first hearing, the

utilities resoundingly answered YES. And, for the most part, they agreed as to why we need reform. They all said that they didn't have the right incentives in place for efficient utility operations. They all said that the ratemaking and resource procurement apparatus was obsolete.
And, they all said that current regulation creates conflict, and tension between a shrinking utility market share and the opportunity for a utility to earn a fair rate of return.

What we haven't explored are the details about why the various distortions are present, and what specifically we as regulators can do to correct them.

At the next hearing, we heard from the utilities about what role they see themselves playing in the electric services industry of the future. Each utility sees itself serving its respective market in different ways. Southern California Edison wants to be a full service electric utility with the ability to compete for additional generating resources. PG&E is content to get out of the business of building new generation if they can get some flexibility in planning and procuring power. San Diego Gas and Electric is somewhere in between. A point that I took away from that discussion --one that San Diego Gas and Electric raised -- was that, whatever we do to reform regulation, give utilities the flexibility to form different models of reform. The notion of one size need not fit all is now permeating our thinking.

In the final hearing, we asked the utilities to present their "solution" to what they see as the "problems" -- consistent with their vision of the future. Not surprisingly, each utility offered variations of incentive ratemaking. SDG&E produced the most detailed proposal, breaking out its operating functions under different performance-based sharing mechanisms. Having recently been authorized a two-year experiment for performance-based gas procurement and generation and dispatch, SDG&E added a proposal for a base rate performance mechanism. Southern California Edison offered a six-point proposal for regulatory reform that consisted of performance based incentives on base rates and fuel costs, increased asset utilization, reasonableness review reform, demand-side management reform, and reforms to resource procurement. PG&E made a very general presentation that outlined its intention to develop a set of performance based incentives which sounded a lot like the other utilities'.

We closed the hearing process by saying that it was now time for us to make some decisions based on the information gathered thus far. We still must, in my judgment, determine our vision. This requires us to decide a few general principles up front, such as:

- **How do we wish to regulate, by managing or by guiding?**
- **Do we wish to have one form of regulation for all utilities or allow differences among them?**
- **Do we acknowledge and embrace competition to advance it, or do we ignore it?**
- **Should change be evolutionary or revolutionary? (a question debated in the last FPH)**

Only after we answer these preliminary questions, can we begin to evaluate the depth of change or reform necessary. We then must clearly identify what portions of the current regulatory framework are broken so that we do not create new sources for the same problems.

Let me make a few brief comments on the proposal's our utilities presented as reform, and then tell you what our Commission's next steps may be.

First off, I don't think that any of the utilities' performance based incentives go far enough to advance a vision, that is, other than the utility vision of essentially the status quo. Each utility wishes to fully participate if delivering electric services to its customers, with some variation as to procuring new power resources. In my view, incentive ratemaking is only a modest reformulation of the current regulatory regime. The most pronounced change incentive ratemaking creates is that it transfers the responsibility for cost management from the regulator to the regulated. Under current cost of service ratemaking, state commissions have the responsibility to review and approve all utility costs. Incentive ratemaking places the cost control burden back onto the utilities. Theoretically, however, traditional historical test-year ratemaking should give the same "answer" as you would expect from a performance-based incentive mechanism.

We gain a great deal by transferring the burden, but we potentially stifle the development of true competition. In other words, if what we mean by competition is to promote choice or other service providers competing in the utilities' service territory, incentive ratemaking will not get you there. Incentive ratemaking, if all of the indices and benchmarks are set appropriately, will force utilities to get their costs down. Although consumers would benefit from lower costs, I maintain that this will inhibit competitors from entering the market, thereby limiting even more change. So, while performance based incentives might better align ratepayer and shareholder interests, it may ultimately delay true competition and all of the attendant benefits competition may bring. In addition, under incentive ratemaking, I am afraid that our resource intensive administrative processes will remain intact, which is in no one's best interest.

Although I haven't developed my own vision, I foresee competition ultimately providing customers with choice. But, how do we get choice, and who should receive the benefits of choice? Our hearings with the industry avoided the issue of retail wheeling so that we could maintain civilized discussions. Nevertheless, developing a vision that includes allowing customers to choose service providers means that we must address which classes of customers will have that choice available. Invariably, our thinking process has to recognize the reality of retail wheeling, and perhaps, as the yellow paper describes "the inevitability of retail wheeling."

Introducing choice can be done incrementally, over time, or rapidly, by opening services up to competition. Our utilities appear to favor evolutionary progress in ratemaking, but not necessarily in combination with advancing competition. Not one utility offered even a suggestion that a customer of the future could choose from various service providers. A revolutionary step would undoubtedly introduce the utilities to pain because our utilities do not have the appropriate tools to compete at this point. We would have to provide those tools. Certain forms of incentive regulation may serve as useful tools for utilities to reduce their cost to become more competitive. High cost

utilities, saddled with old power contracts and mounting social costs, may force us to accept incentive regulation as a transition to competition.

Our Commission will further consider the utilities' incentive proposals as they bring them before us. Regardless of our review of the industry structure, the utilities' proposals will come before us. As I mentioned, we already authorized SDG&E to carry out an incentive experiment. Southern California Edison will be filing its test year 1995 general rate case later this year. They say that the filing will propose their six-point program for regulatory reform that I mentioned earlier.

Our challenge is to begin to formulate a vision whether or not utility proposals go forward. There is a timing dilemma between what the Commission formulates as a vision and when, and the utilities' efforts to respond to today's interest in getting rates under control. In some senses, I see this as a race. The utilities appear to be offering proposals to assuage short term concerns over high costs and high rates. They consider incentives as a bridge to a solution, or a solution in itself. I see the formulation of a vision as the primary goal despite how the utilities respond to short term rate concerns.

This places the Commission, I believe, on a fairly tight time frame, at least in regulatory terms, to develop this vision. We intend to maintain the momentum this industry review process has generated since our Division of Strategic Planning issued its yellow paper. I hope the discussions today also help to stimulate thought in this area because change is upon us. It's not a matter of whether the industry reforms, it's a matter of when. With that in mind, I think California, and the industry can learn a lot from the recent gas industry restructuring. At one of our hearings, I asked Terry Thorne of Enron what counsel he would give to the electric industry, having worked through the gas restructuring. He said, speaking from a regulatory point of view, that "We did not have truly a vision. I would question whether FERC had a vision for the industry. They kind of unleashed these forces and they see where we're going to go." I would like to learn from Mr. Thorne's experience. I think we need a vision for the electric industry. Thank you.

1992 NATIONAL ENERGY POLICY ACT: MARKETS AND MANDATES

Steven M. Fetter
Chairman
Michigan Public Service Commission

Seminar By
U.S. Department of Energy
National Regulatory Research Institute
July 19, 1993
Indianapolis, Indiana

* National Energy Policy Act (NEPA) incorporates two types of changes:

  - Mandates require state regulatory commissions (or other government agencies or private firms) to undertake certain actions within a defined time-frame. Examples: state commissions must consider gas and electric integrated resource planning standards by October 1994; state, municipal, and utility automobile fleets are required to increase use of alternate fuel vehicles according to timetable. Mandates are easy to recognize and hence often the focus of attention when implementing new legislation, but are often less important than fundamental changes in the market.

  - Market restructuring occurs because legislation changes the economic rules that apply to industry participants. Market changes can come about as a result of mandates, but more commonly from other provisions of an act.

* Example of difference from 1978 National Energy Act (NEA):

  - 1978 Act had mandates similar to those in 1992 Act. Example: Commissions had to consider variety of ratemaking standards (such as lifeline rates and time-of-day rates) under Title I of PURPA. Many of the mandates in the 1992 Act are simply additions to those contained the 1978 Act. Although the 1978 mandates received substantial attention at time, they had little permanent impact.

  - Two market changes in 1978 Act continue to have significant impact on State Commission activities.

  - First, conventional wisdom in 1978 was that natural gas had no future -- shortages of the 1970s had convinced many that there was little supply left and it could not be relied upon. Consequently, NEA placed restrictions on use and provided phased deregulation of well-head prices to promote exploration for remaining supplies. Restrictions have now been removed; but phased

deregulation created market pressures that led to open-access transportation under Order 436/500 and ultimately to restructuring under Order 636. These changes in the market have created winners and losers. Multi-billion dollar losses have been sustained by participants who overcontracted on the theory that there would always be a shortage.

- Second, in order to encourage efficiency and small power producers, NEA created cogeneration QFs. Although little noticed at the time, problems relating to regulation of QFs have come to predominate the agenda at many Commissions. In Michigan, the first issue called to my attention after appointment related to a large abandoned nuclear plant transformed into a major QF, 49% owned by the purchasing utility -- an issue that we have finally dealt with six years later.

* Lesson to be learned from the 1978 Act is that each State and the country as a whole needs to identify factors that will lead to fundamental changes in the way the market system operates. Complex economic legislation seldom operates in practice the way it was intended. In 1978, few, if any, predicted that eliminating controls on gas well-head prices would lead to removing pipelines from the merchant function or that the QF market would grow to the extent and in the way it has. Many of the provisions in 1992 Act regarding utility/affiliate relationships grew out of unexpected developments resulting from the 1978 Act.

* I don't have a magic laundry list of salient provisions in Energy Policy Act that will prove to be "hot spots' of the 1990's. After all, as George Elliott warned us, "prophecy is the most gratuitous form of error." Nonetheless, I would like to suggest some relevant questions and observations for your consideration.

* NEPA requires that state commissions consider integrated resource planning for both gas and electric utilities. The conventional wisdom is that electric planning concepts will be incorporated into natural gas, but the transfer could be in the other direction. Would a common planning process move these industries in the direction of having more comparable industry structures? For years, analysts have talked about electric power companies being transformed into Genco's, Transco's, and Disco's -- a structure comparable to that used in natural gas. If IRP principles are applied to both gas and electric industries, it is likely that each will come to recognize and appreciate some advantages in the other's structure. This trend will be accelerated by the expectation that utilities will rely increasingly on independent power producers for new generating capacity.

* NEPA also requires that a utility obtain certification from its state commission before acquiring a foreign utility, but not if it acquires a foreign power producer. This clearly creates incentives to invest in foreign generation instead of transmission or distribution. In a few years, we could see an electric industry structured so that

domestic utilities purchase predominately from independent power producers and are largely Transco's and Disco's in the U.S., but operate as Genco's in other countries. Is such a structure stable and viable? Given the stable financing available to domestic utilities, would foreign power production be financially stronger than in the U.S.? Would domestic utility operations be supporting potentially risky foreign generation? Is this a market in which the small can compete? Or will we see the emergence of giant global generating organizations similar to those developing in the telecommunications field?

* NEPA mandates use of alternative fuel vehicles. Who might control the infrastructure necessary to support these vehicles? Gas utilities might find it natural (no pun intended) to expand into natural gas filing stations, especially if they already operate some for their own vehicles. On the other hand, producers, who have experience dealing with retail gasoline stations, may find this option attractive, especially since Order 636 will require more interaction between producers and customers. How would state commissions react to proposals by local distribution companies to subsidize their own entry into retail establishments? It might even be difficult to detect a subsidy hidden within a utility's rate design.

* I raise these examples, not because they will happen, although they may, but to illustrate the type of issues that could arise as NEPA plays out. History has shown that Commissions often find themselves with intractable problems that could have been avoided with foresight. Understanding where a new Act is likely to lead, or even could lead, is more important than an encyclopedic knowledge of every detail.

* Several points in NEPA stand out as fundamental:

* First, utilities will have the opportunity to become players in the global market. At a time of privatization of government-owned firms, this is both an opportunity and a threat. If done successfully, domestic utilities may gather large profits and return the U.S. to a position of economic leadership. If unsuccessful, ratepayers may find themselves supporting the financially shattered hulk of a utility that will make past diversification fiascos seem almost pleasant. State Commissions have some theoretical ability to control or at least monitor this development, but developing a practical approach may be more difficult.

* Second, since FERC may not mandate retail wheeling, action in this arena will gravitate to the states. The driving force that leads to calls for retail wheeling is the perceived price differential available to some customers, but ultimately the question becomes more a political than economic decision. In Michigan, we have an ongoing proceeding to consider this issue and Mick Hiser will be telling you about that tomorrow.

* Third, there will be expanded incentives for improved conservation. The Act requires

State Commissions to evaluate disincentives for conservation that may be inherent in the standard regulatory paradigm. Many States have recognized this problem and have adopted a variety of incentive programs designed to foster the development of conservation and other worthwhile public policy goals. In Michigan, we have adopted a demand-side management program for Consumers Power Company that adjusts the utility's authorized return on equity based upon its success in meeting specified goals for cost-effective conservation. Programs such as this are likely to become the norm in the future.

* Finally, the job responsibilities of State Commissioners will not get any easier.

  - In the past, each electric utility was an independent entity, developing and operating its own system with some coordination with neighboring utilities. Regulators were largely responsible for after-the-fact review of planning and operating decisions made by utility management. In the future, many utility services that were once monopolistic will become at least partly competitive.

  - In addition, State Commissions will be intimately involved in the planning and even in the decision-making process. It is important to recognize that regulators are making decisions today for conditions expected in the distant future. In considering the possible impacts of NEPA, a horizon of 15 to 20 years may be required.

  - It is not clear how the increased emphasis on planning can occur in harmony with additional competition. Planning, at least as it is currently practiced under integrated resource planning principles, presupposes cooperation between interested stakeholders -- competition assumes the opposite. Future regulators will need to harmonize these conflicting elements in a manner that best suits the overall public interest.

  - Long time horizons will likely be a source of conflicting pressures on regulators. With a long transition period, prudence dictates that regulators move slowly to ensure that irreversible steps are not taken lightly. On the other hand, increased competition will bring calls for regulators to move swiftly to make timely decisions.

  - With increased complexity, Commissioners would be well advised to focus on outcomes rather than details of transactions. In Michigan, because of intransigence on the part of the utility involved, the Commission was forced to examine the details of sale-and-leaseback provision for a large cogeneration facility -- an experience I have no wish to repeat. With the move to international activities, the complexity of transactions will only increase. Under these circumstances, a Commission that attempts to follow the details will quickly find itself unable to see the forest for the trees. Instead, I believe

BASIC LOCAL EXCHANGE RATE ALTERATIONS UNDER ACT 179

Section 304(5)

Provider may alter basic local exchange rates pursuant to notice & comment procedure. Start with this section for any rate alteration.

Section 304(6)

If altered rate does not exceed 1% less than the CPI, it shall take effect 90 days from the date of notice.

Section 304(9)

Commission must hold public hearing on any rate alteration within 45 days from date of notice & issue order within 90 days from date of notice finding 1 of the following:

a) that the rate alteration is just & reasonable. (Case ends.)

b) that a filing under §203 (contested case) should be commenced pursuant to Section 304(8).

c) that there is a likelihood that the proposed rate alteration is not just & reasonable and order a stay of the rate alteration pending a review of the rate under this section.

Section 304(6)

If altered rate exceeds 1% less than the CPI, provider must file for approval.

Section 203

Contested case process. Commission must issue a final order within 150 days from date application or complaint is filed. If hearing is held, Commission shall have an additional 60 days to issue its final order. Time periods are suspended if application does not meet filing requirements of section. Commission may also dismiss applications that do not comply.

Section 304(10)

In determining that a filing under §203 should be commenced pursuant to Section 304(8), Commission shall consider all public comments received pursuant to §304(5) and only review one or more of the following:

a) cost allocations to basic local exchange services.

b) competition.

c) network quality, improvement, & maintenance.

d) changes in costs of providing the service.

e) expenditures between affiliated entities of the provider & the provider.

Section 304(8)

If the Commission finds that a hearing should be held pursuant to §304(9)(b)--then Commission may require, either by complaint or on its own motion, a §203 filing & after the review issue an order approving, modifying, or rejecting the rate proposal including a refund of excessive collected rates and interest pursuant to §304(5).

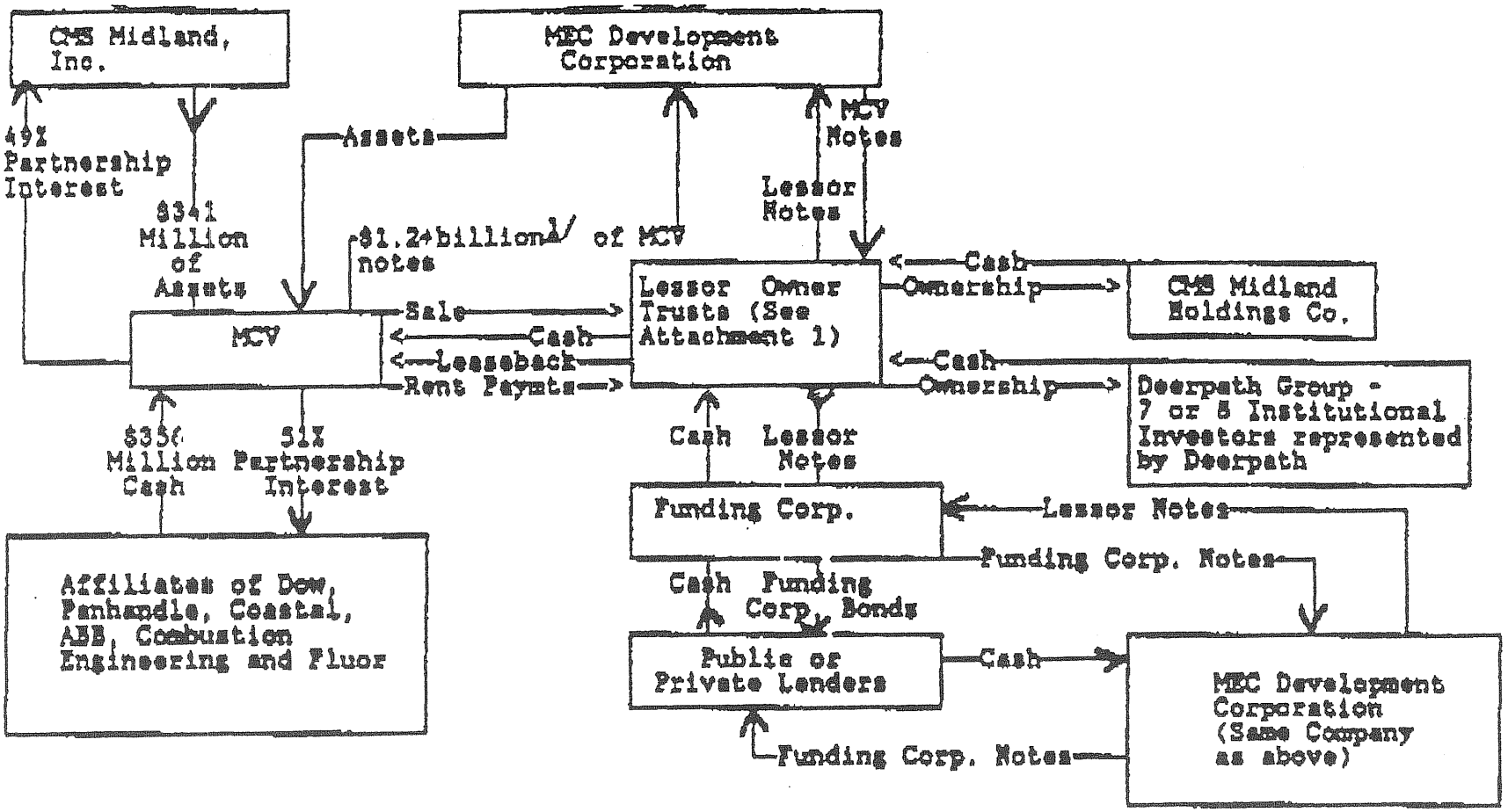
Section 203

Contested case. Commission issues order. Case ends.

that Commissions need to establish clear standards that utilities are expected to meet and then concentrate on monitoring the attainment of those standards. (See overheads.)

* These dilemmas call to mind Abraham Lincoln's words which are as timely as ever:

> "The dogmas of the quiet past are inadequate to the stormy present. The occasion is piled high with difficulty, and we must rise with the occasion. As our case is new, so we must think anew and act anew."


CMS Midland, Inc.
MEC Development Corporation
49% Partnership Interest
$341 Million of Assets
Assets
$1.2+billion1/ of MCV notes
MCV Notes
Lessor Notes
Cash
Ownership
CMS Midland Holdings Co.
MCV
Sale
Cash
Leaseback
Rent Paymts
Lessor Owner Trusts (See Attachment 1)
Cash
Ownership
Deerpath Group - 7 or 8 Institutional Investors represented by Deerpath
$35(Million Cash
51% Partnership Interest
Cash
Lessor Notes
Funding Corp.
Lessor Notes
Funding Corp. Notes
Affiliates of Dow, Panhandle, Coastal, ABB, Combustion Engineering and Fluor
Cash
Funding Corp. Bonds
Public or Private Lenders
Cash
MEC Development Corporation (Same Company as above)
Funding Corp. Notes

REGULATORY CHOICES AND THE ENERGY POLICY ACT

by

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presented at the

National Seminars on the
Public Utility Commission Implementation of
The Energy Policy Act of 1992

Portland, Oregon - July 15 and 16 and

Indianapolis, Indiana - July 19 and 20, 1993

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* The views and opinions of the author do not necessarily state or reflect the views, opinions, or policies of The National Regulatory Research Institute (NRRI), the National Association of Regulatory Utility Commissioners (NARUC), or their contributors.

THE ENERGY POLICY ACT OF 1992

TITLE I AMENDS SECTION 111 OF PURPA AND REQUIRES STATES TO CONSIDER:

- **REQUIRING UTILITIES TO ADOPT INTEGRATED RESOURCE PLANNING,**
- **ALLOWING INVESTMENTS IN CONSERVATION AND DEMAND-SIDE MANAGEMENT TO BE AT LEAST AS PROFITABLE AS SUPPLY SIDE RESOURCES, AND**
- **ENCOURAGING UTILITIES TO MAKE INVESTMENTS AND EXPENDITURES FOR IMPROVEMENTS IN POWER GENERATION, TRANSMISSION, AND DISTRIBUTION**

ABOUT HALF THE STATES ALREADY USE SOME FORM OF INTEGRATED RESOURCE PLANNING OR LEAST-COST PLANNING

TITLE VII OF THE ENERGY POLICY ACT:

- CREATES EXEMPT WHOLESALE GENERATORS (EWGS) TO ENCOURAGE MORE COMPETITION IN ELECTRICITY GENERATION

- PROVIDES FERC WITH BROAD AUTHORITY TO REQUIRE MORE OPEN ACCESS TO UTILITY TRANSMISSION

SINCE PURPA, THE INDUSTRY HAS BEEN SLOWLY MOVING TOWARD MORE COMPETITION IN GENERATION AND WHOLESALE POWER MARKETS (FOR EXAMPLE, COMPETITIVE BIDDING BY STATES AND MARKET-BASED WHOLESALE POWER PRICING BY FERC)

THE ENERGY POLICY ACT:

- EMBODIES THE TENSION BETWEEN PLANNING AND COMPETITION THAT COMMISSIONS HAVE BEEN STRUGGLING WITH TO DEVELOP A REGULATORY APPROACH

- MEANS INCREASING COMPETITION IN THE INDUSTRY IS LIKELY

THIS RAISES THE QUESTIONS:

- WILL CURRENT REGULATORY PROCESSES BE ABLE TO COPE WITH THESE CHANGES?

- WHICH REGULATORY APPROACH(S) WILL BE BEST SUITED FOR THE FUTURE?

REGULATORY ISSUES AND THREE REGULATORY APPROACHES TO ADDRESS THEM:

Regulatory Issue	Traditional	Planning	Markets/Incentives
Ratemaking	• ratebase or rate-of-return regulation • past or future test year to determine revenue requirement	• generally, same as traditional, but modified to encourage (or not discourage) utility demand-side management (DSM) programs • modifications include uncoupling utility rates from sales, compensating utilities for lost revenue, and allowing a higher rate-of-return for DSM investment in ratebase	• price caps • retrospective ratemaking for some performance-type incentives • revenue sharing • deregulation of competitive services

Regulatory Issue	Traditional	Planning	Markets/Incentives
Capacity Additions	• utility capacity ratebased • purchased-power costs passed through to ratepayers	• supply resources considered simultaneously with demand resources	• competitive bidding • incentives for purchased power

Regulatory Issue	Traditional	Planning	Markets/Incentives
Environmental Control	• command-and-control • implemented by environmental regulators	• environmental externalities considered in planning for new resources • quantitative ("adders") or qualitative • implemented by public utility commissions	• emissions trading • emissions taxes • hybrid systems of both trading and taxes • implemented by environmental regulators

Regulatory Issue	Traditional	Planning	Markets/Incentives
Demand-Side Management	• voluntary utility programs (but little incentive for utility to consider)	• supply and demand resources considered together in planning • specific incentives or removal of disincentives for DSM investments	• customer and utility discretion • utility may offer programs voluntarily

ADVANTAGES AND DISADVANTAGES TO DIFFERENT APPROACHES

TRADITIONAL

PROS: EXISTING AND WELL-KNOWN INFRASTRUCTURE

SHORT-TERM OUTCOME IS KNOWN IN ADVANCE

CONS: PERCEIVED TO PROVIDE INADEQUATE INCENTIVES TO MINIMIZE COST AND

CONSIDER EXTERNAL SOCIAL COSTS

AFTER-THE-FACT REVIEWS CONSIDERED BY SOME TO BE UNFAIR

ADVANTAGES AND DISADVANTAGES TO DIFFERENT APPROACHES (CONTINUED)

PLANNING

PROS: INCREASES PUBLIC PARTICIPATION

EXTERNAL SOCIAL COSTS ARE OFTEN INCLUDED

CONS: PROCESS HAS BECOME CUMBERSOME IN SOME STATES

MAY NOT PROVIDE UTILITY WITH CORRECT ECONOMIC SIGNALS TO MINIMIZE COST

DSM SAVINGS HAVE NOT BEEN AS EXPECTED AND COSTS MAY ACTUALLY BE MUCH HIGHER THAN REPORTED

TREATMENT OF ENVIRONMENTAL EXTERNALITIES ARE ARBITRARY AND COSTLY

ADVANTAGES AND DISADVANTAGES TO DIFFERENT APPROACHES (CONTINUED)

MARKETS

PROS: ENCOURAGES THE UTILITY TO MINIMIZE COST

ENCOURAGE INNOVATION

LOWER COSTS TO RATEPAYERS

LOWER ADMINISTRATIVE COSTS

CONS: SKEPTICISM ABOUT COMPETITIVE MARKETS DEVELOPING

FEARS OF MARKET POWER AND SELF-DEALING

INCENTIVES

PROS: CAN ENCOURAGE COST-MINIMIZING BEHAVIOR

ENCOURAGE INNOVATION

MIMICS MARKET OUTCOME

CONS: VIEWED BY SOME TO BE A BRIBE TO THE UTILITY FOR DOING WHAT IT SHOULD BE DOING IN ANY CASE

MAY HAVE UNANTICIPATED RESULTS

NO REGULATION

PRO: IF MARKETS EXIST OR CAN BE DEVELOPED, DEREGULATION MAY BE APPROPRIATE

CON: ORIGINALLY REJECTED BECAUSE OF "NATURAL MONOPOLY" - ORIGINAL REASON FOR REGULATION

ARE THERE CONFLICTS BETWEEN THE APPROACHES?

- TWO POTENTIAL SOURCES OF CONFLICT BETWEEN THE PLANNING APPROACH AND THE MARKETS/INCENTIVES APPROACH:

  - PRE- OR PRIOR APPROVAL OF UTILITY DECISIONS -- THE GREATER DEGREE OF GUARANTEES GIVEN TO A UTILITY, THE LESS COMPATIBLE IT IS WITH COMPETITIVE MARKETS. THIS IS BECAUSE OF THE ASYMMETRY BETWEEN RISK AND REWARD.

  - PLANNING MAY REDUCE FLEXIBILITY AND THE UTILITY'S ABILITY TO RESPOND TO CHANGING MARKET CONDITIONS. THE MORE THE COMMISSION IS INVOLVED IN THE MANAGEMENT OF THE UTILITY, THE LESS COMPATIBLE IT IS WITH COMPETITIVE MARKETS.

- POTENTIAL SOURCE OF CONFLICT BETWEEN THE TRADITIONAL APPROACH AND THE MARKETS/INCENTIVES APPROACH:

  - PRUDENCE REVIEWS AND USED AND USEFUL TESTS CREATE THE OPPOSITE ASYMMETRY THAN ABOVE -- THE UTILITY IS PUNISHED FOR BAD PERFORMANCE BUT CANNOT BE REWARDED BEYOND ITS ALLOWED RATE-OF-RETURN. REDUCES THE UTILITY'S MOTIVATION TO TAKE RISKS (AND FOREGO POTENTIAL REWARDS) IF IT PERCEIVES THE BENEFITS ARE LIMITED.

CONCLUSIONS

- LEGISLATIVE AND REGULATORY ACTIONS HAVE BEEN EVOLVING TOWARD MORE INCENTIVE- AND MARKET-BASED SOLUTIONS

- THERE WILL MOST LIKELY BE A DECREASE IN THE USE OF COST-BASED REGULATION

- FOR NOW, A CONTINUED USE OF IRP; BUT A GRADUAL MOVE AWAY FROM IT IN THE LONG RUN

- NOW THAT THE ELECTRIC INDUSTRY IS BEING RESTRUCTURED, WHAT ARE THE APPROPRIATE REGULATORY REFORMS NEEDED TO TAKE FULL ADVANTAGE OF THE CHANGES?

Presentation by

Russell J. Profozich
Senior Economist
U.S. Department of Energy

on

The Federal Role in Implementation of the Energy Policy Act of 1992

before the

DOE/NRRI National Seminar on Public Utility Commission Implementation of the Energy Policy Act of 1992

Portland, OR & Indianapolis, IN
July 15-16 & 19-20, 1993

Major Elements of the Energy Policy Act of 1992

Title I: Electric & Natural Gas Utility Rate Reform

- Integrated Resource Planning for Electric and Natural Gas Utilities
- Promotion of supply-side and demand-side efficiency

Title VII: Promotion of Competitive Wholesale Electricity Markets

- Exempt Wholesale Generators
- Foreign Utility Companies
- Transmission Access and Pricing

Planning versus Competition

- **Title I -- Planning**

  -- Integrated Resource Planning

  -- Ratemaking Reform

- **Title VII -- Competition**

  -- Competitive Wholesale Generation Markets

  -- Transmission Access and Pricing

  -- Foreign Utility Companies

EPACT Section 712 Amendments to PURPA

Consider the effect of wholesale power purchases on electric utilities and ratepayers

- Potential impact on utility's costs of capital, reliability & rates to consumers
- Whether EWG capital structure provides unfair advantage over utilities
- Consider preapproval for long-term purchases
- Require reasonable assurance of fuel supply adequacy

Impacts of NEW EPACT Authorities

- Major responsibility to implement EPACT lies with the States and with FERC
- Renewed emphasis on State ratemaking authority
- Greater cooperation between State regulators and utilities
- Greater cooperation between State and Federal regulators
- Increases tension between State and Federal authorities

Role for the Department of Energy

- Help make it work
- Address State/FERC ratemaking issues with emphasis on competitive markets
- Options:
  - -- Support dialogue between Federal and State regulators
  - -- Provide technical and financial support to the States
  - -- Participate in rate proceedings at FERC and in the States
  - -- Explore options and help develop solutions/avoid conflicts

Potential Conflicts/Options

- Regional Transmission Groups/Regional IRP
- State Siting Authority/FERC Transmission Access Authority
- State Competitive Bidding Mechanisms/Competitive Wholesale Markets
- State Ratemaking Authority/FERC Ratemaking Authority
- State/Federal Authorities Regarding Registered Utility Holding Companies

Goals of Department of Energy Activities

- Maintain Flexibility -- No Federal Mandates
- Promote development of a competitive, efficient electricity sector
- Minimize costs to consumers, consistent with environmental needs and system reliability
- Recognize Impacts of State and Local Activities on National Issues
  - -- Environment
  - -- Economic Growth and Employment
  - -- Competitiveness and International Trade

Next Steps

- Ongoing Department of Energy Programs

- Development of a National Energy Plan

- Input from the States

SESSION II

TITLE I: GAS INTEGRATED RESOURCE PLANNING ISSUES

PUBLIC UTILITY COMMISSION
IMPLEMENTATION OF
THE ENERGY POLICY ACT OF 1992

"GAS IRP IMPLICATIONS RESULTING FROM THE NATIONAL ENERGY POLICY ACT OF 1992"

by:

J. Michael Biddison, Commissioner
The Public Utilities Commission of Ohio

July 19, 1993
Indianapolis, Indiana

THIS PAPER REFLECTS ON INTEGRATED RESOURCE PLANNING (IRP) CONCEPTS, AS EXPERIENCED FROM THE PERSPECTIVE OF STATE PUBLIC UTILITY COMMISSION (PUC) REGULATION OF ELECTRIC UTILITIES, AND WHETHER OR NOT THEY ARE FULLY APPLICABLE IN TODAY'S EVER-CHANGING NATURAL GAS INDUSTRY.

IN OCTOBER, 1992 THE ENERGY POLICY ACT OF 1992 OR EPACT WAS PASSED BY CONGRESS AND SIGNED INTO LAW BY THEN-PRESIDENT BUSH. EPACT SECTION 115 AMENDS THE PUBLIC UTILITY REGULATORY POLICY ACT OF 1978, (COMMONLY KNOWN AS PURPA), BY ADDING TWO NEW STANDARDS FOR CONSIDERATION IN SECTIONS 302 AND 303 UNDER PURPA TITLE III. THESE TWO STANDARDS INCLUDE:

1) THE USE OF IRP BY EACH GAS UTILITY; AND

2) THE ENCOURAGEMENT OF INVESTMENTS IN CONSERVATION AND DEMAND-SIDE MANAGEMENT (DSM) MECHANISMS.

THE IRP STANDARD REQUIRES THAT THE OBJECTIVE FOR DEVELOPING A PLAN IS TO ENSURE THAT CUSTOMERS ARE PROVIDED ADEQUATE AND RELIABLE GAS SERVICE AT THE LOWEST SYSTEM COST. GAS IRPs WOULD BE FILED AND UPDATED ON A REGULAR BASIS, PROVIDE AN OPPORTUNITY FOR PUBLIC PARTICIPATION AND COMMENT, PROVIDE METHODS OF VALIDATING PREDICTED PERFORMANCE OF DSM MEASURES, AND HAVE TO BE IMPLEMENTED AFTER APPROVAL OF THE STATE PUC. THE EPACT ALSO REQUIRES THAT A GAS UTILITY'S PRUDENT INVESTMENTS AND EXPENDITURES FOR ENERGY CONSERVATION, LOAD SHIFTING, AND OTHER

DSM PROGRAMS ARE AT LEAST AS PROFITABLE AS PRUDENT INVESTMENTS AND EXPENDITURES FOR THE ACQUISITION OF SUPPLIES AND OR CONSTRUCTION OF FACILITIES. THIS STANDARD REQUIRES THAT STATE REGULATORS LINK THE UTILITY'S NET REVENUES TO ITS PERFORMANCE IN IMPLEMENTING COST-EFFECTIVE PROGRAMS AND REQUIRES THAT THE UTILITY'S FINANCIAL PERFORMANCE NOT BE AFFECTED BY REDUCTIONS IN ITS RETAIL SALES VOLUMES.

PURPA SECTION 302, AS AMENDED, DEFINES GAS IRP AS A SYSTEMATIC COMPARISON BETWEEN DSM MEASURES AND SUPPLY TO MINIMIZE LIFE-CYCLE COSTS OF ADEQUATE AND RELIABLE UTILITY SERVICES TO GAS CUSTOMERS. A GAS IRP SHALL TAKE INTO ACCOUNT SUPPLY DIVERSITY NECESSARY FOR SYSTEM OPERATIONS, INCLUDING RELIABILITY, DISPATCHABILITY AND OTHER RISK FACTORS. THEREFORE, THE EPACT REQUIRES THAT DEMAND AND SUPPLY TO GAS CUSTOMERS WILL BE TREATED ON A CONSISTENT AND INTEGRATED BASIS. FROM A DEMAND PERSPECTIVE, THE EPACT ALLOWS DSM TO INCLUDE ENERGY CONSERVATION, ENERGY EFFICIENCY, LOAD MANAGEMENT AND LOAD SHIFTING TECHNIQUES.

PURPA SECTION 303, AS AMENDED, REQUIRES EACH STATE REGULATORY AUTHORITY TO PROVIDE PUBLIC NOTICE AND CONDUCT A HEARING NOT LATER THAN OCTOBER 23, 1994 ON THE APPROPRIATENESS OF THE STANDARDS FOR CARRYING OUT THE PURPOSES OF TITLE III. IF THE STATE REGULATORY AUTHORITY DOES IMPLEMENT EITHER OR BOTH OF THE EPACT GAS EFFICIENCY STANDARDS, IT MUST CONSIDER THE IMPACT THAT IMPLEMENTATION OF SUCH A STANDARD WOULD HAVE ON SMALL BUSINESSES ENGAGED IN THE DESIGN, SALE, SUPPLY, INSTALLATION, OR SERVICING

OF ENERGY CONSERVATION, ENERGY EFFICIENCY, OR OTHER DEMAND-SIDE MANAGEMENT PROGRAMS. THE STANDARDS MUST BE IMPLEMENTED IN A MANNER AS TO ASSURE THAT THE UTILITY ACTIONS WOULD NOT PROVIDE THOSE UTILITIES WITH UNFAIR COMPETITIVE ADVANTAGES OVER SUCH SMALL BUSINESSES.

IN ADDITION TO THE ISSUES OF THE IMPACTS OF SUCCESSFUL IRP PROGRAMS ON A LOCAL DISTRIBUTION COMPANY'S (LDC) EARNINGS, AND THE IMPACTS OF DSM PROGRAMS ON CERTAIN SMALL BUSINESSES, OTHER MAJOR POLICY ISSUES ALSO REMAIN TO BE CONSIDERED BY STATE REGULATORS. THESE INCLUDE THE CONCEPT OF TOTAL INTEGRATED RESOURCE PLANNING AND CONSIDERATION OF ENVIRONMENTAL AND OTHER EXTERNALITIES. TOTAL INTEGRATED RESOURCE PLANNING MAY BE DEFINED AS THE OPTIMAL UTILIZATION OF ELECTRIC AND GAS SUPPLIES.

ACCORDING TO THE NATIONAL REGULATORY RESEARCH INSTITUTE (NRRI), FIFTEEN STATES EITHER HAVE FUNCTIONING GAS IRP RULES IN PLACE OR ARE ACTIVELY PURSUING THE GAS IRP APPROACH. HISTORICALLY, JUSTIFICATION FOR COMMISSION OVERSIGHT OF ELECTRIC UTILITY PLANNING ACTIVITIES INCLUDE:

- THE ABSENCE OF COMPETITIVE MARKETS FOR BOTH SUPPLY-SIDE RESOURCES AND DEMAND-SIDE OPTIONS; AND

- THE PRESENCE OF EXTERNALITIES IN THE FORM OF ENVIRONMENTAL AND SOCIETAL IMPACTS OF A UTILITY'S OPERATIONS.

IN THEORY, THE IRP APPROACH ENSURES THAT ALL COST-EFFECTIVE OPTIONS ARE INCLUDED IN A UTILITY'S RESOURCE MIX, WHICH SHOULD BE APPLICABLE TO BOTH ELECTRIC AND GAS UTILITIES.

ALTHOUGH AT FIRST GLANCE IT MIGHT APPEAR THAT EXISTING ELECTRIC IRP PROCEDURES ARE DIRECTLY TRANSFERABLE TO GAS, THERE ARE SOME FUNDAMENTAL DIFFERENCES BETWEEN THE TWO INDUSTRIES, ESPECIALLY WHEN DEVELOPING COST-EFFECTIVE DSM PROGRAMS. FIRST, MOST ELECTRIC UTILITIES ARE VERTICALLY INTEGRATED COMPANIES WHILE THE NATURAL GAS INDUSTRY CONSISTS OF SEPARATE NICHE-FOCUSED COMPANIES THAT PERFORM PRODUCTION, TRANSMISSION, AND/OR DISTRIBUTION FUNCTIONS. SECOND, LONG RANGE PLANNING FOR ELECTRIC UTILITIES TYPICALLY INVOLVES LARGE SCALE CAPITAL INVESTMENT DECISIONS FOR A 15 - 30 YEAR PLANNING HORIZON WHILE LOCAL DISTRIBUTION COMPANY (LDC) LONG RANGE PLANS RELATE TO THE APPROPRIATE MIX OF LONG-TERM AND SHORT-TERM SUPPLY CONTRACTS AND STORAGE CAPACITY FOR A 3 - 10 YEAR PLANNING HORIZON. THESE AND OTHER STRUCTURAL DIFFERENCES HAVE AN IMPACT ON THE COST-EFFECTIVENESS OF POTENTIAL DSM PROGRAMS.

THE CAPITAL INTENSIVE NATURE OF THE ELECTRIC UTILITY INDUSTRY MAKES COST-EFFECTIVE DSM PROGRAMS AN ATTRACTIVE ALTERNATIVE TO MORE EXPENSIVE CONSTRUCTION PROJECTS. FOR LDCs, HOWEVER, AVOIDABLE CAPITAL COSTS ARE GENERALLY LIMITED TO RELATIVELY LOW COST DISTRIBUTION AND STORAGE FACILITIES. THE BENEFITS RELATING TO GAS IRP ARE NOT SO MUCH TO AVOID FUTURE

CAPITAL COSTS, BUT TO FURTHER ENHANCE THE LDC PLANNING PROCESS. THAT IS, GAS IRP CAN PROVIDE A MEANS FOR A SYSTEMATIC APPROACH BY THE LDC TO BALANCE THE EVALUATION AND ALLOCATION OF ITS SUPPLY AND DSM RESOURCES IN ORDER TO ACHIEVE ITS LEAST COST RESOURCE MIX. IN GENERAL, THOUGH, THE AVOIDED COSTS USED FOR EVALUATION OF THE COST-EFFECTIVENESS OF GAS DSM PROGRAMS WILL BE MUCH LOWER THAN AN ELECTRIC UTILITY'S. THIS IN TURN, MAY MEAN FEWER PROGRAMS WILL PASS THE COST/BENEFIT ANALYSIS SCREENING. THIS IS A CRITICAL DIFFERENCE THAT MUST BE RECOGNIZED IN ESTABLISHING A PROCESS FOR IMPLEMENTATION OF GAS IRP IN ACCORDANCE WITH EPACT.

IN MOST STATES WITH ELECTRIC IRP PROCESSES, THE TOTAL RESOURCE COST TEST (OFTEN REFERRED TO AS THE TRC TEST) IS USED TO DETERMINE THE COST-EFFECTIVENESS OF DSM PROGRAMS. IN THE TRC TEST, THE BENEFITS OF THE DSM PROGRAM ARE THE AVOIDED CAPACITY AND ENERGY COSTS THAT RESULT FROM REDUCED CONSUMPTION. IN MOST CASES, IT IS THE ABILITY TO AVOID EXPENSIVE CAPACITY ADDITIONS THAT DOMINATES THIS ANALYSIS. IN MY STATE (OHIO), SHORT-TERM MARGINAL COSTS ARE SUBSTANTIALLY BELOW AVERAGE COSTS, DUE TO A RELATIVELY INEXPENSIVE FUEL MIX AND ADEQUATE CAPACITY. YET, WITH THE POSTPONEMENT OF LARGE AVOIDED CAPITAL COSTS ASSOCIATED WITH FUTURE CAPACITY ADDITIONS, IT IS STILL RELATIVELY EASY TO DEVELOP COST-EFFECTIVE DSM PROGRAMS FOR ELECTRIC UTILITIES. HOWEVER, THIS MAY NOT BE THE CASE FOR NATURAL GAS UTILITIES, WHERE FUTURE CAPITAL INVESTMENTS INVOLVE RELATIVELY INEXPENSIVE DISTRIBUTION AND STORAGE RELATED FACILITIES.

EVEN IN SITUATIONS WHERE A GAS CONSERVATION PROGRAM CAN PASS A TRC TEST, A PUC MAY WANT TO CONSIDER WHETHER THE TRC TEST ALONE IS SUFFICIENT TO BASE PROGRAM APPROVAL ON. AGAIN REFERRING TO OHIO AS AN EXAMPLE, THE SITUATION OF LDCs IS SIMILAR TO ELECTRIC UTILITIES IN THAT MARGINAL COSTS ARE LESS THAN AVERAGE COSTS. IN THIS INSTANCE, MOST IF NOT ALL CONSERVATION PROGRAMS ARE GOING TO RESULT IN HIGHER RATES IN THE SHORT-TERM. THIS IS BECAUSE THE REVENUE EROSION THAT RESULTS FROM CONSERVATION PROGRAMS IS A FUNCTION OF AVERAGE COSTS, WHILE THE COST SAVINGS IS A FUNCTION OF SHORT-TERM MARGINAL COSTS. AS LONG AS AVERAGE COSTS, I.E. RATES, ARE GREATER THAN MARGINAL COSTS, CONSERVATION PROGRAMS CAUSE A NET LOSS TO THE UTILITY WHICH CAN ONLY BE RECOVERED IN THE NEXT RATE CASE PROCEEDING. THEREFORE, FOR GAS UTILITIES, THERE SIMPLY MAY NOT BE SUFFICIENT FUTURE COST SAVINGS THAT WILL JUSTIFY SHORT-TERM RATE INCREASES.

AN ADDITIONAL CONSIDERATION IS THAT IN RECENT YEARS THERE HAS BEEN AN ABSOLUTE DECREASE IN SALES OF NATURAL GAS BY LDCs WHILE ELECTRICITY DEMAND HAS BEEN GROWING DESPITE THE RECENT EMPHASIS ON CONSERVATION. THIS TREND PUTS ELECTRIC UTILITIES IN A BETTER POSITION TO ABSORB REVENUE EROSION DUE TO CONSERVATION PROGRAMS AND STILL ALLOW FOR A NET INCREASE IN SALES. SINCE NATURAL GAS UTILITIES ARE NOT IN AS STRONG A POSITION TO ABSORB REVENUE EROSION, THEY ARE MORE LIKELY TO FILE FOR AN INCREASE IN RATES DUE TO IRP PROGRAM INITIATIVES. BECAUSE AVOIDED FUTURE CAPACITY IS NOT LIKELY TO INVOLVE LARGE INVESTMENT FOR GAS UTILITIES, THERE IS NOT THE SAME LONG-TERM PAYBACK TO JUSTIFY THE

SHORT-TERM RATE IMPACTS. WITH ALL THE UNCERTAINTIES CREATED BY FERC ORDER 636 AND THE CLEAN AIR ACT AMENDMENTS OF 1990, IT WILL BE INTERESTING TO OBSERVE IF THESE TRENDS REVERSE WITH INCREASING DEMAND FOR NATURAL GAS AS AN ENVIRONMENTALLY BENIGN FOSSIL FUEL.

YET, GAS IRP CAN PROVIDE A MEANS FOR THE LDC TO MANAGE ITS RISK AND PROVIDE ADDITIONAL REGULATORY CERTAINTY. BY UTILIZING THE IRP PROCESS, THE LDC PROVIDES THE OPPORTUNITY FOR PUBLIC INPUT INTO ITS PLANNING FRAMEWORK, IN ADDITION TO INCREASING ITS AWARENESS OF THE REGULATOR'S POSITION AND CONCERNS. THIS INPUT AT A KEY POINT IN THE LDC'S PLANNING PROCESS NOT ONLY MAKES THAT PROCESS A MORE COLLABORATIVE ONE, BUT CAUSES IMPLICIT ACCEPTANCE OF INCREASED RESPONSIBILITY FOR RESOURCE PLANNING BY THOSE PARTICIPANTS.

IN ADDITION, FERC ORDER 636 IS NOW PRESENTING GAS SUPPLY PLANNERS WITH MORE DIVERSE AND EXPANDED SUPPLY OPTIONS. THESE OPTIONS NOW INCLUDE THE FOLLOWING:

- ADJUSTMENTS IN FIRM TRANSPORTATION CAPACITY FROM CURRENT OR ALTERNATIVE PIPELINES VIA CAPACITY RELEASE;

- NO-NOTICE SERVICE OPTIONS AND PIPELINE SALES GAS;

- SEASONAL AND PEAK MONTH SUPPLY CONTRACTS;

- LDC, PIPELINE, OR THIRD-PARTY STORAGE; AND,

. PEAKING SUPPLIES INCLUDING PROPANE AIR PLANTS, LIQUEFIED NATURAL GAS, AND PRIVATE SUPPLY AGREEMENTS WITH LARGE GAS END-USERS OR TRANSPORTERS.

BY INTEGRATING THE ANALYSIS OF THESE OPTIONS INTO ITS OVERALL RESOURCE PLANNING, THE LDC CAN DETERMINE, FOR INSTANCE, WHETHER NO-NOTICE SERVICE OR A PEAK DEMAND REDUCTION PROGRAM IS THE MORE EFFICIENT AND COST-EFFECTIVE MEANS TO FULFILL ITS PEAK DAY REQUIREMENTS.

ALTHOUGH CONSERVATION AND DSM PROGRAMS HAVE NOT HAD AS LARGE A ROLE IN THE LONG-TERM PLANNING PROCESS IN THE NATURAL GAS INDUSTRY COMPARED TO THE ELECTRIC INDUSTRY, THERE MAY BE CERTAIN TARGETED OPPORTUNITIES THAT ARE LIKELY TO BE FRUITFUL, ESPECIALLY WITH THE IMPLEMENTATION OF EPACT. IN OHIO, THESE OPPORTUNITIES COULD ARISE IN THE FORM OF PILOT PROGRAMS FROM OUR COMBINATION ELECTRIC AND GAS UTILITIES AS THE FIRST STEP TOWARD THE CONCEPT OF A TOTAL INTEGRATED RESOURCE PLAN RATHER THAN JUST AN ELECTRIC IRP OR A GAS IRP SHARING THE SAME SERVICE TERRITORY. THE ESTABLISHMENT OF A GAS IRP PROCESS IN CONJUNCTION WITH AN ELECTRIC IRP PROCESS IN A COMBINATION UTILITY SERVICE AREA CAN PROVIDE SYNERGISTIC OPPORTUNITIES THAT MAY MAKE MARGINAL STANDALONE DSM PROGRAMS MORE COST-EFFECTIVE THAN THEY WOULD OTHERWISE BE.

FOR EXAMPLE, IN OHIO, OUR PERCENTAGE OF INCOME PAYMENT PLAN

(PIPP) IS A UTILITY SOCIETAL PROGRAM WHICH BENEFITS LOW-INCOME CUSTOMERS. THE PIPP PROGRAM ENABLES CERTAIN LOW-INCOME CUSTOMERS TO PAY A PORTION OF THEIR INCOME FOR THEIR UTILITY SERVICE, THUS CAUSING ARREARAGES TO ACCRUE. OVER TIME, THESE ARREARAGES ACCUMULATE AND OFTEN BECOME SUBSIDIZED BY THE UTILITY'S REMAINING CUSTOMERS. COUPLE THIS WITH THE FACT THAT ONE OF THE PROBLEMS WITH ELECTRIC LOW-INCOME PROGRAMS IS THAT RELATIVELY FEW LOW-INCOME CUSTOMERS UTILIZE ELECTRICITY AS THEIR PRIMARY HEATING SOURCE. THIS GREATLY LIMITS THE NUMBER OF ELECTRICITY CONSERVATION MEASURES AVAILABLE TO THESE CUSTOMERS. SINCE IT IS VERY EXPENSIVE TO SEND CREWS TO INSTALL THOSE MEASURES, AND SINCE THERE ARE FEW MEASURES OVER WHICH TO SPREAD THE COSTS, THE COST-EFFECTIVENESS OF LOW-INCOME PROGRAMS IS OFTEN QUESTIONABLE. THUS, IT MAY BE MORE EFFECTIVE, ESPECIALLY WITH OUR COMBINATION UTILITIES, TO PROMOTE THE GREATER SOCIETAL GOOD THROUGH INCREASED WEATHERIZATION FUNDING WHICH ULTIMATELY BENEFITS THESE SAME LOW-INCOME CUSTOMERS, WHETHER THEY UTILIZE GAS OR ELECTRICITY AS THEIR PRIMARY HEAT SOURCE. THIS WOULD ENABLE A COMBINATION UTILITY TO DELIVER THE SAME CONSERVATION MEASURES TO ALL CUSTOMERS REGARDLESS OF WHETHER THEY HEAT WITH GAS OR ELECTRICITY. THE COSTS OF SENDING CREWS TO INSTALL THOSE MEASURES COULD BE SPREAD PROPORTIONATELY OVER BOTH THE GAS AND ELECTRIC DSM PROGRAMS, MAKING EACH INDIVIDUAL PROGRAM MORE COST-EFFECTIVE. THE LONG-TERM EFFECT OF SUCH A PROGRAM COULD BE TO LESSEN PRESENT AND FUTURE PAYMENT ARREARAGES IN OUR EXISTING PIPP PROGRAM, THUS PROVIDING A REALIZED LONG-TERM COST BENEFIT TO ALL OF THE UTILITY'S CUSTOMERS.

ALTHOUGH EPACT MAKES IT CLEAR THAT THE INTENT IS TO PROMOTE GAS CONSERVATION AND LOAD MANAGEMENT PROGRAMS, REGULATORS NEED TO GO BEYOND THAT AND BE RESPONSIVE TO FUEL-SWITCHING OPPORTUNITIES AS WELL. THIS DOES NOT MEAN, HOWEVER, THAT REGULATORS SHOULD BLUR THE LINES BETWEEN DSM PROGRAMS AND PROMOTIONAL ACTIVITIES. RATHER, THIS IS SIMPLY A RECOGNITION THAT THERE MAY WELL BE SITUATIONS WHERE IT MAKES SENSE FOR BOTH THE ELECTRIC AND NATURAL GAS UTILITIES TO LOOK INTO THE REPLACEMENT OF ELECTRIC EQUIPMENT WITH NATURAL GAS EQUIPMENT OR VICE VERSA. FOR EXAMPLE, IN THE FUTURE THE REPLACEMENT OF SOME ELECTRIC AIR CONDITIONING LOAD WITH GAS AIR CONDITIONING MAY MAKE SENSE AS AN ELECTRIC DSM PROGRAM AND ALSO AS A GAS VALLEY-FILLING PROGRAM. FROM A REGULATORY PERSPECTIVE, THIS PROGRAM COULD BE CONSIDERED A DSM PROGRAM ON THE ELECTRIC SIDE, BUT A PROMOTIONAL ACTIVITY ON THE GAS SIDE.

ANOTHER REASON TO BEGIN GAS IRP PILOT PROGRAMS WITH COMBINATION UTILITIES, IS THAT MANY DSM MEASURES OFTEN IMPACT THE CONSUMPTION OF BOTH GAS AND ELECTRICITY. FOR INSTANCE, GAS UTILITY WEATHERIZATION IMPROVEMENTS TO BUSINESSES AND HOMES THAT HEAT WITH GAS COULD HAVE SECONDARY EFFECTS WHICH COULD ALSO INCLUDE A REDUCTION IN ELECTRICITY REQUIREMENTS IN THE SUMMERTIME IF THAT BUILDING UTILIZES ELECTRIC AIR CONDITIONING. IN SUCH INSTANCES, THE TRC, PARTICIPANT, OR SOCIETAL TESTS SHOULD BE APPLIED SUCH THAT THE IMPACT OF BOTH FUELS IS INCLUDED, WHICH FURTHER JUSTIFIES A TOTAL INTEGRATED RESOURCE PLAN. IN THE CASE

OF COMPETING GAS AND ELECTRIC UTILITIES WHICH SERVE THE SAME SERVICE TERRITORY, INHERENT CONFLICTS MAY DEVELOP WHEN BOTH UTILITIES PRACTICE IRP, ESPECIALLY WHEN THE PUC APPROVES PROGRAMS WHICH MAY BE VIEWED AS PROMOTIONAL RATHER THAN CONSERVATION-ORIENTED. HOWEVER, WITH EXPERIENCE THESE AND LIKE ISSUES CAN BE OVERCOME IN A MANNER WHICH SATISFIES THE BEST INTERESTS OF BOTH UTILITIES AND THEIR CUSTOMERS.

BY ENCOURAGING THE DESIGN OF GAS AND ELECTRIC IRPs FOR CUSTOMER PLANNING AND FUEL CONSERVATION PURPOSES, STATES HAVE THE ABILITY TO ATTRACT ECONOMIC DEVELOPMENT THROUGH LOWER OVERALL ENERGY COSTS. PROPER DEVELOPMENT AND IMPLEMENTATION OF IRPs WHICH FULFILL SUCH OBJECTIVES CANNOT ONLY PROVIDE REALIZED ECONOMIC BENEFITS TO THE CUSTOMER, BUT ALSO PROVIDE GREATER SOCIETAL BENEFITS THROUGH IMPROVED EFFICIENT USE OF OUR ENERGY RESOURCES.

NORTHWEST NATURAL GAS COMPANY

220 N.W. SECOND AVENUE PORTLAND, OREGON 97209 - 3991

"AN LDC PERSPECTIVE ON GAS INTEGRATED RESOURCE PLANNING ISSUES"

NATIONAL REGULATORY RESEARCH INSTITUTE
SEMINAR ON PUBLIC UTILITY COMMISSION
IMPLEMENTATION OF THE ENERGY POLICY ACT OF 1992

Red Lion Columbia River
Portland, Oregon
July 15, 1993

Bruce R. DeBolt
Senior Vice President
& Chief Financial Officer
Northwest Natural Gas Company
Portland, Oregon

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I. Introduction

A. Northwest Natural is a natural gas utility serving about 360,000 residential, commercial, industrial, and electric generation customers in western Oregon and southwestern Washington.

B. We have a $460 million market capitalization, which makes us a very "middle-sized" LDC by national standards.

C. We serve an area with a healthy economy, in contrast to California, and are growing at a rate twice as fast as the average gas utility.

D. We had 100 bcf of deliveries in 1991, 1992, largest in Pacific Northwest.

E. We have had energy efficiency programs since 1978 and will complete our second integrated resource plan this year.

F. In my remarks I want to give you an LDC's perspective on integrated resource planning and the need for incentive regulation.

G. I must advise listener caution, however, since a portion of my remarks is rated "PI" -- politically incorrect.

II. The Energy Policy Act of 1992 and natural gas utilities

A. Section 115 of the 1992 Act amends PURPA by requiring state utility commissions to consider whether to adopt two new standards for the regulation of natural gas utilities.

B. First, the EPA requires PUCs to consider whether to adopt an integrated resource planning requirement for natural gas utilities. [PURPA section 303(b)(3)] We'll call this the "IRP Standard."

C. Second, the EPA requires PUCs to consider whether investments in conservation and load management measures are "at least as profitable" as other prudent utility resource investments. [PURPA section 303(b)(4)] The second PURPA standard is often referred to as the "DSM Incentives" standard.

D. I trust you have noticed that the Act makes neither standard mandatory.

III. Integrated Resource Planning for Gas Utilities

A. Regarding the first IRP Standard, the Oregon and Washington commissions have already answered affirmatively the question of whether to adopt IRPs for gas utilities.

B. Both states have required biennial integrated resource plans from their natural gas utilities. (Since 1987 in Washington and since 1989 in Oregon). NNG is near completion of its second-generation IRPs. [OPUC Order No. 89-507; WAC 480-90-191]

C. We support the integrated resource plan requirement, and so generally endorse Congress' suggestion that the states consider requiring IRPs of natural gas utilities.

D. We found value in IRPs for several reasons.

1. We found that IRPs are a useful tool for jointly analyzing supply-side and demand-side resources.

2. The IRP has proved to be a complementary business planning tool for our own gas supply strategy.

3. Public participation in IRP has helped us understand our customers better.

4. Last, and perhaps least, IRPs do give our resource acquisitions a small rebuttable presumption of prudency.

E. Now that I have enthusiastically endorsed integrated resource planning for gas utilities, let me suggest what some of the issues are for gas IRPs.

1. For those jurisdictions that have not yet required IRPs from their gas utilities, gas utility planning necessarily will differ from electric utility planning. Key differences are:

a. Planning Time Frame. Gas planning has a shorter time frame. Where large scale electric generating resources may require 10 to 20 year lead times, gas resource planning will be much shorter, from 5 to 10 years.

b. Avoided Costs. Gas avoided costs will usually be lower than (sometimes much lower than) electric avoided costs, so based on the economics, you should not expect gas utilities' conservation programs to be as extensive as electric utility programs.

c. Market Context. Gas utilities are planning in a partially, but dynamically, competitive market. Decisions that are prudent today may be overtaken by other opportunities within days. Gas IRPs must be flexible enough to respond to the fluidity of the natural gas markets.

Oregon and Washington integrated resource planning procedural requirements are the same for electric and gas utilities, but both Commissions have been flexible in how the requirements were applied to gas utilities. This has allowed us to produce plans that are pertinent and useful in real life.

2. Order 636 and related FERC policy changes will affect gas utility IRPs. Straight fixed-variable pricing and incremental pricing for new pipeline capacity mean that an LDC's load factor will be critical to providing "least cost" service to customers.
Load factor management can be accomplished through:

a. reducing peak demand;

b. building cost-effective, off-peak or interruptible loads through creative marketing;

c. retaining high load factor industrial customers; and

d. re-examining main extension policies and rate design.

3. My point is this. Load shifting, load building, and rate design are load management techniques not usually associated with integrated resource planning, which traditionally has focused solely on DSM programs that reduce overall use. Nevertheless, load management activities that build load strategically will be crucial to LDCs seeking to reduce costs. DSM programs that focus only on reducing total energy use will miss the mark for gas utilities.

4. Some states seem to be reluctant to recognize these activities as appropriate for least cost planning. I think it is very important for state regulators to understand the importance of load shaping activities to least cost planning. I contend that the 1992 Act recognized the importance of load factor management to gas utilities, since the language of PURPA specifically equates "demand-side management" with load management as well as conservation. [PURPA section 303(b)(3)].

IV. DSM INCENTIVES

A. Regarding the DSM Incentive Standard, the 1992 Act requires PUCs to consider whether to adopt rates so that DSM measures "are at least as profitable" as other prudent investments. The Act clarifies that this means:

1. Regulators should link a utility's net revenues in part to the utility's performance in DSM; and

2. Regulators should assure that utilities' financial results are not affected by sales lost to DSM. [PURPA section 303(b)(4)]

B. Again, Oregon has already considered these requirements.

1. Oregon allows utilities to earn on their DSM investments in the same manner as supply-side resources [Order 89-1700]; and

2. Oregon encourages utilities to develop their own mechanisms so that revenues lost as a result of conservation programs are recovered in rates.

C. These ratemaking mechanisms, in my judgment, are more than sufficient to remove any dis-incentive a utility would have towards pursuing DSM resources.

D. The question is whether states should adopt mechanisms that go beyond removing dis-incentives to actually incenting the utility towards DSM.

E. I think the answer is "it depends." It depends on what the PUCs are trying to incent. The path may be hazardous.

V. Load Management vs. Conservation

A. SFV pricing and incremental pricing of new capacity point LDCs in some very clear directions. High load factor use of interstate pipeline capacity will be very important in controlling consumers' energy costs.

B. DSM activity that focuses exclusively on reducing total consumption does little to improve the LDC's load factor. In fact, it could result in higher overall costs to consumers. This is because higher pipeline costs are spread over fewer therms, increasing consumers' costs.

C. Some might say this is good, that price signals will encourage conservation of the natural gas resource.

D. I agree that price signals are important. However, we should try to design price signals that reflect the competitive and operational context of the fuel. I encourage regulators to consider that natural gas is a fuel of choice with many competitors, some of which are less environmentally desirable. Regulators should not adopt policies that have the side effect of discouraging the use of natural gas relative to other fuels.

E. Specifically, incentive mechanisms that encourage only traditional conservation activity miss the mark because they ignore the importance of load shifting, off peak load building, and high load factor incremental sales.

VI. Decoupling

A. One mechanism that seems to be in vogue currently is the "decoupling mechanism." Decoupling has been described alternatively as an incentive mechanism, or as a method of removing dis-incentives to DSM.

B. Decoupling is usually defined as any mechanism that severs the link between sales and profits. Actual mechanisms vary greatly, but I have yet to see one that translates the concept into real-life rates and tariffs in a way that can be understood by mortal men.

C. As a mechanism to "remove dis-incentives," I think decoupling is redundant at best, and potentially dangerous to gas consumers at worst. The integrated resource planning requirement itself requires utilities to treat DSM equally, and we do. The Oregon commission's cost and lost revenue recovery mechanisms keep us whole.

D. As an incentive mechanism, I think decoupling fails because it incents total volume reduction without consideration of load management. I think we can do better than that.

E. NNG will support incentive mechanisms for gas utilities that encourage load factor management, which include strategic DSM for peak load reduction but also include cost-effective load building and load maintenance activity.

F. Load management activity will result in both reduced peak use and increased off-peak use. In other words, it will result in more efficient energy use with less impact on consumer prices.

VII. Conclusion

I thank you for your attention, and will be happy to answer questions.

WARNING:

* LISTENER CAUTION IS ADVISED

* A PORTION OF THESE REMARKS IS RATED "PI": Politically incorrect.

THE ENERGY POLICY ACT OF 1992 AND GAS UTILITIES

* Section 115 requires PUCs to "consider" two new standards.

* The "Integrated Resource Planning" standard.

* The "DSM Incentives" standard.

* Neither standard is mandatory.

PACIFIC NORTHWEST IRP EXPERIENCE

* Oregon and Washington already have required IRPs for gas utilities.

* NNG is nearing completion of its second-generation least-cost plans.

* IRPs have been a useful process and a valuable tool for NNG and gas utilities generally.

GAS RESOURCE PLANNING SHOULD BE DIFFERENT FROM ELECTRIC RESOURCE PLANNING

* The time frame is shorter.
* Avoided costs are lower.
* The market is partially -- but dynamically -- competitive.
* Gas IRPs require considerable flexibility.
* FERC Order 636 changed the focus of gas planning.

GAS IRP IMPLICATIONS OF STRAIGHT FIXED-VARIABLE PIPELINE RATES

* Load factor management is more cost-effective for LDC customers than reduced consumption.

* LDCs should:

  - Reduce peak demand
  - Expand off-peak or interruptible loads.
  - Retain high load factor industrial customers.
  - Re-examine growth policies and retail rate design.

* The 1992 Act recognizes load factor management as DSM.

DEMAND-SIDE MANAGEMENT INCENTIVES

* The DSM Incentive Standard:
  - Link net revenues in part to DSM performance.
  - Assure that financial results are not affected by sales lost to DSM.
* Oregon already has complied with the DSM Incentive Standard.
* Current standards effectively remove dis-incentives; going further may be hazardous.
* Design price signals around load factor, not total load reduction.

DECOUPLING

* An incentive mechanism, or a method of removing dis-incentives?

* Easier to understand in concept than to translate into real-life rates and tariffs.

* Assuming effective IRP, decoupling for gas utilities is redundant and potentially dangerous.

* Incentive mechanisms encouraging load factor management are an effective and efficient substitute for decoupling.

Integrated Resource Planning in Gas Utilities

Presented to

The Energy Policy Act of 1992 Seminar
The National Regulatory Research Institute

Presented by

Leonard R. Crook, Jr.
Vice President
ICF Resources Incorporated

July 1993

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INCORPORATED
9300 Lee Highway
Fairfax, Va. 22031-1207

OUTLINE

- **Integrated Resource Planning (IRP) in Gas Utilities: The Problem**

- **Changing Times**
- **Least-Cost Gas Supply Planning and IRP**
- **One Approach to IRP**
- **Major Issues in Gas IRP**

DEFINING INTEGRATED RESOURCE PLANNING

- **IRP is a process used by gas utilities to assess a *comprehensive* set of supply- and demand-side options.**
- **IRP is based on *consistent* planning assumptions in order to identify a resource mix that meets customers' energy requirements reliably at the lowest total cost.**
- **IRP can include measures other than costs, such as social costs and/or benefits (externalities).**

Several Features in the Energy Policy Act of 1992 Encourage Gas IRP

- Amends PURPA (1978) to incorporate Demand-Side Management (DSM).
- Promotes systematic consideration of DSM and supply-side options to minimize life-cycle costs.
- Requires public utilities to address gas IRP.
- Encourage electric IRP and continues reforms in the electric power industry.

THE PROBLEM FACING LOCAL DISTRIBUTION COMPANIES HAS TWO COMPONENTS

- **An abundance of options coupled with major uncertainties:**
  - **Supply-side options vary and are unclear**
  - **Demand-side options are uncertain.**
- **What is expected in an Integrated Resource Plan?**
  - **Composition**
  - **Criteria for Evaluation**

MAJOR RISKS AND OPPORTUNITIES FOR LDCS

- **Risks**
  - — DSM may be required for policy reasons other than resource costs
  - — Least-cost criterion could be applied in a short-sighted, literal manner
  - — Applying the electric utility IRP framework to natural gas may not be appropriate
  - — Many uncertain, judgmental issues
  - — Elements of process could prove costly and might not necessarily be recovered.

- **Opportunities**
  - — Integrates marketing, pricing, and supply planning
  - — Options to explore gas and electricity tradeoffs.

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THE APPLICATION OF IRP/DSM TO GAS HAS LAGGED THE ELECTRIC POWER INDUSTRY

- **Significant difference between the industries has contributed to the lag:**
  - **Industry structure and operations**
  - **Industry experience**
  - **Avoided costs.**
- **Significant barriers to DSM common to both industries:**
  - **Efficacy of DSM**
  - **Incentives**
  - **Rate treatment.**

IRP Has Not Been Applicable to LDCs

- Until the mid-1980's, LDCs had few options for gas supply.
- Declining gas prices throughout the 1980's reduced gas supply costs.
- Pipeline merchant function limited supply-side opportunities:
  - Bundled service
  - Contract demand.
- Rate design "distorted" price signals.

ORDER 636 MAKES LEAST-COST PLANNING MORE ROBUST

- **Ending the pipeline merchant function means LDCS must acquire supply and transportation separately.**

- **Unbundling transportation capacity and explicit pricing of services:**

  - **Transportation (including balancing, no notice)**
  - **Storage**
  - **Peakshaving.**

- **Straight fixed variable (SFV) rate design means that clearer price signals for capacity investments:**

  - **Penalizes low load factor LDCs**
  - **Alternatives to high cost pipeline capacity are more viable**
  - **Opportunities and obligation to achieve higher load factor.**

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OTHER MARKET DEVELOPMENTS ARGUE FOR IRP

- **Reversal of the decade-long slide in gas prices:**
  - **Increase volatility in the spot market**
  - **Changes in seasonality.**
- **Emergence of super marketers:**
  - **Offers a wide array of supply services at various prices**
  - **Able to create customized supply portfolio.**
- **Risk management:**
  - **Contract/spot mixes**
  - **Portfolio development**
  - **Financial derivatives.**

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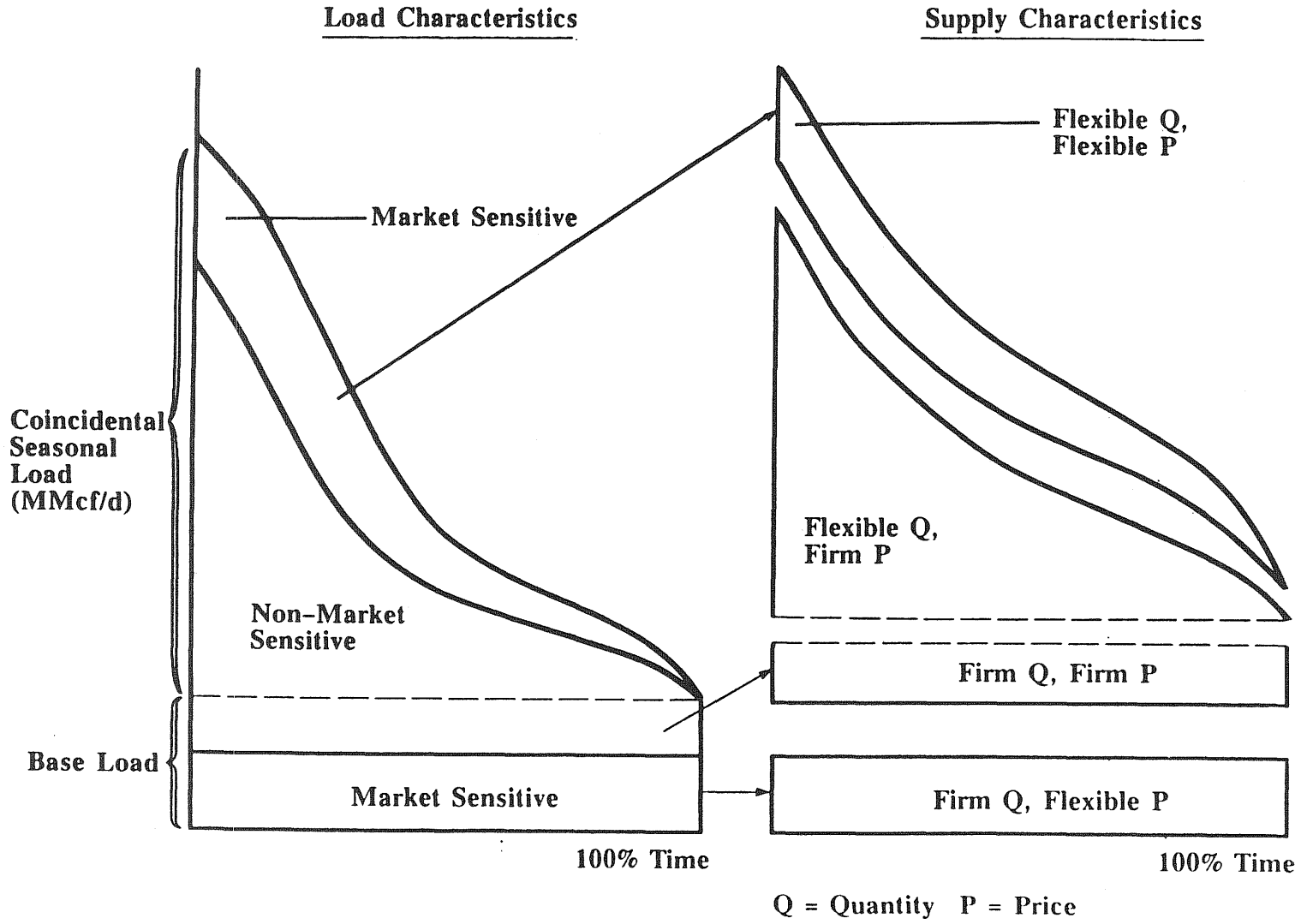
INTEGRATED PLANNING OCCURS AT MULTIPLE LEVELS

- **IRP naturally flows out of utilities' least-cost supply planning efforts.**
- **Least-cost supply planning quantifies the trade-offs between capacity (facilities investments) and supply (gas contracts) and interruptions.**
- **Integrated planning looks at choices over time.**
- **Integrated Resource Planning incorporates DSM options:**
  - **Options that reduce the need to invest on new facilities and new gas supply**
  - **Options that promote a more efficient use of gas facilities.**

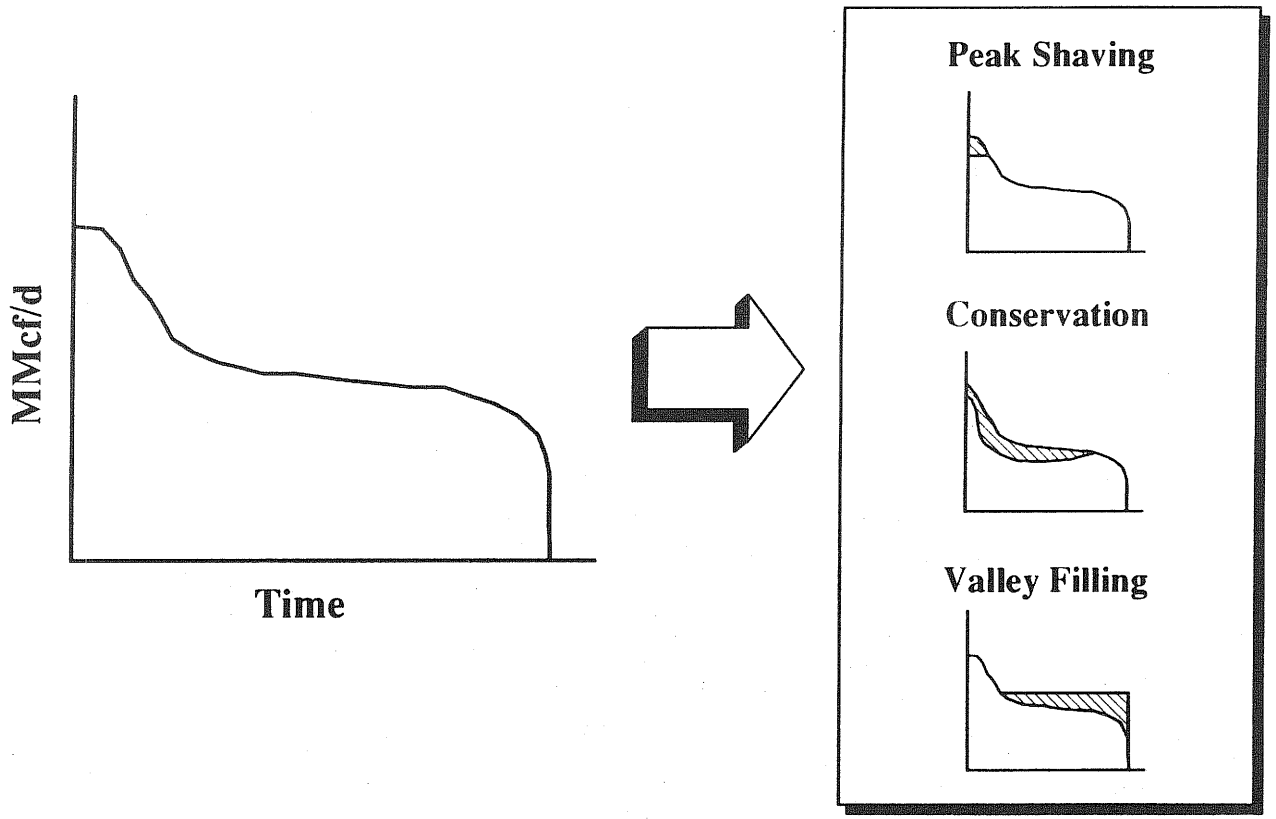
THE LEAST-COST GAS SUPPLY PLANNING STEPS

- **Develop load forecast.**
- **Determine the capacity options available, costs and constraints.**
- **Identify available gas supply options: spot/contract and contract terms, costs (minimum take, surcharges, GIC, escalators).**
- **Select mix of capacity and supply for the expected demand (net of interruption and storage injection) to meet cost minimization criteria (or other criteria).**
- **Test sensitivity of results to alternative assumptions.**
- **Select final mix to minimize Net Present Value (NPV) of expected cost of supply.**

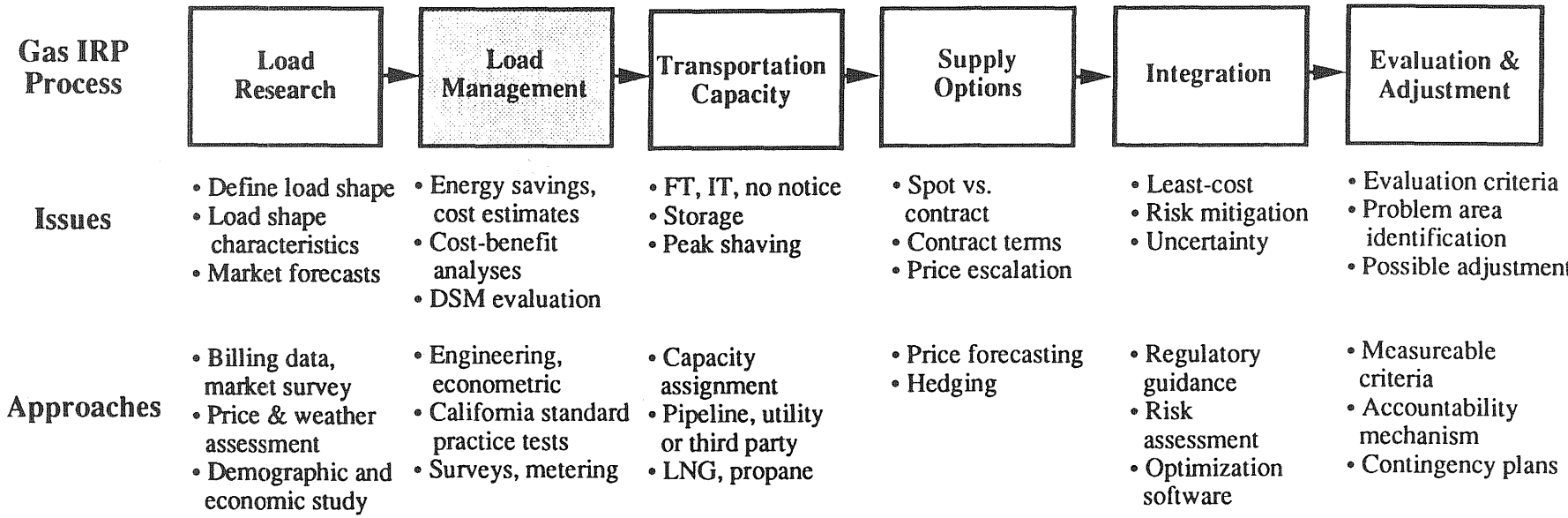
UNDERSTANDING THE LDC'S LOAD PROFILE IS KEY TO LEAST-COST PLANNING



DSM Programs Modify the Load Profile



THE IRP PROCESS IS LITTLE DIFFERENT FROM LEAST-COST PLANNING



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INCORPORATING DSM INTO LEAST-COST PLANNING

- **Major approaches**
  - **Dispatch modelling**
  - **Optimization modelling**
  - **WACOG Effects**
  - **Marginal costs analysis**
- **Key to modelling approaches is to represent DSM options in terms consistent with supply-side options.**
- **Experience with Gas Acquisition Strategy Model[2].**

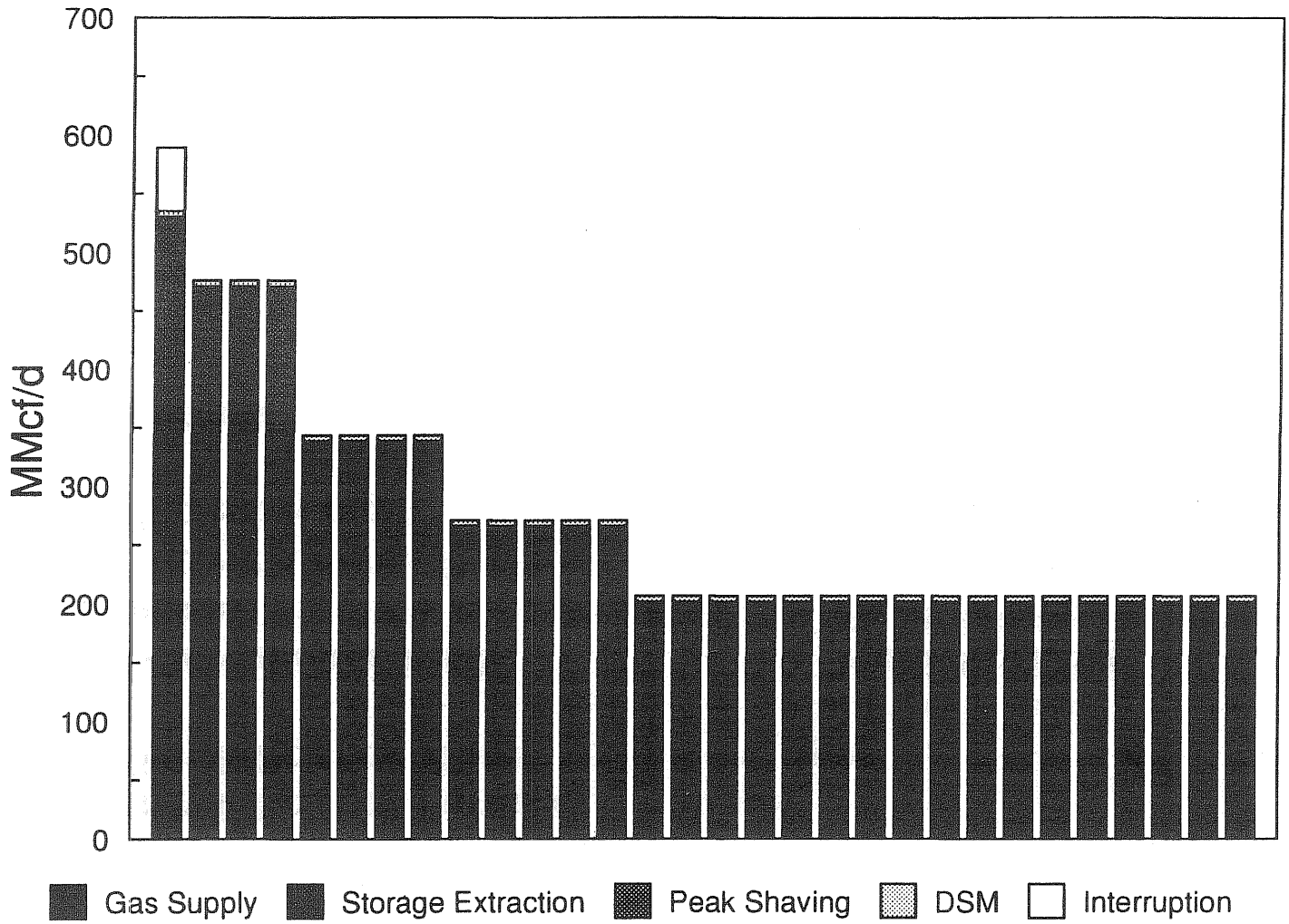
PRESENTING DSM AND SUPPLY OPTIONS ON A CONSISTENT BASIS

- **Costs**
  - **Fixed**
  - **Variable**
- **Supply Effect**
  - **Peak**
  - **Shoulder**
  - **Base**
- **Availability and Operating Rules**
  - **Timing**
  - **Penetration rate**
  - **Recidivism**

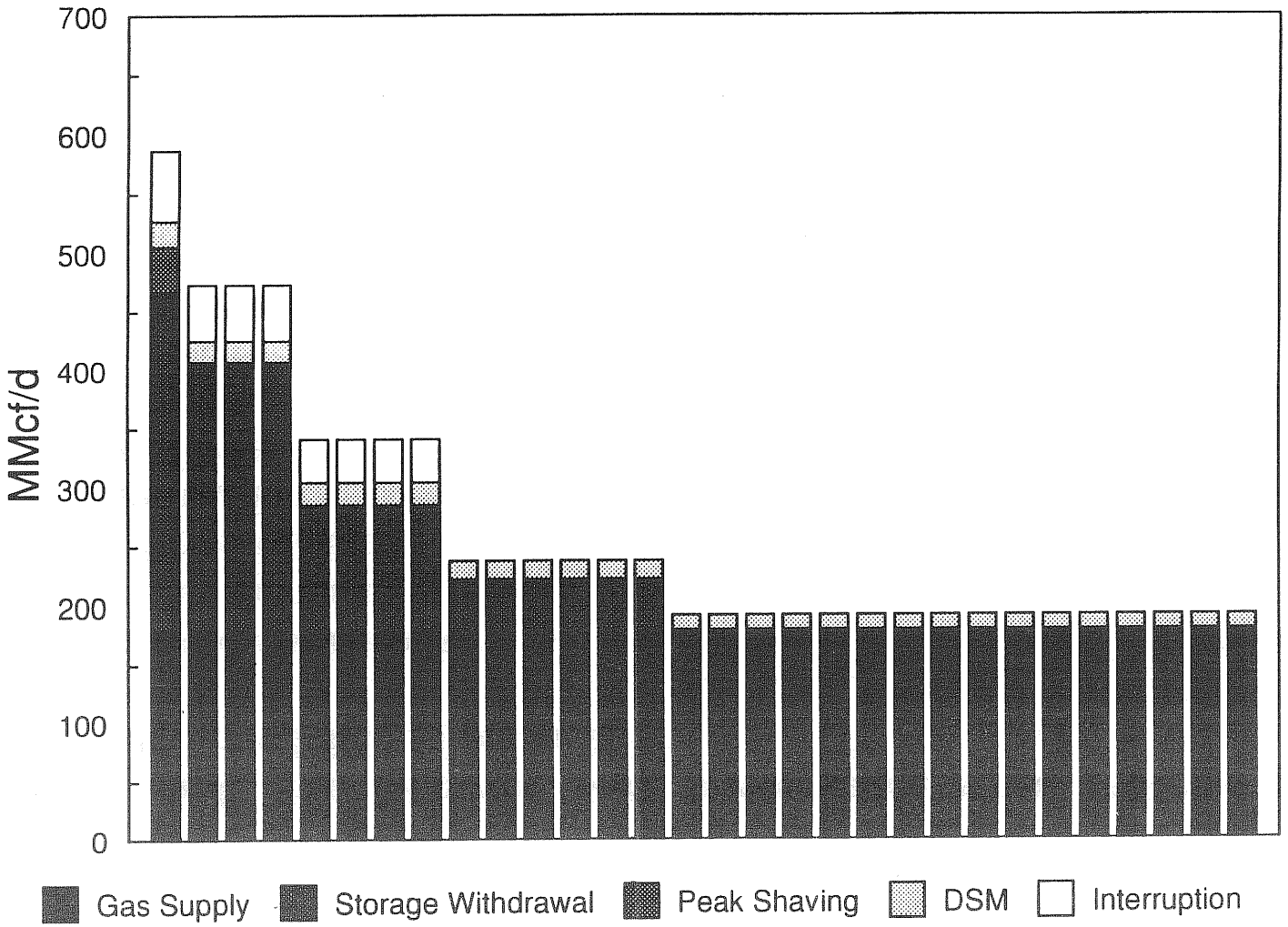
PRESENTING THE OPTIONS

Screened DSM Options	Available Supply Options
Residential High Efficiency Furnaces Residential High Efficiency Water Heaters Retrofits (low-flow shower heads, setback thermostat) Residential Efficient Clothes Dryers Residential Efficient Ranges Audits Industrial Programs	Supply — Spot — Contract • Market pricing • Fixed pricing • Escalated prices • Minimum take Pipeline Capacity — FT — IT Storage Peak Shaving — LNG — Propane Air Interruption — Alternate Fuels

First Case: Abundant Pipeline Capacity



SENSITIVITY CASE: REDUCED PIPELINE CAPACITY



COMMENT ON THE RESULTS

- If properly presented, DSM options will be selected under a least-cost strategy.
- In our example, the following were implemented when expected pipeline capacity additions failed to materialize:
  - Low flow showerheads
  - Up-graded furnace
  - Retro-fitted furnace
  - Weatherization
  - New waterheater.
- Sensitivity runs are required to test for less-than-expected savings or higher-than-expected costs of DSM programs.

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MAJOR CONCERNS FOR EFFECTIVE DSM AND SUCCESSFUL IMPLEMENTATION

- State of the industry:
  - Uncertainty due to Order 636
  - Low avoided costs.

- Load research capabilities and data development lag the electric industry:
  - Load forecasting by customer class and end use
  - Load shape studies.

- Analytic tools need development:
  - Optimization of supply and demand alternatives simultaneously
  - Processing large amounts of data
  - Managing uncertainty
  - Documentation of results in a straightforward, simple manner
  - Avoiding the "mother-of-models" syndrome.

- Evaluation of DSM energy savings and costs:
  - Accurate and reliable assessment of demand-side energy savings and costs
  - Accountability of energy savings and cost estimates.

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THE TREND IS TOWARD INTEGRATED ENERGY RESOURCE PLANNING

- **Raises the issue of electric/gas fuel switching.**
  - **Fuel switching in the form of interruption has been a staple of gas supply planning.**
  - **Complementarity of electric and gas loads and marginal costs.**
- **Trends in the electric industry may result in more fuel switching opportunities:**
  - **Non-utility generation**
  - **All-resource bidding**
  - **Incentive regulation.**

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OBSERVATIONS

- **Benefits of gas DSM are uncertain at best and appear small relative to electric DSM. This does not argue against IRP.**
- **Order 636 increases the need for least-cost supply planning.**
- **The logic of EP Act and the economics of the gas and electric industries argue for integrated *energy* resource planning.**
- **Significant barriers exist to implementing integrated energy resource planning:**
  - **Institutional**
  - **Cultural**
- **Leadership in integrated energy resource planning may have to come from regulators.**

SESSION III

TITLE I: ELECTRIC INTEGRATED RESOURCE PLANNING ISSUES

Integrated Resource Planning: What's Being Integrated?

Presented at the
National Seminar on Public Utility Commission
Implementation of the Energy Policy Act of 1992

July 9, 1993

Organized by the
National Regulatory Research Institute

Clinton J. Andrews
Woodrow Wilson School
Princeton University
Princeton NJ 08544-1013

Integrated Resource Planning: What's Being Integrated?

The Energy Policy Act of 1992 (EPAct)[1] is philosophically ambivalent -- it mandates both planning and market-based activities -- but its Title I has definitively settled the debate about what to call the planning function. Integrated Resource Planning, or IRP, has won out over Least Cost Planning, Capacity Expansion Planning, and even Integrated Resource Management. With that dispute resolved, we can now move on to a tougher question: what did Congress intend planners to integrate in preparing an IRP? The answer to this question should help states decide whether to adopt IRP as recommended by EPAct.

I suggest that there are five sets of factors to be integrated in IRP. The EPAct's definitions section identifies some of them, but others are hidden in neighboring paragraphs. I discuss each set of factors below, then I comment on factors that are not integrated but should be. I conclude with a recommendation that states adopt IRP, but change the basic function of planning.

1. Integrate Supply- and Demand-Side Options

The best-known objective of IRP is to expand the range of options considered during the resource acquisition process. While some interpret this exclusively as a way to promote Demand-Side Management (DSM), the legislation says otherwise. It tells planners to evaluate "the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources."

However, the Act does go on to require that planners "treat demand and supply resources on a consistent and integrated basis." While this would level the playing field for DSM, it need not be done simplistically. Planners are not required to treat supply and demand resources as interchangeable, but merely to apply a consistent evaluation technique. They can recognize the special strengths, weaknesses, and uses of different resource types, and do not need to mask reality by pretending that negawatts and megawatts are equivalent.

Indeed, the states are given much discretion in implementing IRP. The details of the evaluation and procurement processes are not specified, nor are ratemaking issues. Even the choice of performance measures, e.g., price (¢/kWh) or bill ($/month), is left open. As long as a full range of alternatives is fairly evaluated, then states are doing IRP.

2. Integrate Multiple Decision Criteria

EPAct respects the technical realities of electric power systems by directing planners to integrate factors of system operation, risk, and environment. IRP thus must accommodate multiple decision criteria.

System operation factors include "diversity, reliability, dispatchability, [and for DSM] verifiability and durability." This means that the unique characteristics of each resource should be recognized. It also suggests that the special needs of the electric power system (the portfolio of investments) should be identified and addressed. In practice this means that IRP should identify superior *packages* of options, that together improve overall system performance.

Factors of risk include fuel-side and capital-side risks, as well as the uncertainties surrounding future environmental legislation. Uncertainty is poorly incorporated in most current IRP processes. While planners have largely moved away from point forecasts towards ranged projections, their modeling tools rarely allow explicit representation of alternative risk management strategies.[2] EPAct allows states to encourage risk management, whether with a planning-oriented strategy of designed-in robustness, or a market-oriented strategy of designed-in flexibility.

Environmental factors have already been the subject of fierce debate. EPAct gives the debate more, not less salience by focusing on "all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance." In other words, it gives life-cycle analysis of cradle-to-grave environmental impacts a foot in the door.

Previous arguments have focused on externality adders for airborne emissions, e.g., should DSM (a zero-emissions technology) get a credit of 10%, or of 3 ¢/kWh, or of 20 $/ton of CO_2 emissions avoided? While percentage and ¢/kWh adders are easy, they are also simplistic and can stifle more broadly conceived innovation. An impact-based adder, by contrast, is more difficult to assess but better promotes efficient resource allocation.[3] Such methodological choices under IRP can have significant implications for long run economic efficiency, and they are left entirely in the hands of state regulators.

The requirements of the Clean Air Act Amendments of 1990 (CAAA) supersede or dominate the effects of some environmental factors currently included in IRP, especially for airborne emissions.[4] Thus, the future focus should probably shift towards more explicit representations of CAAA compliance in IRP, and towards other environmental factors such as siting and hazardous waste production.

Methodologically, these factors -- system operation, risk, and environment -- can be messy when applied to a benefit-cost analysis IRP framework. Multi-

criteria analysis, a framework rooted in decision science instead of economics, may be better suited for use in IRP.

3. Integrate Existing and New Capacity Decisions

EPAct directs states to encourage "all cost-effective improvements in the energy efficiency of power generation, transmission, and distribution." It explicitly highlights "better maintenance [of], and investment in" such equipment. The boundaries of IRP are thus broadened to include operational options along with investment options, and to consider the system as a whole, rather than only investments in new capacity.[5]

There is an important implication for techniques like environmental externality adders, which is that they now should be applied on a system-wide basis, and not only on new resource choices. In most of the nation (excluding hydro-dominated areas), the existing power plants are dirtier than new capacity options, so that the system-wide perspective may increase planners' interest in fuel switching, repowering, and retirement.[6] Title IV of the Clean Air Act Amendments of 1990 is also pushing utilities in that direction. IRP clearly forces planners to shift from a project evaluation to a portfolio management mindset .

The legislative text on maintenance and operations directs states to "consider the disincentives caused by existing ratemaking policies, and practices, and consider incentives." Thus, performance incentives and other inducements join traditional adjudicatory and standards-based regulatory instruments as tools for implementing IRP.

4. Integrate Multiple Policy Perspectives

The dreaded words "public participation" appear quite early in Title I of EPAct. Along with regular IRP updates, opportunities for public participation and comment should be built into the planning process so as to integrate the perspectives of many stakeholders -- utilities, consumers, environmentalists, independent service providers, and other governmental actors. This suggests that the IRP effort should not be limited to technical planning (deterministic optimization), or even strategic planning (developing steering capacity under uncertainty), which is what most utilities are developing. Instead, state commissions may want to encourage "communicative" planning, or building mutual understanding, as a part of the IRP process.[7]

Such a joint fact-finding orientation has implications for both process and analysis. Specifically, successful outcomes will depend in part upon the credibility and transparency of the process. Also important is analysis that explores a wide range of options (i.e., each stakeholder's favorite option) and demonstrates which options are robust across a wide range of assumptions (i.e.,

each stakeholder's view of the future). Controversy, uncertainty, and complexity can stifle creative thinking and the achievement of consensus, unless the IRP process and its analytic approach are carefully designed.[8]

Some analysts suggest that IRP will lose salience under a more competitive industry environment, because decisions will be made by the marketplace instead of by planners. However, such a shift in decision-making mechanisms will not reduce the need for good public information. It does suggest that IRP's informational role should be emphasized. In a competitive environment, there will continue to be a need to achieve common visions, especially of tradeoffs between economic and social objectives, such as rates versus environmental impacts. IRP may be best suited to establishing a public policy direction, e.g., credible bid criteria, rather than micro-managing specific investments in a competitive marketplace.

5. Integrate Multiple Regulatory Perspectives

Electric power systems are subject to economic and social regulation at the local, state, and federal levels. While nothing in Title I of EPAct mentions regulatory perspectives, this consideration is forced upon IRP implementers by Title VII (Exempt Wholesale Generators and open transmission access) and other facts of life.

Today, a majority of kWh are produced on systems that are interstate in scope.[9] Thus regional coordination and cooperation among states is necessary to keep the lights on. As transmission issues heat up, we can expect the need for integrating multiple regulatory perspectives to increase.

State-Federal relations can also enter the IRP process. Since ratemaking responsibilities are divided between states and the Federal Energy Regulatory Commission on interstate systems, there is a clear overlap of planning interests.

Intra-state coordination can also be important, in terms of building a common vision among public utility commissions, environmental regulators, consumer advocates, and other offices of state government. Economy-environment tradeoffs can not be resolved without such communications, and IRP provides a good mechanism for doing this.

Factors Not Integrated by IRP

EPAct does nothing to encourage two valuable integrative activities. First is the evaluation of total energy flows, and second is consideration of multiple environmental impacts.

State energy planners are currently the only governmental analysts integrating data on multiple energy sources to provide a total energy picture. Unregulated energy sources such as oil are excluded from consideration under IRP. Further, separate IRPs for electric and gas utilities may induce gaps and overlaps suggesting sub-optimality. Thus, state energy planning remains an important function even with the advent of IRP.

State environmental regulators have traditionally evaluated medium-specific impacts of the electric power sector. Air pollution offices enforce the Clean Air Act, water pollution offices enforce the Clean Water Act, and solid waste offices enforce yet another set of laws. Integrated, multi-media permitting is only beginning to enter practice. While it would be natural to build such considerations into IRP, EPAct is mute on the topic, and few state environmental regulators have raised the idea. More could be done.

Conclusions

In summary, IRP as defined by the Energy Policy Act of 1992 requires us to integrate the following:

- supply- and demand-side options
- multiple decision criteria
- new and existing capacity options
- multiple stakeholders
- multiple regulatory perspectives

Doing so requires analytical sophistication and a communicative orientation. In deciding whether to implement IRP, states should be careful, but not daunted.

As the electric power sector becomes more competitive, we may see a change in the function of planning. IRP may become useful for informing decentralized decisions rather than micro-managing them. States with credible IRP processes can expect continued value from them, because they may help to build mutual understanding even when they no longer dictate outcomes.

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1 P. L. 102-486, "Energy Policy Act of 1992," enacted October 24, 1992.

2 Hirst, E., "A non-algorithmic review of uncertainty in electric utility resource planning and decision making," Stanford Workshop paper, Oak Ridge National Laboratory, Oak Ridge TN, 1988, 18 pp.

3 Andrews, C., "The marginality of regulating marginal investments," *Energy Policy*, vol. 20, no. 5, May 1992, pp. 450-463.

4 ibid.

5 Andrews, C., and S. Connors, "Existing capacity – the key to reducing emissions," *Energy Systems and Policy*, vol. 15, pp. 211-235, 1992.

[6] Andrews, C., "Regional differences in emissions reduction opportunities," *Energy Policy*, vol. 21, forthcoming, 14 pp.

[7] Ulrich, W., "Systems thinking, systems practice, and practical philosophy: a program of research," *Systems Practice*, vol. 1, no. 2, pp. 137-163.

[8] Andrews, C., "Spurring inventiveness by analyzing tradeoffs: a public look at New England's electricity alternatives," *Environmental Impact Assessment Review*, vol. 12, no. 1, pp. 209-234.

[9] Based on data in U. S. Dept. of Energy, Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities 1990*, DOE/EIA-0437(90)/1&2, USGPO, Washington DC, 1992.

PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE ENERGY POLICY ACT OF 1992

NRRI/DOE SEMINAR

PORTLAND, OREGON

JULY 15 - 16, 1993

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ENERGY POLICY ACT OF 1992

- ✦ **Promotes IRP process**
- ✦ **Impacts resource choices**
  - → **Renewables**
  - → **Competitive providers**
  - → **Demand-side opportunities**

ACE^3/ASE ENERGY SAVINGS ESTIMATES

4.6 Quads of Energy 1993-2010
(mostly coal and gas)

274 billion kWh 2010

104 (500 mw) coal plants

20% projected electricity growth to 2010

34% carbon emission growth 1990 to 2010

NEW PURPA STANDARDS

16 U.S.C. §2621(D)

(7) **IRP**

(8) **Demand-side profitability**

(9) **Supply-side efficiency**

(10) **Long-term wholesale purchases**

IRP STANDARD

- Evaluate full range of resource alternatives
- Provide lowest system cost consistent with reliability, diversity, dispatchability
- Treat demand and supply resources on consistent and integrated basis
- Account for verification of savings, including durability
- Public input, regular updates, and implementation required

PROFITABILITY OF CONSERVATION INVESTMENTS STANDARD

- Investments in conservation, energy efficiency at least as profitable as energy supply investments
- Consider income lost from reduced sales due to conservation, efficiency
- Conservation, efficiency resources shall be appropriately monitored and evaluated

ENERGY SUPPLY EFFICIENCY STANDARD

- **Consider ratemaking policies to encourage improvements in efficiency in generation, transmission, distribution**

SMALL BUSINESS PROVISO

[Sec. 111(b)]

- Consider impacts of IRP process on small business
- Not provide utilities with unfair advantage

TIME FRAME

IRP

Profitability

Supply-side efficiency

- Commence by October 24, 1994
- Complete by October 24, 1995

16 U.S.C. §2622

LONG-TERM WHOLESALE PURCHASES

- Cost of capital
- Retail rates
- Unfair advantages of exempt wholesale generators
- Advance approval
- Assurance of fuel supply

TIME FRAME

LONG-TERM WHOLESALE PURCHASES

- **Complete by October 24, 1993**

16 U.S.C. §2621(d)(10)(E)

PRIOR PROCEEDINGS

O.K. for: IRP, profitability, supply-side efficiency

Not for: wholesale purchases

"CONSIDERATION AND DETERMINATION"

Procedural Requirements - 16 U.S.C. §2621

- Notice
- Public Hearing
- Evidentiary record
- Written decision based upon record

For all rate-regulated electric utilities

A SUGGESTED APPROACH

Working group

Inventory

Generic or case by case?

Financial resources

Parties

RENEWABLES INCENTIVES

- **Production tax credit for wind and closed-loop biomass (1.5 cents/kWh) (Sec. 1914)**
- **New solar, wind, geothermal, or biomass (not MSW!) facilities owned by state or political subdivision or non-profit cooperative are eligible for a production payment of up to 1.5 cents/kWh (subject to appropriations) (Sec. 1212)**
- **Permanent extension of 10 percent investment tax credit for solar and geothermal energy (Sec. 1916)**

ENERGY EFFICIENCY PROVISIONS

- **Utility rebates for energy conservation measures are excluded from taxable income -**

  100% for residential in 1993
  40% in 1995 then 65% in 1996 for C&I
  ACE³/ASE: 1.15 Quads 1993-2010

- **States required to update residential building energy codes on a regular basis**
  ACE³/ASE: .57 Quads 1993-2010

- **New energy efficiency standards adopted (Sec. 122-124) for:**

  - **commercial and industrial HVAC**
  - **industrial and small motors**
  - **distribution transformers**
  - **water heaters**
  - **incandescent and fluorescent lamps**

  ACE³/ASE: 1.16 Quads 1993-2010

MORE ENERGY EFFICIENCY PROVISIONS

- **Energy efficiency labeling required for lamps, small motors, office equipment, and utility transformers (Secs. 123-125)**
  ACE³/ASE: 1.93 Quads 1993-2010

- **DOE grants for industrial energy efficiency programs to industry associations and states (Secs. 131, 132)**
  ACE³/ASE: 1.75 Quads 1993-2010

- **DOE must issue voluntary guidelines for energy efficiency ratings for residential buildings**

- **HUD must establish a program promoting "energy efficient mortgages**
  ACE³/ASE: .78 Quads 1993-2010

SIGNIFICANCE OF PUHCA REFORMS AND TRANSMISSION ACCESS

- **IPP's, including renewable and advanced combined cycle gas generation, will have greatly expanded market opportunities**

- **The trend toward deregulation of new electricity generating will accelerate**

- **The market for generation of electricity will become increasingly competitive**

  → **advantages for technologies offering economy and flexibility**

  → **may discourage investments in traditional generation technologies**

- **Commissions will have to sort out self-dealing issues**

FEDERAL AGENCY ENERGY MANAGEMENT

- By 2005, all federal agencies required to install, to maximum extent practicable, all energy and water conservation measures with payback of less than 10 years (Sec. 152)

- Agency can retain 50% of bill savings to fund additional DSM (Sec. 152)

- Federal Energy Efficiency Fund - up to $50 million annually (Sec. 152)

- Federal agencies authorized and encouraged to participate in utility DSM programs and accept financial incentives from utilities (Secs. 152, 153)

- DOE must establish energy efficiency standards for new federal buildings (Sec. 10)

ACE^3/ASE: 1.93 Quads 1993-2010

OTHER REGULATORY REFORM PROVISIONS

- **IRP mandated for TVA, WAPA**
  ACE³/ASE: TVA 1.95 Quads WAPA .75 Quads 1993-2010

- **PUC consideration of new PURPA standards required for gas utilities**

  → **IRP**

  → **Profitability of investments in conservation and demand management**

  ACE³/ASE: 2.1 Quads 1993-2010

- **Within 2 years, DOE must conduct:**

  → **A survey of state policies implementing the 3 new PURPA standards for electric utilities**

  → **A survey of IRP policies of electric cooperatives**

OTHER PROVISIONS OF INTEREST

- **DOE must prepare a "least-cost energy strategy" as part of its National Energy Policy Plans which are submitted by the President to Congress (Sec. 1602)**

- **DOE must establish guidelines for voluntary reporting of emissions of greenhouse gases and emission reductions achieved through measures such as energy efficiency (Sec. 1605)**

- **Authorizes funds for RD&D on more efficient use of coal; extends funding for DOE's clean coal program**

- **Produces oil and gas drillers with a partial exemption from the Alternative Minimum Tax, thus reducing their tax liability by an estimated $1 billion over 5 years (Sec. 1915)**

- **Creates demonstration programs and infrastructure and support systems development program for electric vehicles (Title VI); electric vehicles eligible for 10% investment tax credit (Sec. 1913)**

IMPLICATIONS OF ENERGY POLICY ACT

- **Increased need for technical assistance and resource materials for PUC's**

- **Need for greater cooperation/coordination between DOE and EPA**

- **PURPA standards for least-cost planning and net income neutrality criteria for CRER eligibility under CAAA**

  - **Eligibility determinations for CRER could provide a standard for state consideration of IRP and profitability of conservation investments**

  - **Conservation Verification Protocols could provide model for PUC verification under new PURPA standards**

  - **New supply-side efficiency standard could save energy through fuel adjustment clause reforms**

- **Training and education of efficiency experts, planners and implementers**

- **White paper or case studies on small business issue**

SESSION IV

CHANGES TO PUHCA UNDER EPAct

THE ROLE OF EXEMPT WHOLESALE GENERATORS IN THE NEW ELECTRIC POWER INDUSTRY

Kenneth W. Costello
Associate Director of Electric and Gas Research
The National Regulatory Research Institute

Seminars on Public Utility Commission Implementation of the Energy Policy Act of 1992

Portland, Oregon
July 15, 1993

and

Indianapolis, Indiana
July 19, 1993

SEVEN MAJOR QUESTIONS THAT WILL BE ADDRESSED

- WHO ARE EWGS (EXEMPT WHOLESALE GENERATORS)?
- HOW WILL EPAct PROMOTE THEIR DEVELOPMENT?
- WHAT DOES EPAct NOT DO REGARDING THE DEVELOPMENT OF EWGS?
- WHO HAS AUTHORITY OVER EWGS?
  - FERC
  - STATE PUCS
  - REGULATORY CONFLICTS
- WILL EWGS IMPROVE THE ECONOMIC PERFORMANCE OF THE ELECTRIC POWER INDUSTRY?
- HOW CAN STATE PUCS PROMOTE THE DEVELOPMENT OF EWGS?
  - SHOULD THEY?
  - WHAT ARE THE BENEFITS TO RETAIL CONSUMERS?
  - WHAT ARE SOME POTENTIAL PROBLEMS?
- HOW WILL EWGS CHANGE THE STRUCTURE AND PERFORMANCE OF THE FUTURE ELECTRIC POWER INDUSTRY?

I. DEFINING EWGS

- GENERATORS THAT OWN AND OPERATE GENERATING FACILITIES AND SELL POWER AT WHOLESALE TO UTILITIES, WITHOUT BEING REGULATED AS UTILITIES OR HOLDING COMPANIES UNDER PUHCA

- INCLUDES BOTH TRUE INDEPENDENT GENERATORS AND UTILITY-AFFILIATED GENERATORS (E.G., MISSION, ENERGY, PG&E ENTERPRISES, DESTEC, ENRON POWER)

- REQUIREMENTS FOR EWG STATUS:

  - EWG CANNOT SELL DIRECTLY TO RETAIL MARKETS (EXCEPT FOR FOREIGN EWG)

  - EWG MAY OWN ALL OR PART OF ONE OR MORE "ELIGIBLE FACILITIES"

  - EWG CAN BE A HYBRID FACILITY WHERE A PORTION OF THE FACILITY IS INCLUDED IN A UTILITY'S RATE BASE

  - SPINOFF OF EXISTING RATE-BASED FACILITY REQUIRES STATE PUC APPROVAL

  - SELF-DEALING TRANSACTION REQUIRES STATE PUC APPROVAL

  - FERC CERTIFICATION

  - SEC APPROVAL OF FINANCE ARRANGEMENTS FOR EWG OWNED BY A REGISTERED HOLDING COMPANY

II. HOW EPACT WILL STIMULATE THE GROWTH OF EWGS

- LIFTING OF BARRIERS FOR ENTRY
  - VERTICALLY-INTEGRATED UTILITY CAN NOW SELL POWER GENERATED BY FACILITIES DISINTEGRATED FROM THE REST OF ITS ELECTRIC POWER SYSTEM
  - A NONUTILITY (E.G., ENGINEERING FIRM, CONSTRUCTION COMPANY) NOW DOES NOT HAVE TO FEAR BECOMING A UTILITY HOLDING COMPANY WHEN OWNING OR OPERATING A WHOLESALE POWER FACILITY
- GREAT POTENTIAL FOR EWG GROWTH
  - NONUTILITY GENERATORS NOW MAKE UP ABOUT 10 PERCENT OF ALL POWER (OR OVER 50,000 MWS OR OVER 4,000 GENERATING FACILITIES); BUT
  - ONLY A SMALL NUMBER CONSISTS OF STAND-ALONE NON-QF GENERATORS (IN 1989 LESS THAN 5 PERCENT OF THE INTERCONNECTED NONUTILITY CAPACITY WAS NOT QFS)

- EXPERTS PREDICT THAT MUCH OF NEW GENERATING CAPACITY UNTIL THE END OF THE CENTURY WILL COME FROM NONUTILITIES, ESPECIALLY EWGS INCORPORATING COMBINED-CYCLE, GAS-FIRED TECHNOLOGIES; UNLIKE QFS, EWGS WILL NOT BE BURDENED BY SIZE, TECHNOLOGY, OR OWNERSHIP REQUIREMENTS

- FOR EXAMPLE, EXPERTS PREDICT THAT NONUTILITIES WILL BUILD OVER 50 PERCENT OF NEW GENERATING CAPACITY BETWEEN NOW AND THE END OF THE CENTURY

- EWGS WILL LIKELY BE MORE ATTRACTIVE THAN PURPA-QFS (WHY?)

- PLACES EWG-TYPE FACILITIES ON A "MORE LEVEL PLAYING FIELD" WITH PURPA-QFS

III. WHAT EPAct DOES NOT DO

- PRICE REGULATION OF EWGS STILL FALLS UNDER FERC'S JURISDICTION; FERC RULEMAKING MAY IN EFFECT DEREGULATE PRICES FOR MOST EWG TRANSACTIONS

- EWGS STILL DO NOT HAVE THE SAME PRIVILEGES AS PURPA-QFS

  - NO GUARANTEED MARKET (EWGS HAVE TO COMPETE WITH OTHER PRODUCERS) (AS THEY SAY, "IT TAKES TWO TO TANGO")

  - NO GUARANTEED PRICE (EWGS GENERALLY WILL RECEIVE A MARKET-BASED PRICE); BUT

  - APPARENT ADVANTAGES GIVEN TO QFS MAY BE MORE ILLUSORY THAN REAL (E.G., QFS' PRIVILEGES IN STATES WITH POWER PROCUREMENT PROGRAMS MAY BE LIMITED TO ENERGY PAYMENTS FOR POWER OFFERED TO THE LOCAL UTILITY)

- **SOME REASONS WHY EWG INDUSTRY MAY SHOW SLOW GROWTH DURING THE NEXT FEW YEARS**
  - **POPULARITY OF DSM PROGRAMS**
  - **RESTRICTIVE STATE-SANCTIONED POWER PROCUREMENT PROGRAMS**
  - **STATE PUCS LIMITING UTILITY OPPORTUNITIES TO PARTICIPATE AS EWGS**
  - **CONTINUED PASSTHROUGH OF PURCHASED POWER COSTS ON A DOLLAR-FOR-DOLLAR BASIS BY UTILITY BUYERS OF EWG POWER (DO UTILITIES HAVE AN INCENTIVE TO PURCHASE POWER WHEN IT IS ECONOMICAL?)**

IV. REGULATORY AUTHORITY OVER EWGS

- **FERC**
  - **CERTIFICATION OF EWGS (G.0.550-A)**
  - **PRICING OF WHOLESALE POWER INCLUDING THAT PRODUCED BY EWGS**
  - **DETERMINE "JUST AND REASONABLENESS" OF TERMS AND CONDITIONS OF WHOLESALE CONTRACTS**
  - **ASSURANCE THAT WHOLESALE PRICES PAID TO AFFILIATES ARE NOT PREFERENTIAL OR DISCRIMINATORY**
  - **DETERMINE TRANSMISSION-ACCESS AND-PRICING RULES (WILL HAVE IMPORTANT EFFECT ON THE AVAILABILITY OF MARKETS FOR, AS WELL AS THE ECONOMICS OF, EWGS)**

- STATE PUCS
  - AUTHORITY DEPENDS ON HOW STATE LAWS DEFINE THE TERM "UTILITY" (E.G., IF EWGS ARE CONSIDERED UTILITIES, A STATE PUC MAY HAVE THE AUTHORITY TO REQUIRE ADVANCE APPROVAL OF THEIR FINANCINGS)
  - DETERMINE PRUDENCE OF WHOLESALE POWER PURCHASES (PURSUANT TO THE "PIKE-COUNTY DOCTRINE")
  - DETERMINE CONSUMER AND PUBLIC INTEREST EFFECTS OF
    - PLANT SPINOFFS TO THE STATUS OF EWGS, AND
    - POWER SALES INVOLVING AFFILIATED EWGS
  - RETAIL PRICING (RECOVERY OF PURCHASED POWER COSTS FROM RETAIL CONSUMERS)
  - HAS ACCESS TO BOOKS AND RECORDS OF ELECTRIC UTILITIES, EWGS, AND THEIR AFFILIATES
  - HAS AUTHORITY TO APPROVE FOREIGN INVESTMENTS BY PUBLIC UTILITIES NOT PART OF A REGISTERED HOLDING COMPANY (E.G., ILLINOIS POWER FORMING AN EWG IN GREAT BRITAIN)

- **SEC**
  - **PROTECTION AGAINST FINANCING OF EWGS BY REGISTERED HOLDING COMPANY**
  - **ISSUANCE OF SECURITIES BY REGISTERED HOLDING COMPANY FOR FINANCING FOREIGN UTILITY**

- **ADDITIONAL TASKS FOR PUCS**
  - **MORE UPFRONT REVIEWS OF WHOLESALE TRANSACTIONS AS PART OF AN IRP PROCESS OR PURCHASED-POWER PROCUREMENT PROGRAM**
  - **ASSESSMENT OF PROPOSED PLANT SPINOFFS BY UTILITIES**
  - **SCRUTINY OF POTENTIALLY ANTICOMPETITIVE ACTIVITIES SUCH AS CROSS-SUBSIDIZATION AND SELF-DEALING ABUSES**
  - **MORE RETROSPECTIVE REVIEWS OF WHOLESALE PURCHASES BY JURISDICTIONAL UTILITIES**
  - **CONSIDERATION OF NEW PURPA WHOLESALE POWER STANDARDS (SEC. 712 OF EPAct)**
  - **MORE REVIEWS OF UTILITY RESTRUCTURING PROPOSALS**
  - **MORE REVIEWS OF UTILITY INVESTMENTS IN FOREIGN COUNTRIES**

- **POTENTIAL JURISDICTIONAL CONFLICTS**
  - **NO CODIFICATION OF THE "PIKE COUNTY DOCTRINE"**
  - **ENCOURAGEMENT OF EWG DEVELOPMENT BY WAY OF LENIENT FERC TRANSMISSION ACCESS RULES AND LOW TRANSMISSION PRICING**
  - **PRICING, TERMS, AND CONDITIONS OF WHOLESALE POWER CONTRACTS**
  - **DEFINITION OF "COMPETITIVE" MARKETS**
  - **FERC'S ECONOMIC-EFFICIENCY OBJECTIVE VERSUS STATES' BROADER SOCIAL WELFARE OBJECTIVE**

V. THE ECONOMIC EFFECTS OF EWGS

- LIKELY MAJOR EFFECTS
  - MORE INDEPENDENT POWER GENERATION OR MORE NEW GENERATION WILL FALL OUTSIDE THE PURVIEW OF RATE-OF-RETURN REGULATION
  - INCREASED PRESSURE FOR TRANSMISSION ACCESS
  - LOWER MARKET SHARE FOR PURPA-QF WHOLESALE GENERATION
  - ASSUMING OPEN TRANSMISSION ACCESS, CHANGING NATURE OF, AND EXPANDING THE MARKET FOR, WHOLESALE POWER (E.G., MORE UTILITY GENERATION OUTSIDE OF FRANCHISED AREAS)
  - INCREASED PRESSURES FOR COMPETITION IN RETAIL MARKETS
  - LESS VERTICALLY-INTEGRATED ELECTRIC POWER INDUSTRY
  - NONUTILITY POWER SUBSIDIARIES PROVIDING MORE OF PARENT UTILITY COMPANY'S REVENUES AND EARNINGS GROWTH

- INCREASED INTEREST IN FOREIGN INVESTMENTS
  - DEFINITION OF EWGS INCLUDES NON-RATEBASED GENERATORS WHO SELL WHOLESALE IN U.S. MARKETS AND TO FOREIGN FACILITIES (INCLUDING THOSE WHO SELL TO RETAIL MARKETS)
  - STATE PUCS HAVE APPROVAL RIGHTS OVER FOREIGN INVESTMENTS BY EXEMPT HOLDING COMPANIES AND OPERATING UTILITIES AFTER CERTIFYING TO THE SEC THAT THEY HAVE THE ABILITY TO PROTECT CONSUMERS FROM FAILED INVESTMENTS
  - SEC MUST APPROVE FOREIGN INVESTMENTS BY REGISTERED HOLDING COMPANIES, WITH AN ADVISORY ROLE PLAYED BY STATE PUCS (SEC IS REQUIRED BY EPAct TO ISSUE REGULATIONS)
  - STATE PUCS HAVE WIDE ACCESS TO THE BOOKS AND RECORDS OF UTILITIES AND THEIR WHOLESALE POWER SUBSIDIARIES, INCLUDING FOREIGN ONES

- **OBSERVATIONS ON FOREIGN INVESTMENTS**
  - **MANY UTILITIES WILL EXPLORE THE POSSIBILITY OF MAKING FOREIGN INVESTMENTS OVER THE NEXT SEVERAL YEARS**
  - **THE OLD PROBLEMS ASSOCIATED WITH UTILITY DIVERSIFICATION APPLY TO FOREIGN INVESTMENTS**
  - **STRUCTURAL CORPORATE SEPARATION (CREATING THE SO-CALLED "CHINESE WALL") MAY BE THE PREFERRED COURSE OF ACTION: FROM THE UTILITY'S PERSPECTIVE, IT MAY BE THE EASIEST, AND PERHAPS THE ONLY, WAY TO GET STATE PUC APPROVAL WHILE AT THE SAME TIME ALLOWING SHAREHOLDERS TO KEEP ALL THE PROFITS**
  - **STATE PUCS MAY SEE ADVANTAGES FROM UTILITIES INVESTING IN FOREIGN UTILITIES RATHER THAN OTHER DIVERSIFIED ACTIVITIES (WHY?)**

VI. OPPOSING VIEWS ON THE DEVELOPMENT OF EWGS

- ARGUMENTS FOR EWGS
  - INCREASE NUMBER OF WHOLESALE POWER PRODUCERS
  - STIMULATE PRESSURE FOR EASIER TRANSMISSION ACCESS
  - SHIFT RISK ASSOCIATED WITH NEW GENERATING CAPACITY FROM RETAIL CONSUMERS TO PRODUCERS
  - MOVE ELECTRIC POWER INDUSTRY TOWARD MORE OPTIMAL (LESS VERTICALLY-INTEGRATED) STRUCTURE
  - SHIFT POWER GENERATION TO LOWER-COST SOURCES (E.G., FROM PURPA-QFS TO NEW COMBINED-CYCLE, GAS-FIRED GENERATING FACILITIES)
  - ADVANCE COMPETITION IN THE ELECTRIC POWER INDUSTRY
  - PROMOTE THE DEVELOPMENT OF INNOVATIVE GENERATING TECHNOLOGIES
  - COMMENSURATE WITH INTEGRATED-RESOURCE-PLANNING OBJECTIVES

- ARGUMENTS AGAINST EWGS
  - ERODE STATE AUTHORITY
  - DIMINISH ECONOMIES OF SCOPE OR THE BENEFITS OF VERTICAL INTEGRATION (E.G., INCREASE TRANSACTION COSTS, CREATE PROBLEMS OF LONG-TERM CONTRACTING AND EXTERNALITIES)
  - JEOPARDIZE RELIABILITY OF ELECTRIC POWER SYSTEMS
  - ENHANCE THE POSSIBILITY OF ANTICOMPETITIVE ACTIONS BY UTILITIES
    - SELF-DEALING ABUSES
    - CROSS-SUBSIDIZATION
  - LEAVE THE INDUSTRY WITH INADEQUATE REGULATION GIVEN THE HIGH LEVEL OF UTILITY CONCENTRATION IN WHOLESALE MARKETS

- **ASSESSMENT**
  - **ECONOMIES OF SCOPE ARGUMENT IS PROBABLY OVERSTATED, BUT THERE EXISTS NO EVIDENCE TO SUPPORT THIS VIEW**
  - **NONUTILITY POWER SHOULD BE AS RELIABLE AS UTILITY POWER**
  - **GENERATION SECTOR SHOULD BE QUITE COMPETITIVE (ASSUMING BROAD TRANSMISSION ACCESS)**
  - **ALTHOUGH EXPERIENCES WITH NONUTILITIES SO FAR HAVE BEEN ENCOURAGING, THERE STILL EXIST UNRESOLVED QUESTIONS RELATING TO THE FUTURE ROLE OF NONUTILITY GENERATORS IN THE ELECTRIC POWER INDUSTRY**
  - **WHILE EPAct IMPROVES COMPETITION OPPORTUNITIES, REGULATORS WILL PLAY A CRUCIAL ROLE IN ASSURING THAT RETAIL CONSUMERS WILL BENEFIT FROM THE ENTRY OF EWGS**
  - **ABUSES BY UTILITY AFFILIATES CAN BE MITIGATED BY EFFECTIVE STATE PUC AND FERC REGULATION (EPAct GIVES THE STATES MUCH AUTHORITY TO PROTECT RETAIL CONSUMERS FROM THESE ABUSES)**

VII. WHAT QUESTIONS LIE AHEAD FOR STATE PUCS?

- HOW MUCH COMPETITION TO ALLOW?
- WHAT IS THE EFFECT OF FERC WANTING MORE COMPETITION THAN WHAT THE STATES DO?
- HOW CAN CROSS-SUBSIDIZATION OF COMPETITIVE SERVICES BY MONOPOLY OR NONCOMPETITIVE SERVICES BE PREVENTED?
- WHEN SHOULD REGULATORS DEREGULATE CERTAIN SERVICES?
- SHOULD STATE PUCS RESTRICT COMPETITION WHEN IT MAY BENEFIT CORE CONSUMERS IN THE SHORT TERM?
- CAN, AND SHOULD, TRADITIONAL COST-OF-SERVICE REGULATION SURVIVE IN A MUCH MORE COMPETITIVE ELECTRIC POWER INDUSTRY?
- TO WHAT EXTENT SHOULD UTILITIES BE ALLOWED TO COMPETE IN UNREGULATED MARKETS?

Competition

and

Regulation of Electric Utilities under the Energy Policy Act of 1992

David H. Meyer
U.S. Department of Energy
July 1993

Will A New Paradigm Emerge in the Electric Utility Industry?

- **Is the traditional vertically-integrated corporate model changing?**

- **What alternative structure(s) may emerge?**

- **How can/should state regulators influence this evolution?**

What Does the Act Require?

- **Very few direct "requirements" for states or utilities--but some important new options.**

- **Establishes "exempt wholesale generator" (EWG) as a type of entity not subject to Holding Company Act.**

- **EWG status is easily obtained under FERC procedure.**

- **States can allow utilities to purchase from EWGs, rely on traditional cost-of-service regulation, or a combination of both.**

Empirical Trends

- About 60 applications for EWG status so far. Too early to see patterns as to type of owner, size or fuel type of facility, etc.
- Recession and low gas prices have contributed to shakeout in independent-power sector.
- Intense competition now in international markets for new generation; domestic wholesale markets are quiet by comparison.
- Many assert that retail wheeling is coming.

Dynamic Processes

- **Even partial or limited competition triggers major developments:**

  -- **Current rush into international markets**
  -- **Concern over retail wheeling leads utilities to be intensely cost conscious**
  -- **Rising incidence of mergers, corporate restructurings, strategic alliances**

- **One result: State regulators are bombarded with new issues and questions—in no apparent order.**

Toward a New Paradigm

- **Experience with PURPA implementation in 1980s suggests that if a new paradigm emerges it will evolve most rapidly in states where new generation capacity is needed.**

- **If new capacity is needed, state regulators will be under pressure to experiment with competitive procurement to minimize costs.**

- **Regulators are unlikely to block construction of new capacity under cost-of-service regulation.**

- **Question is whether utilities will be interested in cost-of-service approach, if they have other options.**

Simplifying Assumption: Most New Capacity Will Be Built by EWGs

- **Would there be a dynamic process creating pressure to convert capacity now in rate base to EWG status? [Note: Policy Act requires consent by state regulators for such conversions.]**

- **Utilities, with regulators' approval, will reconfigure themselves as regulated retail deliverers and/or competitive wholesale suppliers.**

- **Planning for meeting retail load will be under integrated resource planning (IRP).**

- **Retail sellers' performance as wholesale buyers can be gauged against a regional price index; those who benefit consumers by beating the index should be rewarded.**

Affiliate Transactions: A Core Issue

- **The Policy Act <u>bans</u> utility purchases from an affiliated EWG—unless such purchases are approved by affected state commissions.**

- **Two competing views heard during legislative debate:**
  - **-- That the risks of above-market-cost transactions greatly outweigh possible benefits associated with vertical integration, and that states should not attempt to regulate such transactions.**
  - **-- That some affiliate transactions will benefit consumers and should be allowed.**

- **Reform provisions in Policy Act were predicated on continued protection of consumers' interests. Lawmakers <u>assumed</u> that affiliate transactions, if allowed at all, would be subject to very stringent state regulation.**

Investments in Foreign Utility Companies

- **State commissions are to approve/disapprove of proposed investments by affiliates of utilities under their jurisdiction that are not part of a registered holding company system.**

- **The federal Securities and Exchange Commission (SEC) is responsible for review of proposed foreign investments by registered holding companies or their affiliates. State commissions may make recommendations to the SEC about registered holding company investments abroad, if operating utilities under state jurisdiction might be affected.**

Next Steps

Utilities, prospective EWGs, and many others are waiting to see how state regulators address several key issues:

- **Competition vs. cost of service regulation for new capacity**
- **Ensuring fairness of competition among diverse technologies**
- **Corporate restructuring of utilities (for both domestic and foreign operations)**
- **Conversion of facilities now in rate base to EWG status**
- **Affiliate transactions**
- **Retail wheeling**

Changes to the Public Utility Holding Act - Exempt Wholesale Generators

HOW THIS MAY AFFECT PORTLAND GENERAL ELECTRIC

by

Kathy Phillips-Israel
Manager, Regulatory Strategy - Marketing

Good afternoon. I hope all of you are enjoying your visit in Portland. I work at Portland General Electric, which is the electric utility that serves the metropolitan area surrounding the City of Portland. Our service territory is contained within the State of Oregon. When I was asked to speak at this panel, I was asked to talk about how the creation of exempt wholesale generators will affect how my utility operates. I was asked to respond to the Energy Policy Act by addressing three questions. These are

- What will be the impact on our competitive bidding process to address the emergence of exempt wholesale generators?
- How will the company be affected by affiliated transactions and self-dealing?

and

- How will the company respond to investment in foreign utilities?

Different utilities are going to respond to exempt wholesale generators in various ways. One can speculate as to what factors influence how a utility will behave, and how quickly action will be taken. I believe that one of the reasons I was asked to speak today is because of PGE's large reliance on purchased power, compared to other utilities, and because PGE is facing a resource deficit situation in the near future. It is reasonable to assume that if a new regulatory paradigm is going to emerge in response to exempt wholesale generators, it will arise most quickly in states where resource capacity is needed. In 1992, PGE's resource mix was

approximately 30% purchased power, 25% nuclear, and the remaining 45% from coal, combustion turbines, and some hydro. Our purchased power primarily comes from the Bonneville Power Administration and long term purchases from other utilities. Because of the region's historically low avoided cost, PGE has an insignificant amount purchased from qualifying facilities under the PURPA guidelines. These resources were used to serve a load of approximately 600,000 customers in the urban areas surrounding the City of Portland. Although our service territory is small in terms of square miles served, most of Oregon's population lives within our service territory. Our load is around 2200 average megawatts, with an annual peak in the winter that can approach 3800 megawatts. Our load is expected to grow at 1.5 to 2 percent per year.

In January of this year, PGE closed its Trojan nuclear power plant. Overnight the utility went from 30% purchased power to 55% purchased power. These additional power purchases are spot market purchases and serve as "placeholders" until longer term resources can be acquired. It is the company's goal to have 520 average megawatts on line by 1996 to replace the loss of its nuclear power plant. This brings me to the first question to answer about the impact of exempt wholesale generators--that is, how has our competitive bidding process been affected with the creation of exempt wholesale generators? There has been no immediate impact. Due to the tight time frame in which our utility was looking to acquire resources, PGE did not use a competitive bidding process for the Trojan replacement power.

The company received unsolicited bids totaling 5,000 megawatts; 1,120 megawatts were short-listed. We are currently negotiating with 3 potential bidders. Because of questions around the impact of purchases on the company's cost of capital and other issues raised in Section 712

of the Act, PGE will require an equity position in these projects. This position represents our short term position. We are currently evaluating financial and other risks associated with additional long term power purchases from all suppliers, including exempt wholesale generators. This investigation is occurring in conjunction with a generic proceeding on the Energy Policy Act, being conducted by the Oregon Public Utility Commission.

PGE is using a competitive bidding process to acquire 50 average megawatts of renewable resources. The purpose of this bid is to assess the commercial readiness and potential of renewable resources. Again, PGE will require an equity position in the selected project.

The company plans to go out for an all source competitive bid during the first quarter of 1994. It is too early to say how the emergence of exempt wholesale generators will affect this bidding process as our policy has not yet been developed. PGE is in the assessment stage; we are trying to identify and understand the issues and are exploring the need for regulatory incentives for purchased power. I like to compare where we are now to where we were five years ago regarding our strategy on demand-side resources. Five years ago, PGE had little acquisition from demand-side resources and although DSM was not actively pursued, the utility was not actively pursuing supply-side acquisitions either. When the utility came closer to load resource balance, PGE began to assess the issues around DSM, along with others in the region. An incentive mechanism was developed jointly with our Commission. Today, PGE has established a well defined commitment to DSM. I envision that the same process will take place for developing a strategy regarding purchased power and exempt wholesale generators.

Now I would like to turn to the issue of how PGE may be affected by affiliated transactions as a result of the emergence of exempt wholesale generators. This is an area which

will not affect PGE. In the 1980s, PGE diversified its business by creating subsidiaries in real estate, leasing, resource development and brokering. Most of these ventures were not successful. In 1991, PGE made a strategic decision to close or sell its subsidiaries and focus on the core business. I do not envision PGE revising this strategy by creating a subsidiary to develop resources as an exempt wholesale generator. Thus, self-dealing will not be an issue.

Because of our focus on the core business, PGE is also unlikely to turn to foreign investments as a result of the creation of exempt wholesale generators.

Let me summarize what our strategy is regarding the Energy Policy Act. Our primary impact from the emergence of exempt wholesale generators will be the company's position on whether to build or buy resources--or more likely, what combination of the two and what criteria to use in making the decision to build or buy. We do not have a well defined policy at this time, but we are actively pursuing an understanding of the issues so that we can form our policy. PGE is exploring the need for purchased power incentives--and, by this, I mean two things. First is the issue of whether disincentives exist around purchased power, and if so, developing alternative regulation to remove these disincentives. Removal of a disincentive would simply put purchased power on a level playing field with other options. We are considering whether we should ask for ratebase treatment for purchased power, and for the longer term, questioning if ratebase regulation and current least cost planning methodologies are obsolete. We are exploring how PGE can remain competitive if it acquires more expensive resources due to recognition of externalities while exempt wholesale generators may have cheaper power to sell because its resource selection did not consider the cost of externalities. Second is the issue of whether an incentive is appropriate for purchased power--that is, an incentive to make purchased

power look more attractive than other supply-side and demand-side options. We are exploring these issues realizing that we are facing an increasingly competitive environment. We know that we will have to compete with exempt wholesale generators to retain our customer base. Our goal is to position the utility as the provider of choice, and we will develop a strategy to meet that goal.

[This paper was presented at the National Seminar on Public Utility Commission Implementation of the Energy Policy Act of 1992, conducted by the National Regulatory Research Institute and U.S. Department of Energy, on July 15 - 16, 1993 in Portland, Oregon]

Changes to PUHCA under EPAct: Entergy's Perspective on EWGs, Affiliate Transactions, and Self-Dealing

Kent Foster
Vice President, Regulatory Affairs
Entergy Services, Inc.

There are members of this panel more qualified than I to describe the changes made to PUHCA by the Energy Policy Act of 1992. What I would like to do is describe how Entergy is addressing the area of affiliate transactions with its state regulators.

Entergy is a registered holding company under PUHCA that serves over 1.4 million customers in the states of Arkansas, Louisiana, and Mississippi. We are regulated by FERC, the SEC, and by state and local regulatory commissions in those three states, including the City of New Orleans.

Entergy is also in what we believe to be the culminating stages of a merger with Gulf States Utilities, Inc., a utility serving customers in both Louisiana and Texas.

Once our merger is approved, we hope by the end of this year, Entergy will also be regulated by the Public Utility Commission of Texas and will be the second largest utility in the nation, in assets.

The operating public utilities in our System are Arkansas Power & Light, Louisiana Power & Light, Mississippi Power & Light, and New Orleans Public Service Inc. Once the merger is approved, Gulf States Utilities will become our fifth operating company.

As the vice president for regulatory affairs for our System's service company, Entergy Services, Inc., I represent the regulated side of our business. Until 1989 Entergy was known as Middle South Utilities, Inc.

In keeping with the change in our name, in that same year Entergy launched an initiative we called "Olive Branch," that successfully resulted in the settlement of some long-standing disputes with our region's retail regulators. Over the course of the next year, we wrote off almost a billion dollars of investment in a canceled nuclear plant, spun off some of our excess capacity into a wholesale subsidiary, Entergy Power, Inc. embraced the idea of least-cost planning, and embarked on a course to develop resources on the demand side of the meter.

Our LCP efforts, as we envision them, are driven toward the optimization of our planning throughout four (soon to be five) retail regulatory jurisdictions. We believe we are mapping out a new road. While it is true that when you don't know where you're going, any road will lead you there, in our case we know where we want to go, but must build a road to get us there. We have diverse retail regulatory jurisdictions and no central forum for dispute resolution.

Beyond the merger and our Least-Cost Planning initiatives, Entergy has also embarked on an expansion program. Some might mistake it for diversification. But I should emphasize here, we're not interested in diversity or adversity.

We are only willing to entertain "calculated risks" on the basis of "educated guesses." So what that means is, when we consider expansion, even into the unregulated facets of this industry, we "stick to our knitting." That is, we do what we know how to do, only more of it.

- Our expansion programs are limited in scope, that is expansion within businesses we know -- our core business.

- Moreover, the service and reliability of our regulated core business will not be affected in any way by our investment in any unregulated venture.

- We will not jeopardize the financial stability of our core business to finance an unregulated venture.

- And I don't mean just financial jeopardy, I mean intellectual jeopardy, as well. We will not let our diversified businesses reduce the quality of our people in the regulated side of the business.

There is a clearly defined wall -- a Chinese Wall -- between the regulated and unregulated entities we develop. We've established that with our regulators and have filed with the SEC a proposal establishing the wall and the transfer pricing mechanism that will control the value of transactions between each side of the wall.

I can assure you, the unregulated businesses will be financially and operationally independent of Entergy's retail operations. We have agreed to market pricing for services rendered across the wall. There will be no traditional "cost of service" arrangement, as the SEC normally imposes.

We've explained the wall's status to our regulators. We've heard -- and factored in -- their observations.

We've achieved consensus where possible and our protective wall includes the following fundamental elements designed in concert with our regulators to insulate retail customers from potential cross subsidy:

- Access to books and records;

- Cost allocation and transfer pricing principles to preclude cross-subsidies:
  - a 5% adders to services provided by the utility to the nonutility;
  - asset and data transfers at market price unless detrimental to ratepayers;
  - compensation for the transfer of product rights, copyrights, and patents to the non-regulated entity; and
  - 50/50 profit sharing for the marketing of utility products.

- Books of the non-regulated subsidiaries will be kept in accordance with generally accepted accounting principles;

- Access to knowledgeable officers concerning non-regulated businesses;

- Financial report filing requirements;

- Independent audits of affiliated transactions;

- Prohibition of diversion of utility talent to nonutility operations;

- Prior notification of transfer of assets exceeding $100,000 to non-regulated subsidiaries; and

- Top priority given to utility service in making resource allocation decisions.

Now, to get specific about some of our expansion efforts. I'll list them and -- when appropriate -- show how the expansion links with Least-Cost Planning.

First, though, I spoke earlier about Entergy Power, Inc. This subsidiary's goal is to become a low-cost producer of bulk electric power and, in turn, compete in that bulk power market on a national basis. We expect big things to happen in the bulk power market, and we want Entergy Power to compete effectively. Sharpening our competitive skills, in fact, is part of the reason behind Entergy Power's creation. We believe independent power producers and the wholesale power market will soon constitute the biggest -- and most lucrative -- change in this industry.

As utilities cut their capacity margins, defer investments in new capacity, and rely more heavily on conservation and demand-side management, the market for purchased power will grow. And we look to be a supplier of that power.

We think competition is good for the industry and our customers. We want to compete head-to-head with other utilities. In our opinion, electric power is destined to be a service that customers choose like any marketable item.

Now, regarding our other expansion efforts. In 1991 we formed a partnership with First Pacific Networks, Inc., a high-tech Silicon Valley-based company. This is an ambitious partnership that we think has enormous potential in the Least-Cost Planning field. Right now, near Little Rock, Arkansas, we're testing a device known as "PowerView." PowerView enables customers to monitor, control -- and reduce -- electric power consumption.

Using fiber optic cable, the PowerView technology will enable the customer to control everything from the use of appliances to obtaining a readout -- on their television screen -- of how much that appliance costs to operate on a monthly basis.

Entergy, meanwhile, can use PowerView's technology for automated billing services, remote turn-on/turn-off service, and remote control meter reading.

PowerView's features all have Least-Cost Planning implications. For instance, if our internal expenditures drop because of savings from PowerView's operation, that directly influences rate structures and future capacity needs.

We've also channeled our activity in another direction. Again, it involves our core business, but it extends beyond a development outside Little Rock. This effort extends to Argentina. We have recognized that it is, indeed, a global marketplace, even for those of us in the staid, slow-growing electric utility industry.

Our interest there involves a project that has the potential for a significant return. I'm returning to our ownership portion of the Argentine electric utility that is being privatized by the government. The investment is with shareholder dollars. We feel it's a good investment, and our customers will not be affected in any way.

The venture is a chance to secure a return on an investment that simply can't be matched in our service area -- or in many other areas, for that matter. This is

an area where the expected annual increase in electric demand reaches 5 to 6 percent. The region we currently serve expects an increase more along the lines of 1 to 2 percent. It simply makes sense to participate in this Argentine privatization effort.

We see it as a way to strengthen Entergy Corporation, make it a more attractive investment and, ultimately, bring capital into our region.

Returning to the domestic projects we've pursued, we've acquired a Memphis-based energy services company with a leading-edge energy efficiency technology. The energy efficiency market is one we think will expand dramatically in the coming years.

Energy efficiency services and products will become more and more important to customers, particularly commercial customers. Again, making and "educated guess," we knew someone in our region was going to fill that market niche. Our region -- our studies showed -- was under-served in that area.

Plus, more energy efficiency again pushes out the need for expensive new capacity and serves the interest of our Least-Cost Planning program.

Overall, we believe the electric power industry will evolve into a competitive one that resembles other industries. Consequently, quality, reliability, and cost will control the market. We're comfortable with that direction. We think free markets work, if given the chance.

We see the future as one in which electricity suppliers charge competitive market-based rates for new generating capacity while sticking to regulated rates for generating plants already on-line

In summary, the principal motivation behind our strategies and plans is to secure improved financial performance for our shareholders and lower, more competitive prices, for our customers.

We believe these goals are not exclusive of one another and can be achieved simultaneously through cooperative efforts between us and our regulators -- as our experience already demonstrates.

CHANGES TO PUHCA UNDER EPAct

by

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Senior Research Specialist
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presented at the

National Seminars on the
Public Utility Commission Implementation of
The Energy Policy Act of 1992

Portland, Oregon -- July 15 and 16, 1993

and

Indianapolis, Indiana -- July 19 and 20, 1993

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• PUHCA REFORM: EPACT TITLE XII -- WHERE ARE WE NOW?

TITLE VII -- ELECTRICITY

Subtitle A -- Exempt Wholesale Generators

Section 711 -- PUHCA Reform

- Exempt Wholesale Generator
- Eligible Facility
- State Consent for Existing Rate-Based Facilities
- Protection Against Abusive Affiliate Transactions
- Reciprocal Agreements (Daisy-Chains) Prohibited

Section 713 -- Public Utility Holding Companies to Own Interests in Cogeneration Facilities

Section 714 -- State Commission Access to Books and Records

Section 715 -- Investment in Foreign Utilities

Section 711 – PUHCA Reform

Exempt Wholesale Generator – Any person, determined by FERC, to be engaged directly or indirectly through affiliate(s) and exclusively in the business of owning and operating all or part of:

- eligible facilities, and
- selling at wholesale

FERC will promulgate rules within 12 months of enactment.

Eligible Facility – A facility, which is either

(A) used for the generation of electricity exclusively for sale at wholesale

OR

(B) used for the generation of electricity and leased to one or more utilities, provided that the lease is treated as a sale at wholesale

BUT

not an existing rate-based facility unless state commission consent has been obtained.

State commission consent for existing rate-based facilities to be an eligible facility requires:

every state commission having jurisdiction over retail rates to make a specific determination that allowing it to be an eligible facility

(1) will benefit consumers

(2) is in the public interest, and

(3) does not violate state law.

For an affiliate of a registered holding company, the determination is required to be made by every state commission having jurisdiction of the registered holding company.

No hybrids without state consent.

Exempt holding companies may own EWGs.

Registered holding companies may own EWGs, but are still subject to SEC regulation on financing; guaranteeing securities; service, sales, or construction contracts; or other relationships between the EWG and the registered holding company, its affiliates, and associated companies.

Ownership of EWG(s) does not make one a holding company.

Protection Against Abusive Affiliate Transactions –

No wholesale purchase power agreements between an EWG and an affiliate utility

UNLESS

Every state commission having jurisdiction over retail rates makes specific determinations in advance:

(1) sufficient regulatory authority and resources, and access to books and records

(2) the transaction

(a) will benefit consumers

(b) not violate state law

(c) not provide the affiliated EWG any unfair competitive advantages, and

(d) is in the public interest.

Section 713 – Holding companies may own cogeneration facilities.

Section 714 – Books and Records

(1) Upon written order of a state commission, a state commission may examine the books, accounts, memoranda, contract, and records of:

(a) a jurisdictional utility,

(b) any EWG selling at wholesale to a jurisdictional utility, and

(c) any utility or holding company affiliated or associated with an EWG selling to a jurisdictional utility

wherever located

(2) The state commission will not disclose trade secrets or sensitive commercial information

Subtitle B – Federal Power Act; Interstate Commerce in Electricity

Section 721 – FPA Section 211 Amended

Upon application of any person generating electricity for sale for resale, the FERC may issue an order requiring a transmitting utility to provide transmission services (including any necessary enlargement of transmission capacity) if the order meets the requirements of Section 212 and would otherwise be in the public interest.

FERC will not issue such an order if, after considering regional or national reliability standards, guidelines, or criteria it finds the order would unreasonably impair continued reliability.

§ 211(c)(1) is deleted.

Add a "regulatory out" clause when the transmitting utility, subject to ordered transmission services, makes a good-faith effort to obtain siting, etc., for enlargement of transmission capacity, but fails.

Section 722 – Transmission Service – FPA Section 212

(a) Strike out old (a) & (b) and replace with language concerning the rates, charges, terms, and conditions for transmission services of a transmitting utility subject to section 211 order:

- **which permit recovery of an appropriate share of legitimate, verifiable, and economic costs, including any benefits to the transmission system and the costs of enlargement of transmission facilities**

- **promote economically efficient transmission and generation of electricity**

- **are just and reasonable**

- **are not unduly discriminatory or preferential**

- **to the extent practicable, costs incurred are properly allocated to provision of service are recovered from applicants and NOT from existing wholesale, retail, and transmission customers**

- new sections are to be read in pari materia (not in lieu of other authority of FERC under the law)

- antitrust (Sherman and Clayton Act and section 5 of Federal Trade Commission Act relating to unfair methods of competition) still apply

- no orders inconsistent with state retail marketing access (franchise laws)

- mandatory retail wheeling and sham wholesale transactions are prohibited

- retail wheeling → (1) directly to ultimate consumers or (2) an entity selling to ultimate consumers, EXCEPT TVA, RECoop, an entity with an obligation to serve the public under state or local laws that are grandfathered or use their own facility

- special provisions exist for ERCOT, electric utilities that are territorially restricted by federal law, and the Federal Columbia River Transmission System (BPA)

Section 723 – Information Requirements

A good-faith request to a transmitting utility to provide wholesale transmissions that requests specific rates and charges and other terms and conditions must be provided (mutually acceptable) within 60 days.

OR

The transmitting utility, within 60 days, must provide a detailed written explanation of (1) the basis for the proposed rates, charges, terms, and considerations, and (2) an analysis of physical or other constraints

Section 724 – Sales by EWG

Rates or charges are unlawful if they involve an undue preference from an affiliate.

SESSION V

TITLE VII CHANGES TO THE FEDERAL POWER ACT

A CUSTOMER'S VIEW OF RETAIL WHEELING

by

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National Seminars on the
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The Energy Policy Act of 1992

Portland, Oregon

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PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE ENERGY POLICY ACT OF 1992 PORTLAND, OREGON - JULY 15TH-16TH, 1993

A CUSTOMER'S VIEW OF RETAIL WHEELING

My name is Steve Michel. I am general counsel to the New Mexico Industrial Energy Consumers (NMIEC). NMIEC is a group of twenty large New Mexico corporations who have joined together in an ongoing effort to lower their utility rates in the State. The members of NMIEC have over 11,000 employees in New Mexico, with a total payroll exceeding $325,000,000. They pay over $60,000,000 in State taxes each year, and have over $1.1 billion of capital invested in the State. Over $380,000,000 in New Mexico purchases are made each year by NMIEC's members. Many of the members of NMIEC have facilities throughout the United States and the World.

Let me begin this paper with the general disclaimer that, despite my representation of NMIEC, my comments here do not represent the views of anyone but myself. Furthermore, let me also say that this is a rapidly changing field of regulation, and I'm not going to pretend I know how everything will shake out when retail wheeling is put in place.

The utilities have generally painted a grim picture of retail wheeling. The doomsday scenario they portray, however, I do not believe is a real one. Even though we do not know exactly what will happen with wheeling, most of the questions that remain center around how much will consumers benefit from its promulgation. I do not believe a realistic case can be made that there is significant downside consumer risk associated with retail wheeling. I'm not going to tell you there is no risk to the financial well-being of some utilities, though - if the economic protection which electric utilities have enjoyed was not threatened, we would probably not be having this debate.

This paper will explore several questions. They are:

1) *What is "retail wheeling"?*

2) *Why is retail wheeling needed?*

3) *Will retail wheeling happen?*

4) *What will be the impact of retail wheeling?*

5) *Are the problems raised by the opponents of retail wheeling real, and if so, can they be solved?*

6) *What has been the experience in New Mexico with retail wheeling?*

I. WHAT IS "RETAIL WHEELING"

"Wheeling" occurs when a utility transports someone else's power across its transmission lines. Wholesale wheeling is transporting someone else's power to someone who is going to resell it - such as another utility. *Retail wheeling* is transporting power to someone who is going to use it, i.e. an end-user or ultimate consumer.

II. WHY IS RETAIL WHEELING NEEDED?

One of the purposes of the regulation of electric utilities and cooperatives has been to capture the benefits of natural monopoly economies of scale while at the same time avoiding the harms which can be engendered by monopolies in the marketplace. Our experience has been, however, that in many instances regulation in the United States has failed, and ratepayers have been required to pay rates which have allowed utilities to recover the costs of inefficient, overpriced and excessive plants and services.

Using an example I'm familiar with, in New Mexico over the years there has been a wide divergence of electric rates in different regions of the State, which have been caused by inefficiency and mismanagement among some of the States' electric utilities and cooperatives. This divergence has been unfair to those citizens who reside and operate businesses in those parts of the State which have endured these excessive rates. New Mexico ratepayers pay some of the highest rates in the country. The average rate in most parts of the State is well over $.08/kWH. There is no justification for this, and evidence of that is the fact that one New Mexico utility is able to provide service at less than two-thirds the cost of New Mexico's other utilities - and earn a healthy return. Why should one customer have to pay 50 percent more than another customer for the same electricity, simply because he has located his home or business in the wrong place? The problem, which is not unique to New Mexico,[1] is that our regulatory system has been unable to prevent utilities from incurring costs and charging rates which include tremendous amounts of excess, unnecessarily expensive, capacity, and imprudent expenditures. Recovery of these costs by utilities is nothing more than a subsidy, or "bailout" if you will, of utility shareholders by utility ratepayers.

Competition in the electric industry, which would result from retail wheeling, would allow consumers to choose the least-cost utility to serve them. This would necessarily cause a more efficient and economic allocation of resources, and lower rates to consumers which would better reflect the value of electric service. Ratepayers would no longer be required to pay higher

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[1] In New York, Pennsylvania, Ohio, and Arizona, the highest industrial electricity rates are more than twice the lowest industrial rates charged by electric utilities within those states. "Rate Disparities By State for 20,000 kW Loads With a 68% Load factor," ELCON publication with data prepared by Drazen-Brubaker & Associates, Inc., 1992.

rates to bail inefficient utilities out of their bad investments. Inefficiencies would not be tolerated in a competitive wheeling environment.

III. WILL RETAIL WHEELING HAPPEN?

Although there are any number of possible ways that retail wheeling might happen, I truly believe it will happen. John Anderson, of ELCON, has identified a number of inroads toward wheeling which are occurring even today.[2] For example:

1. The Public Service Commission of South Carolina has issued an order in which it encouraged Carolina Power & Light Company to evaluate and consider retail wheeling as part of its overall integrated resource planning. (Order # 93-261 at 20; 4/8/93).

2. The Texas PUC recently issued a proposed rule which included retail wheeling as a demand side management option. Although the proposed rule was not adopted, the Texas PUC indicated it would consider retail wheeling as part of a broader rulemaking later on.

3. The Michigan PSC is considering retail wheeling experiments involving the states two largest IOU's. Although the outcome is not clear, this is a strong message in favor of wheeling from a large industrial state.

4. New York State has allowed retail wheeling for many years. Low cost power generated by the New York Power Authority is wheeled directly to industrial and other end-users, often to promote various economic development objectives.

5. In New Mexico, legislation was introduced to mandate retail wheeling. Although that legislation failed, a two-year legislative committee was set up to study the issue and presumably to find a way to implement wheeling in the state. Additionally, army and air force bases in the state have given notice to El Paso Electric of their intention to put their electric loads out to bid.

6. The California PUC recently issued a study reviewing current trends and conditions in the electric industry, with the intent of positioning California for the inevitable changes in the industry. Particular attention was given in that study to a future with retail wheeling.

7. A bill recently filed in the Massachusetts legislature by the Massachusetts Division of Energy Resources would permit non-utility generators to make limited direct

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[2] Dr. John A. Anderson, Presentation to the INFOCAST Conference, "Power Transmission - Access, Pricing & Policy", Washington D.C., May 14, 1993.

power sales to commercial and industrial end-users in designated areas of economic hardship.

8. Competition in the electric industry is also being heralded internationally. One particular example is the UK, where the electric system has been privatized and separated into generation, transmission and distribution entities. Retail wheeling is required for any customers with a 1 MW load or more. Similar schemes are in place in Australia and New Zealand. The lights are still on in London and Sydney, and other European nations, as well as Canada, are looking very closely at adopting requirements similar to those in the UK.

9. Finally, and perhaps most significant, the Nevada legislature has just enacted the nation's first retail wheeling bill. The bill, designed as an economic development tool, would allow retail wheeling in certain very specific circumstances: applicants must be companies that invest at least $50 million in the State, agree to remain in the State for at least 30 years, and whose product contains at least 50 percent recycled goods. The bill represents Nevada's attempt to lure North Star Steel to locate a new facility in Nevada rather than Arizona. Passage of this law is a major inroad for retail wheeling.

A further basis for my belief that retail wheeling is coming is that I also believe large users will not sit idly by while states take their time fashioning detailed wheeling schemes, or seek to avoid retail wheeling altogether. There are too many options available to creative industrial users to effectuate the benefits of retail wheeling - whether or not formally permitted. Among the available strategies are:

* *utility brokered power* - where a utility would make a purchase of power at wholesale, and sell it to an industrial customer at the wholesale price plus a mark-up. This could be implemented as a buy-through provision of an interruptible contract.

* *franchise jumping* - where industrial users would obtain a right-of-way to a neighboring utility or other power source. This would supply the industrial user with several options for power.

* *joint ventures with LDCs* - where an industrial user would seek joint ventures with gas distribution companies to develop gas-fired QFs or EWGs (exempt wholesale generators). Southern Union Gas Company has recently made a proposal along these lines to the City of El Paso, Texas.

* *municipalization* - where a city would municipalize its power system and would then be able to shop for the lowest cost power source. Once a municipal utility, the city could obtain "wholesale" wheeling from FERC on behalf of all of its customers, or some of its customers. The city of Clyde, Ohio is a municipal utility with w 22 MW load. Sixteen of those MWs are for Whirlpool, and when Clyde obtains wheeling for Whirlpool it is

not "retail wheeling."[3]

Utilities and communities have and will assist large businesses in these ventures because of the economic benefits which these companies can provide. As D.D. Hock, Chairman, President and CEO of Public Service Company of Colorado matter-of-factly said in comments recently delivered to the American Bar Association's Annual Conference on Electricity Law and Regulation: *"Retail wheeling will become a reality in industrial markets."* (emphasis in original).

IV. WHAT WILL BE THE IMPACT OF RETAIL WHEELING?

I believe consumers will enjoy considerable benefits from the competition which would result from retail wheeling. Currently, utilities are permitted to charge rates to recover their embedded costs. Typically, these embedded costs include stale technology, imprudent investments and expenses, excess capacity and other inefficiencies. Under a competitive wheeling arrangement, costs would move toward efficient long run marginal cost, i.e. the cost in the long run of most efficiently producing a kWH of electricity: inefficiency and excess capacity would be priced out of the market.

In addition, we need to realize the benefits of retail wheeling will not just show up in electric bills. Virtually *every* good and service - including interim goods used in the manufacture of other products - has an energy cost embedded in it. Reducing electricity prices to a competitive level would have positive repercussions throughout our economy as well as the world economy - even if only large users are able to take advantage of wheeling initially.

Finally, one must remember that retail wheeling is not just for big business. While larger users will certainly be among the first to benefit, all consumers should be permitted to choose their electric supplier. The retail wheeling bill in New Mexico, introduced by Senator Tom Wray (SB 501), would have allowed individuals and groups of small consumers to wheel electricity for their needs. This is entirely appropriate.

Among the benefits of retail wheeling which I believe will be realized are:

1. Inefficient planning and operation will not be tolerated.

2. Institutional changes will be required to facilitate market efficiencies. Cost control and innovation will be encouraged and rewarded.

3. Preferential or discriminatory treatment for certain customers or customer classes will have no place in the competitive market engendered by retail wheeling.

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[3] Anderson, John A., "Retail Wheeling - Is It Coming?", Presentation to 61st Annual Conference of the California Municipal Utilities Association.

4. Market efficiencies will promote the proper use of energy resources, which is the most effective way to promote environmental protections.

5. Prices will be driven to the lowest possible levels. Utilities will be forced to compete, i.e. they will be price takers, not price makers.

6. The assets the utilities like to call "stranded investment," but which I think should more appropriately be called "overpriced investment," will be written down their economic value.

While naysayers like to bring up what they consider the failures of deregulation in other industries as an argument against retail wheeling, let's take a moment and consider whether deregulation has ever really been a failure. The three most common examples of deregulation have been in the areas of natural gas, airlines, and telephones.

With regard to natural gas deregulation, while residential consumers have not had the benefit of natural gas deregulation, prices to transporters of gas have uniformly fallen - and that has had positive repercussions throughout the economy. Local distribution companies have been forced to compete with the independent producers to capture the loads of large consumers. The result has been, by all accounts, a more efficient and less costly supply of natural gas to all those who have been willing to take advantage of the deregulation of the industry.

With telephone deregulation, certainly we all have cursed the complexity of multiple carriers, and few of us understand exactly how the telephone industry operates. But let's not forget the days when AT&T, "Ma Bell", was the only choice in town. There is no question that the price of long-distance calling has fallen dramatically since the days of monopoly phone service. And while the system of choosing phone service is complex, and often frustrating, we are all able to make many more long distance calls, at lower cost, than we were prior to deregulation.

And finally, let's look at the airline industry. There is no question that deregulation has increased competition and driven down prices. The former Council on Competitiveness reported in 1992 that consumers received more than $10 billion in benefits annually from deregulation. And while the consumer price index in 1992 rose 3 percent, average airline prices *fell 11 percent.*[4] Today, flying is a transportation option for everyone, not just business executives.

Has deregulation of these industries failed? I do not believe that it has. And while perhaps deregulation could have been accomplished in better ways, it has certainly represented a net benefit to society.

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[4] Jones, Richard H., "Airline Deregulation - Looking Ahead", ABA Public Utility Section News, Vol. 33, No. 2, Spring, 1993.

V. ARE THE PROBLEMS RAISED BY OPPONENTS OF RETAIL WHEELING REAL, AND IF SO, CAN THEY BE SOLVED?

The problems raised by the opponents of retail wheeling generally fall into three categories: legal, technical and environmental. These problems, to the extent they are real, can be overcome.

The major claims of the utilities and other opponents of retail wheeling are that retail wheeling will cause higher rates to small users, decreased reliability to all users, and adverse environmental consequences throughout society. Contrary to their claims, however, higher rates will only occur if state commissions require residential users to bail utility shareholders out of the overpriced investments which the wheeling customers avoid. In New Mexico the retail wheeling bill which was before the legislature would have specifically prohibited such bailouts. I believe this type of prohibition is essential for the full benefits of retail wheeling to be realized. There is no evidence that service reliability will suffer from retail wheeling - in fact, the evidence is to the contrary. And finally, with appropriate safeguards, I believe the fear of environmental degradation through the advent of retail wheeling is misplaced.

A. Legal

There are several issues that fall under the banner of "legal" questions. First is whether states have the power to enact retail wheeling. A second issue is how should state commissions deal with the potential problem of meeting the needs of large customers switching back and forth between the regulated and unregulated sectors. The final issue is, assuming that commissions choose not to burden the non-wheeling customers with the overpriced investment costs which the wheeling customers have been able to avoid, what will be the result of the "constitutional taking" claims which utilities are likely to make.

The first issue is, is it legal for states to order retail wheeling? While I am certain that some creative utility lawyers will try and find ways to show the states have no such power, in my mind, the National Energy Policy Act, while perhaps not giving explicit recognition to the States' power, certainly gave implicit recognition. Section 722 of the Energy policy Act reads: "Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy to an ultimate consumer." Congress certainly has the power to regulate all aspects of utility service, and has delegated a portion of that power to State commissions - specifically, the power to set retail rates. The question is, quite simply, is retail wheeling one of the areas Congress has decided to explicitly regulate, or to leave unregulated. If it does not fall into one of these categories - states are free to enter the field. Because Congress has not explicitly regulated retail wheeling, and because the section 722 language leaves the clear impression that Congress has not intended retail wheeling to be unregulated, states are free to go forward and regulate this field.

The second legal issue of how to deal with returning customers, has been raised in a

number of settings. I completely agree that all customers should pay the cost required to serve them - no more and no less. This is no different than is currently the case. Many large and industrial customers are required to sign long-term contracts with specified minimum demands so that other customers would not be burdened by a later decision on their part to leave the system. The same would presumably be true for re-entering customers. Because of this, the problem of returning customers has, in my mind, already been solved.

I also think it is somewhat premature to identify this as a problem. In the onslaught of AT&T advertising to entice customers to "return to AT&T," it is apparent that the phone company is not concerned about being able to serve customers who left the system. I would expect the same might be true in the electric industry. Claims that returning customers will force utilities to construct expensive new baseload facilities overnight which will ultimately be paid for by captive residential ratepayers are, I believe, simply scare tactics. More realistically, a shopping customer is going to have a contract with a distant supplier. This contract will spell out termination provisions since that supplier will not want to be left with unused capacity. The customer, seeking to avoid an interruption, will be highly motivated to line up a future electricity supply well in advance. This future supply contract will also contain termination provisions that protect the supplier. This is how procurement works when competitive suppliers deal with customers and prospective customers in any market.

The remaining legal issue centers around how the wheeling service should be priced, and this gets into the "constitutional taking" issue which utilities raise whenever their earnings are threatened. This pricing issue relates to those services which would still be regulated, i.e. electric service to non-wheeling customers and wheeling rates to wheeling customers. My belief is that in order for the full benefits of wheeling to be realized, utilities must not be permitted to pass along the costs of their overpriced investments through regulatory price-setting. Regulated rates must be no more than that required for the utility to earn a fair return on its *used and useful* plant and its *prudently incurred* expenses.

Assuming that utilities are not permitted to pass along the costs of their "overpriced investment," which, in order for wheeling to be of real benefit, utilities must not be permitted to do, the issue becomes whether there will have been a constitutional taking? I believe the answer is no. (I personally dislike the term "stranded investment," since the only reason it would be "stranded" is because it is too expensive for the marketplace. A better term, and the one I prefer to use is "overpriced investment.")

Opponents of retail wheeling have argued that retail wheeling would allow large users to escape their "responsibility" to pay the utilities' costs, and that responsibility would *have to* be absorbed by the utilities' remaining customers. I disagree with these opponents on both counts. There is *no responsibility* to pay utilities for excessive costs. By law, utilities are permitted to recover only the *value* of the service they provide. This stems from the constitutional requirement that property may not be taken without fair compensation. To allow utilities to recover costs which they incurred over and above the value of the service they provide amounts to nothing more than an uneconomic "bailout" of the utilities' shareholders -

who should ultimately be responsible for inefficient management. Certainly one would not argue that in condemning a parcel of land, government (i.e. taxpayers) should pay $1 million for land worth only $500,000. By the same token, ratepayers should not be paying $.10/kWH for electricity which can be produced for, and which is worth, only $.06/kWH, and I find it hard to believe the Constitution would require otherwise.

Regardless of what I say on the "takings" argument, I can assure you this will be an aggressively fought issue which the utilities will raise in any and every forum available.

B. Technical

Although I have heard a number of utilities claim that retail wheeling will somehow affect system reliability, it's never been made entirely clear to me exactly how that would happen. As a matter of fact, I have even heard the argument in some settings that wheeling does not really do anything except move dollars. There is no reason for me to believe claims of diminished reliability will be sustained when electricity production is deregulated through retail wheeling, and plenty of reason to believe otherwise.

Perhaps the most compelling demonstration that retail wheeling is technically feasible is to look at how the electric industry operates now. While utilities claim that their systems were not designed to accommodate wheeling for retail customers, they conveniently ignore that they have been wheeling *for each other* for years without any insurmountable problems. Now, though, and only when somebody else wants to step in and wheel power, do we hear the claims that the industry is not technically able to wheel power, and service reliability will suffer. These claims are nonsense, and are disputed by a number of studies on the subject as well as comments by a number of *utility industry* executives.

With respect to reliability, a 1989 Congressional study by the Office of Technological Assessment as well as a 1990 FERC Task Force report concluded that although changes would be required, there were no technological impediments to retail wheeling.[5] Furthermore, in the several instances where retail wheeling has been allowed, no reliability problems have been experienced. Among the examples of existing and working retail wheeling arrangements are the following:[6]

1) First are the international examples mentioned previously: the UK, Australia and New Zealand.

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[5] See, Kelly, Burns & Rose, "An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report", The National Regulatory Research Institute (NRRI), January 1990.

[6] Many of these examples are reported in Dingle, John R., "Retail Wheeling in the Electric Utility Industry: It's Working", Cogeneration and Resource Recovery, July/August 1992, at 10-13.

2) Gulf States Utilities wheeled power from two municipals to what was then a Stauffer Chemical Plant in Louisiana. This transaction continued for a number of years.

3) Dow Chemical company entered into an agreement with Detroit Edison in 1979. Dow wheeled power generated at one of its plants in Canada through several IOUs in the United States for consumption at a Dow facility in Consumers Power Company's service territory.

4) As was also mentioned earlier, there are several retail wheeling transactions now taking place in new York. The New York Power Authority (NYPA) currently provides power from the Fitzpatrick nuclear plant and from the St.Lawrence-Franklin D. Roosevelt hydro facility to customers located in the service territories of Consolidated Edison, Long Island lighting and Niagara Mohawk. In all, 141 MWs of Fitzpatrick power is wheeled to twelve end-users.

5) The Capital District Energy Center is a qualified cogeneration facility (QF). This QF sells 11 MWs of capacity and associated energy to Aetna Life & Casualty Insurance Company. The 20-year agreement was approved by the FERC on December 20, 1988.

6) For a number of years, Pacific Gas & Electric has wheeled power from the Western Area Power Administration (WAPA) to the Lawrence Livermore National Laboratory (LLNL). WAPA also sells power from Colorado River Storage Project to the Ogden Defense Depot. The power is wheeled by Utah Power & Light Company. In total, WAPA hydropower is wheeled through 42 transmission agents to 148 end-user customers in Arizona, California, Colorado, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Utah and Wyoming.

7) Similarly, Bonneville Power Administration (BPA) serves federal government agencies, the power needs of eight aluminum producers as well as eight other end users and several irrigation districts.

Finally, as John Hayes, Chairman, President and CEO of Western Resources, an investor-owned utility, said in remarks to the Edison Electric Institute: "... it is inconceivable to me that retail wheeling will be impeded by a lack of technology."[7]

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[7] Hayes, John E., "A Look Forward to Deregulation, A Look Back at the Telephone Industry," EEI's Financial Conference, Scottsdale, Arizona, October 13, 1992.

C. Environmental concerns

The environmental issues which I will address are two-fold. First is the claim that retail wheeling will encourage the production of cheap, dirty power. Second is the related claim that retail wheeling will hinder efforts toward effective demand side management. I believe these environmental issue can and should be solved as part of a comprehensive retail wheeling program.

The argument has been made that retail wheeling will encourage the production of cheap, dirty power - in an effort by utilities to provide lowest-price energy. Certainly, given the nature of competition, if other things are left the same, I believe that is generally true. Therefore, I think it is important that retail wheeling, as it starts to take hold in various states, be accompanied by either regional, or national standards on environmental impacts associated with all forms of energy production. Until uniform standards are in place, utilities in states with more stringent regulations and resultant higher cost electricity could be at a disadvantage when seeking to sell their power elsewhere. However, let me also mention that this effect is counterbalanced to some extent. Because it is a fairly safe assumption that environmental regulations will generally become tougher as time goes on, utilities with clean production will be ahead of the rest in terms of costs, and this will provide an incentive for utilities to provide "clean" power. The answer to varying state environmental regulations and policies is not to prohibit retail wheeling, but to create level playing fields and uniform environmental requirements wherever possible - regionally or nationally. Supplying goods and services in such a way that they are required to recoup their true, total costs makes economic sense, as well as policy sense.

But we must also keep in mind that the issue of electricity costs appropriately reflecting their true economic and societal impact cuts two ways. We have two price problems with electricity in much of the United States: one is that ratepayers are paying too much for the bare costs of production, and second is that ratepayers in a number of instances are paying too little for the "external" costs of electricity. To cause ratepayers to pay the external costs of electricity, while continuing to force them to subsidize inefficient production costs, is not fair at all - and results in an uneconomic allocation of energy resources. Retail wheeling would help ensure that electricity purchasers only pay the appropriate costs for the energy they consume.

The second environmental issue raised with respect to retail wheeling has to do with whether retail wheeling will discourage demand side management. To the contrary, I believe retail wheeling is an essential component of a utility's integrated resource planning, including demand side options.

One problem identified by DSM proponents is that although retail wheeling may reduce capacity needs, it does not dissuade energy use, and therefore does not mitigate externalities, such as CO_2 emissions, associated with energy consumption. Despite the energy implications of wheeling, though, wheeling would tend to curb excessive capacity additions and the construction of unnecessary utility assets. And because the construction of excessive capacity leads to an incentive by utilities to sell more energy to recover costs, I believe wheeling could tend to curb

energy consumption as well. Retail wheeling will promote the most efficient allocation of resources. If natural gas or solar power is least impacting and therefore least expensive on a total cost basis, it should be the lowest priced source of energy, and retail wheeling will enable customers to take advantage of that resource, to the extent it is cheaper, and relieve them of the burden of purchasing costly (in financial and environmental terms) energy.

VI. WHAT HAS BEEN THE EXPERIENCE IN NEW MEXICO WITH RETAIL WHEELING?

As you are probably aware, at the last session of the New Mexico legislature, a bill was introduced which would have mandated retail wheeling by all utilities in the State. The bill, SB 501, was introduced by a freshman Senator, Tom Wray. Senator Wray convinced Senate leadership in both parties to support his bill.

There are several features of the bill which are significant, and which I'd like to point out to you today. First of all, the bill would require both retail wheeling and self-service wheeling. Self-service wheeling would allow a company to wheel power from one of its facilities to another of its facilities in the State. A second provision in the bill would have prevented regulators from passing the costs of idled capacity on to any ratepayers or wheeling customers. Fairly strict guidelines were laid out for the wheeling rate to be established. Third, any out-of-state utility wishing to wheel power into the state would have to permit New Mexico utilities to wheel power to the out-of-state utility's customers. Finally, the bill provided that retail wheeling should be used as a resource in utility integrated resource planning before additional investments would be allowed in generation or transmission facilities. The bill also required the New Mexico Public Utility Commission to promulgate rules and regulations for IRP within 300 days of the passage of the bill. These last provisions prompted New Mexico's environmental community to support Senator Wray's bill.[8]

Senator Wray's bill met with a good deal of opposition from the utilities in the State, utilities out of the State, and the NMPUC. The bill passed out of the Conservation Committee "without recommendation," and was tabled in the Corporations Committee in lieu of a bill creating a legislative task force to study the issue. The task force, comprising eight legislators from both houses, is to report to the full legislature prior to the January 1995 session. Organizational meetings were held this past week. The task force will comprise three phases: an education phase, a public testimony phase, and a decision phase. My own assessment is that that at least four of the eight members are inclined towards a retail wheeling bill. I would not,

[8] Senate Bill 501 was supported by the New Mexico Conservation Voters Alliance (CVA). CVA's membership includes the local chapters of groups such as the Sierra Club, the Wilderness Society, Wildlife Federation, Forest Guardians, Environmental Law Center, etc. The position of CVA does not, however, bind or commit individual members or any of the national organizations to a position. It is significant, though, that New Mexico's environmental community supported the retail wheeling bill, which is a departure from other parts of the country.

at this point, count any of the members as being against wheeling. So, I think there is a good chance that a successful wheeling bill will be introduced in New Mexico in the next eighteen (18) months.

I might also point out that there are rumors that a self-service wheeling bill might be introduced in New Mexico in the 1994 legislative session. Such a bill would be designed as a sort of "first step" experiment in wheeling.

VII. CONCLUSIONS.

Retail wheeling holds great promise for improving the future of our energy supplies in this country. If properly, thoughtfully and fairly implemented, I believe it will go a long way toward ensuring America has a competitive, efficient and long-term energy supply to serve its needs.

RETAIL WHEELING: A PROPOSED EXPERIMENT IN MICHIGAN

Michel L. Hiser
Michigan Public Service Commission

Seminar By
U.S. Department of Energy
National Regulatory Research Institute
July 20, 1993
Indianapolis, Indiana

RETAIL WHEELING: A PROPOSED EXPERIMENT IN MICHIGAN

I. Introduction

A. Wheeling: An Important and Controversial Component of EPA

1. Resolution pivotal to passage of the Act
2. Both wholesale and retail addressed

a. Proactive measures re wholesale
b. Specifically reserving retail to states

3. Delicate balance reached

a. Proponents pleased to see the door opened
b. Opponents relieved to hold line on retail wheeling

B. Retail Wheeling

1. The core of industry restructuring

a. Pivotal to where the industry is headed

(1) Degree of competition
(2) Nature of regulation

b. Service delivery

(1) Vertical integration
(2) Individual companies: generation, transmission, distribution

II. Retail Wheeling Provisions in the EPA

A. Amendment of FPA Removes Federal Preemption

1. Section (g) added: "No order may be issued under this Act which is inconsistent with any State law which governs the retail marketing areas of electric utilities."
2. Section (h) further adds: "Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer."
3. Both sections expressly eliminate preemption argument

B. Conclusion

1. Amendments to FPA are unambiguous
2. Regulation of retail wheeling has been left entirely to the states

III. The Michigan Retail Wheeling Proposal

A. Origin

1. Commission order on competitive bidding in October 1992

a. Industrial customer request
b. Commission invited proposals
c. Predates EPA passage

2. Application filed shortly thereafter (1992)
3. Contested proceeding held, order is pending

B. Legal Foundation

1. Federal

a. FPA amendments (see above) address federal supremacy clause concern
b. Commerce clause precludes state regulation that imposes an undue burden on the free flow of commerce among the states

(1) Counter to this is retail wheeling promotes competition
(2) Promotes least cost planning, an acknowledged concern of state regulators

c. FERC policy re competition and industry restructuring

2. State

a. Broad authority in Michigan: "The Public Service Commission is vested with complete power and jurisdiction to regulate all public utilities in the state except municipality-owned utilities, . . . and is vested with the power and jurisdiction to regulate all rates, fares, fees, charges, services, and all other matters pertaining to the formation, operation, or direction of such public utilities."
b. No specific wheeling powers

C. Policy Question: Should retail wheeling be introduced?

1. *Proponents arguments in favor*

    a. *Non-utility producers, large industrial and institutional customers, economists*
    b. *Competition will promote efficiency and service quality*

        (1) *Is the crucial missing link in the evolution to a competitive market for electricity*
        (2) *Will erode monopoly inefficiencies*

            (a) *Inefficient producers (franchise protection)*
            (b) *Obstructionist practices for self serving purposes (benefit of supply competition may not reach customers)*

        (3) *More options available*

            (a) *Pressure on price*
            (b) *Better meet customer needs*
            (c) *Purchase only what is needed (unbundling of services)*
            (d) *e.g. -- industrial cogeneration (self help wheeling)*

        (4) *New options expected*

            (a) *Market creativity*

    c. *Direct customer participation promotes market efficiency (buyer seller interaction)*

        (1) *Quality products at competitive prices*

    d. *Gas industry serves as a model*

2. *Arguments against*

    a. *Utility companies, Wall Street, captive utility customers, traditional regulators*
    b. *View retail wheeling as a scam*

        (1) *By large, politically influential industrial customers to extract reduced electric prices*
        (2) *Only thing wheeled will be money*
        (3) *No economic efficiency expected*

(a) No new resources created
(b) Same suppliers could sell to utilities
(c) Service unbundling could be done through regulation

(4) Large customers want to capture short-term benefits from surplus capacity and declining marginal costs for some utilities

(a) Captive customers left holding the bag
(b) Will return to utility later if advantageous

c. Competitive bidding will force price competition
d. Electric and gas industries are very different

D. Convincing Arguments on Both Sides

1. Suggesting to me that a well-crafted experiment is worth undertaking
2. Staff as a whole is divided on this issue

E. Key Issues and Concerns to be Addressed in an Experiment

1. Technical feasibility
2. Safety and reliability
3. Servicing unbundling, cost separation, and pricing
4. Characteristics and diversity of transactions
5. Contractual arrangements
6. Power supply performance
7. Transmission capacity constraints
8. Load impacts (line loading, line losses, reactive flows, etc.)
9. Obligation to serve
10. Customer re-entry (rights and penalties)
11. Customer/utility cooperation
12. Metering
13. Efficiency gains/losses
14. Customer impact (participant/non-participant)
15. Impact on utility (financial, planning, etc.)
16. Impact on neighboring utilities

F. Key Elements of ABATE Proposal

1. Characterized as a five-year experiment
2. Scope

a. Two largest utilities (Consumers Power, Detroit Edison)
b. 1% of peak: 60 MW, 90 MW (150 MW total)

3. *Implemented when <u>new</u> capacity is needed*

    a. *Integrated Resource Plan*
    b. *Capacity solicitation*

4. *Eligibility*

    a. *Demand must be 5 MW or more*
    b. *2 MW minimum, 10 MW maximum at location*
    c. *All customers meeting above qualify*

5. *Eligible suppliers broadly defined*

    a. *Utilities, QFs, NUGs, EWGs, customer generation*
    b. *No restrictions on location*

6. *All loads eligible (base, peak, backup, partial)*
7. *Power pooling permitted*
8. *Power brokering required*
9. *Power reassignment permitted*
10. *Cost of service pricing*
11. *Data collection primarily to test technical feasibility*
12. *Implementation through collaboration re program details*
13. *Existing transmission facilities only*
14. *Utility must provide standby service*
15. *Return rights same as for any new customer (no penalty)*
16. *Regulatory flexibility*

G. *Key Staff Modifications for Commission Consideration*

1. *Consider for supply side replacement only*
2. *No pooling*
3. *Power brokering not required*
4. *Recognition of ancillary services not covered by standard wheeling tariff*
5. *Five-year return notice required*
6. *Early return penalty*
7. *Customer limit of 15 MW*
8. *More extensive data requirements to address economic benefits and impact*
9. *Consider pricing by competitive bidding*
10. *Separate metering of wheeling load*

IV. Conclusion

A. Uncharted Waters

1. *Rough waters*
2. *High stakes involved*

B. Presents Enormous Regulatory Difficulties

1. *Restructuring will be very complex*
2. *Hybrid industry difficulties*

    a. *Subsidies*
    b. *Self dealing*

3. *Innovative regulatory approaches necessary*

C. Retail wheeling issue is real and now

1. *Pressure building across the nation*
2. *All eyes will be on Michigan if experiment is implemented*
3. *It will not quietly fade away*

TRANSMISSION ACCESS AND PRICING ISSUES AT THE COMMISSION[1]

by

J. Stephen Henderson
Deputy Associate Director
Office of Economic Policy
Federal Energy Regulatory Commission

Presentation to
NRRI Seminar on Implementation of the Energy Policy Act of 1992

Indianapolis, Indiana
July 20, 1993

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1 The analyses and conclusions are those of the author and do not necessarily reflect the views of the Federal Energy Regulatory Commission, any individual Commissioner or any other staff member.

OVERVIEW

- Exempt Wholesale Generators
- Transmission Information NOPR
- Transmission Access
- Policy Statement on Good Faith Requests and Responses
- Regional Transmission Groups
- Transmission Pricing Inquiry

PUHCA Exemption for EWGs

- Exempt Wholesale Generator is any Person Owning or Operating All or Part of an Eligible Facility *and* Selling Electricity at Wholesale

- FERC Must Approve EWG Applications for a PUHCA Exemption

- FERC Has 60 Days to Determine the Status of an EWG Application

- FERC Has Ministerial Responsibilities Only

FERC Final Rule--Order 550

- EWG Applicants Must File:
  - Sworn Statement Attesting to Eligibility for EWG Status
  - A Description of Facilities
  - Any Necessary State Commission Orders
- FERC Has 60 Days; After that, Application is Granted by Default
- Applicants May Not Amend Deficient Applications
- FERC will Monitor Compliance

Current Status of Matters

- An EWG may Own a QF (Richmond Power Enterprise)

- EWG may Sell Byproducts like Flyash or Steam (Richmond)

- Two Interpretations In Rehearing of Order 550

  - An Operator may be an EWG and Not Sell Electricity if it has an Agency Relation to the Owner that Does Sell Electricity (Solved KFM Pepperell Case)

  - The Lease of the Facility is Treated as a Sale (Solved InterAmerican Energy Case)

- Commission Has Received 49 Applications, Approved 24, Denied 9, Pending 15, Withdrawn 1

Transmission Information NOPR

NOPR Issued March 30, 1993

Final Rule Due by October 24, 1993

Proposed Rules Require That Base-Case Power Flow Models and Information Be Available

Overview of Transmission Access

Transmission Service

- Types of Services
- Non-Price Terms and Conditions

Mandatory Access

- New 211 Authority as a Result of the Energy Policy Act

Voluntary Access

- Market Based Pricing of Power Sales
- Mergers

Types of Transmission Service

"Wires" Service

- Point-to-Point Service
- Network or System Service

Ancillary Services

- Voltage Support or Reactive Power Service
- Load Following Service
- Scheduling Service
- Operating and Spinning Reserves
- Black Start

Transmission Terms and Conditions of Service

Third-Party Service should be Comparable to that Provided for the Transmission Owner's Own Power Sales, Including:

- Commitment to Provide Firm Service at a Cost-Based Price to Any Wholesale Market Participant, Nonfirm Service Provided as Available
- Commitment to Expand Capacity if Third Party is Willing to Pay Expansion Costs
- Commitment that Firm Transmission Service Has Priority over Nonfirm Uses of the Grid
- Commitment that Firm Service can be Resold

Firm Service Need not be Provided if Reliability would be Degraded

Restrictions should Occur Only to Ensure System Reliability or Other Technical Reasons

Transactions Costs of Requesting Service should be Minimal

Mandatory Access Under Section 211
As a Result of Energy Policy Act of 1992

Commission Can Order Transmission Service Upon Request if the Service:

- **Is in the Public Interest**
- **Does not Unduly Degrade Reliability**
- **Does not Involve Retail Wheeling (State and Local Issue)**

Who Can Request? Any Electric Utility, PMA or Independent Generator

Who Must Provide Service? Any Electric Utility, including Those in ERCOT, Muni's, Coop's and PMAs

Mandatory Access Under Section 211 (Cont.)

Administrative Procedure is Cumbersome:

- Third Party Must Make a "Good Faith" Request to Utility
- Transmitting Utility has 60 Days to Respond
- Third Party Can Request Service Under 211
- Commission Must First Propose an Order and Allow Parties to Consider It
- Commission Then Can Order Transmission Service subject to Rehearing

Commission's Authority Is Untested -- Tex-La v. TU Case is Pending

Emerging Issues:

- What Transmission Service is in the Public Interest?
- Which Services? *e.g.*, Network Service, Scheduling Service, Load Following, *etc.*
- Can Transmission Service Be Ordered if There's an Existing Contract?

Voluntary Access:
Market Based Pricing Standards for Power Sales

Seller Lacks Market Power

- A Utility Showing is Required
- Workable Competition is Not the Standard, Thus Far

Generation Market Power

- Seller Does Not Dominate the Relevant Market
- Small Market Shares are Acceptable, HHIs are OK Too

Market Based Pricing Standards (Cont.)

Transmission Market Power

- Seller Cannot Block Competitive Suppliers from the Buyer
- IPPs and Far-Away APPs Control No Transmission that Could Block Competitors
- Open Access Transmission Tariff is Sufficient, but the Commission Has Not Required it
- Seller Could Show that its Grid is Irrelevant to the Market, i.e., No Low-Cost Suppliers Can Be Blocked
  - De Minimis Argument in UI/Unitil Case

Market Based Pricing Standards (Cont.)

Potential Affiliate Abuse

- IOU Selling Power to its APP
  - Concern is that Price is "Too Low"
  - Bid or Benchmark Test in TECO/Terra Comfort
    - Offer to Sell or Show Comparable Prices

- APP Selling to its Affiliated Utility Buyer
  - Concern is that Price is "Too High"
  - Bid or Benchmark Test in Edgar/BECO Case
    - Competition or Comparable Deals

Policy Statement on Good Faith Requests and Responses

Commission Issued Policy Statement on July 14, 1993

Requests Must Be Specific Enough to be Modeled

Responses Must Be an Executable Contract If Capacity is Available, or a Study Agreement If Not

Network Service May Be Requested and the Commission Believes It Can Order Network Service

- Commission Requested Comments on Its Legal Authority to Order Network Service

Regional Transmission Groups

Comments on Consensus RTG Draft Requested in November 1992.

Activity is Progressing in Several Regions, Although Some Have Stalled

FERC Is Likely to Issue a Policy Statement to Encourage Further Development

- **Full Participation is Needed, Including State Commissions**

Overview of Transmission Pricing

Traditional Pricing -- Postage Stamp

Current Pricing Policy -- And versus Or Issue for Incremental Cost

Future Inquiry Into Possible Reform

- Firm Service: Parallel Path, Distance Sensitivity, and Contract Pricing
- Nonfirm Service: Demand Charges and Spot Pricing

REGIONAL TRANSMISSION GROUPS

THE NEXT STEP IN TRANSMISSION ACCESS

by

Michael D. Oldak

Regulatory Counsel
National Rural Electric
Cooperative Association

Regional Transmission Group Negotiations

During the House Energy and Commerce Committee and Subcommittee on Energy and Power markups, the issue of regional transmission associations was discussed at some length. The House leadership instructed the proponents of various proposals to work together to develop a single approach on which all could agree. Over the months, numerous negotiating sessions were held. Finally, FERC and the Department of Energy called all the parties together, established certain criteria which it required, and after marathon negotiations, an agreement was reached one-half hour before the House-Senate Conference adjourned. When one of the House members objected to the last-minute introduction of a complex legislative proposal, the RTG agreement was dropped, with a promise to address the issue next year. Since that time, FERC has included the RTG agreement in a Notice of Request for Public Comments On Regional Transmission Group Proposal. Comments are due December 10. The question still remaining is the extent to which FERC can certify RTGs without additional legislation.

The negotiated RTG agreement provides for a voluntary system of regional transmission planning and use with a comprehensive system of checks and balances. Before any RTG group may operate, they must receive FERC certification and then they are subject to varying degrees of Commission oversight.

To be certified, the RTG governing agreement must be filed with the FERC, and after notice and an opportunity for a hearing, the RTG will be certified if FERC finds that the agreement is just, reasonable, not unduly discriminatory or preferential, consistent with Part II of FPA and that it meets specific requirements.

> The first requirement is that membership be open to all entities which could be subject to, or could apply for wheeling order under section 211. The RTG must be of sufficient size and scope to promote transmission services consistent with reliable, efficient, and competitive wholesale power markets, and Part II of the Federal Power Act. Membership in RTG may not be compelled by FERC and withdrawal may be permitted as provided for in the RTG's Governing Agreement. Additionally, compliance with the Governing Agreement will not subject members to other sections of the Federal Power Act.
>
> Second, members of an RTG must accept affirmative obligations to: (1) provide transmission services to other members (consistent with and no less comprehensive than 211, 212 and 213); (2) enlarge transmission capacity as needed; and (3) maintain system reliability (as measured by continued conformance with generally applicable and recognized guidelines).
>
> Third, members must coordinate, in a timely manner, transmission planning on a regional basis, share transmission planning information (as provided by agreement or on request) and work to achieve certain planning goals. These goals include ensuring forecasted loads; accommodation for resources and requirements for transmission services, including known needs of non-members, consistent with state utility, siting, and environmental laws; ensuring efficient utilization, expansion and coordination of

interconnected transmission systems; and enabling reasonable and efficient utilization of power supply resources.

Fourth, all governance and decision making must be fair, take into account interests of all members, and be consistent with Part II. The Governing Agreement must also provide a fair and equitable dispute resolution process, which results in timely resolution of disputes. Additionally, if a member consents on a case-by-case basis not to seek review of a dispute, the Commission may not set aside, remand or issue a compliance order except on the same grounds as a court under applicable contract law (Sections 10 and 11 of Title 9 U.S. Code). However, binding arbitration or any other limitation of Commission review may not be a condition of RTG membership or exercise of any right of membership.

Fifth, to provide equality of rates, non-regulated entities must provide rates which are consistent with section 212, filed with FERC, and may be subject to suspension or refund as provided in the Governing Agreement.

As part of the rights granted to a certified RTG, the group may establish service priorities when capacity is constrained and may also provide for reciprocal transmission services with other RTGs.

To provide the check on RTG activities, the Commission is authorized, during the certification preceding, to impose terms and conditions to ensure conformance with the section and public interest. The RTG has 60 days to accept or essentially withdraw its application. FERC may not impose an obligation to accept a planning decision of the RTG as a condition. However, a member's decision does not relieve the member's obligation to provide the service or enlarge its facilities.

Additionally, on complaint or its own motion, the Commission may at any time require information, modify or revoke certification and make a determination whether any actions are consistent with the Governing Agreement, any filed rates, the certification order, or whether or the action is unjust, unreasonable, unduly discriminatory or preferential.

In determining consistency, the Commission is required to give a rebuttable presumption of consistency for any action that is not contested. The Commission is also required to give substantial deference for decisions rendered on an adequate record, by an independent arbitrator, under an approved alternative dispute procedure.

If the Commission finds that any action is inconsistent, it may remand the action to the RTG for timely modification, set aside the action, or issue an order requiring consistency with Governing Agreement or rates.

Because RTG members are obtaining the benefits of transmission access through their FERC-certified RTG, RTG members may not seek Section 211 orders requiring another RTG member to provide transmission services unless the RTG's dispute resolution mechanism has failed to provide resolution within the Governing Agreement's specified time

period. RTG members are also exempt from Section 213(a) requirements for detailed written explanations for unacceptable rates, terms, conditions or constraints.

Non-members may always use Section 211 to obtain transmission services from RTG members.

Rates for RTG members are subject to sections 205 and 206. Specifically, the negotiated RTG agreement provides that sections 205 and 206 apply to the Governing Agreement (including rates, terms and conditions specified therein), initial rates not specified in the Governing Agreement, and changes in rates, terms and conditions. Dispute resolution may only be used regarding these changes if it applies to changes under both section 205 and 206.

Federal entities are specifically allowed to become members of an RTG; however, their rates must be consistent with section 212(i). Regardless, the negotiate RTG agreement requires FERC to review and approve or set aside any binding arbitration decision involving a Federal entity, but provides that FERC review shall be in lieu of transmission rate proceedings otherwise required by Federal law.

To ensure that the RTG language does not provide for Federal preemption of state laws, the negotiated RTG agreement provides that FERC shall not certify an RTG if each state commission having retail rate jurisdiction over members files a notice of disapproval. Additionally, the agreement provides that certification of an RTG does not affect State siting, environmental or utility regulatory authority that could otherwise be exercised over members and that planning must be consistent with applicable state utility, siting and environmental regulation.

REGIONAL TRANSMISSION GROUPS
THE NEXT STEP IN TRANSMISSION ACCESS

by Michael D. Oldak

A SYSTEM OF CHECKS AND BALANCES

- Certification Requirements
- Commission Authority over RTGs

CERTIFICATION REQUIREMENTS

- Filing, notice and opportunity for hearing
- Governing Agreement must be
  - *just, reasonable, not unduly discriminatory or preferential*
  - *consistent with Part II of FPA*
- Governing Agreement must meet specific requirements

MEMBERSHIP

-Open to all Section 211 entities

-Sufficient scope and size to

promote transmission services consistent with

- *reliable, efficient, and competitive wholesale power markets*
- *Part II of the Federal Power Act*

-Membership in RTG may not be compelled by FERC

-Withdrawal permitted as per Governing Agreement

-Compliance with Governing Agreement will not subject members to other sections of Federal Power Act

AFFIRMATIVE OBLIGATIONS

- Provide transmission services to other members

(consistent with and no less comprehensive than 211, 212 and 213)

- Enlarge transmission capacity as needed
- Maintain system reliability

(as measured by continued conformance with generally applicable and recognized guidelines)

PLANNING REQUIREMENTS

- Coordinate in a timely manner transmission planning on a regional basis
- Share transmission planning information

(as provided by agreement or on request)

- Achieve planning goals

PLANNING GOALS

- Ensure forecasted loads, resources and requirements for transmission services are accommodated
- including known needs of non-members
- consistent with state utility, siting, and environmental laws
- Ensure efficient utilization, expansion and coordination of interconnected transmission systems
- Enable reasonable and efficient utilization of power supply resources

GOVERNANCE AND DECISION-MAKING

- Fair
- Take into account interests of all members
- Consistent with Part II

DISPUTE RESOLUTION

- Provide a fair and equitable dispute resolution process
- Provide for timely resolution
- No limitation of Commission review as a condition of RTG membership or exercise of any right of membership
- If a member consents on a case-by-case basis not to seek review of a dispute, the Commission may not set aside, remand or issue a compliance order except on the same grounds as a court under applicable contract law (Sections 10 and 11 of Title 9 U.S. Code)

NON-REGULATED ENTITY RATES

- Consistent with section 212
- Filed with FERC
- May be subject to suspension or refund

(see Governing Agreement)

RTGs MAY

- Establish service priorities when capacity constrained
- Provide reciprocal transmission services with other RTGs

COMMISSION AUTHORITY DURING CERTIFICATION

- FERC may impose terms and conditions ... to ensure conformance with section and public interest

(RTG has 60 days to accept or reject conditions)

- FERC may <u>not</u> impose an obligation to accept a planning decision of the RTG as a condition.

(However, a member's decision does not relieve the member's obligation to provide the service or enlarge its facilities)

COMMISSION AUTHORITY OVER RTGS

On complaint or its own motion the Commission may at any time:

- require information
- modify or revoke certification
- Determine whether actions are consistent with
  - Governing Agreement
  - filed rates
  - certification order, or
  - unjust, unreasonable, unduly discriminatory or preferential

DETERMINING CONSISTENCY

- Rebuttable presumption of consistency for any action that is not contested
- Substantial deference for decisions rendered
- on an adequate record
- by an independent arbitrator
- under an approved alternative dispute procedure

IF INCONSISTENCY

- Remand to RTG for timely modification
- Set aside action
- Issue an order requiring consistency with Governing Agreement or rates

SECTION 211 WHEELING ORDERS

- RTG members may not seek Section 211 orders requiring another RTG member to provide transmission services
- Unless ADR failed to provide resolution within Governing Agreement specified time period

SECTION 213 (A) WRITTEN EXPLANATIONS

- RTG members exempt from Section 213(a) requirements for detailed written explanations for unacceptable rates, terms, conditions or constraints

RIGHTS OF NON-MEMBERS

- Nonmembers may use Section 211 against RTG members

RATES

- Sections 205 and 206 apply to:
  - Governing Agreement (including rates, terms and conditions specified therein)
  - Initial rates not specified in Governing Agreement
  - Changes in rates, terms and conditions
  - Dispute resolution may only be used regarding these changes if it applies to changes under both section 205 and 206

FEDERAL ENTITIES

- Federal agencies or instrumentalities may be a members of an RTG
- Rates must be consistent with section 212(i)
- Regardless, FERC shall review and approve or set aside any binding arbitration decision
- FERC review shall be in lieu of transmission rate proceedings otherwise required by Federal law

STATE LAW

- No certification if each state commission having retail rate jurisdiction over members files a notice of disapproval
- Certification of an RTG does not affect State siting, environmental or utility regulatory authority that could otherwise be exercised over members
- Planning must be consistent with applicable state utility, siting and environmental regulation

Energy Policy Act of 1992:

Transmission Access and Pricing Implementation Issues

National Regulatory Research Institute/DOE
Conference on Public Utility Implementation
of the Energy Policy Act

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Senior Vice President
Finance, Regulation,
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July 20, 1993

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July 16, 1993

Introduction

The Energy Policy Act of 1992, and in particular Title VII of the Act, represent probably the most significant potential change for the electric utility industry since the Federal Power Act and the Public Utility Holding Company Act were initially passed in 1935. There are probably dozens of specific implementation issues arising from the amendments to the Federal Power Act giving FERC broader authority to mandate wheeling -- certainly too many to cover in the short amount of time we have today. What I would like to focus on are two of the issues most critical to us -- appropriate transmission pricing and retail wheeling. These are both issues which have serious implications at the state regulatory level, and thus will be of particular interest to you.

Transmission Pricing

As you all know, an almost entirely new FERC has recently been constituted, along with the appointment by the President of a new Chair, Elizabeth Moler. This newly constituted Commission is already making great strides in dealing with some of the key issues affecting the electric utility industry, and in particular, issues related to implementation of the Energy Policy Act. We are particularly grateful to the Commission for recently initiating a public inquiry on its transmission pricing regulatory policies. Transmission pricing is, as stated by several Commissioners when the Notice of Inquiry was issued, the "linchpin" of efficient bulk power markets. Without correct transmission pricing, both users

and builders of transmission will face inaccurate price signals, and bulk power markets will be less efficient.

The Commission's past rigidity with respect to its transmission pricing policy, and apparent lack of concern for the economic interests of retail and other native load customers, has been one of our major concerns with FERC regulation and a concern of most state regulatory commissions as well. FERC's existing transmission pricing policy was established in the context of a single case without broad public input, and then applied to other cases with very different facts. The current Commission has recognized the need for a generic hearing on this issue, with broad public input, and we are greatly appreciative that the Commission has responded to many of our frustrations. While the Commission has certainly made no promises that it will change existing policy, it is clear from the recently issued Notice and Request for Comment on Transmission Pricing that the Commission has an open mind towards potential changes to its policies, and will seriously consider concerns and suggestions that various parties will make in response to the Commission's request.

Current FERC transmission pricing policy, as first annunciated in the Northeast Utilities merger case, is to allow transmitting utilities to charge either fully allocated embedded costs or incremental costs, but not both. Incremental costs are measured as either the actual cost of new facilities needed to satisfy a request or opportunity costs. The stated basis for this current FERC policy, as expressed in Northeast Utilities is to balance three

objectives; (1) protecting native load customers, (2) providing the lowest reasonable transmission rate, and (3) precluding the collection of monopoly rents by the transmitting utility.[1]

We believe that while the current FERC policy may satisfy the latter two of these objectives, it does not adequately protect the economic interests of native load customers in all cases. If a proposed transmission service requires new facilities that provide little or no benefit to native load customers for the life of those facilities, then native load customers are faced with either paying a share of the costs of those new facilities (from which they receive no benefit), or being reimbursed for the incremental costs of the new facilities without any contribution from the third party for using the transmitting utility's existing facilities.

There are cases where the Commission's existing policy may lead to the correct result. For example, if new facilities built to satisfy a particular transmission request benefit all transmission users (native load and third parties) relatively equally, it may be reasonable to roll the costs of the new facilities into embedded cost rates paid by all users. However, FERC's current policy is based on the premise that all grid additions (with the exception of radial lines) benefit all users due to the integrated nature of the grid, and therefore

[1] Northeast Utilities Service Company (Re Public Service Company of New Hampshire), Opinion No. 364, 56 FERC ¶61,269 at 62,050 (1991), order on reh'g, Opinion No. 364-A, 58 FERC ¶61,070 (1992).

should be paid for by all users.[2] It is this premise that we believe results in economic harm to native load customers in many cases where native load customers face higher costs due to either the addition of new facilities from which they receive little or no benefit, or to changes in use of existing facilities which increase a transmitting utility's operating costs (e.g., redispatch or opportunity costs).

FERC's current pricing policies are also based on the premise that embedded or incremental cost recovery is sufficient to make a transmitting utility and its native load customers at least neutral towards the provision of transmission service. We believe this presumption is not true in all or even most circumstances. FERC's thinking is that if third parties pay embedded costs and incremental costs are lower, then native load benefits because the third party pays a share of the costs of the existing system that would otherwise be paid by native load customers. Alternatively, according to FERC, if the third party pays incremental costs, than native load sees no impact -- that is, their costs of transmission remain exactly the same. This reasoning by the Commission, however, ignores the fact that in most cases, the third party user will be using up some of the margins available in the existing system that native load customers have paid for (and under FERC's policy, could be required to continue to pay for). The third party essentially gets to use some or all of the margins in the existing system for free, and thus the native load customer is harmed.

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[2]See Public Service Electric and Gas, Docket No. ER92-280-001, Order Granting Motion to Intervene and Denying Requests for Rehearing, Issued May 17, 1993.

Current FERC policies also result in inefficient price signals to potential users of transmission service and inefficient signals to owners of transmission for potential expansion of the system. Potential users, if faced with transmission prices that are lower than actual costs imposed on the system, may locate generation further from load than would be economically efficient. Furthermore, under FERC's current policies, there is no price signal indicating congestion at certain locations of the network, so that generation may be sited at locations where congestion is increased, rather than at more efficient locations where there is no congestion. Finally, under FERC's current policies, owners of transmission have no incentive (and probably have a disincentive when their native load customers are harmed) to build new transmission when needed, nor do state regulatory agencies have any incentive to approve the construction of new facilities.

EEI is currently in the process of evaluating alternatives to FERC's current policies, and hopefully we will succeed in developing a position that we hope will be attractive to the Commission. We also hope to work closely with NARUC, because we believe our interests in protecting native load customers through appropriate transmission pricing coincide.

The NARUC Electricity Committee last fall requested that FERC initiate a consultative process to address some of these issues. We support this request, primarily out of self interest. We are the ones who will be caught in the middle if state and federal policies are not coordinated and consistent. An informal process whereby state and federal

regulators can discuss these issues, while certainly not a panacea, should go a long way to addressing some of these concerns. Most importantly, we urge all state commissions to participate in the FERC proceeding. FERC needs to hear your concerns.

Retail Wheeling

Turning now to the issue of retail wheeling, while it is fairly clear that Congress has banned retail wheeling, the precise authority of the states either to mandate retail wheeling or to set the price, terms, and conditions is not so clear. Some have argued that because Congress precluded FERC from having such authority, it is clear that states were left with the authority by default. Some point to the so-called "savings clause" which essentially says that nothing in the Act affects a state's ability to order retail wheeling under any authority it may have.

Our own view is that the answer is not clear. Almost all transmission services, retail or wholesale, involve or affect interstate commerce. As the Supreme Court held in the Florida Power & Light case, even transactions where the generator and customer are within the same state have indirect consequences for the interstate network, and are thus within FERC's jurisdiction, and not the state's[3]. The savings clause, in our view, simply

[3]FPC v. Florida Power & Light Co., 404 U.S. 453 (1972), dealt with wholesale sales. However, the FERC has interpreted the Court's ruling to apply to transmission as well, stating "transportation of power over a utility transmission grid which is used in interstate

leaves the question of what state authority is to another day. Thus, until the courts address the issue, which I am sure they will at some point, I don't think the ultimate question of whether or not retail wheeling is within the jurisdiction of states can be answered with any certainty.

Notwithstanding the legal jurisdictional issue, several states are now considering the issue of retail wheeling, most notably New Mexico and Michigan. In addition, Nevada has recently passed legislation, which although it has the retail wheeling moniker, is really much more a bill providing an economic development rate to a single particular customer which the state is courting. Nonetheless, proponents of retail wheeling are likely to promote passage of the Nevada legislation as a major watershed event, even though New York has had similar legislation on the books for years, and most states have similar economic development programs which are not all that different than the Nevada plan.

New Mexico had legislation introduced late last year by State Senator Tom Wray, which was defeated in favor of a two-year legislative study of the issue. The New Mexico legislation would have mandated retail wheeling for all customers, and had no provisions to effectively protect smaller utility customers without the economic clout to shop for power. Michigan has a state regulatory proceeding ongoing with respect to a request by large industrials for a retail wheeling "experiment". A decision in the Michigan case is not

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commerce is subject to this Commission's jurisdiction even when all parties to the wheeling transactions are located within the same state." Florida Power and Light Co., 29 FERC at p. 61,291.

expected until October. If you want a good compilation of all of the arguments for and against retail wheeling, I would highly recommend reading the voluminous testimony that has been filed in the Michigan case.

The arguments being made to support retail wheeling or "bypass" in these arenas have been seductive and reasonable on the surface, but conveniently ignore some very difficult issues that renders the concept of retail wheeling uneconomic and unworkable. Unless these issues are resolved, retail wheeling will have serious consequences to electric utilities and their customers without choices. In the few minutes that I have today, I would like to point out why the retail wheeling arguments being made don't pass careful scrutiny, and what the implications of some of the proposals made in New Mexico and Michigan could be on electric utilities and their customers.

First, I want to respond to what I believe is an ingenious -- but totally false -- argument which large industrials are now making to support their case for retail wheeling. The argument goes something like this: we (the industrial customer) are paying in our rates the costs of demand-side management programs that benefit other customers. We can help our utility avoid the need for new capacity just as well -- if not better -- than these least cost programs, simply by leaving our local utility and purchasing elsewhere. It is a seductive, albeit incorrect argument.

Aside from the stranded investment cost impacts on other customers from using retail wheeling as a DSM measure, the fact of the matter is that as long as a retail customer is interconnected with and located in the control area of an electric utility, that utility can not avoid new capacity via retail "wheeling." Retail wheeling does not absolve a utility of continuing to serve the retail customer. It is solely an accounting transaction. Suppose the generating source from which that retail customer is purportedly buying does not generate or does not exactly match the demand of the customer. The physical nature of power systems is such that the generation of the local utility will automatically increase to make up for the lost generation. If the local utility (or another interconnected utility) does not maintain sufficient generating capacity to make up for the loss, then load will have to be immediately shed -- but ironically the load that must be shed will not necessarily be the retail wheeling customer, even though that customer's "purchase" created the problem. Depending on power flows at the time of the outage, the wheeling utility may very well have to shed load on another part of its system, affecting its own franchise customers.

Perhaps even more importantly, the presence of retail wheeling is, in our view, totally incompatible with integrated resource planning processes, and in fact the mere threat of retail wheeling is going to make electric utilities reluctant to invest in demand side management programs that raise rates in the short term, but have benefits in the long term. Thus, I think you can expect to see environmental and consumer groups opposing retail wheeling at the state level.

There are, of course, other arguments being made in favor of retail wheeling. Claims of specific benefits include increased competitive pressure on utilities to control costs resulting in lower costs for all customers. A related argument suggests that, because utilities are already at risk of losing customers through relocation, self generation, or cogeneration, there is no increased risk to utilities due to retail wheeling. Proponents of retail wheeling, take issue with the notion that only large customers will benefit from retail wheeling. Again, their view is that competitive pressure will hold down rates for all customers. But this argument, among other deficiencies, ignores the capital intensive nature of electricity supply. More than two-thirds of the costs of providing service to customers are fixed costs. When any customer leaves, those costs are stranded. Any conceivable operating efficiencies from competition at the retail level would be overwhelmed by capital losses utilities would suffer.

The proposed New Mexico legislation precluded the ability of utilities to collect for stranded investment from their remaining customers. I think the result of such a clause would be to force at least some utilities into bankruptcy -- and as far as I know, federal bankruptcy courts will not be bound by the rules set by state regulatory commissions or even state legislatures. The argument made all too often that these costs should be borne by stockholders on the theory that they should have foreseen changes in the rules constitutes, in my view, the ultimate in Monday morning quarterbacking.

Proponents of retail wheeling totally ignore all of the detailed implementation issues that would come with retail wheeling -- and they do not answer the most important questions of all -- who has rights to wheeling and who doesn't, and how are costs unbundled and allocated between wheeling customers and captive customers? They simply suggest that all these details can be worked out by regulators in a transitional period. Yet it is difficult to evaluate their claimed benefits to retail wheeling without understanding how a retail wheeling scheme would work and who would be eligible to participate. In fact, a shortcoming of all proposals for retail wheeling is a glossing over of the very real problems with a blind faith that they will somehow be worked out over time.

Part of the problem we face today in responding to arguments for retail wheeling is that those who see potential efficiency gains from competition in bulk power markets extend those potential gains to retail markets. They ignore one major fact however -- competition in bulk power markets can lead to efficient results if purchasers are choosing between market-based alternatives -- as in the case of competitive bidding for bulk power purchases. But retail customers would be choosing between regulated embedded cost-based rates of their local utility and market-based alternatives from other suppliers. There is no reason to believe that competition in this context will lead to efficient results. Only if retail customers are willing to see all rates deregulated, and pay market-based rates regardless of supplier, will retail wheeling make any sense at all from an efficiency standpoint. But I believe those advocating retail wheeling would prefer having the ability to choose between regulated and market rates. And when market rates exceed

embedded costs, they want the option to return to regulated rates. In my view, they can't have it both ways.

The question I find most interesting is that if retail wheeling has all these benefits that are claimed for it, why haven't state regulators already jumped on the bandwagon. Surely, there isn't a conspiracy to keep customer rates higher than necessary by keeping retail customers captive to their local utility. The fact of the matter is that electric utilities are a public service business. As the Supreme Court said in Munn vs. Illinois, it is a business "affected with the public interest". The public interest demands that there be an electric utility standing ready to provide service when a customer flicks a light switch. This public interest demands that all customers be served, regardless of their profitability. The regulatory framework and service obligations that are necessary to satisfy this public interest can not be wished away by those seeking short-term gains. Retail wheeling, at its very basis, would result in a fundamental restructuring of the electric utility industry away from its public service roots. I would ask if we are really ready to make that move, and if we are, can it be done on a piecemeal, state-by-state basis.

Other Issues

Turning briefly to some other key issues, in addition to the recently announced inquiry on transmission pricing, the Commission is already well along on other Energy Policy Act

implementation requirements. It has already completed, well in advance of the statutory deadline, work on a rule to define qualification criteria for exempt wholesale generators. We believe the Commission successfully balanced the interests of many parties and satisfied the intent of Congress to place FERC in a ministerial role with respect to EWG certification. We believe the final rule is workable, and commend the Commission for its timely issuance of final rules.

The Commission is also well along on a proceeding required by Section 213(b) of the Energy Policy Act. This section requires the Commission to issue rules within one year on information it will collect to inform the public on potentially available transmission capacity and potential constraints. Comments have been filed by numerous parties in this rulemaking, and I think the generally excellent job done by the Commission in its proposed rule is borne out by comments filed by all sides of the transmission debate. While we have some concerns about some of the specific data requirements suggested by FERC, all in all we believe they are seeking the right kind of data to allow potential users of the transmission system to do an initial screening of potentially available transmission capacity, which is what we believe was intended by the Section 213(b) requirement.

The Commission has also initiated a Request for Public Comment on the issue of Regional Transmission Groups (RTGs). EEI was disappointed that because of the timing involved, the consensus RTG agreement developed by many parties was not adopted in

the final Energy legislation. But we were pleased that former Chairman Martin Allday saw fit to initiate a proceeding to determine whether or not the consensus proposal could be implemented absent specific statutory authority.

In EEI's comments in this proceeding, we suggested that there is substantial uncertainty as to whether or not all aspects of the proposal could be implemented by rule, and such uncertainty in and of itself could provide a disincentive to the formation of RTGs, which we fully support. Thus, we suggested as an alternative, the issuance of a Policy Statement by the Commission which would provide sufficient certainty to potential RTG participants as to the minimum criteria that FERC would require to provide an RTG with the types of benefits suggested by the consensus proposal. Then, FERC would have a general basis for evaluating individual RTG applications, but it would not be tied down to a prescriptive rule that would limit the flexibility of regions to take alternative approaches dependent on their needs.

The comments filed in the Commission RTG inquiry covered a broad spectrum of potential solutions, from leaving RTG approval as solely a case-by-case determination all the way to implementing the consensus proposal with substantial changes. But of most interest is the fact that all of the over 100 sets of comments filed supported the notion and concept of regional transmission groups, which should provide a strong foundation to get started. We believe the EEI suggested approach of a Policy Statement offering general guidance and minimum criteria represents a reasonable middle-of-the-road approach

which will best encourage the development of RTGs. While we do not know the exact schedule, it has been indicated that FERC will deal with the RTG issue in some manner before the end of this summer.

Thus, the new Commission has hit the ground running, and is placing an increasing emphasis on electricity issues, which we believe is entirely appropriate given the critical role to be played by the Commission in future power supply and regulation. The presence of new Commissioners and a new Chair with strong backgrounds and interests in electricity issues is certainly gratifying to us, and regardless of whether they agree or disagree with us on future issues, we know they will give electricity issues the proper attention they deserve.

While the Commission has already begun to tackle all of the Energy Policy Act implementation issues that they are required to address by the statute, Chair Moler has also indicated a desire to address related critical issues to successful implementation of the Energy Policy Act, such as the appropriate terms and conditions for transmission service, what constitutes transmission service subject to a FERC order under the Act, and stranded investment issues and problems. The Commission will be addressing additional issues in the context of several requests for mandatory wheeling now before it. While I don't have the time today to discuss these issues, they are nevertheless critical to successful implementation of the Energy Policy Act, and need full discussion and consideration in the future.

SESSION VI

SECTION 712 OF EPAct

REMARKS TO THE
NATIONAL REGULATORY RESEARCH INSTITUTE
CONFERENCE ON THE ENERGY POLICY ACT OF 1992
INDIANAPOLIS, INDIANA
JULY 20, 1993

By: John B. Howe
J. Makowski Associates, Inc.
Speaking for:
The Electric Generation Association

REMARKS TO THE
NATIONAL REGULATORY RESEARCH INSTITUTE
CONFERENCE ON THE ENERGY POLICY ACT OF 1992
INDIANAPOLIS, INDIANA
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Speaking for:
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Introduction

Good afternoon. First, on behalf of the Electric Generation Association, I would like to extend our thanks to the NRRI for the opportunity to speak to you today. We also appreciate the Department of Energy's initiative in bringing many of you together and co-sponsoring this conference. The deadline of October 24 is coming fast upon us and it a very efficient use of everyone's time to have a conference such as this one as well as last week's companion conference in Portland.

Let me first say a few words of introduction about the EGA. We are a national trade group based in Washington, D.C. which represents the interests of competitive power generation and related services. Our membership includes both utility affiliates engaged in the competitive power market as well as true independents. As the power market increasingly turns to competitive procurement to select new generating resources, we expect to see the divide between "rate based" and "competitively-procured" generation supplanting the distinction between "utility" and "independent" generation. In the EGA's view, this is one of the watershed implications of the Energy Policy Act of 1992.

As a Bostonian, it is delightful for me to come to Indiana, the boyhood home of Larry Bird. Like millions of other Americans, I am a lover of Abraham Lincoln, and it is equally a pleasure to come to that great hero's boyhood home. As I took an after-dinner walk last night I strolled through the Indiana Government Center and came across a very wonderful, poignant statue of Abraham Lincoln as a young man. The statue depicts him in outgrown britches and wearing through at the elbow, with big, gangly awkward hands and feet; it is quite an extraordinary statue.

A moment ago I commended the NRRI for organizing these two events in short order. In fact, these conferences are two of the most efficient things that have been done in the entire Section 712 process. I will be entirely blunt about this, as I have been with people who were involved in the "other side" in getting Section 712 written into EPAct. In our industry's view, this section of the Act does not have terribly noble parentage. The legislative language is somewhat wooly and Bob Burns has spoken to you about some of the vagaries of the requirements. So I am sort of left quoting another American hero of mine, Admiral Stockdale: "Why am I here?"

The answer from our perspective is that the "Just Say No" utilities in the PUHCA reform debate did not get their way on the larger question of whether there should be reform in the wholesale generation industry. So they got this provision written into the law to get the proverbial "second kick at the cat." A big problem, however, is that they got fifty kicks at the cat, which we find most distressing. So I would like to address briefly -- and thanks to Meg Meal's fine presentation, I can be briefer on several of the points -- the EGA's perspective on Section 712 Questions 1 and 2. We would also like to present some more procedural concerns of the members of the competitive power industry about how these hearings are conducted.

By the way, both Meg and I had an enjoyable lunch with Larry Kolbe, our next panelist. We found that all three of us planned to address exclusively the first two questions. There seems to be an emerging consensus that Question 3, dealing with preapproval of wholesale contracts, involves something of a policy call that each of you is going to have to make within the context of your statutes and staffing considerations. Question 4 seems to have emerged as the great non-issue of Section 712. I haven't seen anyone take the prospect of advance regulatory review of fuel plans terribly seriously. To echo what Meg Meal had to say about another question, the financial markets do an excellent job of regulating IPPs' fuel plans. We are subjected to very extensive scrutiny on those plans.

In any event, many of you, and many of us, are somewhat frustrated by the vagueness of the requirements of this section of the statute. We would like to suggest a streamlined approach so that we don't get involved in "reinventing the wheel" fifty times. Furthermore, the EGA's position is laid out succinctly in a white paper which I would be happy to have sent to you if you would simply furnish me with your business card at the end of the panel.[1]

The IPP industry players' positions are quite consistent on these questions. Several individual companies have been active in these proceedings. Our sister organization, the National Independent Energy Producers, has produced a very fine white paper on the Section 712 issues as well. If you have opened your docket and solicited comments already, you will in find that these papers are, in all likelihood, already on file in your state.

Both in his April paper on Section 712, and in the synopsis in his more recent June 1993 paper on the EPAct, Bob Burns's has reflected our own views, so I will quote briefly from the synopsis:

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[1]A copy of the EGA's white paper, as it was filed in the Iowa Section 712 proceeding, is attached to these remarks.

> The Section 712 standards are difficult to justify on the basis of carrying out the purposes of Title I (of PURPA) ... In fact, the heavy-handed regulatory approach implied by the Section 712 standards may be contrary to the purposes of PURPA Title I.

In a nutshell, it is the EGA's view that these issues have been somewhat overblown and subjected to selective interpretations by those utilities who feel their competitive position adversely affected by the reforms taking place in market structure. Most serious analysts, however, see competition as an inevitable fact of life in the mature electric marketplace of the future. The progress of competition is inexorable. Initiatives to try to stem the onset of competition are doomed to fail in the long run, so we believe it would be far more constructive to try to adapt to this new environment and try to take advantage of the lower costs to ratepayers that it can provide, rather than trying to frustrate it.

Question 1: Impact of Purchased Power on Utility Credit Ratings

On Question 1, let me echo some of the things that Meg Meal had to say. First off, remember that the ultimate standard, as you fulfill your ratemaking responsibilities, is: what approach to power procurement by utilities results in the lowest costs to ratepayers? Utilities should be encouraged to obtain the best deal on behalf of ratepayers. So, even assuming arguendo that reliance on purchased power results in higher capital costs, these may still be offset by the lower cost for power that the independent producer is able to offer.

But that's not the whole story. The fact is, as has been suggested, that the purchased-power decision is not made in a vacuum. It is made in a particular context: the need for additional generating resources on a utility's system. If the utility doesn't purchase power, it is going to have to build it or obtain it through demand-side management or through some other means. And it is the full cost of all of these options that provides the relevant comparison.

One additional observation bears mention. The competitive power industry has developed a considerable body of experience over the fifteen years since the passage of PURPA. There is a clear trend, an increased level of sophistication on the part of project developers, utilities as well as state and federal regulators. We're finding ways to mitigate many kinds of risks, shift them and allocate them to the parties best able to manage them, and thereby actually reduce the risks of a project. It is our industry's firm view that purchased power can and has improved many utilities' financial condition. You'll find many statements by utilities in some of the Section 712 proceedings that that is the case -- that they have consciously pursued purchased power strategies as a means of improving their financial health.

I'm not saying that no purchased power agreement can impose a debt-like obligation. That simply wouldn't be a credible position to take. But we should, as Ken

Rose suggested today, try to pursue the lowest-cost lunch available, with due consideration for all relevant factors!

Let me echo another important factor alluded to earlier today. We are now entering an era in which EWGs will grow in importance and in all likelihood overtake QFs as the principal source of new capacity in the competitive marketplace. In this environment, contracting will be voluntary; there is no automatic right for EWGs to sell energy to utilities. To assume that an EWG could obtain a contract to sell power to a utility on terms that subject it to unnecessary risk would be to assume that the utility will sign a contract that is adverse to its interests. I don't believe that would be a prudent or a likely thing for a utility to do. If a utility has a need for dispatchability on its system, for coordinated maintenance, for a given level of availability, these can be ensured through contract provisions with EWGs, including mechanisms such as penalties and rewards as actual performance levels fall short of or exceed targeted levels.

These views are being presented simply to prevent this debate about cost of capital impacts from being turned on its head. Ten years ago, many people were saying that purchased power was the way to go at a time when utilities were experiencing great cost overruns on construction projects. Then, in the late '80s, the credit rating agencies began to say, "wait a minute, purchased power is not entirely without risk." We would agree, that's a credible position for the credit rating agencies to take. But when, in a further step, the interpretation is made by some utilities that purchased power is more risky than the construction of rate-base generation facilities, given the historical record, we frankly think that's stretching it. My personal view on this is that we're headed down a slippery slope if we start to get into making pro forma capital structure adjustments for utilities that enter into purchased power agreements because of the debt-like characteristics of the contracts. If we do it for purchases, why we would not likewise, when a utility files for a certificate to build a new plant under traditional rate base regulation, perform an adjustment to the cost of that plant? Such an adjustment could be justified as an advance recognition of the fact that, in all likelihood, that utility is going to experience financial stress some years in the future when it is immersed in an expensive building campaign. If we're comparing apples to apples, why not recognize the probability of that cost up front in the evaluation? But then we could go on and make other adjustments for other miscellaneous and speculative factors. However, I think we're talking about edging over a very slippery slope.

Let's take Bob Burns's advice and remember the purposes of Title I of PURPA. The way to make our national electric system lower cost for ratepayers is not to adopt standards that make the EWG industry less efficient. Instead, we should focus on ways to spur regulated utilities to greater efficiency.

Question Two: Effects of Debt Leveraging on Reliability and "Unfair Advantage"

Question two pertains to the impact of debt leveraging on reliability and the possibility of an "unfair advantage" for EWGs. Now, let's not rely on the sweeping allegations and idle speculation of some -- let's look at the facts. Look, if you would, at some of the studies referenced in Meg Meal's presentation. These studies demonstrate a truly excellent record of reliability on the part of the independent power industry over the years. Fifteen or twenty years ago, it was common to read about new utility plants achieving availability levels in the range of 50 to 60 percent. When the independent power industry started up, independents made claims that they could achieve levels of availability in excess of 80 percent. Many utilities were skeptical. We now have several studies that document the IPPs' claims. General Electric, for example, has done a study of plants that make use of its Frame 7 turbine. My company is proud to have three of our facilities included in that study, which found availabilities in the range of 90 percent. So, to repeat, on the question of reliability we should look at facts and not allegations.

On the question of "unfair advantage," please recognize first off that the initial level of leverage does not persist over the life of a project, but reflects initial debt only; it is paid down over the life of a long-term contract, typically 15 or 20 years (whereas utilities typically retain a capital structure of approximately 50/50 debt/equity continuously). Still, it is common knowledge that IPPs do finance with a higher proportion of debt than utilities, up to 80% or more. The financial markets, however, effectively regulate how much debt will be allowed for a particular project. We find that the amount of debt a project takes on is truly a function of what the cold-eyed bankers are willing to lend. They impose a scrutiny and a discipline on our projects that exceeds, in my view, the scrutiny that it is possible for a regulatory agency to give to a utility power plant. Another major advantage of this form of project finance is that the banker's scrutiny of the project's underlying fundamentals and quality is given up front, rather than years later in a retrospective prudence review, after the dollars have been irrevocably spent.

Consider, also, that if every new homeowner had to start out with 50 percent equity, we'd be a nation of renters. It is a matter of national policy that we support broad home ownership in this country. Likewise, the Congress has spoken on electric power that competition and freer entry into the market are in the national interest. A regulatory requirement for a level of equity capitalization not required by the financial market would interfere with this objective.

Procedural Concerns

In my remaining time I would like to move beyond these four questions and focus a bit on matters of process. The EGA believes that this round of hearings that is to be conducted by October can be done so efficiently, comprehensively and without taxing the resources of your agencies, the ratepayers or other interests by following a few simple

guidelines. As I suggested, these are sort of squishy questions. We don't think you are going to find firm answers; we think you will probably come out at the end of the day saying that it's up to a case-by-case factors but that if utilities follow certain guidelines there should be no need, for example, for pro-forma adjustments and so forth. You will certainly get a lot of opinions. But one thing is for sure: there are not fifty distinct answers. Yet the EPAct requires fifty proceedings!

Since balanced public participation is an important issue, let me point out some other considerations. Each utility is principally concerned with the determination in one particular state (or a few, in the case of multi-state holding companies). Also recognize that the utilities participate in these proceedings with ratepayer dollars, which are spent under the rubric of "regulatory expense." Your agencies are each responsible for the conduct of one proceeding.

Now I'd like to speak up for the competitive power industry. We are, relatively speaking, a small industry in terms of the number of substantial players that are in a position to participate in hearings. But you can be certain we care very much about the policies and precedents that are established in each of your forums. We take these proceedings very seriously. We've devoted a lot of resources to developing research and testimony and factual evidence to demonstrate that there is no need for the suggested standards. Furthermore, our industry is not in the business of litigation; we're in the business of producing power as economically as possible. We do not believe that anyone's interest by duplicative, grind-em-down litigation. Bob's paper explicitly states that full-blown evidentiary hearings are not required.

The independent power industry is also known, or at least I hope it is, for coming up with innovative, lower-cost ways of doing things. If you haven't yet opened your proceeding, or if you've had an initial round of comments or are a little way into things and uncertain how to proceed, you may be looking for concrete suggestions on procedures. So let me offer the following suggested approach:

- Solicit an initial round of comments, perhaps limited in length, on the four questions. Positions are very well developed at this point; many companies have already filed extensive position papers in several states.

- You may review the papers and decide whether there are any matters at issue at all in your state. At this first stage, you may find there is no need to go further. There are many utilities that don't think these issues are worth pursuing in any detail.

- It is possible, of course, that based on these initial papers, you will find matters at issue. If so, you could take things to a second stage.

- Based on the comments, you may identify issues that you believe involve questions of law or policy only. If so, you can ask for selective briefing on the narrow issues that you think are open to question, and then make your determination.

- If you find there are important and relevant matters that you think are open to factual dispute, you could structure limited procuderes focused on those narrow issues of fact.

- Based on whatever level of public input you deem necessary, i.e., unsworn comments, briefs or testimony, you could issue a set of proposed findings.

- All parties would be free to react to this order. If there are no objections, you will able to wind up these proceedings quickly and without taxing your resources.

Now, by no means do I suggest we are unwilling to engage these issues. To the contrary, our industry has gone to great lengths to do so; we believe this approach capitalizes on efforts to date and avoids wasting all of our resources.

Conclusion: The Benefits of Competition

I'd like to close by echoing something Ken Costello said this morning. I've discussed our view that Section 712 was crafted as a rear-guard action by the "Just-Say-No" utilities. But we must in all candor recognize that regulation itself has set up a clash of interests between the competitive power industry and the traditional, regulated utility industry. Frankly, one of the sticking points that you all are going to have to struggle with over the next few years is how to realign incentives so that all parties will want to pursue a least-cost outcome. At this time, in virtually every jurisdiction, purchased power is treated strictly as a dollar-for-dollar passthrough item in utilities' cost of service. Under this regulatory framework, no matter how prudent a utility's purchasing practices are, there is zero profit potential in purchasing power. So even if there is a negligible risk in purchasing power, if the risk is positive but the profit potential is zero, then from the narrow perspective of the shareholder only -- I'm not talking the ratepayer perspective, but strictly the shareholder -- the risk/reward profile of purchased power is negative. Even if there is a tremendous risk for a utility in building, but the profit potential is positive, then the utility will find that that risk/reward potential is more advantageous to it. This may well lead to a systematic bias in favor of building rather than buying.

The cost treatment of demand-side management was also brought up this morning. Looking at all of these options, you must recognize that your policies on the regulatory treatment of the build, the buy, and the save options have a tremendous influence on the behavior of utilities. If those policies are not well thought through and consistent, I dare say they can have a distorting influence, and we can end up with resource procurement policies that are not least-cost from the ratepayer perspective.

Let me also emphasize our industry's view that the allocation of risk is not necessarily a zero-sum game. In going through the rigorous project finance process, independent power producers are forced, with a very sharp and clear eye, to figure out what the risks are going to be down the road as best they can. They must find a way of allocating them in a way that satisfies long-term lenders. This process results in a degree of discipline that goes far beyond the discipline that utilities lived under for years under rate-base regulation.

In the long run, the EGA's hope is that we can get beyond disputes that are based on distinctions between the "NUGs" and the "UGs," the independents vs. the utilities, and so forth. Competition is here to stay and employing competition in place of regulation fundamentally changes behaviors and incentives and can lead to lower cost results. I am quite confident, looking at the experience of the telecommunications and natural gas industries, that this is what we will find out down the road. Some in the utility industry say they can't imagine that independent project developers can put together and finance projects at lower cost than they can, given the buying power advantages of large, well-financed utility companies. Well, I say, imagine! If our eyes are open to the potential of competition, amazing things can happen and are happening. Speaking for my own company and knowing the experience of others, I can assure you that we are competing vigorously in many states right now; as we force our suppliers and vendors, our consultants and attorneys to compete and control costs, we're putting bid estimates under the microscope and we are finding we are able to get our bid estimates down to levels that haven't been seen in years.

So: keep your eye on the gold ring! Competition leads to greater choice and lower cost outcomes; this is why it is the central organizing principle of virtually every other segment of our economy. You must never simply see competition as just another tool in your regulatory tool kit. It is a force of a fundamentally different nature. Your role in the future, as Ken Costello suggested this morning, will change. The electric generation marketplace has now reached a state of maturity. We believe you will be acting not so much as keepers of the narrow gate, but rather as guardians of a more open and fluid competitive process. This will be a challenging and interesting role for you.

On behalf of the Electric Generation Association, we wish you the best of luck in confronting these new challenges and look forward to working with you. We thank you very much for this opportunity.

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SECTION 712 OF THE EPAct

NRRI Seminar on Public Utility
Commission Implementation of the Energy Policy Act of
1992

July 20, 1993

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Introduction

- Power Purchase Contracts and Cost of Capital
  - What makes for debt-equivalence?
  - Importance of contract terms
  - Importance of regulatory treatment
  - Offsetting benefits of purchased power
  - Options for regulators
- Debt Leverage Used By IPPs and EWGs
  - Is there a competitive advantage?
  - Does it endanger project reliability?
  - Options for regulators

What Makes for Debt Equivalence?

- Debt obligations must be paid no matter what the circumstances

- Power purchase obligations are paid according to specific contract terms and conditions

  - Take-or-pay contracts create an obligation regardless of seller's performance

  - Take-and-pay contracts create an obligation only if the seller delivers power according to performance, scheduling, and reliability standards in the contract

- Power purchase payments are often treated as pass throughs, like fuel and labor costs

- Rating agencies' concerns are based primarily on demand and regulatory disallowance risks, which utilities incur in all resource procurement decisions (buy, build, DSM)

Contract Terms Mitigate Utility Risk

- Take-and-pay contract terms allocate risks away from the utility and its ratepayers to the power seller:
  - Fixed or indexed prices (as opposed to cost plus)
  - Performance standards, including monetary penalties or early termination for deficiencies in operations
  - Dispatchability and limits on maintenance scheduling
  - No payments due until power is delivered
  - Penalties or early termination if development and construction milestones are not met
  - Security deposits or other collateral during development, construction and operating phases to backstop seller's obligations
  - Buyout provisions

Regulatory Treatment Mitigates Utility Risk

- Preapproval of contract terms and conditions

- Regulatory environment that supports and encourages utilities to purchase power

- Recovery of payments through a fuel clause mechanism rather than base rates

- Integrated resource planning processes that help to avoid overcapacity and disallowance risks for capacity additions

- Regulatory-out clauses

Benefits of Purchased Power

- Avoid development and construction risks (cost overruns, completion delays)
- Avoid financing stress of building programs and rate case lag
- Avoid need to access capital markets and putting investor's capital at risk
- Enhance system and fuel supply flexibility and diversity
- Lower power costs and retail rates
- Minimize stranded investment
- Overall Improvement of competitive position

The Rating Agencies Look Beyond Financial Ratios

- Standard & Poor's: "The buy-versus-build debate must be viewed within the larger context of a utility's competitive position."

- Fitch: "Well-designed purchase programs that demonstrate good project diversity and favorable economics should not impact ratings."

- Duff & Phelps: "Financial ratios alone cannot be adjusted to adequately and fairly represent risk. One or even several ratios cannot tell the whole story. Thus, we analyze such key qualitative factors as the types of generation behind a company's purchased power contracts, the contract terms, the reliability of the power source, the cost of the power, and the need for the capacity."

Difficulties with Capital Structure Adjustments

- Cannot isolate purchased power impact on ratings from rating agencies' reports

- Creditworthiness and credit ratings are based on overall utility strength, not just financial ratios

- "Debt-equivalence" assigned by rating agencies may not result in a rating downgrade

- A change in rating may not harm ratepayers

- Current ROE methodologies are based on market prices, which already reflect risk

Options for Regulators

- Consider benefits of purchased power alongside the risks

- Consider risk-reward profile of a purchase strategy alongside alternative resource options

- Consider overall impact on ratepayers, not "debt-equivalence" in isolation

- Remove disincentives for purchasing, provide a level playing field for sellers, and let competitive forces work

- Consider alternatives to return-on-rate-base ratemaking to reward utilities for successful purchasing

Debt Leverage and Competitive Advantage

- No evidence that IPPs/EWGs enjoy a systematic cost-of-capital advantage over utilities

- Direct cost-of-capital comparisons between utilities and IPPs do not reflect substantive differences between corporate finance and project finance

- Regulators' concern should be overall cost of power and reliability of that power, not the cost of capital component in isolation

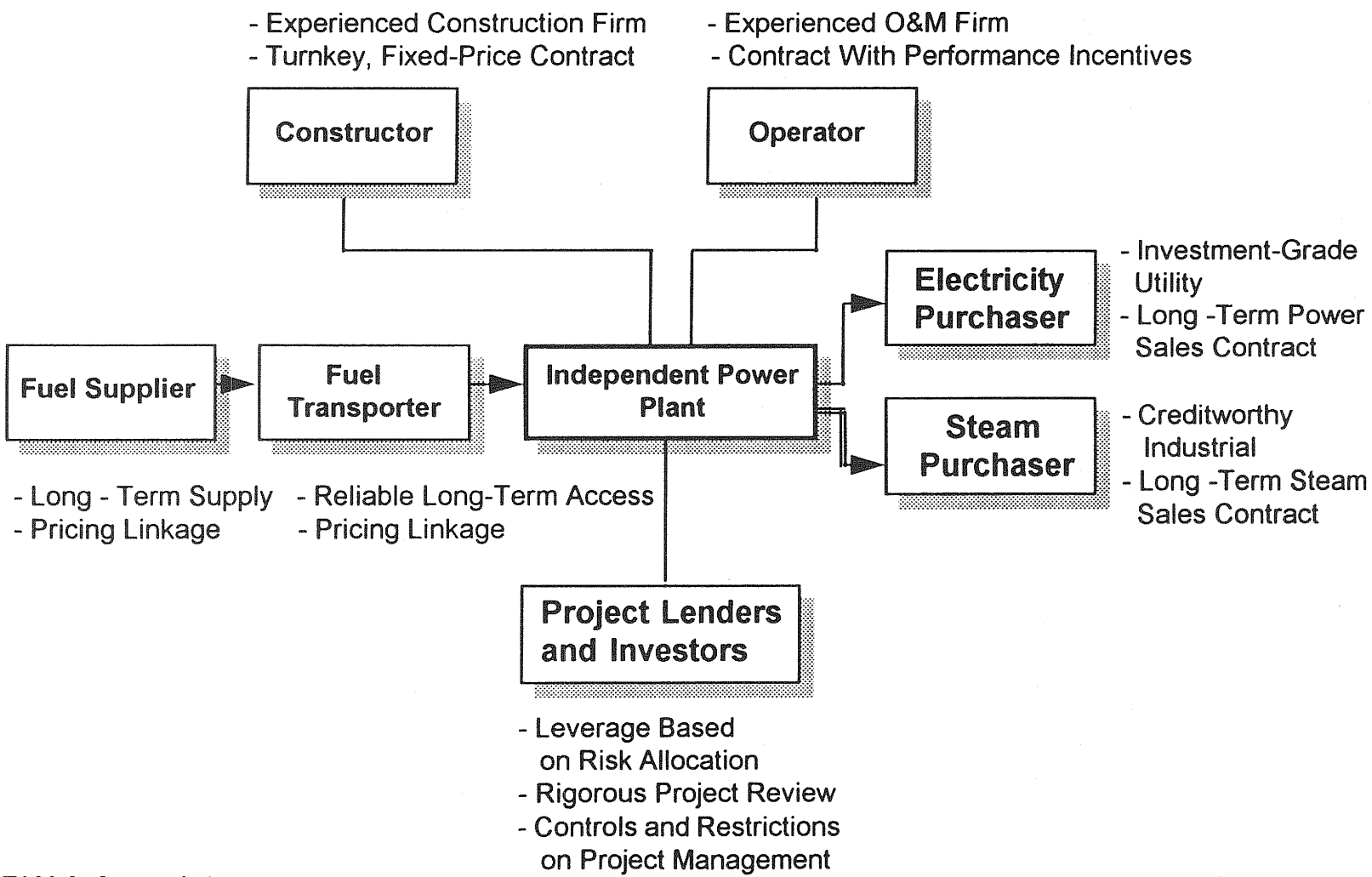
Project Finance Versus Corporate Finance

- Most concerns regarding leverage focus on IPPs that utilize project finance, which is structurally different from corporate finance

- Cost of capital and leverage for an IPP reflects risk allocation to project suppliers

- Project-finance lenders impose restrictions in exchange for debt leverage

Structure of a Project-Financed Power Project



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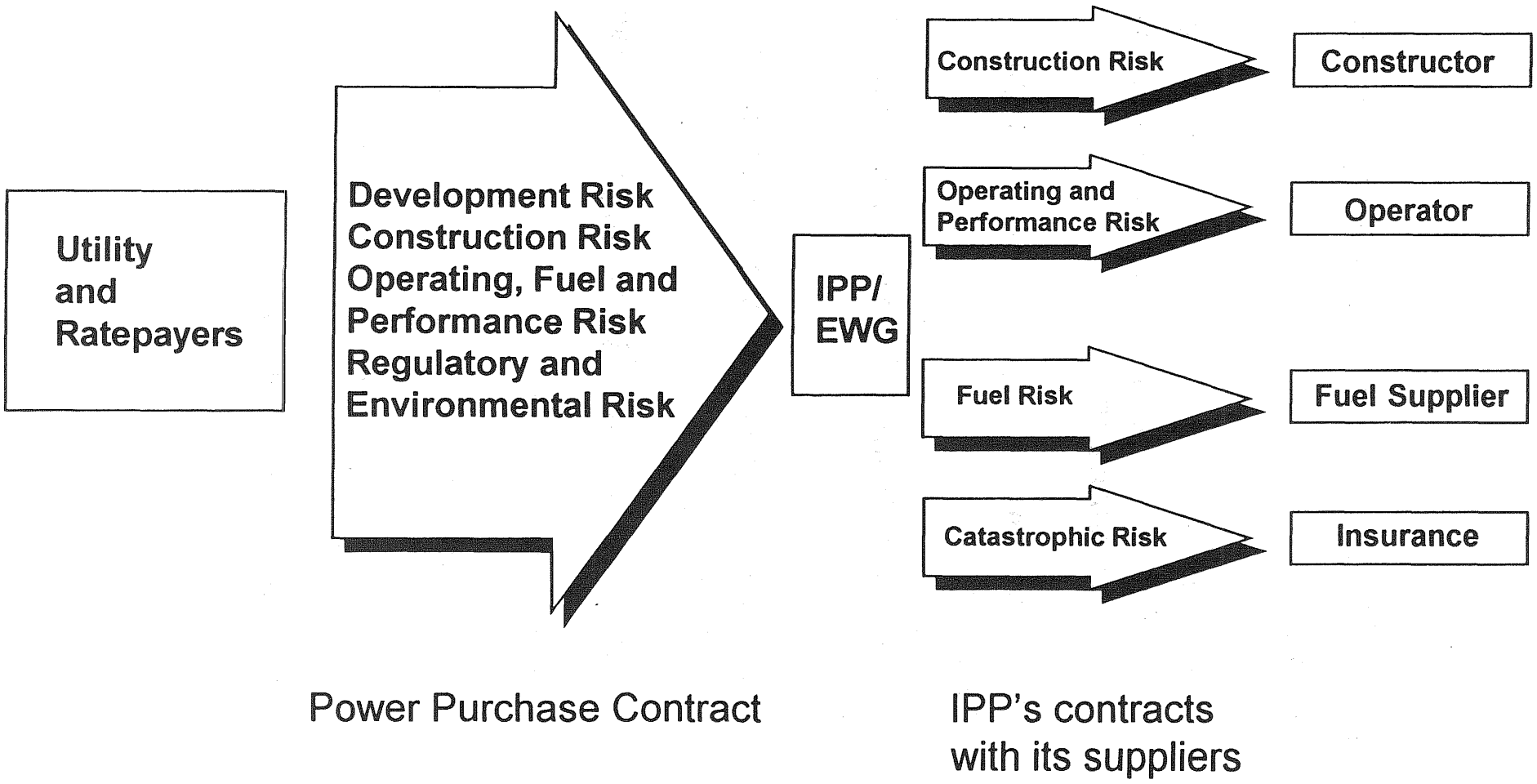
Transfer and Allocation of Risk



Power Purchase Contract

IPP's contracts with its suppliers

Lender Requirements in Exchange for Debt Leverage

- Rigorous review of project and contractual arrangements by lenders and independent consultants prior to construction
- Scheduled amortization of principal reduces leverage over time
- Shorter debt terms (15 years) than utility bonds (30 years)
- Independent engineering oversight during construction, operation
- Budget oversight and right to approve contract changes
- Insurance requirements
- Debt service and overhaul reserve funds
- Limits on owner's access to and use of cash flows
- Other restrictive covenants

Debt Leverage and Reliability

- No evidence that reliability is linked to debt levels

- 15 years of IPP purchases have shown IPPs to be as or more reliable than utility-owned generation

- Performance and reliability assurances are built into the terms of the power purchase contract

Studies of Reliability

- Office of Technology Assessment, 1989: No evidence to suggest that non-utility generators were less reliable than traditional utility power plants

- Gulf Coast Cogeneration Association, 1987: Survey of 3,126 MW of cogeneration in Texas: 96% availability, 84% capacity factor

- Pacific Gas & Electric, 1988: 1,621 MW of non-utility firm capacity operated at a 94.8% capacity factor

- Virginia Power, 1991: "The independent capacity already in service has had excellent reliability with availabilities in excess of 90%.

Source: National Independent Energy Producers

Summary

- Power Purchase Contracts and Cost of Capital
  - Power purchase contracts with performance standards are very different from debt obligations
  - Contract terms and regulatory treatment can reduce or eliminate "debt-equivalence"
  - Regulatory treatment should consider the benefits of purchased power, the utility's overall resource mix and competitive position, and impacts on ratepayers before making adjustment for "debt-equivalence"
- Debt Leverage Used by IPPs and EWGs
  - No evidence of competitive advantage due to ability to leverage
  - The financial markets effectively allocate risks and "regulate" the capital structures of EWGs and IPPs
  - Utilities and regulators should look to performance and reliability standards within the bounds of the purchase contract

CREDIT IMPACT OF PURCHASED POWER

PUBLIC UTILITY COMMISSION IMPLEMENTATION OF THE NATIONAL ENERGY POLICY ACT OF 1992

NATIONAL REGULATORY RESEARCH INSTITUTE

PORTLAND SEMINAR, JULY 16, 1993

CHERYL RICHER, DIRECTOR

STANDARD & POOR'S CORP.

I'd like to thank you for the opportunity to be here. My remarks today address the credit ramifications of a utility's decision to purchase power. The "buy vs build" debate will continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act. Although S&P, as well as other rating agencies, have been very vocal for the past several years in addressing the risks associated with purchased power, this legislation now requires regulators to consider the impact of purchasing on a utility's cost of capital. To the extent that purchasing negatively effects bond ratings, the resulting higher cost of capital translates into higher electric rates.

I would like to state up front, that a purchase strategy may in fact be less risky than building new capacity. Certainly, investor-owned utilities scared from the last baseload construction cycle would attest to that statement. However, the electric utility industry's entire approach to resource planning has undergone a radical transformation. It is becoming increasingly difficult to generalize about whether utility bondholders are better off if their utility buys, builds, or or conserves.

The most important point I can make here today, is that acquiring any resource involves risk. Having said that, I'd like to discuss the

benefits and risks specific to purchased power. Then I'll walk you through an example of the methodology S&P uses to evaluate the off-balance-sheet liability incurred by a utility that purchases. I'll conclude by briefly highlighting several ratings that have been impacted by purchases, and offer some suggestions to offset purchased power.

(SLIDE: BENEFITS OF PURCHASING POWER)

The benefits of purchasing can be quite compelling. Purchasing utilities avoid construction risk. They also avoid the associated financial stress caused by regulatory lag which is typical in a building program. Second, utilities that purchase power escape putting substantial amounts of capital at risk. There are many examples where utilities have written off or failed to fully earn a return on capital invested in plant.

Very importantly, the structure of a contract can transfer operating risk from the utility to the NUG. With a take-and-pay contract, the utility pays for power only if it is delivered. S&P believes that the risk of purchased power is materially reduced when a utility enters into this type of arrangement.

Next, purchased power may be cheaper. However, when evaluating the economics of purchasing you must also consider the cost to the utility of the additional off-balance-sheet leverage. Another non-economic benefit is diversification. Purchases may contribute to fuel supply diversity and flexibility. They may also enable the utility to stagger the timing of supply additions. As a consequence, the utility may be better positioned to adapt to uncertain future demand, and avoid stranded investment given the spectre of retail wheeling.

Regardless of whether a utility buys or builds, adding capacity means incurring risk. However, to the extent that there are any risks due to purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for risks assumed in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense. Some of the noteable regulatory disallowances of purchased power costs are the Tuscon Electric Power purchase from Century Power, the Gulf States purchase from Southern Co., and the Southern California Edison QF purchases from its affiliate Mission Energy. Last month, the court of appeals upheld the Minnesota Public Utilities Commission's decision to deny Interstate Power recovery of costs, tied to a purchased power

contract, deemed to be excess capacity.

Therefore, purchases are not risk free. When a utility enters into a long term purchased power contract with a fixed cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexiblity, and long term contractual commitments represent — at least in part — off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account to evaluate buy and build options on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. Our approach is unique because we fold our qualitative analysis into our quantitative methodology.

(SLIDE: DETERMINING THE POTENTIAL DEBT EQUIVALENT)

We begin by determining the potential debt equivalent. We do this by calculating the present value of the capacity payments over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense, which includes debt service,

depreciation, and a return on equity. We take the total fixed payment, as opposed to only the debt service portion, since the utility is obligated to pay the the entire amount. In most cases utilities provide us with the actual capacity payments. If unavailable, or where capacity and energy payments are not broken out -- such as in energy only contacts -- we'll estimate the capacity payment.

But we don't stop with the potential debt equivalent. We recognize that not all obligations have the same characteristics. Some are more debt-like than others.

(SLIDE: RISK SPECTRUM)

I can illustrate the difference in the relative debt characteristics of purchased power obligations by using the concept of a risk spectrum. A risk spectrum is simply a range from 0% to 100%. Obligations on the high end of the scale would be considered more firm, or debt-like, those on the low end, less firm. This spectrum is important because the place where an obligation falls on the scale -- or what we call the risk factor -- will determine what portion of the obligation S&P adds to a utility's

reported debt.

As you can see here, we have divided the risk spectrum into 3 segments. This is because various off-balance-sheet obligations have different risks. Sale/leasebacks of major generating facilities are viewed as virtual debt equivalents given their strategic importance and the "hell-or-high water" nature of lease commitments. Although a range is illustrated, we have typically applied a 100% risk factor to sale/leasebacks. Next, obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. Take-and-pay contracts are less firm because payments are conditional upon delivery of energy. The practical range of risk factors for take-and-pay performance contracts has narrowed to between 10% and 30%.

(SLIDE: DETERMINING THE RISK FACTOR)

Determining the risk factor reflects our analysis of the risks a utility incurs under a purchased power contract. This encompasses a qualitative analysis of market, operating, and regulatory risks. It also incorporates our evaluation of the extent to which these risks are borne

by the utility. The analysis is subjective, but not arbitrary. We evaluate each contract individually, or may lump contracts with similar attributes together. Some of the key factors under each broad risk category are shown on this slide. Depending on circumstances, risks will either be borne by the utility, or be shifted to ratepayers or the NUG.

Looking at the first subheading, lower risk factors would be applied if the power is economic and needed. It might seem odd to suggest that a utility would contract for uneconomic power it doesn't need. Unfortunately, several of the New York utilities find themselves furiously buying out NUG contracts, as both demand and avoided cost have fallen. Operating risks can be mitigated if plant performance is reliable, payment is conditional, and if the utility has some control over maintenance and dispatch. Regulatory risk is lowest when a contract is preapproved and capacity, as well as energy, payments are recovered through a fuel clause type mechanism. Also, a regulatory-out clause passes disallowance risk to the NUG.

If risks have not been mitigated in this manner, a higher risk factor would likely be utilized. In general, take-or-pay obligations are viewed as more onerous than take-and-pay because of the requirement to pay for

capacity whether or not energy is available. An extreme case would be a unit specific purchase of expensive nuclear capacity under a firm take-or-pay arrangement. Here the risk factor might be as high as 80%.

(SLIDE: CALC. DEBT EQUIVALENT)

I'll show you how these adjustments are made using the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Recall that we start by taking the present value of just the capacity payments, discounted at 10%. As you can see from this schedule, payments escalate through 1997, and then stabilize and extend through 2023. The net present value of these payments is $1.3 billion. Let's assume that after evaluating the contract we arrive at a 20% risk factor. We multiply $1.3 billion by 20% and get a debt equivalent of $265 million.

(SLIDE: ADJUSTMENT TO DEBT)

This slide shows the adjustment to ABC Power's capital structure. When we add $265 million to reported debt of $1.4 billion and recalculate the capital structure ratios, leverage increases to 58% from 54%.

(SLIDE: ADJUSTMENT TO INTEREST)

This slide illustrates that ABC Power's unadjusted pretax interest coverage for 1992 was 2.6 times. We calculate pretax interest coverage by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, we calculate an interest expense equivalent. The $265 million of debt is multiplied by a 10% interest rate to arrive at $27 million. When $27 million is added to both the numerator and the denominator, the ratio falls to 2.3 times.

The purchased power issue is somewhat complex, but we feel strongly that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. We combine a qualitative analysis with the traditional present value approach so that the adjustment to debt is understandable and useful. This is particularly helpful in the regulatory process, since our adjusted ratios are the ones we base our ratings on. S&P's policy and philosophy is to be as open about the rating process as possible.

Over the past few years, several ratings have been lowered due to

purchased power obligations. Examples are Virginia Electric Power Co., Boston Edison, Southern California Edison and Oklahoma Gas & Electric. But more pervasive are ratings which are lower than they might otherwise be owing to purchased power liabilities. We have revised many outlooks to Stable from Positive, and to Negative from Stable due to purchased power concerns. As a result, S&P anticipates further rating downgrades over the next couple of years. However, a lot will depend on how utilities and regulators respond to our analysis.

(SLIDE: OFFSETS TO PURCHASED POWER)

There are severalways utilities can offset purchased power liabilities, including higher returns on equity or higher equity components in the capital structure. Another possibility might be some type of incentive return mechanism. All of these methods would achieve the same purpose, which is to increase earnings and cash flow. This could restore adjusted financial ratios to where they were prior to calculations incorporating debt and interest equivalents.

As competition increases in the electric utility industry, we recognize that power supply strategies will grow more complex. And we

understand that a utility's purchased power obligations need to be evaluated in a broader framework than the one I have addressed.

The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance — and still find itself in trouble if its rates are not competitive.

Therefore, purchased power should be considered when selecting incremental resources. Indeed, purchasing may be the least expensive, and least risky strategy. But it is not risk free. S&P's methodology quantifies risk by explicitly recognizing the key qualitative factors of markets, operations, and regulation. We further analyze contracts to determine who is taking the risk: the NUG, the utility, or the ratepayer. The adjusted financials are useful in assessing relative risk between purchasing and non-purchasing utilities.

Benefits of Purchasing Power

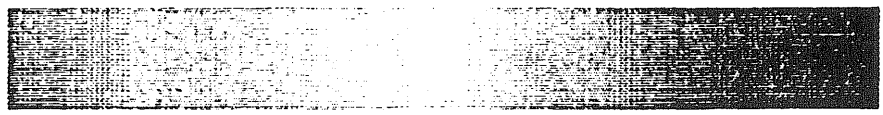
- Avoid Construction Risk & Financing Stress
- Avoid Putting Capital at Risk
- Transfer Operating Risk via Performance Standards
- Lower Power Costs
- Achieve Greater Supply Flexibility & Diversity
- Minimize Stranded Investment Risk

Determining The Potential Debt Equivalent

The Potential Debt Equivalent Equals the Present Value of Future Capacity Payments Discounted at 10%

- The Entire Capacity Payment is Used in the Calculation, Not Just the Part Representing Debt Service
- Actual Capacity Payments are Used as Set Out in the Contracts
- Capacity Payments are Estimated Where Capacity and Energy Cost Components are Not Readily Apparent

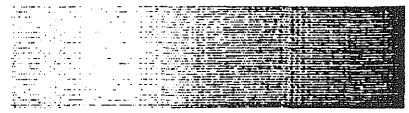
Risk Factors For Various Off Balance Sheet Obligations



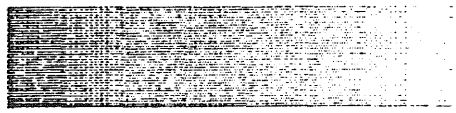
0% 100%

Sale/Leaseback (non-capitalized)

Take-Or-Pay



Take-And-Pay



Determining The Risk Factor

The Risk Factor Chosen is a Function of a Subjective (Not Arbitrary) Analysis of Qualitative Risks

Market	Need for Power
	Economics
Operating	Performance Standards
	Reliability
	Dispatchability
	Control Over Maintenance
	Flexibility and Diversity
Regulatory	Preapproval
	Regulatory Recovery Mechanisms
	Regulatory Out Clause

ABC Power Company

Calculation of Debt Equivalent
(Millions $)

	Annual Capacity Payment	
1993	115	
1994	120	
1995	125	
1996	130	
1997	135	
"	"	
"	"	NPV of Capacity Payments Discounted at 10% = $1.3 Billion
"	"	
2023	1300	$1.3 Billion x 20% Risk Factor = $265 Million

ABC Power Company

Adjustment to Capital Structure
(Millions $ Year-End 1992)

	Orig. Capital Structure		Adj. Capital Structure		
	$	%	$	%	
Debt	1,400	54	1,400	49	} 58
Adjustment to Debt	--	--	265	9	
Preferred Stock	200	8	200	7	
Common Equity	1,000	38	1,000	35	

ABC Power Company

Adjustment to Pretax Interest Coverage
(Millions $ Year-End 1992)

		Orig. Pretax Int. Cov.	Adj. Pretax Int. Cov.
Net Income	120		300
Income Taxes	65	300	+ 27
Interest Expense	115	115 = 2.6x	115 = 2.3x
Pretax Available	300		+ 27

Interest Associated with Adjusted Debt = $265 Million x 10%
= $27 Million

Offsets To Purchased Power Liabilities

- Higher Common Equity Component
- Higher Authorized ROE
- Incentive Return Mechanism

SECTION 712 ISSUES: RISK IDENTIFICATION, ALLOCATION AND COMPENSATION

Prepared for

NRRI CONFERENCE ON IMPLEMENTATION OF
THE ENERGY POLICY ACT OF 1992
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July 20, 1993
(edited August 3, 1993)

Overview

- Section 712 requires consideration of:
  - Effects of long-term purchased power on a utility's cost of capital;
  - Whether high Exempt Wholesale Generator ("EWG") debt ratios provide an unfair advantage or threaten reliability;
  - Whether Commissions should implement advance approval procedures;
  - Whether Commissions should require fuel supply adequacy assurance.
- Focus here is on the first two points. (Note that the second point refers only to EWGs, but it's hard to see how to accomplish it without learning something about all non-utility generators ("NUGs"); therefore, this presentation makes no distinction.)
- Today's basic message: free lunches in financial markets are few and far between; better decisions will result if this fact is kept firmly in mind, and both ratepayers and shareholders will end up better off.

"The Law of Conservation of Risk"

- Building electric generating plants is intrinsically a very risky business:
  - It requires large sums of capital,
  - Sunk into extremely illiquid assets,
  - For which the marginal operating cost is, relative to other industries, a very small fraction of total cost.
- Such circumstances can be a recipe for financial disaster, as both rate-regulated and non-rate-regulated companies can attest. Such ventures therefore are not normally undertaken without some contract, explicit or implicit, to transfer a manageable share of the risk to the customers who will benefit from the venture's existence.
  - A legally protected service franchise area is an example of one such contract.
  - A power purchase contract is another.
- For any given project, there will be a core set of business risks that depend on the project and not on who owns it. Such risks cannot be eliminated; at most, they can be transferred (with varying degrees of reliability) by contract. For emphasis, I refer to this as "the law of conservation of risk."

Questions for Sensible Risk Management

- For the core business risks, two essential questions arise:
  - Who is the best party to bear the risk?
  - How much will it cost the other parties to shift the risk to this party?
- All else equal, the best party to bear the risk is the party in the best position to manage it. For example, the party operating the plant is the natural choice to bear plant performance/reliability risks.
- However, this only can work in the long run if the financial and institutional arrangements permit that party to expect fair compensation for bearing the risk in question.
- NUGs are an attractive idea in part because investor-owned utilities today are in a poor position to bear plant construction risks (because there has turned out to be more downside than upside under cost-of-service regulation, while NUGs may be able to strike a more balanced bargain).
- The utility may often be a better party to bear some of the financial risks (for reasons discussed below), but to decide whether this is actually true, it is vital not to fool oneself into believing that the mere shifting of a plant to a NUG's books (instead of a utility's) creates a free lunch.

Risk and Least Cost Planning

- Power purchase contracts can be evaluated in a number of ways (*e.g.*, as part of centralized least-cost planning, through competitive bids for power of specified characteristics, etc.). Regardless of the mechanism, the ultimate goal is the least-cost way to satisfy the energy service needs of customers.

- The terms of the proposed contract with a NUG will set forth *many* of the costs, which then can be evaluated relative to other NUGs and other options (utility-built supply, DSM, etc.). However, it would be a mistake to assume that *all* relevant costs are monetized in the contract's terms.

- True identification of the least-cost option also requires identification of the costs to ratepayers and/or shareholders of any risks that the purchased power agreement ("PPA") shifts to the utility.

- Otherwise, the unpriced risk shifts do indeed create an unfair advantage for NUGs and a non-least-cost resource plan for ratepayers.

An Example of Risk Transfer and Least Cost Planning

- Consider an example:
  - The same plant may be built either by a financially sound utility or a NUG, which in either case will be dedicated to use in the utility's service territory and operated on a fully integrated basis; the only difference is what corporation owns it.
  - Investment bankers accurately report that the NUG can finance the plant at 80 percent debt at a much lower interest rate than the utility would have if it were financed 80 percent by debt.
  - Does this mean the NUG gives ratepayers a free lunch in the form of lower capital costs?
- The answer is obviously "no":
  - The business risk of the venture is the same regardless of who owns it, by the way the example was constructed.
  - The mere existence of a different name printed on the pieces of paper that represent stock ownership cannot possibly be of sufficient worth to bondholders to induce a substantial discount in the cost of debt.
- What these facts have to imply is a risk transfer from the NUG to the utility through the PPA.

An Example of Risk Transfer and Least Cost Planning (continued)

- How much the risk transfer costs varies with the specific facts, for example:
  - How much risk remains with the NUG?
  - How much debt and/or other purchased power contracts does the utility already have?
  - How do the business risks (*i.e.*, the risks with no debt at all) of the plant in question compare with those of the utility's existing operations?
- The following figures explore two ways to price risk transfer as the share of NUG-supplied power increases: Figure 1, increase the utility's allowed return on equity; or Figure 2, increase its hypothetical regulatory equity ratio. The assumptions are:
  - The underlying business risk of the proposed plant is identical to the average business risk of the utility's existing operations;
  - The risk that remains with the NUG (*i.e.*, that is *not* transferred to the utility through the purchased power agreement) corresponds to one of three levels relative to the overall risk of the utility: (1) NUG's overall risk = NUG's debt risk (*i.e.*, high risk transfer); (2) an intermediate case; and (3) NUG's overall risk = utility's overall risk (*i.e.*, no risk transfer).

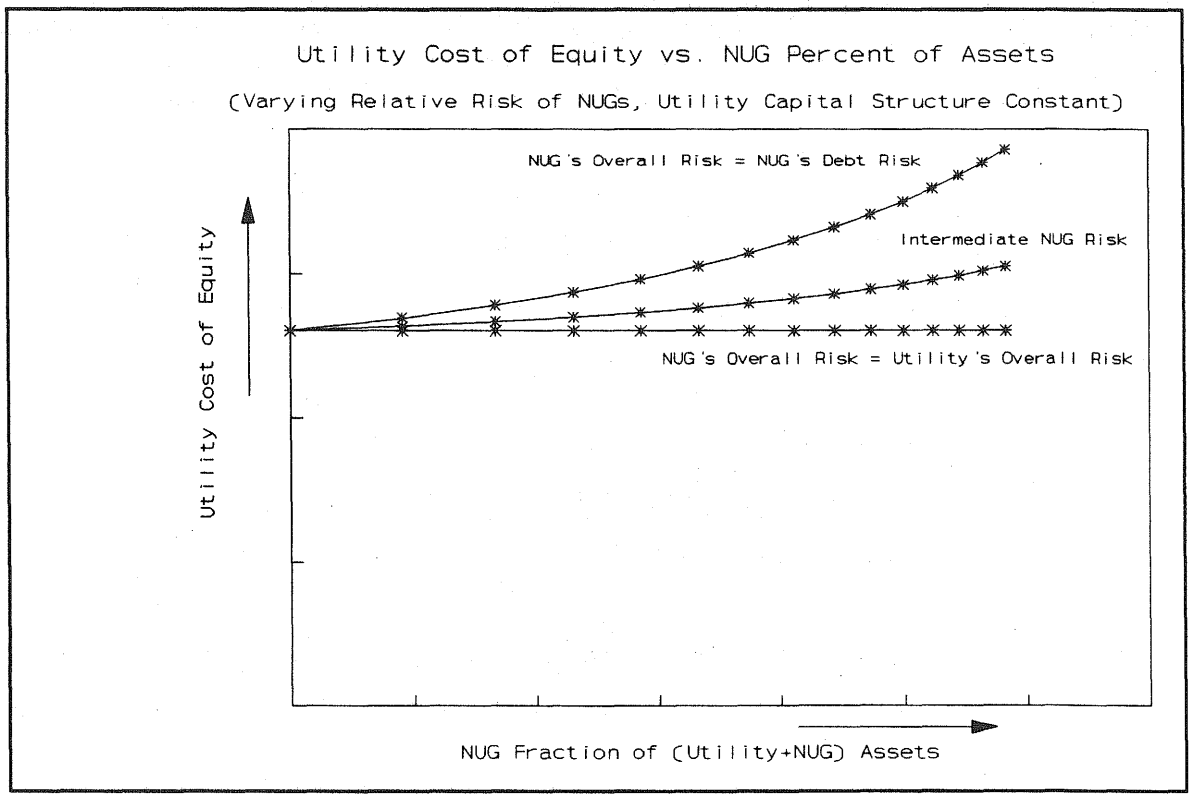

Figure 1

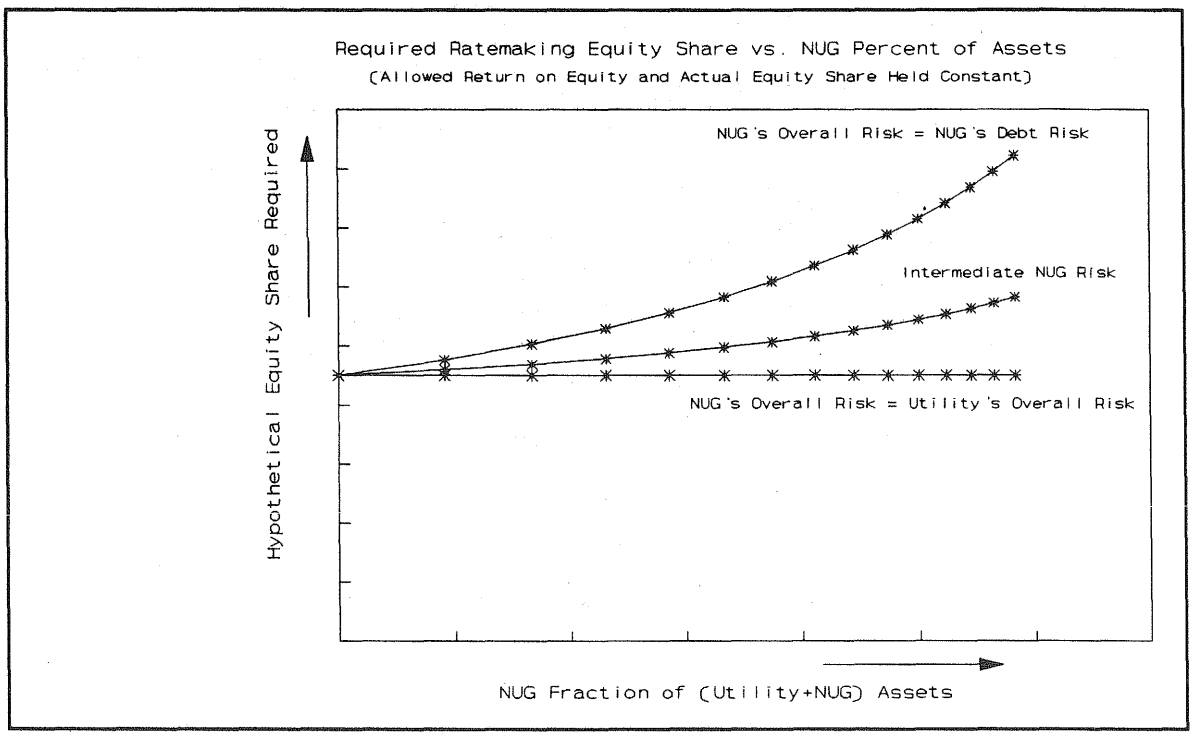

Figure 2

Some Other Observations

- All else equal, bond ratings are lower when the proportion of purchased power is higher. But managers and regulators had better worry more about purchased power risks than the rating agencies do, because ratepayers and shareholders both stand between bad outcomes and bondholders. Utility bondholders are normally the *last* in line to be harmed, if purchased power contracts go sour.

- Even though no free lunch underlies high NUG debt ratios, it may still make sense to have the utility -- with fair compensation -- bear some of the NUG's financial risk:

  - This reduces the odds of NUG bankruptcy, thereby reducing the expected deadweight costs of financial distress.
  - It also may improve reliability, by lowering the odds that the operator will be tempted to cut corners.

- In practice, risks cannot be allocated perfectly by contracts. Consider the economic discussions of "efficient breach" of a contract: if breaching is cheaper than paying, in the modern world, contracts seem to get breached.

- For this reason, an explicit "regulatory out" clause in PPAs has a lot to recommend it; it permits explicit compensation for the *de facto* regulatory option to force renegotiation of contracts that turn out later to be "too" costly. If these options turn out to have too high a price, it may signal the need for today's regulators to work harder to bind their successors.

Conclusions

- If fair compensation is possible, it is efficient to have risks borne by those best able to control them; if that party cannot be compensated fairly, however, other parties may need to bear that risk instead.

- In general, the core business risks of a proposed project may be different from those of a utility's other operations, so the no-risk-shift cost of capital of a NUG may differ from a utility's. However, there are no free lunches in financial markets; if a deal looks like it's giving customers something for nothing, either:
  - The no-risk-shift business risk is for some reason far lower than the utility's, or
  - There's an unpriced risk transfer embodied somewhere in the PPA.

- The first explanation should always be viewed with suspicion, if the goal is minimizing ratepayer costs:
  - If the NUG's core business risk really is that much lower, high NUG debt levels should be possible without any financial guarantees by the utility (institutional issues aside).
  - Conversely, if financial guarantees are required for the NUG to raise capital, they represent a valuable commitment by the utility and/or its ratepayers, which has a cost.
  - Moreover, if the utility's cost of debt is affected, its ratepayers and/or its shareholders are affected even more.

- Therefore, anything that claims to be a least-cost plan that includes long-term purchased power has to include an explicit cost somewhere in the calculation for the value of the risk transfers to ratepayers and/or shareholders that are implicit in the purchased power agreement.

REMARKS TO
THE NATIONAL REGULATORY RESEARCH INSTITUTE CONFERENCE ON
THE ENERGY POLICY ACT OF 1992

by

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presented at the

National Seminars on the
Public Utility Commission Implementation of
The Energy Policy Act of 1992

Portland, Oregon

July 15 and 16, 1993

COMPARISON OF RISK

IPP Contracts ("buy")
versus
Utility Construction ("build")

	BUY	BUILD
Demand Risk	even	even
Construction Risk	lower	higher
Operating Risk	even to lower	even to higher
Regulatory Risk	lower	higher
TOTAL FINANCIAL RISK	**lower**	**higher**

HOW COMPETITION REDUCES IPP COSTS

	IPP	UTILITY	REDUCTION IN COST/KWH
TURNKEY CONSTRUCTION	Turnkey	Cost-plus	Avoids Overruns
BIDDING CAPITAL & FUEL	Profit Incentives	Pass-through	5% Below Uutility Costs
CONSTRUCTION TIME (coal)	33 Months	48 Months In Capacity Costs	10% Reduction
AVAILABILITY			
Coal	88-90%	81%	5-7% Reduction
Gas	94-96%	87-92%	In Capacity Costs
NEW TECHNOLOGIES	AFB,IGCC	PC	Increased Efficiencies, Environmental Progress
COST OF CAPITAL	10.2%	9.8%	4% Above Utility
TOTAL COSTS	**85-95% of "Avoided Cost"**	**Avoided Cost**	**5-15%**

UTILITY VS IPP CAPITAL CHARGE RATE

- **Despite leveraging an IPP's capital charge rate is higher than a regulated utility's.**

	UTILITY	IPP
WACC	9.1%	8.5%
Debt Life	35	15
Reserve Fund	N/A	Annual Deposit: 1/2 of Pre-Tax Cash Flow Maximum Balance: 1/2 of Annual Debt Payment
Book Life	35	35
Tax Life	20	20
Discount Rate	10.75%	10.75%
Income Tax Rate	34%	30%
Property Tax Rate	4%	4%
Inflation	4.5%	4.5%
CAPITAL CHARGE RATE	**9.76%**	**10.17%**

UTILITY VS IPP COST OF CAPITAL

- **Leveraging can lower an IPP's cost of capital, even though debt and equity costs more for IPP's.**

	UTILITY	IPP
Debt Fraction	50.0%	80.0%
Equity Fraction	50.0%	20.0%
Interest Rate	9.5%	10.5%
Equity Return	12.0%	15.0%
WACC	**9.1%**	**8.5%**

UTILITY VS. IPP FINANCING COSTS

- **Despite leveraging, an IPP's financing costs are higher than a regulated utility's.**

	UTILITY	IPP
Cost of Capital	9.1%	8.5%
Debt Life	35 years	15 years
Reserve Funds	no	yes
Financing Cost (Capital Charge Rate)	9.8%	10.2%

MITIGATING REGULATORY RISK FOR IPP'S

- Good IPP contract terms
- Competitive procurement
- Least Cost Plan/Integrated Resource Plan
- PUC-approved contract
- Section 210 of PURPA (for QF's)

SECTION 712 OF EPAct

by

Robert E. Burns
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The National Regulatory Research Institute

presented at the

National Seminars on the
Public Utility Commission Implementation of
The Energy Policy Act of 1992

Portland, Oregon -- July 15 and 16, 1993

and

Indianapolis, Indiana -- July 19 and 20, 1993

PURPOSES OF TITLE I OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

To encourage:

(1) Conservation of energy supplied by electric utilities

(2) The optimization of the efficiency of use of facilities and moreover by electric utilities, and

(3) Equitable rates to electric consumers

Sec. 101. Purposes.

The purposes of this title are to encourage--

(1) conservation of energy supplied by electric utilities;

(2) the optimization of the efficiency of use of facilities and resources by electric utilities; and

(3) equitable rates to electric consumers.

Sec. 111. Consideration and Determination Respecting Certain Ratemaking Standards.

(a) CONSIDERATION AND DETERMINATION.--Each State regulatory authority (with respect to each electric utility for which it has rate-making authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. For purposes of such consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of such consideration and determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law.

(b) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.--

(1) The consideration referred to in subsection (a) shall be made after public notice and hearing. The determination referred to in subsection (a) shall be--

(A) in writing,

(B) based upon findings included in such determination and upon the evidence presented at the hearing, and

(C) available to the public.

(2) Except as otherwise provided in paragraph (1), in the second sentence of section 112(a), and in sections 121 and 122, the procedures for the consideration and determination referred to in subsection (a) shall be those established by the State regulatory authority or the nonregulated electric utility.

(c) IMPLEMENTATION.--(1) The State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law--

(A) implement any such standard determined under subsection (a) to be appropriate to carry out the purposes of this title, or

(B) decline to implement any such standard.

(2) If a State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility declines to implement any standard established by subsection (d) which is determined under subsection (a) to be appropriate to carry out the purposes of this title, such authority or nonregulated electric utility shall state in writing the reasons therefor. Such statement of reasons shall be available to the public.

(3) If a State regulatory authority implements a standard established by subsection (d)(7) or (8), such authority shall--

(A) consider the impact that implementation of such standard 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

(B) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.

(d) ESTABLISHMENT.--The following Federal standards are hereby established:

(7) INTEGRATED RESOURCE PLANNING.--Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

(8) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.--The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investment in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

(9) ENERGY EFFICIENCY INVESTMENT IN POWER GENERATION AND SUPPLY.--The rates charged by any electric utility shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution. In considering regulatory changes to achieve the objectives of this paragraph, State regulatory authorities and nonregulated electric utilities shall consider the disincentives caused by existing ratemaking policies, and practices, and consider incentives that would encourage better maintenance, and investment in more efficient power generation, transmission and distribution equipment.

(10) CONSIDERATION OF THE EFFECTS OF WHOLESALE POWER PURCHASES ON UTILITY COST OF CAPITAL; EFFECTS OF LEVERAGED CAPITAL STRUCTURES ON THE RELIABILITY OF WHOLESALE POWER SELLERS; AND ASSURANCE OF ADEQUATE FUEL SUPPLIES.--(A) To the extent that a State regulatory authority required or allows electric utilities for which it has ratemaking authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

(ii) whether the use by exempt wholesale generators (as defined in section 32 of the Public Utility Holding Company Act of 1935) of capital structures which employ proportionally greater amounts of debt than the capital structures of such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply; and

(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

(C) Notwithstanding any other provision of Federal law, nothing in this paragraph shall prevent a State regulatory authority from taking such action, including action with respect to the allowable capital structure of exempt wholesale generators, as such State regulatory authority may determine to be in the public interest as a result of performing evaluations under the standards of subparagraph (A).

(D) Notwithstanding section 124 and paragraphs (1) and (2) of section 112(a), each State regulatory authority shall consider and make a determination concerning the standards of subparagraph (A) in accordance with the requirements of subsections (a) and (b) of this section, without regard to any proceedings commenced prior to the enactment of this paragraph.

(E) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall consider and make a determination concerning whether it is appropriate to implement the standards set out in subparagraph (A) not later than one year after the date of enactment of this paragraph.

(b) TIME LIMITATIONS.--(1) Not later than two years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by section 111(d).

(2) Not later than three years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by section 111(d).

(a) REVENUE AND RATE OF RETURN.--Nothing in this title shall authorize or require the recovery by an electric utility of revenues, or of a rate of return, in excess of, or less than, the amount of revenues or the rate of return determined to be lawful under any other provision of law.

(b) STATE AUTHORITY.--Nothing in this title prohibits any State regulatory or nonregulated electric utility from adopting, pursuant to State law, any standard or rule affecting electric utilities which is different from any standard established by this subtitle.

Sec. 301. Purposes; Coverage.

(a) PURPOSES.--The purposes of this title are to encourage--

(1) conservation of energy supplied by gas utilities;

(2) the optimization of the efficiency of use of facilities and resources by gas utility systems; and

(3) equitable rates to gas consumers of natural gas.

For purposes of this title--

(9) The term "integrated resource planning" means, in the case of a gas utility, planning by the use of any standard, regulation, practice, or policy to undertake a systematic comparison between demand-side management measures and the supply of gas by a gas utility to minimize life-cycle costs of adequate and reliable utility services to gas consumers. Integrated resource planning shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and shall treat demand and supply to gas consumers on a consistent and integrated basis.

(a) ADOPTION OF STANDARDS.--Not later than 2 years after the date of the enactment of this Act (or after enactment of the Energy Policy act of 1992 in the case of standards under paragraphs (3) and (4) of subsection (b)), each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility shall provide public notice and conduct a hearing respecting the standards established by subsection (b) and, on the basis of such hearing, shall--

(2) adopt the standards established by paragraphs (2), (3) and (4) of subsection (b) if, and to the extent, such authority or nonregulated utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law.

(b) ESTABLISHMENT.--The following Federal standards are hereby established:

(3) INTEGRATED RESOURCE PLANNING.--Each gas utility shall employ, in order to provide adequate and reliable service to its gas customers at the lowest system cost. All plans or filings of a State regulated gas utility before a State regulatory authority to meet the requirements of this paragraph 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 requirement that the plan be implemented after approval of the State regulatory authority. Subsection (c) shall not apply to this paragraph to the extent that it could be construed to require the State regulatory authority to extend the record of a State proceeding in submitting reports to the Federal Government.

(4) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.--The rates charged by any State regulated gas utility shall be such that the utility's prudent investment 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 investment 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.

(c) PROCEDURAL REQUIREMENTS.--Each State regulatory authority (with respect to each gas utility for which it has ratemaking authority) and each nonregulated gas utility, within the two-year period specified in subsection (a), shall adopt, pursuant to subsection (a), each of the standards established by subsection (b) or, with respect to any such standard which is not adopted, such authority or nonregulated gas utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

(d) SMALL BUSINESS IMPACTS.--If a State regulatory authority implements a standard established by subsection (b)(3) or (4), such authority shall--

(1) consider the impact that implementation of such standard 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

(2) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.

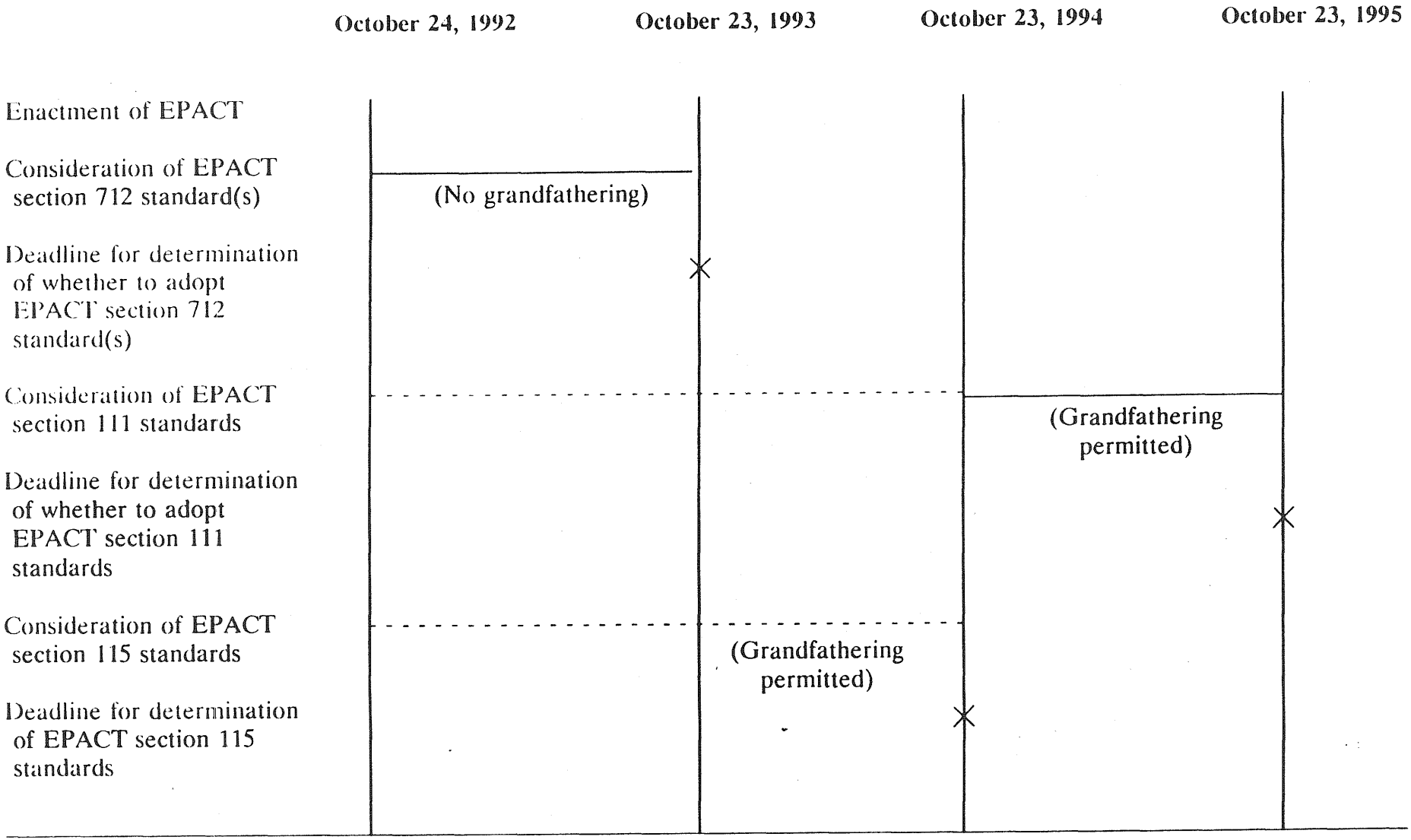
TABLE 2

EPACT SECTION 712 STANDARD ON THE PURCHASE OF LONG-TERM WHOLESALE POWER

Section 712's Four Evaluations	Primary Topic(s)	Affected Wholesalers	Primary Issues	The Purposes of PURPA Title I are to encourage:
712 (i)	Cost of capital and retail rate impacts	All wholesalers	- Risk allocation between IOUs and ratepayers - Revenue assurance to wholesalers and host utility	(1) Conservation of energy supplied by electric utilities, (2) Optimization of the efficient use of electric utility facilities and (3) Equitable rates to electric consumers
712 (ii)	Debt/equity ratio and reliability	EWGs only	- Revenue assurance to host utility - Supply assurance to host utility	
712 (iii)	Contract preapproval	All wholesalers	- Revenue assurance to host utility and wholesaler	
712 (iv) (Precondition for (iii))	Fuel supply adequacy (Precondition for contract preapproval)	All wholesalers	- Revenue assurance to host utility - Supply assurance to host utility	

Source: Authors.

TIME LINE



Consideration Periods:

Mandatory _____

Optional - - - - - - - -