

SCOMM

109:2

FILE CONTENTS PAGE:

August 6, 1998 Agenda
August 6, 1998 Committee Packet
July 30, 1998 Additional items for Committee Packet
August 5, 1998 letter from Gail Chambers, Weidner Investment Services
August 3, 1998 letter from Max Lowe, Regal Alaskan Hotel
August 6, 1998, "Alaska Electric Utility Restructuring", Donn T. Wonnell, Counsel
For Municipal Light & Power
August 6, 1998, Aurora Power Presentation
Aurora Power Resources' Application to APUC to Establish a Pilot Program
August 6, 1998, testimony of Robert A. Wilkinson, Copper Valley Electric
August 6, 1998, "Electric Industry Restructuring", ARECA Report
August 6, 1998, testimony of Bruce Scott, Matanuska Electric Association
Written statement of Mike Kelly, Golden Valley Electric, dated July 1998
August 6, 1998, testimony of Eugene Bjornstad, Chugach Electric Association
July 29, 1998 news article, "Utilities Lick Wounds After Encounter
With Sharp-Toothed Power Traders"
July 16, 1998 DRAFT, Solicitation and Request for Proposals
July 10, 1998 news article, "Deregulation puts electricity reliability in question"
August 7, 1998, "Basic Perspectives on the Electric Power Industry", Municipal
Light & Power

ALASKA STATE LEGISLATURE

Joint Committee on Electric Utility Restructuring

Senate Members:

Sentor Bert Sharp, Co-Chairman

Senator Loren Leman

Senator Robin Taylor

Senator Al Adams

Address: 119 N. Cushman, #201

Fairbanks, AK 99701-2879

Telephone: (907) 452-7885

FAX: (907) 456-4221



House Members:

Rep. Norman Rokeberg, Co-Chairman

Rep. Alan Austerman

Rep. Fred Dyson

Rep. John Davies

Address: 116 W. 4th Avenue, #640

Anchorage, AK 99501-2133

Telephone: (907) 258-8191

FAX: (907) 258-2916

AGENDA

August 6, 1998

- 10:00 a.m. Opening Remarks from Co-Chairmen
- 10:15 a.m. CEA (Eugene Bjornstad, General Manager)
- 10:40 a.m. ARECA (Eric Yould, Executive Director)
- 11:05 a.m. APUC ➤
- 11:30 a.m. ML&P (Meera Kohler, General Manager)
- 11:55 a.m. - 1:15 p.m. - Lunch break
- 1:15 p.m. Announcements
- 1:30 p.m. MEA (Wayne Carmony, General Manager, or Bruce Scott, Consumer Relations)
- 1:55 p.m. GVEA (Mike Kelly, President & CEO)
- 2:20 p.m. Aurora Power (Mary Ann Pease, Vice President)
- 2:45 p.m. IBEW (Gary Brooks, Business Manager, or Ann Hayes) ↑
- 3:05 p.m. 4-Dam Pool (Robert Wilkinson) ↗
- 3:15 p.m. - 3:30 p.m. - Afternoon break (coffee and snacks at Glacier Brewhouse)
- 3:35 p.m. Committee Discussion
- 5:00 p.m. Adjourn

➤ = no written testimony submitted

ALASKA STATE LEGISLATURE

Joint Committee on Electric Utility Restructuring

Senate Members:

Sentor Bert Sharp, Co-Chairman

Senator Loren Leman

Senator Robin Taylor

Senator Al Adams

Address: 119 N. Cushman, #201

Fairbanks, AK 99701-2879

Telephone: (907) 452-7885

FAX: (907) 456-4221



House Members:

Rep. Norman Rokeberg, Co-Chairman

Rep. Alan Austerman

Rep. Fred Dyson

Rep. John Davies

Address: 716 W. 4th Avenue, #640

Anchorage, AK 99501-2133

Telephone: (907) 258-8191

FAX: (907) 258-2916

COMMITTEE PACKET FOR AUGUST 6, 1998 MEETING

1. Copy of enabling resolution
2. April 30, 1997 AG opinion (NOTE: **If you read nothing else, please read this. Rep. Rokeberg**)
3. October 10, 1997 ARECA letter to Rep. Rokeberg
4. Articles from July 1998 **Governing**:
 - a. "Power Politics"
 - b. "An Electrifying Breakthrough"
5. "Power Business" from September 29, 1997 **Fortune** magazine
6. Information from Patricia M. DeMarco at Anchorage Economic Development Corporation:
"Transition Cost Issues for US Electricity Utilities"
7. Columbia Steel Case (111 F.3d 1427)
8. APUC Order, Docket U-97-201, Order #3
9. NCSL information
 - a. "Standing the Electricity Industry on Its Head", **State Legislatures**, March 1997, with accompanying fax memorandum updating it.
 - b. Glossary of Terms from NCSL Web Site.

DEPARTMENT OF LAW**OFFICE OF THE ATTORNEY GENERAL**

April 30, 1997

TONY KNOWLES, GOVERNOR**PLEASE REPLY TO:**

☒ 1031 WEST 4TH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501-1994
PHONE: (907) 269-5100
FAX: (907) 276-3697

☐ KEY BANK BUILDING
100 CUSHMAN ST., SUITE 400
FAIRBANKS, ALASKA 99701-4879
PHONE: (907) 451-2811
FAX: (907) 451-2846

☐ P.O. BOX 110300-DIMOND COURT HOUSE
JUNEAU, ALASKA 99811-0300
PHONE: (907) 465-3600
FAX: (907) 465-6735

The Honorable Norman Rokeberg
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

The Honorable Jerry Sanders
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

Re: APUC Authority

Dear Representatives Rokeberg and Sanders:

At the House Labor and Commerce Committee hearing on HB 235 on April 16, 1997, you asked Robert A. Lohr, Executive Director of the APUC for a report on the Commission's authority to issue an electric utility a certificate to compete with an existing utility, and to impose conditions that protect the public from "cream-skimming." Because these questions involve a review of legal authorities, the Attorney General's Office, as legal counsel for the Commission, was asked to prepare this response.

The APUC Has Authority Under Current Law to Issue Certificates Allowing Competition in Electric Utility Service.

A. *Statutory Certification Authority*

The Alaska legislature has required a public utility to obtain a certificate of public convenience and necessity from the Alaska Public Utilities Commission before operating or receiving compensation for providing the utility commodity or service. AS 42.05.221(a).¹ Through this statute, the

¹ SECTION 42.05.221. CERTIFICATES REQUIRED. (a) A public utility may not operate and receive compensation for providing a commodity or service without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will

4:05 p.m.
MAY 01 1997

legislature placed control over entry into the utility business in the Commission's hands. Nothing in this statute suggests that the certificates granted by the Commission are exclusive, or that the Commission's authority to grant a certificate is restricted or limited if the applicant would compete with an existing utility.

AS 42.05.241 establishes procedural and substantive guidelines for the Commission in exercising its authority to grant certificates. This statute provides:

A certificate may not be issued unless the commission finds that the applicant is fit, willing and able to provide the utility services applied for and that the services are required for the convenience and necessity of the public (emphasis added)

In compliance with this statute, the Commission must examine the question of whether the public needs the additional service when it considers granting a competing certificate. The Commission cannot grant the competing certificate unless, after examining the question, it finds that the public convenience and necessity do require the competing service.

The term "public convenience and necessity" cannot support an argument that competing certificates are prohibited. Interpreting this term, one court looked back to previous decisions and said:

The court has stated that the "public convenience and necessity" standard allows the department to exercise wide discretion to take into account a broad range of factors in making the determination whether it has been met. Almeida Bus Lines, Inc. v. Department of Pub. Utils., 203 N.E. 2d 556 (1965). Holvoke St. Ry. v. Department of Pub. Utils., 198 N.E. 2d 413 (1964). Newton v. Department of Pub. Utils., 160 N.E.2d 108 (1959) (all of which discussed the propriety of using the value of competition as a basis for making a "public convenience and necessity" finding).

Zachs v. Department of Public Utilities, 547 N. E. 2d 28 at 32 (Mass. 1989). (State reporter citations omitted).

Therefore, although it requires the question to be addressed and a finding made, AS 42.05.241 gives the Commission the policy-making authority to grant a competing certificate, including

require the service. Where a public utility provides more than one type of utility service, a separate certificate of convenience and necessity is required for each type. A certificate must describe the nature and extent of the authority granted in it, including, as appropriate for the services involved, a description of the authorized area and scope of operations of the public utility. . . . (emphasis added)

The Honorable Norman Rokeberg

April 30, 1997

Page 3

a competing electric utility certificate, if the Commission decides that the public will benefit from competing utility service.

B. Natural Monopoly Theory

It is true that in the past the Commission has not issued certificates authorizing competitive provision of electrical service. This long-standing policy is not based on lack of authority or on any legal restriction prohibiting the Commission from issuing a competitive utility certificate. The non-competitive policy is based on an economic theory widely accepted in the past, but now subject to question (or already rejected) in policy debates all over the United States and in some foreign countries as well. The economic theory was that utilities, including electric utilities, are natural monopolies and should have exclusive service territories because competition would mean wasteful duplication of the capital investment in facilities required to provide the service.

As discussed above, the natural monopoly theory is not formalized in Alaska's statutory scheme, and therefore no statutory change is required before the Commission can consider whether the public convenience and necessity require any competing certificate to be issued. The Commission has authority to change its monopoly policy in granting certificates.

The natural monopoly theory is also not formalized in the legal concept of a certificate. In Alaska, a series of court decisions resulted from competition between electrical utilities in the 1960's and 1970's. These cases involved competition between REA cooperative electric utilities certificated by the Commission, and municipally owned utilities operating under statutory authority. Before 1970, the municipal utilities were not required to obtain certificates from the Commission.

In the first of these cases, the Alaska Supreme Court rejected the argument that a certificate granted by the Commission was an exclusive right to provide service in the specified service area. It is arguable that this ruling only addressed the situation of competition from an uncertificated utility operating under a municipality's statutory authority. Nevertheless, it is clear that the court rejected the argument that the natural monopoly theory must lead to the conclusion that a certificate is an exclusive right to serve a particular area. Homer Electric Association v. City of Kenai, 423 P.2d 285 at 288-289, n. 16. (1967). See also, Chugach Electric Association v. City of Anchorage, 426 P. 2d 1001, 1003 (1967).

In these decisions, the court recognized that the effect of holding that a utility certificate was not exclusive could be uneconomic duplication of facilities. The court urged the legislature to fix this problem. See Homer, 423 P. 2d at 290; Chugach, 426 P.2d at 1004-05. In response the legislature adopted

The Honorable Norman Rokeberg

April 30, 1997

Page 4

AS 42.05.221(d).² This provision, while making explicit the Commission's authority to eliminate undesirable duplication of facilities, is carefully drafted not to require the Commission to eliminate all competition. This statute directs the Commission to eliminate the competition only if the Commission finds 1) that there is competition, and 2) that the competition is not good for the public. Like AS 42.05.241, AS 42.05.221(d) clearly leaves the door open for a policy-making determination that competition between electrical utilities may be good for the public.

C. Longstanding Interpretations

Finally, the Commission has in the past interpreted its statutes to give it authority to issue competing certificates when it concluded that competition was in the public interest, and the legislature has apparently agreed. In interpreting a statute, the court will give some weight to a long-standing agency interpretation. Nat. Bank of Alaska v. State, Dept of Rev., 642 P.2d 811 at 815 (Alaska 1982). The APUC has granted competing certificates for refuse collection utilities: (Re Claude Bailey d/b/a Valley Refuse, et al, 7 APUC 97 (1985); Re Wasilla Refuse, Inc., 8 APUC 106 (1987); for radio common carriers, (RE Competition and Deregulation of Radio Common Carriers as Public Utilities, 5 APUC 86 (1982)); and for water utilities (Re Eagle Utilities, Inc., 7 APUC 548 (1986). For telecommunications utilities, statutory directives (state and federal) now require the Commission to grant competing certificates. In adopting a mandate for competition in long distance telephone service (AS 42.05.800-AS 42.05.890 , § 2 ch 93 SLA 1990), the Alaska legislature did not think that the underlying statutory scheme for certification needed amendment before the Commission had authority to grant competing certificates.

² SECTION 42.05.221. CERTIFICATES REQUIRED. ...

(d) In an area where the commission determines that two or more public utilities are competing to furnish identical utility service and that this competition is not in the public interest, the commission shall take appropriate action to eliminate the competition and any undesirable duplication of facilities. This appropriate action may include, but is not limited to, ordering the competing utilities to enter into a contract that, among other things, would:

- (1) delineate the service area boundaries of each in those areas of competition;
- (2) eliminate existing duplication and paralleling to the fullest reasonable extent;
- (3) preclude future duplication and paralleling;
- (4) provide for the exchange of customers and facilities for the purposes of providing better public service and of eliminating duplication and paralleling; and
- (5) provide such other mutually equitable arrangements as would be in the public interest.

(emphasis added)

The Honorable Norman Rokeberg

April 30, 1997

Page 5

II. The Commission Has Some Authority to Prevent Cream-skimming.

When competition in utility service is permitted, it is predictable that competitors will seek to serve the most profitable customers. The competing utilities may be less willing to serve smaller users, typically residential and small commercial customers. The result may be that service deteriorates while costs rise for those customers. The practice of targeting service only to the most profitable customers is called "cream-skimming." Existing statutes, including AS 42.05.221(d),³ AS 42.05.241⁴, AS 42.05.271,⁵ and the Commission's general powers, AS 42.05.141⁶, give the Commission some authority to deal with

³ See page 4.

⁴ SECTION 42.05.241. CONDITIONS OF ISSUANCE. A certificate may not be issued unless the commission finds that the applicant is fit, willing and able to provide the utility services applied for and that the services are required for the convenience and necessity of the public. The commission may issue a certificate granting an application in whole or in part and attach to the grant of it the terms and conditions it considers necessary to protect and promote the public interest including the condition that the applicant may or shall serve an area or provide a necessary service not contemplated by the applicant. The commission may, for good cause, deny an application with or without prejudice. (emphasis added)

⁵ SECTION 42.05.271. MODIFICATION, SUSPENSION OR REVOCATION OF CERTIFICATES. Upon complaint or upon its own motion the commission, after notice and opportunity for hearing and for good cause shown, may amend, modify, suspend, or revoke a certificate, in whole or in part. Good cause for amendment, modification, suspension or revocation of a certificate includes

(1) the requirements of public convenience and necessity;
(2) misrepresentation of a material fact in obtaining the certificate;
(3) unauthorized discontinuance or abandonment of all or part of a public utility's service;
(4) wilful failure to comply with the provisions of this chapter or the regulations or orders of the commission; or
(5) wilful failure to comply with a term, condition, or limitation of the certificate. (emphasis added)

⁶ SECTION 42.05.141. GENERAL POWERS AND DUTIES OF THE COMMISSION. (a) The Alaska Public Utilities Commission may do all things necessary or proper to carry out the purposes and exercise the powers expressly granted or reasonably implied in this chapter, including

(1) regulate every public utility engaged or proposing to engage in such a business inside the state, except to the extent exempted by AS 42.05.711;
(2) investigate, upon complaint or upon its own motion, the rates, classifications, rules, regulations, practices, services and facilities of a public utility and hold hearings on them;
(3) make or require just, fair and reasonable rates, classifications, regulations, practices, services and facilities for a public utility;

The Honorable Norman Rokeberg

April 30, 1997

Page 6

cream-skimming problems. However, because of limitations within these statutes or their general nature, the Commission's authority may not reach all variations of cream-skimming problems that may arise.

The discussion below shows how these statutes provide Commission authority to protect the public against cream-skimming, and discusses the limitations.

AS 42.05.221(d). Where the Commission finds competition exists and is not in the public interest, this statute authorizes the Commission to take action to "eliminate the competition and any undesirable duplication of facilities." This statute seems to contemplate a remedy that would eliminate the competition, not a remedy that would seek to make competition serve the public interest. For example, if an appropriate cream-skimming remedy may be to order a competitor in a concentrated market to also serve a remote community, this statute does not seem to provide that authority.

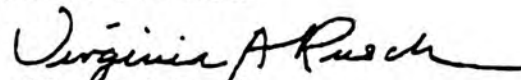
AS 42.05.241. This statute gives the Commission broad authority to impose conditions needed to protect the public when it grants a certificate. The Commission can attach to the grant of a certificate the terms and conditions it considers necessary to protect the public interest. One common remedy against cream-skimming is specifically authorized in this statute--the Commission can require a certificate applicant to provide a service that the applicant does not seek to provide. The language also clearly authorizes other remedies the Commission may devise at the time a certificate is granted. However, if the need for a condition to prevent cream-skimming does not become apparent until after the certificate is granted, this statute may not help.

AS 42.05.271. This statute is quite broad, and, along with the Commission's general powers, AS 42.05.141, arguably provides authority to address cream-skimming by requiring a utility to provide service to neglected customers. However, in the past, Commission orders have been challenged on the basis that the Commission's statutory authority is not "explicit," resulting in costly litigation over the extent of the Commission's "implied" authority.

Very truly yours,

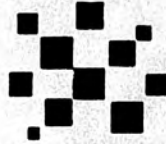
BRUCE M. BOTELHO
ATTORNEY GENERAL

By:



Virginia A. Rusch
Assistant Attorney General

VAR:jem



Anchorage Economic Development Corporation
The Center of Opportunity

July 21, 1998

Representative Norman Rokeberg
Alaska State Legislature
P.O. Box 221721
Anchorage, AK 99502-1721

RE: Electric Utility Restructing

Dear Norm:

I'm enclosing some information I thought might be of use to you. Please call if I can do anything to assist you with the process.

Sincerely,

Patricia M. DeMarco, Ph. D.
President

Enclosures

TRANSITION-COST ISSUES FOR US ELECTRICITY UTILITIES¹

Eric Hirst, Lester Baxter, and Stan Hadley

Oak Ridge National Laboratory, Oak Ridge, Tennessee 37831-6206;
email: Hirstea@ornl.gov

KEY WORDS: electricity, regulation, competition, finances, economics

ABSTRACT

The US electric-utility industry is in the midst of major changes. These changes include deintegration of the industry and substantial increases in competition. A major consequence of these changes is the exposure of transition costs. These costs, which amount to \$100–\$200 billion nationwide, reflect the differences between regulated prices for electricity generation and the prices that might occur in fully competitive power markets. The large financial stakes, equivalent to nearly the total value of US electric-utility common stock, guarantee controversy. Debates occur over transition-cost amounts; analytical and market methods to estimate these costs; the assets and liabilities to include in such calculations; the assumptions used in developing these estimates; approaches that can be used to offset some of these costs; the allocation of the remaining costs among utility shareholders, different classes of retail customers, independent power producers and other wholesale suppliers, and taxpayers; and appropriate cost-recovery mechanisms.

CONTENTS

1. BACKGROUND	120
2. THE ECONOMICS OF TRANSITION COSTS	124
3. TRANSITION-COST ALLOCATION	127
3.1 Pro-Recovery Arguments	127
3.2 Anti-Recovery Arguments	129
3.3 Government Decisions	130

¹The US Government has the right to retain a nonexclusive royalty-free license in and to any copyright covering this paper.

4. ESTIMATION APPROACHES	134
4.1 Market Valuation	135
4.2 Administrative Valuation	136
4.3 Criteria to Assess Methods	138
5. FACTORS THAT AFFECT TRANSITION-COST ESTIMATES	140
5.1 Regulatory Factors	142
5.2 Wholesale-Market Factors	142
5.3 Accounting Factors	143
5.4 Summary	143
6. STRATEGIES TO ADDRESS TRANSITION COSTS	144
6.1 Market Actions	144
6.2 Depreciation Options	147
6.3 Rate-Making Actions	148
6.4 Utility Cost Reductions	149
6.5 Summary	150
7. CONCLUSIONS	151

1. BACKGROUND

Transition costs (TCs) are the potential monetary losses that electric-utility shareholders or other parties might experience because of structural changes in the electricity industry. These are not new costs, but rather sunk costs and future obligations that may not be recoverable in competitive electricity markets. In rough terms, transition costs are based on the difference between regulated retail electricity prices for generation services and the competitive-market price of power. The retail-monopoly franchise that investor-owned utilities enjoy today permits them, with approval from their state regulatory commission, to charge customers for all the costs of producing and delivering electricity. In a competitive electricity market, the frequent interaction of buyers and sellers, rather than regulators, will set prices. If these prices are below embedded costs, then transition costs will occur.

Transition costs are a much more serious problem in the United States than in other countries that have restructured their electricity industry. Unlike other countries in which governments own most of the electric-system facilities, private companies account for the vast majority (about 75%) of US electricity production, investment, sales, and revenues; government- and consumer-owned utilities account for the remaining one fourth. Also, the boundaries between state and federal jurisdiction complicate treatment of TCs in the United States.

Consider a simple example of transition costs. The total costs of generation include capital (depreciation, interest payment on bonds, return on common equity, and taxes); fuel; and operations and maintenance (O&M). Traditionally, these costs are reviewed by state regulatory commissions. If approved, these costs are then incorporated into the rates that the utility is allowed to charge its customers. In this example, the utility has capital costs that are equivalent to 2.1 cents per kWh, fuel costs of 1.6 cents per kWh, and O&M costs of 0.7 cents

per kWh, leading to a total embedded cost of generation of 4.4 cents per kWh. By comparison, the market price of power in this case is only 2.5 cents per kWh. These numbers suggest that the utility would lose the equivalent of 1.9 cents per kWh if it sold electricity to its retail customers at competitive market prices.

Failure to fully and fairly consider such costs could be a major impediment to industry restructuring. Studness (1) argues that "Recovery of stranded investment is clearly the central point of contention in the debate over utility competition.... Utilities argue that the 'regulatory compact' entitles them to full recovery; customers claim that no such entitlement exists." The Federal Energy Regulatory Commission (FERC) in its final rule on open-access, nondiscriminatory transmission service, devoted 187 pages of its 780-page order to TCs (2). FERC noted that "the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment."

Transition costs can include four classes of costs:

1. assets, primarily in expensive power plants and excess generating capacity;
2. liabilities, primarily in power-purchase contracts, fuel-supply contracts, and deferred income taxes;
3. regulatory assets (whose value is based on regulatory decisions rather than on market forces), including deferred expenses for power plants and costs for demand-side management programs that regulators allow utilities to place on their balance sheets; and
4. public-policy programs, including tax collection, environmental compliance beyond that required by law, demand-side management programs paid for by all customers, special programs for low-income customers, and support for energy research and development. Unlike the other three categories, the costs in this category are current, not sunk.

Several entities have estimated the TC amounts that individual utilities might face. For example, Moody's Investors Service (3) analyzed data for 116 utilities (representing more than 80% of the assets of all US investor-owned utilities). They estimated that TCs could amount to \$133 billion, almost 90% of shareholder equity. (All monetary values are in 1994 dollars.) All told, 34 of the 116 utilities included in Moody's analysis had potential transition costs in excess of their equity (Figure 1). Oak Ridge National Laboratory (4) developed national after-tax estimates for investor-owned utilities that ranged from \$16 billion to \$268 billion, and suggested that the most plausible range is \$72-\$104 billion. Prudential developed a TC estimate of about \$30 billion (5).

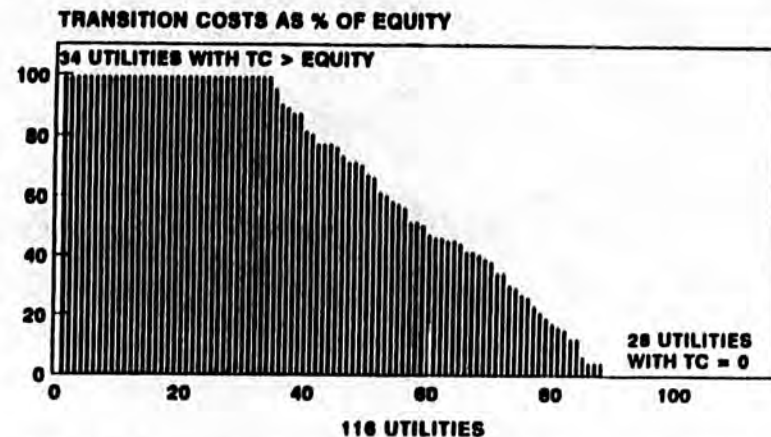


Figure 1 Moody's estimates of transition costs relative to shareholder equity for 116 US investor-owned electric utilities.

Resource Data International (RDI) estimated a nationwide TC of \$184 billion (6). Of this total, \$134 billion is accounted for by investor-owned utilities, \$29 billion by municipal utilities, and \$20 billion by cooperatives. (Most of the other estimates we reviewed dealt only with investor-owned utilities.) Utility-owned generating units account for the largest share of the \$184 billion, \$65 billion. RDI calculates the nationwide TC for nuclear units at almost \$79 billion, offset by a negative TC for fossil and hydro units of \$15 billion. Regulatory assets account for \$45 billion of TC, power-purchase contracts with nonutility generators for \$38 billion, power-purchase contracts with other utilities for \$49 billion, and sales contracts for a negative \$11 billion. California, New York, and Texas together account for more than 40% of US transition costs, according to this analysis.

RDI also identified several utilities that had below-market costs, leading to a total negative TC of \$54 billion. In general, these utilities had little exposure to nuclear plants and had many other generators with embedded costs below market prices. These utilities also had few regulatory assets and had large potential gains from their power-sales contracts. States with zero or negative TCs include Utah, Tennessee, Oregon, Oklahoma, Washington, Minnesota, Kentucky, Wisconsin, Iowa, and Montana.

The estimates, which were developed by different entities, at different times, with different metrics and assumptions, vary. For example, the estimate by Prudential Securities is considerably lower than the other national estimates cited above. This difference is at least partially caused by Prudential's inclusion of fewer utilities in its analysis, its assumption that only future revenues from

commercial and industrial customers are at risk, and its use of a higher market price for electricity that includes capacity. Studies that use similar assumptions, even though their specific estimation approaches differ, often yield more similar results. The correlation coefficient (r) between estimates of utility transition costs from Oak Ridge National Laboratory and from Moody's study is 0.84, for example, for the 111 companies in both analyses.

Our review of these estimates of transition costs leads to several conclusions. First, although the methods used and results obtained differ across these analyses, they generally suggest that the potential losses associated with TCs are substantial. Second, they show that the losses are unevenly spread among both utilities and regions. Third, the range of recent estimates of the nationwide losses is much smaller than the range estimated a few years ago; this reduction in range is a consequence, we believe, of growing agreement on what assets and liabilities should be considered in calculating TCs. Fourth, despite the narrowing of recent national estimates, the results obtained, even for the same situation, can differ substantially depending on the perspective of the entity making the estimates, the analytical approach used, and the assumptions made. Figure 2 shows six estimates of the TCs that Central Power & Light might face (7). These estimates differ by a factor of more than three, the utility's estimate being the highest and the large industrial customers' estimate the lowest.

A full treatment of TCs would consider appropriate ways to calculate TCs; estimates of the TC amounts for individual utilities, states, regions, and the United States as a whole; strategies to mitigate these amounts; allocation of the remaining TCs among utility shareholders, different classes of customers, independent power producers, and taxpayers in general; and the mechanisms

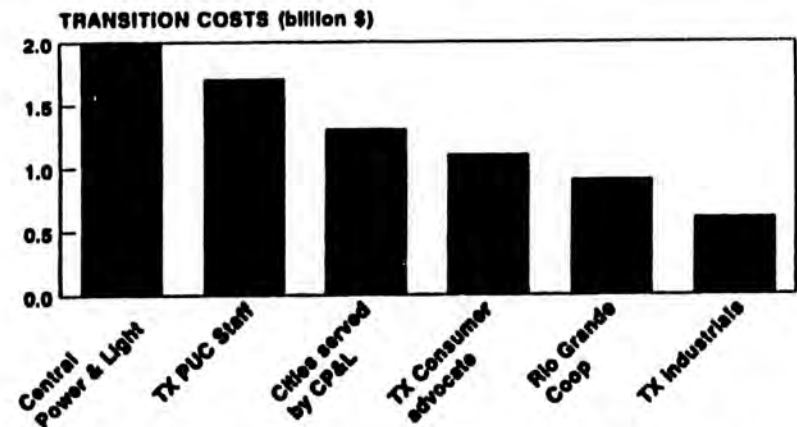


Figure 2 Alternative estimates of the transition costs faced by Central Power & Light Company.

used to allocate or recover TCs. Section 2 presents an economic framework for the definition and discussion of TCs. Section 3 discusses policy and legal issues associated with the allocation of remaining TC amounts among various stakeholders. Section 4 discusses various analytical and market-based approaches to calculating TCs. Section 5 analyzes the sensitivity of TC results to changes in input assumptions, primarily to identify the critical factors in determining TC amounts. Section 6 discusses several strategies to recover or reduce transition costs. Section 7 summarizes our key findings. See (8) for additional details.

2. THE ECONOMICS OF TRANSITION COSTS

Traditionally, state regulators have used cost-of-service methods to establish retail rates. Under cost-of-service rate making, regulators give utilities the opportunity to recover all the prudent costs the utility incurs to satisfy the demand for electricity services within its franchise area. These costs include the return of (depreciation) and return on investments in utility plant (generation, transmission, and distribution) and the ongoing costs of fuel, power-purchase, and O&M. Many of these costs are considered sunk or embedded because they have already been incurred or reflect obligations to incur future costs. (Costs that are not sunk include short-term or avoidable fuel and power-purchase costs.) In contrast, prices in a competitive market more closely reflect marginal production costs, that is, the additional costs that suppliers incur to meet current and future demand.

Transition costs are most likely to occur when utility rates are above market prices for generation services. Under these circumstances, customers will be motivated to purchase from lower-cost sources, or utilities will be motivated to reduce rates. Rose presents a simple comparative model that illustrates the implications these circumstances have for transition costs (9). Figure 3 presents a situation for a hypothetical utility and an alternative power supplier. To simplify, we remove from this example the costs for transmission, distribution, and other nongeneration costs. Under most circumstances, the utility will be able to recover these costs because it will remain the only supplier of such services (i.e. restructuring proposals continue to envision the transmission and distribution of electricity as monopoly services). These costs will probably be recovered through access fees or through regulated rates for transmission and distribution services.

The MCG_u curve in Figure 3 represents the utility's marginal cost of generation and its price for generated electricity under the new competitive regime. The figure shows the right portion of the marginal cost curve when the utility's economies of scale are exhausted. The average cost of generation (ACG_u) is also the utility's price curve under the existing embedded-cost pricing regime.

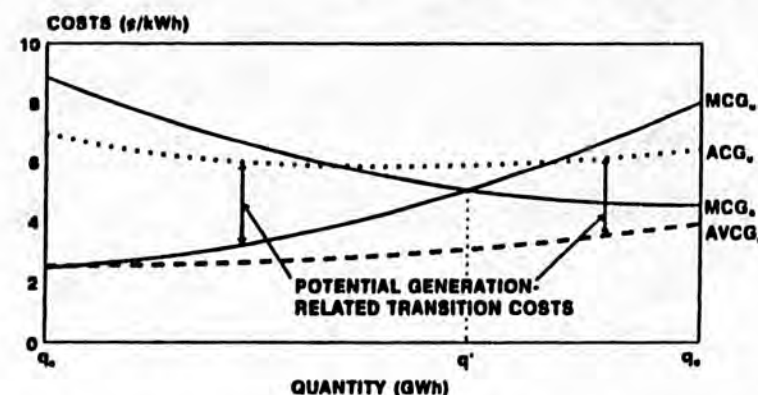


Figure 3 Comparative static model of utility transition costs. This figure is simplified to show certain features of TCs. Most importantly, the figure represents a single small increment in time, perhaps a single hour, and does not reflect the complex relationships among utility costs, prices, and market prices over longer periods. Also, the figure implies that the utility sells its generation output at marginal cost. If this was the case, the utility will also be unable to recover some or all of its average fixed generation costs when MCG_u is less than ACG_u , as depicted on the left side, unless the market price for generation is greater than ACG_u .

In this example, the utility's marginal generation costs exceed its average generation costs only at high levels of production. The utility will only recover its fixed generation costs when prices equal or exceed its average generation costs. The utility's average variable cost of generation curve ($AVCG_u$) lies below its average generation cost curve. The difference between these two curves reflects the utility's average fixed costs of generation. The final curve depicts a competitor's marginal cost of generation (MCG_a). This curve, drawn with its origin at the right axis, assumes a generally flat slope over the initial range of output and then gradually increases. This curve can also represent the market price of electricity from multiple suppliers. Finally, the horizontal axis reflects different combinations of utility and competitor power supplies that meet an incremental demand for electricity. At the right-most point (q_u), all the demand is met by the utility, while at the left-most point (q_a) all the demand is met by the competitor. Point q^* represents the optimal combination of generation supply for this level of demand, the point where utility marginal costs and supplier costs are equal.

The difference between the utility's average generation costs and its average variable generation costs to the right of q^* are unrecoverable when generation services are provided by the competitor. This area includes the utility's average fixed generation costs. These latter costs are the TCs faced by the utility, assuming that the utility does not sell this potential output in another market. The

utility does not face any other generation costs when it is no longer supplying generation. Thus, the utility does not incur the portions of average generation costs related to variable costs, such as fuel and variable O&M, when it is not generating electricity. The utility's average fixed generation costs remain however, even when a competitor is generating the electricity. Thus, Figure 3 depicts the amount of TCs when the utility previously met all demand (q_0) but now generates only the optimal quantity (q^*). In addition, the difference between the utility's average generation costs and its marginal generation costs to the left of q^* is unrecoverable when generation services are priced at the utility's marginal cost.

We make several observations about TCs based on this economic perspective:

1. The presence and amount of TCs depend on the marginal generation costs for the utility and alternative supplier and on the relationship between the utility's marginal and average generation costs.
2. TCs can occur when a competitor's marginal generation costs are below the utility's marginal generation costs or when the utility's marginal generation costs are less than its average generation costs.
3. When the competitor's marginal generation costs are less than the utility's, then the potential generation-related transition costs equal the utility's average fixed generation costs (if the utility does not sell this electricity in another market).
4. When the competitor's marginal generation costs are less than the utility's, then the potential generation-related transition costs equal the utility's average generation costs minus the market price for generated electricity (if the utility does sell this electricity in another market).
5. Reductions in the utility's marginal generation costs will reduce the probability of economic bypass to competitive suppliers and, thus, of incurring transition costs, except when such reductions increase the amount that marginal costs are below average costs.
6. Properly structured competitive markets will motivate utilities to reduce generation costs and thereby reduce their TCs over time.
7. Competitive markets will define the market price for electricity (which will equal the marginal cost of electricity generation if the market is efficient) and the level of TCs.
8. As a result, transition costs are not static but will change over time, depending on changes in the competitive market price for electricity and the utility's generation costs.

One additional complication that some utilities face is that not all generation costs are included in today's average cost of generation. Today's average costs reflect sunk costs and historical obligations that extend into the future. Two important historical obligations, long-term power-purchase contracts and fuel-supply contracts, are included in today's average costs. Two other future costs may not be fully included and are not avoidable by utilities or society at large. These are the costs associated with the decommissioning of nuclear power plants and the environmental mitigation or restoration costs associated with past utility actions. Because these two classes of costs are largely unknowable today, it is not possible to accurately include them in today's TC estimates.

3. TRANSITION-COST ALLOCATION

Perhaps the most important, and difficult, TC issue facing regulators is deciding how to allocate nonmitigable transition costs among the various parties. Not surprisingly, debates on this issue at the state and federal level have been quite heated. In part, this controversy is a consequence of the large dollar amounts at stake. The controversy may also result from the fact that this issue has to be decided primarily on the basis of policy rather than science. In other words, science has little to contribute to legislative and regulatory decisions concerning the allocation of these costs. Opinions differ strongly on whether utilities are entitled to full recovery of their TCs. Large industrial customers, consumer advocates, and some regulators argue that there is no constitutional entitlement to the recovery of such costs; indeed, these costs should be subject to the same types of prudence and used-and-useful criteria that commissions have long applied to utility actions. On the other hand, many utilities argue that the Takings Clause of the US Constitution (Fifth Amendment) requires full compensation for such costs; they suggest that these costs were incurred with the approval of regulators.

3.1 Pro-Recovery Arguments

The primary proponents of the argument that utilities are entitled to and should receive full recovery of their transition costs are, not surprisingly, the investor-owned utilities themselves. Baumol, Joskow, & Kahn offer arguments, based on economics and regulatory policy, supporting shareholder recovery of TCs (10). They suggest that increasing economic efficiency should be the primary objective of restructuring the electricity industry. They argue that, when properly structured, competitive markets are more likely to increase economic efficiency than are regulated markets. These efficiency gains will involve both productive efficiency (i.e. providing goods at minimum cost) and allocative efficiency (setting prices correctly, based on marginal costs). The authors argue

that unless TCs are properly addressed, the efficiency gains from competition may be eroded. The authors' primary conclusion is that equity and productive efficiency considerations support a policy of full TC recovery for utility shareholders. On the equity side, the authors believe that shareholders have not previously received compensation from their allowed equity returns for the risk they now face of not being able to recover their investments because of changes in government policy. Further, they note that utilities incurred most of these costs with the full approval, and sometimes at the mandate, of regulators. Should shareholders fail to recover TCs, the efficiency consequences include distortion of competition between utilities and alternative suppliers, extension of the time to competition, and the possibility of increased capital costs to the electricity industry. The authors indicate that TC recovery can be compatible with efficient competition when the recovery mechanism is properly structured. To ensure that competition between rival suppliers is based on efficiency, the authors recommend that the costs of historical obligations be assessed from all customers who have benefited from those obligations.

Rowe & Graening develop legal arguments to justify full payment to utility shareholders of TCs (11). On the basis of the Takings Clause, they argue that the government may require private property owners to cede rights to that property to serve the public good, but it must then ensure just compensation to the owner. Paying transmission owners the embedded costs of their transmission system is irrelevant, in part because transmission is an integral part of a utility's larger generation, transmission, and distribution system. Allowing others to use a utility's transmission system adversely affects the value of a utility's generation assets, and for this reduction in value the utility is entitled to full compensation. Rowe & Graening write:

The integration of distribution, transmission and generation into a tightly woven commodity delivery system performs as a whole. One part severed from the others can drastically reduce the property's comprehensive value. If the wires are severed from the generation, their loss will destabilize the value of the overall property. The result would be akin to a tricycle with only two wheels broken and going nowhere.

Kolbe & Tye argue that the rates of return historically allowed by state public utility commissions (PUCs) were insufficient to compensate shareholders for the risk associated with retail competition (12). For utility shareholders to have been automatically compensated by regulators for the risk of TCs, the allowed rate of return would have had to have been much higher than the actual cost of capital. Further, the increment above the cost of capital is very case specific (i.e. it depends on the particular situation facing that utility). Kolbe & Tye believe it is unlikely that PUCs were performing the necessary company-specific calculations to determine the authorized ROE.

3.2 Anti-Recovery Arguments

Large industrial customers and low-cost utilities, among others, oppose payment of full transition costs to utilities (13). They argue that payment of TCs to utilities will have anticompetitive and uneconomical consequences by providing payments to high-cost producers that will discriminate against low-cost producers. Full-cost recovery also ignores any utility responsibility for these costs and their consequent obligation to pay for at least some of them. Navarro believes that allowing full recovery of TCs is unfair to consumers, would provide a shield for high-cost producers and discriminate against low-cost producers, and would reward utilities for past "bad management decisions" (14).

Rose argues that TC recovery by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy. He states that the concept of transition costs, and arguments for its recovery by utility shareholders, has little basis in economic theory, legal precedence, or precedence in other deregulated industries.

Rose first considers the argument that TC recovery is required for economic efficiency. This argument is based on a narrow definition of efficiency preventing uneconomical bypass of the utility's system (i.e. selecting another supplier when the utility is the lowest-cost provider for that customer). He argues instead for a broader perspective on efficiency, one that considers the long-term promotion of competitive markets and incentives for suppliers to minimize costs over time. In his view, longer-term gains from price reductions to consumers are likely to exceed the shorter-term losses from uneconomical bypass. Rose further argues that allowing TC recovery may impair the development of competitive markets by reducing utility incentives to lower costs, acting as a barrier to entry and exit of other suppliers in the marketplace, and creating an asymmetry between utility risk and reward. Finally, even if competitive forces lead to utility bankruptcies, Rose notes that society's resources will be more efficiently allocated after the financial readjustments bankruptcies will bring.

Rose next considers the argument that cost recovery is required to comply with historical regulatory policy (i.e. the "regulatory compact"). He discusses differing interpretations of this compact and concludes that full TC recovery would be inconsistent with historical regulatory policy in many states. The only entitlement granted to utilities is the revocable privilege to serve an exclusive territory, from which stems the obligation to serve. This entitlement is not an agreement to pay all prudent (and other) costs; customers have no reciprocal obligation to purchase from the utility unless a written contract is in place.

Bradford, in contrast to Kolbe & Tye, believes that utility shareholders historically have been compensated at levels high enough to cover the risks of some loss on strandable investments (15). Indeed, between 1977 and 1991, the annual

total return to shareholders for 81 utilities averaged 13.3% per year, higher than the 13.2% for unregulated industrial firms even though electric-utility stocks were less risky than the market as a whole.

3.3 Government Decisions

At the federal level, the Council of Economic Advisers favors utility recovery of transition costs (16, p. 187):

In unregulated markets the possibility of stranded costs typically does not raise an issue for public policy—it is simply one of the risks of doing business. However, there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. . . . The case for allowing recovery is even stronger where stranded costs arise from regulatory obligations imposed on utilities [such as qualifying facilities]. . . . To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.

FERC, in its Order 888, clearly favors utility recovery of "legitimate, prudent, and verifiable [wholesale] costs" (2). Similarly, the California PUC (17) and the California Legislature (18) both decided to allow utilities the opportunity to recover their retail transition costs. FERC provides an extensive discussion of the many comments it received on this issue, both for and against cost recovery, and the basis for its decision to allow utilities the opportunity to recover all their TCs. FERC's decision limits utility recovery of costs to only those that can be directly attributable to FERC's Order 888 mandating open-access transmission. If, for example, a wholesale customer physically leaves a utility's service area, the utility's losses associated with this departure would not qualify for cost recovery under FERC's rule. In addition, FERC limited recovery to costs incurred prior to July 11, 1994, the date of its original stranded-cost notice of proposed rulemaking. Finally, FERC requires a utility to demonstrate that it had a "reasonable expectation" that it would continue to serve the departing wholesale customer for a certain amount of time. Thus, although FERC decided to allow utilities the opportunity to recover 100% of the costs stranded by increased transmission access, FERC clearly limited these opportunities to those that are a direct consequence of its actions.

Both FERC and California dealt with the allocation of costs among parties. With respect to the utilities themselves, both entities put in place mechanisms

to encourage utilities to cut costs (see Section 6). FERC ruled that departing wholesale customers will pay the transition costs associated with their departure. This decision ensures that neither utility shareholders nor other wholesale customers bear the costs associated with a particular customer's departure.

The California Legislature sought to ensure that residential and small commercial customers would benefit from restructuring that state's electricity industry. To that end, the legislature authorized the issuance of up to \$10 billion of government bonds, the proceeds of which would be used to guarantee residential customers a minimum 10% rate reduction and help pay for TCs. The lower interest rate on government versus utility bonds, the longer amortization period (10 vs 5 years), the exemption from state income taxes, plus the possibility of an exemption from federal income taxes will be used to provide the rate reduction to residential customers. (These securitization benefits have a cost: The state guarantees that retail electricity consumers will pay the interest and principal associated with these bonds.) The Legislature decided that all retail customers will pay for transition costs through a nonbypassable competition transition charge, allocated across rate classes in a manner similar to the cost allocation in place as of June 1996. The California legislation is important because it provides the utilities with strong assurances for recovering a substantial portion of their transition costs and it "securitizes" some of these costs in a way that reduces their magnitude. The Pennsylvania General Assembly authorized the Pennsylvania PUC to issue qualified rate orders to utilities for the issuance of transition bonds (19). As in California, these bonds would require a lower interest rate because of the state's backing (19, Section 2812, p. 73):

Notwithstanding any other provision of law, the Commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment or termination by any subsequent action of the Commission. . . . The Commonwealth will not limit, or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility.

Hanger, a Pennsylvania PUC Commissioner, suggests "different recovery levels for different types of stranded investments" (20). Commissions can consider the degree of utility-management responsibility for the transition costs that exist in each category. In addition, the transition costs associated with utility-owned generation assets include both a return of investment and a return on investment; commissions can consider these types of costs differently for recovery purposes. For example, commissions may allow either no return or a reduced return on equity on certain assets contributing to TCs. Alternatively,

commissions may allow only a return of capital without any return on investment. Under this policy, shareholders would forego their equity return and might also have to pay the long-term debt return to bondholders.

The New Hampshire Public Utilities Commission (21) and the Vermont Public Service Board (22) adopted TC positions more favorable to customers and less favorable to utility shareholders than did FERC or California. The New Hampshire PUC noted that, with the exception of purchases from qualifying facilities, the "New Hampshire electric utilities' historical prerogative to make resource decisions have [sic] not been significantly compromised by legislators or regulators." The Commission proposed to use New England regional electric rates as a key element in determining the amount of TCs that individual utilities could recover. That is, the utilities in the worst financial shape, as measured by their retail rates, will get the least relief in TC recovery. Specifically, the Commission stated that "it is our preliminary view that utilities with rates at or below the regional average should be provided a greater opportunity to recover net, verifiable, nonmitigable stranded costs than should utilities with rates above the regional average." The Commission reasoned that each New Hampshire utility operated under comparable economic and regulatory conditions, including participation in the same power pool, access to the same fuel markets, and the requirement to conform to the same state laws and regulations. Given these similar operating environments, one can assume that differences in utility rates are attributable primarily to utility-management decisions.

The Vermont Public Service Board is especially concerned about transition costs because rates in Vermont are increasing at the same time that they are decreasing in other New England states. The difference is primarily a consequence of the \$4 billion, 30-year contracts that the Vermont utilities signed several years ago with Hydro-Quebec. These contracts account for about 60% of the transition costs for the Vermont utilities.

The Board notes that the transition to competitive electricity markets may provide "substantial opportunities for utilities" that can be used to offset what would otherwise be TCs. The Massachusetts Department of Public Utilities (23) also notes that today's utilities have certain competitive advantages, such as "substantial physical assets including plant, equipment, and sites acquired over the monopoly period, and largely financed by ratepayers; and, in some cases, intangible assets, such as name recognition and customer loyalty." [The overall market-to-book value for the common shares of 50 large US utilities was 1.4 as of June 1996. This high valuation by utility shareholders can be interpreted as a sign of confidence that regulators will allow considerable TC recovery, that utilities stand to gain in competitive electricity markets, or both.]

The Board also plans to limit TC recovery to a five-to-ten-year transition period. It emphasizes the utilities' obligations to mitigate TC amounts and offers to provide TC recovery only after all mitigation strategies have been implemented.

The 11 mitigation strategies identified by the Board include renegotiation of power-purchase contracts; buy out or buy down of power-purchase contracts; economic operation of existing facilities and contracts; shutdown of uneconomic generating units; renegotiation of fuel-supply contracts; cost reduction; sale of uneconomic assets; write-off or write-down of uneconomic assets; appropriate load growth; exchange of underutilized assets; and refinancing of obligations through low-cost, long-term bonds (similar to the method planned for California).

The regulatory and legislative decisions in favor of cost recovery may be motivated by both philosophical and practical reasons. Philosophically, the federal and California governments recognize that many of the utility decisions that led to above-market costs (especially the purchase of electricity from qualifying facilities) were actively promoted by government. Even where decisions were not promoted by governments, governments acknowledge that the regulatory commissions approved those actions. The Vermont and New Hampshire decisions, on the other hand, favor retail customers over utility shareholders and emphasize the historical and legal responsibility of utility managements for their resource-acquisition decisions.

Practically, it might be very difficult to implement a new industry structure without the support of utilities. If utilities were informed that they would not be permitted to recover most of their TCs, they could find many ways to delay implementation of competitive markets. For example, although the Michigan Public Service Commission mandated a retail-wheeling experiment in 1994, retail wheeling has yet to begin in that state. Thus, we speculate that utilities in many jurisdictions will be allowed to recover most, but certainly not 100%, of the TCs that they cannot reasonably mitigate.

The Massachusetts Department of Public Utilities took just such a pragmatic view in its recent order (23, pp. 264-265):

In this rulemaking, we have determined that the electric companies have not established a clear legal entitlement to stranded cost recovery. At the same time, we acknowledge that the legal question of whether stranded costs are recoverable in the restructuring of the electric industry is one that PUCs and the courts have never addressed, let alone resolved. It continues to be our belief that litigation over stranded cost recovery would delay the introduction and benefits of competition for consumers. Furthermore, as a matter of sound public policy, the Department reaffirms that allowing electric companies a reasonable opportunity to recover stranded costs is in the public interest because such recovery would: 1) ensure the provision of sound electric services during the transition to competition; 2) affirm reliability of commitments, which is an essential element in any future industry structure; 3) promote federal and state coordination and ensure equal treatment of similarly situated utilities; and 4) avoid costly, reform-delaying litigation.

In deciding on how much money a utility is entitled to recover from its customers, the Department will require full documentation on such costs from each utility, including sensitivity analyses.

Some utilities have generating assets with book values below market prices. Although this situation of negative TCs has received little attention, regulators in some states will have to decide how to allocate these benefits between utility shareholders and retail customers. Presumably, the same principles that determine the allocations for positive TCs should apply to negative TCs. As noted by the staff of the Texas PUC (24), "In the transition to a competitive retail electricity market, to the extent utilities with *positive* ECOM [TCs] are granted recovery of such costs from ratepayers or otherwise, utilities with *negative* ECOM should likewise be required to pass through to ratepayers the benefits of their low cost generation resources."

Finally, having decided on the amount of TCs and the allocation of these costs among different parties, regulators must select an appropriate cost-recovery mechanism. As discussed by Baxter, Hirst, & Hadley, the mechanism chosen should promote competition and economic efficiency in bulk-power markets. In addition, the method should be administratively simple and equitable (8).

4. ESTIMATION APPROACHES

Estimation methods are important for three reasons. First, the TC estimate one obtains depends strongly on the method used to develop that estimate. (TC estimates also depend strongly on the assumptions made, as discussed below.) Second, the literature provides few details on different estimation methods. Third, regulators need simple methods for checking the reasonableness of the results their utilities present to them.

Utilities and regulators can use a variety of approaches to calculate TCs. San Diego Gas & Electric (25) developed a useful typology of estimation methods (Table 1). This framework considers three categories: administrative versus market valuation, ex ante versus ex post valuation, and top-down (TD) versus bottom-up (BU) valuation. Administrative approaches use forecasting,

Table 1 Alternative ways to compute transition costs

	Market valuation		Administrative valuation	
	Ex ante	Ex post	Ex ante	Ex post
Bottom-up	Assets sold at auction	After-the-fact purchase-price adjustment	Asset-by-asset value projections	Assets valued after restructuring
Top-down	Bundles of assets spun off	Deferred valuation of spun-off assets	Projection of regulated rate by customer class	After-the-fact adjustment of regulated prices

modeling, or other analytical techniques to estimate TC amounts. Market valuation relies on the purchase price of particular assets to determine the market value of assets, although analysis may be needed to compare market and regulated values. Ex ante approaches determine TC amounts before restructuring of the electricity industry is completed, while ex post approaches delay the valuation until restructuring has been achieved. See Baxter for an assessment of the eight approaches identified in Table 1 (26).

4.1 Market Valuation

The California Public Utilities Commission proposed that the utilities divest themselves of up to half of the fossil-fired generation they own, in part to help estimate transition costs (17). Wilson advocates the sale of assets as a preferred way to determine their true market value (27). Of course, a utility would have to sell all its generating assets, both those with above-market value and those with below-market value to determine the amount of TCs it faces (see the discussion below on administrative valuation). Nuclear and hydro units, however, pose special problems, as indicated by both the California PUC and Wilson. Lesser & Ainspan (28) note that administrative valuation requires upfront estimates of future market prices for electricity, which "will invariably be incorrect, [and therefore] the amount recovered by utilities will either be too much or too little." Use of periodic trueups also poses problems "because it requires continued definition of two key variables: the market price and the embedded price at a given time." They believe that several market prices will exist at the same time, and as evidence, note the multiplicity of prices for an airplane seat for a particular flight. (On the other hand, market- and survey-based electricity price indices exist for several locations; regulators could use these indices to define market prices.) Defining regulated costs may also be difficult given the interaction between such costs and utility cost-reduction efforts. For example, pressure from the regulator and from competitive markets may induce a utility to cut its overall heat rates, reduce its O&M costs, and take other actions that reduce its electricity-production costs.

The sale price obtained through an auction, by comparison, defines the current market price of an asset. That price will reflect the buyer's estimate of the net present value of the revenues to be generated by the asset (the product of electricity generation and the time-varying market price of power in this case) minus the ongoing costs of the asset (fuel plus O&M), plus any salvage value. An auction eliminates the need for regulators to estimate future production, book value, or market prices of electricity. All of that is left to the bidders. If the structure of the future bulk-power market is undefined at the time of the asset sales, however, the prices bid might be low because of the systemic risk of an unstable market structure.

For example, all the generation in a region could be auctioned simultaneously over a period of several months. Potential bidders would have to demonstrate their financial viability by posting "earnest money" on all generating units on which they wanted to bid. The regulator would limit the amount of capacity that any single bidder could purchase, to prevent horizontal market-power problems. To promote an efficient auction, the current owners of these generators would be required to provide detailed information about these resources before the auction began. And potential bidders would have the right to conduct their own audits of these facilities.

When considering the specific market valuation approach to use, the potential tax implications should be assessed (29). A sale of assets, such as the divestiture of utility generating plants for cash, will be treated as a taxable event for federal and state income tax purposes. A spin-off transaction will not be considered a taxable event if the transaction comports with tax laws dealing with spin-offs. The potential tax consequences of different market valuation approaches suggest a need to consult with the Internal Revenue Service prior to implementing a specific process. Asset sales may also raise complications with mortgage bonds, many of which are backed by specific assets.

4.2 Administrative Valuation

Administrative valuation approaches use analytical techniques to estimate the market value of utility assets and obligations (30). A BU, *ex ante*, administrative approach would involve calculation of the unit-by-unit performance of each of a utility's power plants in a hypothesized competitive generation market. Some early estimates of TCs were too high because they were based on an analysis of only those generating units with book values above market values, leading to an estimate of gross TCs. An accurate assessment of such costs must include all assets, those with book values below as well as above market values, to derive an estimate of net transition costs. (A similar situation occurs with long-term obligations, such as power-purchase and -sales contracts. A power-sales contract with a price above, or a power-purchase contract with a price below, the market price of power reduces a utility's TCs.) Calculating the return provided by each generating unit involves detailed production-cost simulations for both the utility in question and the surrounding utilities and independent power producers. These simulations would show the number of hours each year that each generating unit operates, its variable production costs, the market price of power that hour, and from these numbers, the profitability of each unit. Such calculations require thousands of assumptions concerning present and future customer locations, loads, load shapes, and peak loads; transmission-system operation, expansion, constraints, costs, and pricing rules; operating costs and performance of all existing and new generating units; fuel prices;

government decisions on siting and environmental restrictions for new power plants and transmission lines; and so on. A BU analysis requires similarly detailed calculations of stranded liabilities (especially power-purchase and fuel-supply contracts), regulatory assets, and public-policy programs. The method developed by Resource Data International is probably the leading example of a BU method (6).

The TD approach, rather than using the individual asset or liability as the unit of observation, treats the utility as the unit of observation. In a TD, *ex ante*, administrative approach, the utility's average embedded cost of electricity production is compared with an average assumed market price. This approach is much simpler than the BU approach, primarily because it requires only a few assumptions and elementary calculations. However, it is also much less detailed and therefore provides fewer insights into the specific assets, liabilities, and costs that account for a utility's TC situation. FERC's revenues-lost approach is a TD method.

Transition costs can be assessed from at least two perspectives: 1. that of the utility, assuming that customers face the same prices they would have faced without retail wheeling, and 2. that of remaining retail customers, assuming that the utility's earnings are unaffected by retail wheeling. In reality, neither utility shareholders nor retail customers are likely to bear 100% of the TC losses. For analytical convenience only, we adopt the utility perspective in the following discussion.

If the utility bears all the losses, its costs are equal to the net present value of the differences in net income between the no-wheeling (Base) and retail-wheeling (RW) cases:

$$TCs = NPV \sum_{t=1}^T (Net\ income_{Base,t} - Net\ income_{RW,t}), \quad 1.$$

where *NPV* is the net present value, often calculated at the utility's return on equity for the *t* years through year *T*. Determining *T* is a difficult policy choice because the annual values of TCs can be positive for several years and then turn negative, depending primarily on the assumptions one makes about the future price of bulk-power electricity. Net income is the difference each year between the utility's revenues and its expenses, where expenses include all operating costs, depreciation, taxes, and interest payment on bonds.

If the utility keeps the sales at risk, its earnings loss (change in net income) is

$$(1 - \text{income tax rate}) NPV \sum_{t=1}^T \sum_{j=1}^N [kWh_{RW,tj} \times (\text{Utility total production cost/kWh} - \text{Market price})_{tj} + \text{rate-design adjustments}_{tj}], \quad 2.$$

where the subscript j refers to one of the N customer classes, and the term $kWh_{RW,j}$ is the annual energy loss that the utility experiences because of RW.

The first term in Equation 2 inside the summation signs is the amount of money lost because the utility now collects from wheeling customers only the market price for electricity, whereas before it collected the total cost (fixed plus variable costs) of production and purchased power. The estimates of average utility production cost and market price must be consistent with each other. Specifically, all prices and costs must be measured at the same level in the transmission and distribution (T&D) system (e.g. at the generator busbar) to consistently reflect electrical losses in the T&D system, and they must include only comparable costs (e.g. generation only with T&D costs excluded). Also, both annual averages must be weighted by electricity consumption, not by time. Because marginal cost and wholesale price generally increase with demand, consumption-weighted values are higher than time-weighted values by roughly 5–10%.

The second term represents any losses associated with rate design (i.e. non-production costs that are not fully reflected in T&D wheeling rates). For example, this term could include the annual costs of public-policy (e.g. low-income) programs that are assigned to generation. Implementation of this approach is simple. One first estimates the total production costs for each applicable rate class and then estimates, in a consistent fashion, the market price that each class would face. These calculations require only a rudimentary knowledge of the utility's production costs and the wholesale power market. Second, one estimates the effects of rate design on lost revenues. The losses associated with rate design will also differ across rate classes because the tariff designs may differ in their allocations of generation versus other costs to different classes. This process requires an understanding of utility accounting and ratemaking. The results for each of the N rate classes is then summed to obtain the utility's total TC estimate.

The term $(1 - \text{income tax rate})$ shows that any losses experienced by a private firm are offset in part by reduced federal and state income-tax payments. For example, if a utility's combined federal and state income tax rate is 36%, its shareholders will face only 64% of any losses associated with retail wheeling. Taxpayers will bear the remainder through lower tax receipts.

4.3 Criteria to Assess Methods

How should regulators decide among the various analytical and market approaches discussed above (Table 1)? When faced with conflicting claims about TCs, policymakers need a framework to assess different cost estimates and estimation approaches. We identified eight criteria related to implementation,

administrative ease, public availability of data and models, consideration of relevant assets and liabilities, the time period considered, market price and value determinations, price and value comparisons, and treatment of market forces.

Implementation describes how valuation is conducted technically and procedurally. Administrative valuation methods typically are implemented using computer models. Market valuation methods are implemented by auction, sale, spin-off, or some other market process. Implementation also refers to the need for regulatory proceedings to review estimates, estimation methods, or supporting data.

Administrative ease refers to the relative difficulty of implementing the approach and administering any associated proceedings.

Are the data and models necessary to calculate TCs publicly available or proprietary? Much of the data needed is available from reports that utilities file with their state regulators and with FERC. A proprietary model may be available through licensing agreements or other commercial arrangements.

The relevant assets and liabilities criterion indicates whether the approach includes those items that analysts agree should be included in TC estimates. The relevant categories, as discussed above, include utility-owned generation assets; long-term obligations, such as power-purchase contracts and fuel contracts; regulatory assets, such as the phase-in of an expensive power plant; and possibly public-policy programs. Public-policy programs would only be appropriate to include if the utility remains obligated to implement these programs and the costs are not recovered through an appropriate funding mechanism.

The time periods used to estimate TCs vary depending on the level of aggregation in the analysis. For example, the time periods covered for utility generation and power-purchase contracts often differ depending on the book lives of the generating units and the terms of the contracts.

Estimates of future market prices for bulk-power electricity are made either by using analytic techniques (price estimates—the basis for administrative valuation) or by observing appropriate market indicators; see (8) for examples. Price estimates can be developed either endogenously or exogenously. Endogenous price estimates are not predetermined assumptions and they are not externally imposed by the analyst; they are the result of market simulations or an analysis that explicitly accounts for the economics of plant dispatch in a region. Hence, they are an intermediate result of the analytic method used to calculate TCs. In contrast, exogenous price estimates are derived directly from an assumption or an observation about the cost of different generation options.

TC approaches invariably involve a comparison of value (or price) under regulation versus market conditions. This comparison includes three elements:

parity, return on equity (ROE), and taxes. Parity refers to whether the regulated price and the market price include comparable elements. Comparing a fully bundled residential retail rate, which includes generation, transmission, distribution, and customer service costs, to a competitive-market price for generation service is inappropriate if the objective is to estimate TCs caused by the deregulation of generation. ROE is important because it can have a substantial effect on TC estimates. TC estimates might assume that utility shareholders are held harmless and earn the full authorized ROE on these potentially stranded assets. Alternatively, the analysis might assume a lower ROE to account for the reduced risk associated with a regulator's guarantee that certain costs will be recovered. Taxes indicate whether the effects of income taxes are included in the approach, as discussed above. A dollar revenue loss to the utility does not equal a dollar loss to shareholders because the utility does not have to pay federal, state, and local income taxes on the lost revenue. More generally, development and comparison of TC estimates require attention to certain key assumptions and their internal consistency. These assumptions concern the return of, as well as the return on, equity; the time period to be used in analyzing TCs; and consistency in the determination of the market and regulated prices for individual assets and liabilities. Consistency refers to analysis at the same level in the T&D system, inclusion of generation services only, and consideration of the load shape for the customer classes in question. Market forces will affect the actions of utilities and of other participants in bulk-power markets. For example, high-cost utilities will likely respond to increased competition by cutting costs and improving the performance of their generating units (e.g. by reducing forced outage rates). Many utilities will pursue previously protected markets to increase sales. Such efforts will affect the TCs that utilities ultimately face. The wider marketplace will also respond to increased competition. Over time, electricity prices will change as more consumers and suppliers participate in competitive markets. If current capacity surpluses tighten, prices should rise, thus stimulating development of new supplies. The interaction of demand and supply over time will in turn determine future market prices, which directly affect TCs. Rose uses the term "dynamic efficiency" to describe the long-term effects of these market forces (9). Over time, supply costs for utilities and other generators will approach the industry's marginal costs of generation.

5. FACTORS THAT AFFECT TRANSITION-COST ESTIMATES

Table 2 shows some of the many factors that affect utility operations, costs, and therefore transition costs. We divided these factors into three categories.

Table 2 Factors affecting the amount of transition cost a utility faces

Factor	Wholesale market	Accounting
Generation assets		
Capital costs (initial cost, depreciation, taxes, etc)		Yes
Fixed production operations and maintenance		Yes
Variable production operations and maintenance	Yes	
Forced and planned outage rates	Yes	
Liabilities		
Power-purchase fixed costs		Yes
Power-purchase variable costs	Yes	
Deferred income taxes		Yes
Regulatory assets		Yes
Annual nonfuel expenses		
Public-policy programs that are expensed		Yes
Other costs (e.g. administrative and general expenses) not in wheeling rates		Yes
Other factors		
Load growth by customer class	Yes	
Customer-class load factors	Yes	
Customer-class loss factors	Yes	
Inflation rate		Yes
Tax rates (i.e. income, property, and revenue)		Yes
Wholesale-power prices	Yes	
Difference between wholesale purchase and sale prices	Yes	
Number of customers that choose retail wheeling	Yes	
Transmission capacity for wholesale transactions	Yes	
Ancillary-service costs		Yes
Regulatory factors		
Year retail wheeling begins	Yes	
Number of years for which TC recovery is allowed		Yes
Type and frequency of rate cases		Yes
Authorized return on equity		Yes

Regulatory factors are those that the state regulator can influence, wholesale-market factors affect the interactions between the utility and wholesale power markets, and accounting factors affect the utility's income statement and balance sheet but not its interactions with wholesale markets.

We used the Oak Ridge Financial Model to conduct the analyses presented in this and the following sections (31). First, we created a base-case utility, using historical data from the Energy Information Administration. We simulated the finances, operation, and rates of this utility from 1995 through 2005 assuming

no retail wheeling and the traditional cost-of-service regulation. Then we hypothesized a pattern of retail wheeling, starting at zero in 1995, increasing linearly to 42% of the retail load in the year 2000, and remaining constant from 2000 through 2005. We assumed that the state regulator would permit recovery of stranded costs for the 10-year period from 1996 through 2005. The utility's earnings loss (\$699 million) amounts to 45% of shareholder equity. If remaining retail customers bear all the TCs associated with retail wheeling, their rates increase relative to the non-wheeling case by a maximum of 24% in the year 2000. For additional details, see (32).

5.1 Regulatory Factors

PUCs have substantial influence over the timing and extent of retail wheeling and therefore over the TC amounts that a utility or its customers might face. These factors include the year that retail wheeling begins, the number of years for which transition costs are calculated, and the type and frequency of rate cases.

For a variety of reasons, many states have delayed the onset of retail wheeling. One motivation for such delays is the decline in TCs that the passage of time provides. The natural decline in fixed production costs is a powerful incentive to slow implementation of retail wheeling. For the base case, fixed production costs decline by 50% between 1995 and 2005; about half this decline is caused by depreciation, with the remainder caused by inflation and load growth. (During this 10-year period, the utility builds no new generating units. As a consequence, its reserve margin declines from 34% in 1995 to 6% in 2005.) Each one-year delay reduces the utility's TCs by about 18%, assuming that the utility is allowed to recover costs for a full 10-year period. A three-year delay from 1996 to 1999 cuts the amount almost in half. Of course, these results assume that state regulators and utilities can prevent retail customers from finding other, lower-cost sources of electricity (e.g. through cogeneration).

5.2 Wholesale-Market Factors

The interactions between a utility's generating resources (both its own generating units and its power-purchase contracts) and the wholesale market affect the amount of TC losses. As shown in Equation 2, TCs depend on the difference between a utility's production costs and the market price. And a utility's production costs depend on market conditions and the utility's opportunities to buy and sell power on the wholesale market.

Changes in wholesale prices affect TC estimates in exactly the same way (but with the opposite sign) as do changes in utility variable production costs. For example, a decrease in wholesale price will reduce the amount of power the utility sells on the market and will increase the amount of power it buys in exactly

the same way that an equal increase in production costs would. Because of this symmetry, we show results only for changes in wholesale prices. As wholesale prices increase, the losses caused by retail wheeling decrease. Indeed, if wholesale prices increase by more than 1.6 cents per kWh above their base-case values, retail wheeling increases earnings to utility shareholders. Conversely, as wholesale prices decrease, TCs increase.

As the number of customers that choose to "leave" the utility increases, the TC amounts increase. The loss to the utility increases linearly with the number of RW customers (i.e. the loss per RW customer does not vary with the amount of retail wheeling). The loss to remaining customers, however, increases much more rapidly. This difference occurs because, as the number of retail-wheeling customers increases, the number of remaining retail customers among whom the loss is spread decreases.

5.3 Accounting Factors

Our base-case utility has \$800 million in regulatory assets, compared with total assets in 1995 of \$4950 million. Increasing the regulatory assets by 50% increases losses by 9% (\$63 million). The base-case utility spends \$40 million a year on public-policy programs, equivalent to 2% of revenues. Eliminating these programs would cut TCs by 4%. Decreasing the fixed O&M costs of generation decreases TCs. A \$10/kW decrease in fixed costs cuts TCs by 10%, comparable to the effect of a 0.25 cents/kWh change in either marginal production cost or wholesale price.

Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution equipment and people to support the basic services of generating capacity, energy supply, and power delivery. These services cost about 0.4 cents per kWh. Generating capacity accounts for many of these services and their costs. A utility that can sell these ancillary services to retail-wheeling customers can use the fixed-cost portion of these revenues to offset what would otherwise be TCs. Each 0.1 cents per kWh of ancillary-services charge reduces its losses by 3%.

Changes in inflation rate, customer load factors, T&D losses, or load growth all have very small effects on TC estimates.

5.4 Summary

The analyses discussed above show that, although many factors affect estimates of transition costs, only a few factors really matter (Figure 4). The key variables that most affect losses include the year that retail wheeling begins, wholesale prices (or, equivalently, utility marginal production costs), the percentage of customers that wheel, fixed production costs, regulatory assets, and charges for certain ancillary services. Many other factors, including frequency and type of

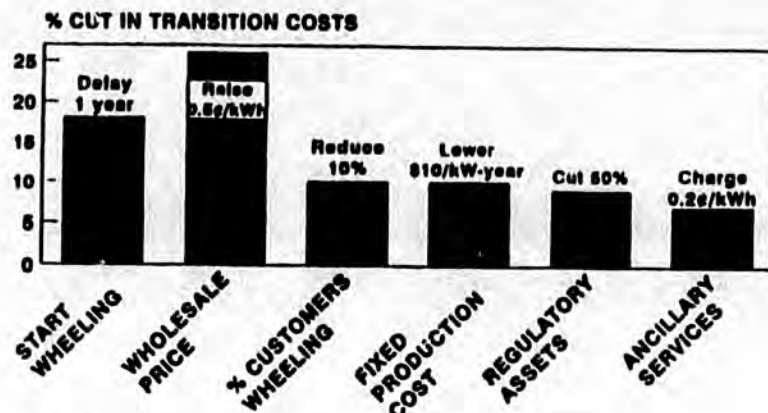


Figure 4 Effects of the key factors that influence transition costs. The base case against which these results are developed assumes that retail wheeling begins in 1996, the wholesale price is 2.5 cents per kWh (and the marginal cost of the utility's generation is 2.4 cents per kWh) in 1995, 50% of the commercial/industrial customers plus 25% of the residential customers are wheeling by the year 2000, fixed production costs are \$186 per kW in 1995, and no ancillary-services charge is levied.

rate cases, public policy-program costs, inflation rate, customer load factors, transmission and distribution loss factors, and load growth, have only small effects on the losses caused by retail wheeling.

6. STRATEGIES TO ADDRESS TRANSITION COSTS

Given the large dollar amounts often associated with TCs, regulators, utilities, their customers and suppliers, and others have a strong interest in seeking ways to offset these costs. Strictly speaking, transition costs, because they reflect sunk costs and future obligations, cannot be "mitigated." However, utilities and their regulators may be able to reduce other costs and thereby offset some of what would otherwise be TCs. Most of the strategies we identify involve shifting costs over time or among different segments of the economy. We discuss four major types of strategies to address transition costs: market actions, depreciation actions, rate-making actions, and utility cost reductions. See (33) for additional details on these strategies.

6.1 Market Actions

Market actions affect the market structure for electricity or rely on market mechanisms, such as auctions or sales, to affect the distribution of TCs. A prominent strategy calls for the rapid and broad opening of retail electricity markets (i.e. retail wheeling) at the earliest possible date. Monopoly franchises

for retail electricity sales are eliminated, and all consumers have a choice of electricity suppliers. Such a strategy maximizes both competitive pressures on suppliers and consumer welfare gain.

An alternate strategy is to delay the onset of competition and create a more deliberate opening of retail electricity markets. Retail access is eventually granted to all consumers, but not until several years after the initial group gets access. A variant on this strategy is to give all consumers access at the same time but delay the onset of access by several years. This strategy sacrifices a portion of consumers' welfare gain to enable producers to recover a larger share of their sunk costs.

Divestiture, selling all or part of a utility's generation portfolio to separate companies, is widely discussed (34). Divestiture could address several issues. The sale provides a readily identifiable market value for the asset(s), which is necessary to estimate TCs, and also separates the unregulated generation business from the regulated T&D business. Some analysts argue that utility divestiture is necessary to ensure competitive markets and to reduce potential conflicts between unregulated and regulated business operations. Divestiture also reduces the possibility that a utility will exercise its monopoly power over transmission to benefit its competitive generation position.

A divestiture strategy is most commonly applied to generation, but analysts also discuss the sale of transmission assets. (Revaluing generation, transmission, and distribution assets is a similar strategy, except the utility retains ownership of all assets.) This discussion is motivated by the belief that the market value of transmission assets exceeds their book value. In such cases, the above-book proceeds from a transmission sale are used to partially offset the below-book market values of certain generating assets. Setting aside potential legal issues, problems arise for transmission-poor utilities faced with potential TCs (35).

Marketing existing excess capacity or energy, or capacity or energy freed by departing customers, is a clear strategy to increase revenues and thereby offset TCs. Indeed, FERC's approach defines mitigation as the sale of available energy at market prices. Some proposals, including FERC's, give departing customers the opportunity to market energy freed by their departure from the utility.

Finally, improving system load factors, either by reducing peak demand or by increasing off-peak energy sales, should lower utility costs. Such a marketing strategy should affect the amounts of TCs a utility will face.

We now quantify several of these market actions (Table 3). (As in the previous section, we analyze TC losses as if they all fall on utility shareholders.) The timing and extent of retail wheeling can substantially affect the losses a utility will face. For the base case discussed above, a two-year delay in the start of retail wheeling from 1996 to 1998 reduces the utility's losses by 33%. A

Table 3 The effects of different strategies to address transition costs

Transition-cost strategy	% change in utility transition costs ^a
Market actions	
Accelerate RW with full implementation by 1998 instead of 2000	+72
Delay RW by two years	-33
Delay RW by two years and cut amounts by 50%	-70
Increase system load factor 5 percentage points (from 56% to 61%) by cutting peak demands	+20
Increase sales by 10% and hold system peaks unchanged (increase load factor from 56% to 62%)	-17
Charge 0.2¢/kWh for capacity-related ancillary services	-6
Depreciation options	
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years)	+34
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years); extend depreciation from 50 to 75 years for T&D	+28
Utility-cost reductions	
Lower customer-service costs from \$70 to \$45/customer-year	-13
Lower A&G costs from \$176 to \$100/customer-year	-37
Lower T&D O&M costs from \$23 to \$11/kW-year	-28
Lower fixed O&M costs for nuclear and coal plants by \$10/kW-year	-16
Make must-run contract dispatchable at 3¢/kWh and pay owner lost profits	-9
Lower fixed costs for power-purchase contracts from \$45 to \$30/kW-year	-12

^aThe base-case loss is \$699 million, equivalent to 45% of shareholder equity.

two-year delay, combined with a 50% reduction in the ultimate amount of retail wheeling would cut the utility's losses by 70%. On the other hand, accelerating full implementation of retail wheeling by two years, from 2000 to 1998, would increase the utility's losses by 72%.

If the utility is able to cut peak demands without affecting sales, its load factor will increase. An 8% reduction in peak demand yields an increase in system load factor from 56% to 61%. Although such a strategy lowers utility costs and average retail prices, the revenue reductions are greater than the cost reductions. Cutting peak demand increases the utility's TCs by 20%. On the other hand, if the utility improves its system load factor by increasing off-peak sales by 10% while holding peak demand fixed, its costs will decrease more than its revenues, and its TCs will decline by 17%. The difference in results between these two cases occurs because of the utility's retail rate tariffs. These results suggest that the utility, with approval from its PUC, may want to revise these allocations in response to changes in system load factor.

Finally, the utility might be able to sell generation-related ancillary services, such as regulation and operating reserves. We assume that the utility can sell these capacity-related services for 0.2 cents per kWh more than the operating costs associated with these services. Selling these services to wheeling customers would cut TCs by 6%.

6.2 Depreciation Options

Depreciation expenses for unamortized generation plants contribute directly to fixed generation costs. As a result, analysts have devoted considerable attention to examining how plant depreciation could be modified to address TCs.

Traditional regulation permits lengthy depreciation periods for the capital-intensive investments in generating facilities. For large power plants, these depreciation schedules may last for up to 40 years. Accelerating depreciation shortens the time during which capital costs are recovered. Accelerated book depreciation increases depreciation expenses over the shortened depreciation period but eliminates these expenses once the plant is fully amortized. The primary motivation for accelerated depreciation is to increase the recovery of a utility's fixed costs while its retail franchise is still intact.

Because accelerated depreciation increases depreciation costs immediately, an alternative is to offset these cost increases by decelerating depreciation of other utility assets. For most utilities, the T&D plant is the largest capital asset after generation. Thus, one strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of transmission or distribution assets, or both. Southern California Edison proposed such a strategy to more rapidly recover shareholder investment in a nuclear plant and still hold retail rates constant (36).

A depreciation reserve is the accumulated annual depreciation expense on a utility's balance sheet that is deducted from the plant-in-service account. The depreciation reserve reflects the amount of investment in the plant-in-service that has been recovered from ratepayers. Transferring depreciation reserves from T&D accounts to generation-plant accounts is an explicit strategy to revalue the associated assets. Such a transfer will reduce the net book value of the generation plant and increase the net book value of the T&D plant by the amount transferred. South Carolina Electric & Gas proposed that this strategy be used to reduce the net book value of a nuclear plant to the average value of nuclear plants in the region. FERC rejected this proposal because it would have shifted costs from generation to transmission.

Table 3 quantifies several of these depreciation options. In the base case, the 800-MW nuclear unit is not fully depreciated until 2009, and the 750-MW coal unit is not fully depreciated until 2016. Accelerating depreciation so that

both units are fully depreciated by 2000 raises TCs by 30% (16% from the nuclear unit and 14% from the coal unit). This strategy increases losses for the first several years (through 2000) and then reduces losses thereafter. However, the net present value of the increases is greater than that of the decreases. The utility had a total of \$800 million in regulatory assets as of 1995. Accelerating the depreciation of these assets from 12 to 6 years increases TCs by almost 4%. The utility's losses increase because more of the depreciation occurs earlier and therefore has a larger effect on the net present value of the losses. However, if this asset was depreciated even faster, over four or fewer years, the utility's TCs would decline. In this case, most of the costs would be recovered before many of the utility's customers became eligible for retail wheeling.

Extending the book-depreciation lifetime of T&D assets from 50 to 75 years reduces utility TCs, but only slightly. Such a strategy can help to mitigate the effects of accelerated depreciation of generation assets. In this case, the combined strategy increases the utility's loss by 28%, six percentage points less than would occur without the extended T&D depreciation schedules.

6.3 Rate-Making Actions

In most jurisdictions, current rate design recovers variable costs and some portion of fixed costs through a volumetric energy charge. Even for those customers that pay energy and demand charges, some fixed costs are recovered through the energy charge. A tariff for all ratepayers that includes an energy rate close to the utility's marginal costs, and a fixed charge close to the utility's fixed costs, would provide a more accurate price signal. The utility is able to compete successfully for sales during times when the utility is the low-cost provider, thus avoiding uneconomical bypass of the utility's generation system. The lower energy rate that will result for most utilities from such a rate restructuring will also increase electricity demand (37). Such demand increases will increase revenues and reduce TCs.

Perhaps the simplest example of rate unbundling is the rate-restructuring option described above, which provides more appropriate price signals to consumers. Electricity services and costs can be further unbundled to include T & D costs and ancillary services costs. Unbundling generation services in addition to power delivery, energy, and capacity may help address transition costs. For example, while the costs of ancillary services are a small part of a utility's total costs, charging for these costs may reduce TCs.

Performance-based rate making (PBR) replaces cost-of-service rate making with either a price or revenue cap that is adjusted periodically for inflation and a minimum productivity-improvement target. A PBR mechanism that shifts market risks from consumers to the utility could encourage the utility to reduce costs and improve productivity. PBR is attractive as a TC strategy when some of these cost savings are credited toward the utility's TCs.

Charging departing customers exit fees is the opposite of charging captive customers for TCs. Most, but not all, proposals link the exit fee to those embedded utility costs incurred on behalf of the departing customer. Exit fees can be structured as a lump-sum payment or as a stream of payments. Exit fees attract considerable interest from utilities and regulators, and the use of exit fees is the strategy FERC selected to address TCs for wholesale customers. A properly structured exit fee makes the utility indifferent (with regard to recovering the utility's historical investment on the customer's behalf) to a customer's decision to leave or stay and discourages uneconomical bypass of the utility's system.

Access charges for transmission or distribution service can be structured to include TC recovery. The access charges can be fixed (dollars per customer) or volumetric (cents per kWh). The fixed charges could be collected as a lump sum or as a payment stream. Charges set for transmission access are under FERC jurisdiction, while charges for distribution access are under state jurisdiction. Access charges are appealing because they recover TCs from all electricity users except those few that are completely disconnected from the utility grid. This is the approach selected by the California Legislature in its specification of a competition transition charge.

To examine the effects of exit fees, we estimated one-time exit fees for residential and commercial/industrial (C/I) customers in two ways. First, we based the exit fee on the utility's losses during the first year of retail wheeling (1996) and assumed that the utility would be entitled to that amount for each of the 10 years in the original cost-recovery period. Second, we based the exit fee on the utility losses for each of the 10 years. The first approach led to higher exit fees, which would overcompensate the utility for its losses. This overcompensation is a consequence of the declines from year to year in annual TCs, which drop because of load growth, decreases in depreciation expense, and increases in wholesale prices.

6.4 Utility Cost Reductions

To be considered as TC strategies, most of the following options require regulatory approval to allow cost reductions to be used to offset TCs. Cost reductions that enhance the quality and level of service provided are economic-efficiency gains and thus are distinguished from strategies that shift costs over time or among different economic actors. Generation-cost savings could come from reducing plant heat rates and O&M costs and from retiring uneconomical plants. Competitive forces from a restructured electricity-generation industry will induce utilities to pursue such cost reductions to retain existing customers and to attract new ones. However, these cost-cutting pressures raise concerns that plant maintenance and safety will suffer, particularly for nuclear plants. Utilities will also be motivated to reduce costs in other areas, such as T&D and customer service, if these reductions decrease TCs for shareholders.

Utilities with above-market power-purchase contracts can reduce costs by restructuring these contracts. Depending on the history of the specific contract and the utility's financial status, the utility may be able to restructure the contract or buy out the above-market portion of the contract at a discount. Power producers will have incentives to renegotiate contracts if maintaining the existing contracts threatens the financial survival of the purchasing utility. In addition, provisions of certain power-purchase contracts may become incentives to renegotiate once a competitive generation market is established. Finally, depending on their debt costs and discount rates, some producers may prefer a contract buyout with up-front payments rather than continuing to receive payments over extended periods during a time of substantial changes in market structure and operation.

We quantify several of these utility-cost options in Table 3. If the utility could lower its customer-service costs from \$70 to \$45 per customer-year, its losses would drop by 13%. If it could cut its administrative and general costs from \$176 to \$100 per customer-year, its TCs would drop by 37%. Finally, cutting its T&D O&M costs from \$23 to \$11 per kW-year would cut losses by 28%.

If the utility lowers the fixed O&M costs for its nuclear and coal units by \$10 per kW-year, its losses will drop by 16%. If the must-run 600-MW contract can be dispatched at its running cost (assumed to be 0.3 cents per kWh below its contract payment of 3.3 cents per kWh), its capacity factor will decline from 75% to 17%. The savings that accrue from the utility's ability to obtain cheaper electricity from its own plants and from other purchases is equivalent to 19% of its losses. If, as seems more realistic, it must compensate the owner of this contract for its losses, the utility's losses are cut by only half as much. If the utility can lower the fixed payments from \$45 to \$30 per kW-year for the 1600 MW it has under contract, its TC losses will decline by 12%. Whether the kinds of cost reductions outlined above are reasonable depends on the individual circumstances facing each utility. For example, a utility might have high distribution costs, not because it is inefficient, but because its customer density is low or its geographic area is subject to extensive and destructive storms.

6.5 Summary

The results discussed above apply only to the hypothetical utility we created. The benefits and costs of the different strategies discussed here will depend on the utility's specific situation concerning its above-market costs in utility-owned generating units, long-term contractual obligations, and regulatory assets. A few of the strategies discussed here have the potential to substantially affect the TCs that a utility would otherwise face. Changes in the start date, pace, and extent of retail wheeling could have large effects in shifting costs between utility shareholders and retail customers. Charging an exit fee to departing customers would have comparable effects. Cutting various nongeneration O&M costs as well as the nonfuel O&M costs for generating units could have substantial

cost-reduction effects, although the savings for the utility examined here may be unusually large.

At the other end of the spectrum, extending the book-depreciation schedules for a utility's T&D investments is likely to have only small effects on TC amounts. (Indeed, all the depreciation options considered here shift costs over time but do not affect the total transition costs.) Similarly, shortening the depreciation period for regulatory assets also has only a limited effect on a utility's potential losses. Finally, charging wheeling customers for ancillary services will have a modest effect on TC losses.

7. CONCLUSIONS

The US electricity industry is in the midst of major changes. Today's electricity industry is dominated by vertically integrated utilities, which enjoy retail-monopoly franchises. Tomorrow's industry may involve separate companies that generate, control, transmit, and distribute electricity. The generation sector may be competitive and largely free of economic regulation. The transition from one type of structure to another will, for some utilities, expose costs that cannot be sustained in competitive markets.

These transition costs are the potential monetary losses that utility shareholders or other parties might experience because of structural changes in the electricity industry. Roughly speaking, transition costs reflect the difference between regulated retail electricity prices for generation services and the competitive-market price of power.

These costs already exist and are, in general, being paid for by today's retail electricity consumers. Legislators, regulators, and others need to address these costs up front and establish clear rules on how they will be measured and shared among different groups. Government failure to render clear policy decisions will cause serious problems, including extensive litigation, delays in the implementation of competitive markets, and de facto "deals" that favor economically and politically powerful interests. Finally, dealing with transition costs is, as the name implies, not an enduring issue. Once the transition from today's vertically integrated, regulated, monopoly industry to a more competitive industry is complete, this issue will disappear. However, the large dollar amounts at stake ensure that transition costs will be a critical issue for several years.

Transition costs include four types of costs: assets, primarily in expensive power plants and excess generating capacity; liabilities, primarily in power-purchase contracts, fuel-supply contracts, and deferred income taxes; regulatory assets, whose value is based on regulatory decisions rather than on market forces; and public-policy programs, including tax collection, demand-side management programs paid for by all customers, and special programs for low-income customers. Unlike the first three categories, the costs in this category

are current, not sunk; these costs could be discontinued if the programs were stopped.

Estimates of transition costs vary widely, with many falling in the range of \$100-\$200 billion for the United States as a whole. By comparison, total shareholder equity in US utilities is about \$190 billion. Not only is a great deal of money at stake, but that money is distributed unevenly across utilities and regions. Certain regions (such as the Pacific Northwest) have almost no exposure to transition costs, while other regions (such as California and the Northeast) face substantial problems.

Utilities and regulators can use a variety of approaches to calculate transition costs, categorized along three dimensions. The first dimension is the use of administrative versus market procedures to value the assets in question. Administrative approaches use forecasting, modeling, or other analytical techniques to estimate transition costs. Market valuation relies on the purchase price of particular assets to determine their market values. The second dimension concerns when the valuation is done, either before or after restructuring is completed. The third dimension concerns the level of detail involved in the valuation, top-down versus bottom-up valuation.

Regardless of the method used to estimate transition costs, one must make certain assumptions. Although many factors affect the calculation of transition costs, only a few factors make a big difference. The most important factors include future market prices of electricity, utility marginal costs of production, when retail wheeling begins, extent of retail wheeling, amount of utility regulatory assets, and utility fixed production costs. On the other hand, certain factors are likely to have very little effect on estimates of transition-cost amounts, including public-policy program costs, the inflation rate, load growth, customer load factors, and transmission and distribution system loss factors.

Of the critical factors that affect transition costs, some can be influenced by the utility and some by the PUC, and some are essentially beyond the control of either party. As examples, the PUC can affect the start date and extent of wheeling, although market forces may overwhelm regulation where large price disparities exist; and utilities can seek to cut their fixed and variable production costs. But wholesale prices—the most important factor—are largely independent of utility or PUC actions.

Strictly speaking, transition costs, because they reflect sunk costs and future obligations, cannot be mitigated. However, regulators can allocate these costs among different groups. In some cases, regulators and utilities can find ways to cut costs and can then use these savings to offset what would otherwise be transition costs.

Because of these large dollar amounts, state and federal regulators are committing considerable time and attention to transition costs. The Federal Energy Regulatory Commission devoted almost 25% of its 1996 landmark decision

(Order 888) on open-access transmission to transition costs. Similarly, the California Public Utilities Commission recognized the critical role that transition costs play in restructuring the California electricity industry "to assure the continued financial integrity of California's investor-owned utilities. . . ." The California Legislature affirmed the Commission's support for utility recovery of transition costs.

The New Hampshire and Vermont regulators emphasized the role of utilities in mitigating transition costs. Both commissions plan to allow cost recovery only for those costs that remain after utilities have exhausted their mitigation opportunities. And both states adopted a broad view of mitigation, including actions that some might not consider mitigation, such as utility writeoffs of uneconomic assets or disallowance of costs associated with rates that are above the New England regional average.

Regulators and legislators must pay close attention to transition costs, primarily because of the large amounts involved in many states. Some of the transition-cost issues discussed here are analytical. But others are primarily policy issues. In particular, the allocation of transition costs among different stakeholders is a critical policy issue on which legislators and regulators will play a key role.

Visit the Annual Reviews home page at
<http://www.annurev.org>.

Literature Cited

1. Studness CM 1996. The optimal recovery of stranded investment. *Public Util. Fortn.* 134(3):40-41.
2. US Federal Energy Regulatory Commission. 1996. Promoting wholesale competition through open access non-discriminatory transmission services by public utilities; recovery of stranded costs by public utilities and transmitting utilities. Final Rule. Doc. Nos. RM95-8-000, RM94-7-001, Order 888, Washington, DC, Apr. 24.
3. Hackett A, Cohen J, Abbott S. 1996. *Moody's Calculates Little Change in Potential Stranded Investments*. New York: Moody's Investors Serv.
4. Baxter L, Hirst E. 1995. *Estimating Potential Stranded Commitments for US Investor-Owned Electric Utilities*. ORNL/CON-406. Oak Ridge, TN: Oak Ridge Natl. Lab.
5. Prudential Securities. 1996. *A Free Market for Power Would Mean Revenue Losses for All Utilities—But Some Would Suffer More than Others*. New York: Prudential Secur.
6. Resource Data International. 1996. *Power Markets in the US*. Boulder, CO: Resour. Data Int.
7. Orans R. 1996. *Rebuttal Testimony for Central Power and Light Company, before Texas Public Util. Comm., Dec. 14/96*, San Francisco.
8. Baxter L, Hirst E, Hadley S. 1997. *Transition-Cost Issues for a Restructuring US Electricity Industry*. ORNL/CON-440. Oak Ridge, TN: Oak Ridge Natl. Lab.
9. Rose K. 1996. *An Economic and Legal Perspective on Electric Utility Transition Costs*. NRR1 96-15. Columbus, OH: Natl. Regul. Res. Inst.
10. Baumol W, Joskow P, Kahn A. 1994. *The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power*. Washington, DC: Edison Electr. Inst.
11. Rowe J, Graening P. 1996. Property law: It's physical—and logical. *Electr. J.* 9(7):44-51.

12. Kolbe AL, Tye WB. 1996. Compensation for the risk of stranded costs. *Energy Policy* 24(12):1025-50
13. IPALCO Enterprises. 1995. *Restructuring the Electric Utility Industry, the Real Problem and the Real Solution: Customer Choice Through Universal Access*. Indianapolis: IPALCO
14. Navarro P. 1996. Electric utilities: the argument for radical deregulation. *Harvard Bus. Rev.* Jan/Feb:112-25
15. Bradford PA. 1996. Till death do us part or the emperor's new suit: Does a regulatory compact compel stranded investment recovery? *PUR Util. Q.*, 3rd Quart.
16. Council of Economic Advisers. 1996. *Promoting Competition in Electricity*. Econ. Rep. Pres. Washington, DC: US Gov. Print. Off.
17. California Public Utilities Commission. 1995. *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*. R.94-04-03 I, Decis. 95-12-063, Dec. 20, as modified by Decis. 96-01-009, Jan. 10, 1996, San Francisco
18. California Legislature. 1996. *Assembly Bill 1890, Chapter 854, Statutes of 1996*, Sacramento, CA
19. Pennsylvania General Assembly. 1996. *The Electricity Generation Customer Choice and Competition Act*. Assembly Bill 1509. Harrisburg, PA: Penn. Gen. Assem.
20. Hanger J. 1996. *Investigation into Electric Power Competition*, Statement of Commissioner John Hanger, Pennsylvania Public Utility Commission, Harrisburg, PA
21. New Hampshire Public Utilities Commission. 1996. *Restructuring New Hampshire's Electric Utility Industry: A Preliminary Plan*. DR 96-150. Concord, NH: Public Util. Comm.
22. Vermont Public Service Board. 1996. *The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers*, Doc. No. 5834, Montpelier, VT, Dec. 30
23. Massachusetts Department of Public Utilities. 1996. *Electric Industry Restructuring Plan: Model Rules and Legislative Proposal*. D.P.U. 96-100. Boston, MA: Dep. Public Util.
24. Texas Public Utility Commission. 1997. *Rep. 75th Texas Legislature, Volume III—Potentially Stranded Investment (ECOM) Report: A Detailed Analysis*, Austin, Tex.
25. San Diego Gas & Electric Co. 1994. *Comments of San Diego Gas & Electric Company on Proposed Policies Governing Restructuring Electric Services Industry and Reforming Regulation*. Submitted to Calif. Public Util. Comm. Doc. R.94-04-03 I, June 8, San Diego, CA
26. Baxter L. 1995. *Different Approaches to Estimating Transition Costs in the Electric-Utility Industry*. ORNL/CON-423. Oak Ridge, TN: Oak Ridge Natl. Lab.
27. Wilson R. 1996. *Auctions of Stranded Costs*. Stanford, CA: Stanford Bus. School
28. Lesser L, Ainspan M. 1996. Using markets to value stranded costs. *Electr. J.* 9(8):66-74
29. Deloitte & Touche. 1996. *Federal, state and local tax implications of electric utility restructuring*. Presented at Natl. Conf. State Legis., Denver
30. Hirst E, Hadley S, Baxter L. 1996. *Methods to Estimate Stranded Commitments for a Restructuring US Electricity Industry*. ORNL/CON-424. Oak Ridge, TN: Oak Ridge Natl. Lab.
31. Hadley S. 1996. *ORFIN—An Electric Utility Financial and Production Simulator*. ORNL/CON-430. Oak Ridge, TN: Oak Ridge Natl. Lab.
32. Hirst E, Hadley S, Baxter L. 1996. *Factors that Affect Electric-Utility Stranded Commitments*. ORNL/CON-432. Oak Ridge, TN: Oak Ridge Natl. Lab.
33. Baxter L, Hadley S, Hirst E. 1996. *Strategies to Address Transition Costs in the Electricity Industry*. ORNL/CON-431. Oak Ridge, TN: Oak Ridge Natl. Lab.
34. Rose K. 1995. *Electric Utility Industry Restructuring and Transition Costs: Reconciling Economic Efficiency and Regulatory Consistency*. White Pap. 4, Jt. NARUC/EEI Semin. Regul. Transit. Environ., Providence, RI
35. Hempling S, Rose K, Burns R. 1994. *The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market*. Columbus, OH: Natl. Regul. Res. Inst.
36. Southern California Edison. 1994. *Testimony on the Competition Transition Charge*. Submitted to Calif. Public Util. Comm., Doc. R.94-04-03 I, Nov. 18, Rosemead, CA
37. Valle A, Bidwell M. 1995. Restructuring rates creates value and reduces stranded costs. *Electr. J.* 8(10):19-25

[BACK TO ABOUT DEREGULATION](#)

A GLOSSARY

UNDERSTAND THE TERMINOLOGY OF DEREGULATION

The following is a glossary of terms that will help you better understand the electric industry, deregulation, and the Pilot Program.

[A](#)/[B](#)/[C](#)/[D](#)/[E](#)/[F](#)/[G](#)/[H](#)/[I](#)/[J](#)/[K](#)/[L](#)/[M](#)/[N](#)/[O](#)/[P](#)/[Q](#)/[R](#)/[S](#)/[T](#)
[U](#)/[V](#)/[W](#)/[X](#)/[Y](#)/[Z](#)

Affiliate

A company that is controlled by another or that has the same owner as another company. [Top](#)

Aggregator

A firm, licensed by the commission, that signs up a large group of consumers to bargain on their behalf for the lowest possible price for electricity. The firm "aggregates" or combines many smaller customers into one large customer for purposes of negotiation. It purchases the electricity for the group. [Top](#)

Base Load

The minimum energy level a company must provide to its customers on a constant basis. [Top](#)

Basic Service

The four charges for generation, transmission, distribution, and transition that all customers must pay in order to retain electric service. [Top](#)

Broker

A firm, licensed by the commission, that acts as an agent or "middle man" in the sale and purchase of electricity but never owns the electricity and typically does not own generating facilities. [Top](#)

Bulk Power Market

Wholesale purchases and sales of electricity. [Top](#)

Chapter 56

The Public Utility Commission's regulations that establish rules for payment of utility bills, requests for service, payment of deposits, billing, termination of service and complaint handling. These regulations are to protect residential customers of regulated electric, gas, water, steam heat, and sewer companies in

Pennsylvania.[Top](#)**Commission**

The Pennsylvania Public Utility Commission.[Top](#)

Conservation

Reducing a customer's electricity use to decrease the need to generate electricity.[Top](#)

Consumer Education

Efforts to provide consumers with skills and knowledge to use their resources wisely in the marketplace.[Top](#)

Customer Assistance Programs (CAPS)

Alternative collection program set up between a utility company and a customer that allow customers to pay utility bills on a percentage-of-the-bill they owe or percentage-of-customer-income instead of paying the full amount owed. These programs are for low income people who can't pay their bills. These customers must agree to make regular monthly payments based on their new payment plans.[Top](#)

Daily Peak

The maximum amount of energy or service demanded in one day from a company or utility service.[Top](#)

Demand

A measure of customer or system load requirements over a measured period of time.[Top](#)

Departing Member

A member consumer served at retail by an electric cooperative corporation that has given notice of intent to receive generation service from another source or that is otherwise in the process of changing generation suppliers. These persons shall nonetheless remain members of the electric distribution cooperative corporation for purposes of distribution service.[Top](#)

Deregulation

Removal or relaxation of regulations or controls governing a business or service operation such as utilities.[Top](#)

Distribution

The local wires, transformers, substations, and other equipment used to distribute and deliver electricity to

end-use consumers from the high-voltage transmission lines.[Top](#)

Distribution Charges

Part of the basic service charges on every customer's bill for delivering electricity from the electric distribution company to your home or business. The distribution charge is regulated by the Public Utility Commission. This charge will vary according to how much electricity you use.[Top](#)

Distribution Line

The local part of an electric system that delivers electricity to most customers.[Top](#)

Distributive Power

A packaged power unit located at the point of demand. While the technology is still evolving, examples include fuel cells and photovoltaic applications.[Top](#)

ECAR

Council Ohio, Western Pennsylvania (Allegheny, Penn Power, Duquesne).[Top](#)

Electric Distribution Company (EDC)

The company that owns the power lines and equipment necessary to deliver purchased electricity to the customer.[Top](#)

Energy Conservation

To reduce or manage energy consumption in a cost-effective manner.[Top](#)

Energy Services Company (ESCO)

A company offering specialized or customized services for efficiency or financial savings to customers.[Top](#)

Escape Provision

A contract provision which allows a party such as an electric customer to get out of it. Usually, there is a penalty.[Top](#)

Fixed Price

A price which remains the same, usually for a set time period.[Top](#)

Flat Rate

A fixed charge for goods and services that does not

vary with changes in the amount used, volume consumed, or units purchased.[Top](#)

Formal Complaint

A written dispute or disagreement about a utility problem filed by a consumer with the Public Utility Commission. A formal complaint is assigned to an Administrative Law Judge (ALJ) who holds hearings to develop a record. After the hearings, the judge issues a decision. (See informal complaint.)[Top](#)

Generation

Production of electricity from a power plant.[Top](#)

Generation Charges

Part of the basic service charges on every customer's bill for producing electricity. Through deregulation, generation service is competitively priced and is not regulated by the Public Utility Commission. This charge depends on the terms of service between the customer and the supplier.[Top](#)

Green Power or Greencos

Demand side management and other non-polluting sources of energy generation.[Top](#)

Grid

A network for the transmission of electricity throughout the state or nation.[Top](#)

Gross Receipts

The total revenue for a calendar year for all electric distribution companies and electric generation suppliers which are derived from the sales of electric energy.[Top](#)

Hourly Metering or Time of Use Metering

Tracking or recording a customer's consumption during specific periods of time that can be tied to the price or energy.[Top](#)

Informal Complaint

A dispute or disagreement about a utility problem filed by a consumer with the Public Utility Commission's Bureau of Consumer Services (BCS). A BCS investigator reviews the informal complaint and provides the customer with a response to their dispute. Most responses are in the form of a decision that the customer or company can appeal. If an informal complaint is appealed, it becomes a formal

complaint. (See Formal Complaint.)[Top](#)

Intangible Transition Charge

The amounts on all customer bills, collected by the electric utility to recover transition bond expenses.[Top](#)

Interruptible Rate

A special utility rate given to those who agree to have their service reduced or temporarily stopped as part of an agreement with the utility company. Circumstances for service interruptions can be period of high demand or high cost periods of short supply for the utility and/or system emergencies.[Top](#)

Investor-owned Utility

A utility company owed and operated by private investors.[Top](#)

Kilowatt (kW)

(1) A measure of demand for power during a preset time-minutes, hours, days, months; (2) 1,000 watts - Ten 100 watt light bulbs use one kW of electric power.[Top](#)

Kilowatt-hour (kWh)

The basic unit of electric energy for which most customers are charged. The amount of electricity used by ten 100-watt light bulbs left on for 1 hour. Consumers are charged for electricity in cents per kilowatt-hour.[Top](#)

Load

The amount of electricity being used at one time by a customer, circuit or system.[Top](#)

Load Profile

Information on a customer's usage over a period of time, sometimes shown as a graph like the one on the bill.[Top](#)

Load Management

Shifting use of electricity from periods of high demand to periods of lower demand, when the cost of electricity usually is lower.[Top](#)

Marketer

A company, licensed by the Commission, that buys and resells electricity, but that typically does not own generating facilities.[Top](#)

Non Basic Service

Any category of service not related to basic services (generation, transmission, distribution and transition charges). [Top](#)

Office of Consumer Advocate (OCA)

A government office that represents the interest of residential utility consumers before the Public Utility Commission in rate and service cases and before other state and federal regulatory agencies and courts. [Top](#)

Office of Small Business Advocate (OSBA)

A state government office that represents the interests of small business consumers by participating in PUC rate cases and other state and federal regulatory cases. [Top](#)

Off-Peak/On-Peak

Blocks of time when energy demand and price is low (off-peak) or high (on-peak). [Top](#)

Pilot

A utility program offering a limited group of customers their choice of certified or licensed energy suppliers on a one year minimum trial basis. [Top](#)

Power Pool

Combining electric power supplies. Two or more interconnected electric systems planned and operated to supply power in the most reliable and economic manner. (POOLCO) [Top](#)

Price Cap

Situation where a price has been determined and fixed. [Top](#)

Public Input Hearings

Meetings where consumers can give input to the PUC. Sworn and unsworn testimony to the PUC judge and to the utility, consumer advocate and PUC staff. The PUC conducts hearings in the service area of the utility who requested the rate increase. Sometimes consumers can point out problems with the quality of the utility's service, management, or policies which would affect the outcome of the case. [Top](#)

Public Utility Code

The law which sets the powers and the duties of the Pennsylvania Public Utility Commission. It also sets many of the guidelines the PUC uses for utilities' rates and service standards.[Top](#)

Public Utility Commission (PUC)

The state regulatory agency that provides oversight, guidance and direction to electric public utilities.[Top](#)

Real-Time Pricing

Rates that reflect the actual cost of providing service at a given time creating fluctuating prices.[Top](#)

Regulations

A rule or law established by the federal or state government which sets procedures that a utility must follow.[Top](#)

Reliability

The providing of adequate and dependable generation, transmission and distribution service.[Top](#)

Renewables

Includes technology such as solar photovoltaic energy, solar thermal energy, wind power, low head hydro power, geothermal energy, landfill and mine based methane gas, energy from waste and sustainable biomass energy.[Top](#)

Resellers

Companies that purchase utility service from a wholesaler and resell it to consumers.[Top](#)

Restructuring

The reorganization of traditional monopoly electric service to allow operations and electric charges to be separated or "unbundled" into generation, transmission, distribution and other services. This will permit customers to buy generation services from competing suppliers.[Top](#)

Retail Wheeling

Also known as retail customer choice -- A utility company is required to transport electricity from a generating plant it does not own directly to its retail customers. This gives retail customers the ability to purchase electricity from the sources they choose.[Top](#)

Retail Customer Choice

See Retail Wheeling[Top](#)

Rural Electric Cooperative

Customer owned electric utility that distributes electricity to members and that receives lower-cost financing through the federal government.[Top](#)

Securitization

The act of pledging assets to a creditor through a note, lien or bond.[Top](#)

Spot Market

Short-term purchases of electricity from surpluses available for a short time.[Top](#)

Stranded Benefits

Special collection programs, renewable energy and demand side management programs, lifeline rates and other utility resources funded by a monopoly utility that may not be funded if the utility's competition does not have similar costs.[Top](#)

Stranded Commitment

Assets and contracts associated with shifting to competition which are above market prices and hence result in non-competitive conditions for the utility.[Top](#)

Stranded Investments

A utility investment, such as in facility and equipment, that is not supported by market prices.[Top](#)

Supplier (Electricity Supplier)

A person or corporation, generator, broker, marketer, aggregator or any other entity, that sells electricity to customers, using the transmission or distribution facilities of an electric distribution company (EDC).[Top](#)

Title 52

The section of the Pennsylvania code that governs utilities.[Top](#)

Transition Charge

A charge on every customer's bill designed to cover an electric utility's transition or stranded costs as determined by the Public Utility Commission.[Top](#)

Transmission

Interconnecting electric lines which move high voltage electricity from where it is produced to the point of distribution to customers. [Top](#)

Transmission Charges

Part of the basic service charges on every customer's bill for transporting electricity from the source of supply to the electric distribution company. The Public Utility Commission regulates retail transmission prices and services. This charge will vary with your source of supply. [Top](#)

Unbundling

Breaking down services offered into parts so each part can be billed. [Top](#)

Universal Service

Policies, protections and services that help low-income customers maintain electric service. [Top](#)

Utility Competition

Two or more electric suppliers providing the same or similar goods or services in the same marketplace and for the same customers. [Top](#)

Variable Price

A price which can change by the hour, day, month etc. [Top](#)

Weatherization

Modifying a home or structure to conserve energy. Methods include: Sealing window and door frames with caulking or gaskets, installing storm doors and windows and adding or increasing insulation. [Top](#)

Wheeling

The transmission of power that has been generated by one entity over lines of another utility system. [Top](#)

Wholesale Competition

A market structure where municipal and other utilities can exercise choice in electricity suppliers in order to meet customer needs. [Top](#)



Alaska

Rural

Electric

Cooperative

Association, Inc.

703 W. Tudor Rd., #200
Anchorage, AK 99503-6650
(907) 561-6103
FAX (907) 561-5547

Electric Service for 357,000 Alaskans

October 10, 1997

Representative Norman Rokeberg
Alaska State Legislature
716 West 4th Avenue, Suite 640
Anchorage, AK 99501

Dear Representative Rokeberg:

This letter is in response to your letter of August 18, 1997 in which you posed a number of questions regarding HB-235 and the issue of deregulation in the State of Alaska.

Many of my responses are subjective in nature because no one really knows what the long term impact of electric utility deregulation will be. One thing seems certain, though: the end result will be greater regulation than we presently have. One need only look at the impact of telecommunication deregulation on the Alaska Public Utilities Commission (APUC) work load to draw this conclusion.

With one primary exception, the electric industry in Alaska has opposed deregulation. This reflects the fact that almost all of the utilities in Alaska are consumer owned and don't feel the profit motive to try to take away a neighbor's customers. They are already in the mindset of working to provide the lowest possible rates to their members. However, perhaps more importantly, we don't have the infrastructure in Alaska to allow for full, open, competitive choice. In the Lower 48 states, there are a multitude of transportation paths by which electricity can be brought to a prospective customer. In Alaska, we don't even have an unconstrained transmission system from Anchorage to Fairbanks, nor, in some cases, even across adjoining service territories. If deregulation is required by federal law, criteria should be set at the state level to insure that all classes of consumers can participate on a "level playing field" and are protected from rate increases.

As you know, approximately 90% of the electricity generated by utilities in Alaska comes from consumer owned utilities. Under this ownership makeup, the boards of directors and managers of the utilities have maximum incentive to keep the cost of electricity as low as possible. In the Lower 48, almost 75% of the generation comes from investor owned utilities (IOUs) which have profit motive as their driving force. With IOUs, there is the tug and pull of competition to drive the competitor out of the market place with predatory pricing in pursuit of an unregulated monopoly that then allows price gouging. We are not dealing with a simple product here in Alaska where market forces will quickly keep prices in check.

In the Lower 48 with the mature transmission line system in place, there are numerous generation choices and the possibility of an unregulated monopoly is probably slight. In each village of Alaska, there is only one generation choice. In the interconnected Railbelt, there are only three generation choices (Chugach, Anchorage ML&P, and Golden Valley) and their rates are remarkably equal.

DEMOCRACY IN ACTION

Outsiders can come in and try to build new generation, but that takes a lot of time, significant investment, adequate zoning, and compliance with environmental regulations. It also creates the duplication that the current system was set up to avoid. While this outsider is attempting to get up and running, the local utility will probably change its price structure (at the expense of other customers) to undercut the new competitor.

As mentioned above, the cost of electricity from the Railbelt's three generation and transmission utilities is very similar. They are also all three consumer owned with little surplus cash as might be expected with an IOU. Consequently, none of the three have a significant economic advantage over each other outside of the actual makeup of their consumers (one may have a higher number of business verses residential customers). Under competition, there may be some minor savings that could be realized by tightening up on overhead expenses, but as a general rule, this is not going to result in dramatic reductions in their overall rates. Furthermore, unlike the telecommunications industry, we are not going to see any quantum breakthroughs in new technology in the power generation field.

Certainly, we will see technology advances in fuel cells, wind generation, storage devices, remotely-controlled operations, and computer-driven internal combustion and turbine-driven prime movers, but these will generally result in gradual reductions in the cost of power production. Where then, will the rate reductions come from that the three Railbelt utilities will use to compete with each other? Very simply, they will "rob Peter to pay Paul." I wouldn't be so concerned if they were all investor owned utilities where outside owners would take the hit, but as consumer owned utilities, it seems that they will just be forced to "eat their young," so to speak.

We would all like to see the industry run as efficiently as possible, and acknowledge that some form of deregulation will probably come to Alaska. We hope to shape the form of deregulation to give maximum economic advantage to all consumers without sacrificing the gains that we have made in Alaska over the past 20 years. We look forward to working with you and your committee to this end. Following are the responses to the questions that you asked.

1. Should APUC be given explicit statutory authority to allow competition?

- If APUC is given authority to allow competition without Legislative guidance, then unbridled deregulation will have come to Alaska. So the bigger question is: "...is deregulation good for Alaska, and if so, what should it look like?" Everyone has their own opinion on this issue based on their past experience and general philosophy. With deregulation, APUC will become a much bigger agency than what it is now. Just look at the number of docket items that they have to deal with now that the telecommunications industry has become "deregulated." The electric utility industry believes that the individual boards of directors can make better rate choices for their customers than can APUC for the entire industry. Nevertheless, if deregulation is to be imposed, we believe that HB-235 both gives APUC the authority to allow deregulation and strict criteria to protect all classes of customers.

2. Are there any private investor owned electric utilities? How many are there and what are the company names, parent company names and where is the home office located?

- There are 23 investor owned utilities in the State of Alaska providing about 9% of the total electric utility sales. A listing of these utilities and their addresses is included in Attachment 1.

3. *Does federal and state law allow private investor owned companies to purchase public electric cooperatives? If yes, under what conditions?*
 - To our knowledge, there are no prohibitions on investor owned utilities buying either cooperatives or municipal utilities. In both instances, the investor owned utility would need to buy out the debt and capital credits of the member owned utilities. This could represent quite a penalty to the ratepayers as much of the municipal debt is tax exempt, and virtually all of the cooperative debt is at a federally subsidized rate.
4. *Generally speaking would an investor owned buyout of a public cooperative require 50% plus 1 of the current subscribers to vote yes or would the public cooperative by-laws govern voting percentages?*
 - The buyout formula is generally spelled out in the by-laws of each cooperative. Some are quite stringent requiring two thirds of a fifty percent response. I have not polled the cooperatives to find out what the voting requirements are at each different utility.
5. *How would the cooperative assets previously financed with federal or state dollars be sold or accounted for in an investor owned buyout?*
 - See response to question 3 above. Basically the federal debt would need to be defiesed. Disposition of state debt would be dependent upon the covenants of the State lending agency. Grants, on the other hand, become the assets of the cooperative, and, unless stipulated to the contrary in the grant agreement, would be eligible to be transferred at the discretion of the negotiating parties.
6. *Have there been any public electric cooperatives purchased by private investor owned companies in Alaska?*
 - Yes. Glacier Highway Electric Cooperative in Juneau was bought out by Alaska Electric Light and Power in the late 1980's. This consolidation eliminated competition in the Juneau area, but APUC economic regulation has helped to insure that AEL&P receives a fair rate of return on its investment and that the ratepayers do not get hurt. I think that each utility buyout regardless of which way it goes has to be evaluated on its own merits. For instance, AVEC, which is a cooperative, attempted to buy out Bethel Utilities, an IOU, but the transaction was blocked by APUC even though the overall impact would have been to lower rates for all parties. Golden Valley Electric Association, the Fairbanks cooperative, is attempting to buy out Fairbanks Municipal Utilities, a municipal owned electric utility (subject to review and approval by APUC).
7. *What is the major difference between electric utilities in Alaska taking into account both urban and rural areas as compared to the lower 49 states?*
 - The biggest difference is the lack of an adequate transmission line system to allow full choice. A second major difference is the lack of choices. Finally, we are already a consumer owned utility state whose primary objective is reliable, affordable power as opposed to profitable power for the utility. As mentioned earlier, the ratio of consumer owned utilities to investor owned utilities in Alaska is roughly 9:1. This is almost a mirror image of the situation in the Lower 48 states. Furthermore, the transmission grid system in the Lower 48 states is highly developed and reaches virtually all communities and business sectors through a myriad of puths. This means that there are numerous utility choices available to consumers. In Alaska, we have a very rudimentary transmission line

system in the Railbelt area and virtually no interconnection in rural Alaska. Exacerbating the inability to move power around the State of Alaska is the absence of the multitude of providers available in the Lower 48 states. Unlike the telecommunications industry, investment in power generation is extremely capital intensive. For that reason, there is rarely little more than one entity that is interested in bringing power to an entire village or community. However, to ensure that even that single utility would invest the requisite capital to provide for a community, exclusive service areas were granted through the jurisdiction of APUC.

8. *Is there any state or states that have a similar electrical utility distribution system?*

- No. And interestingly enough, deregulation could result in an even more backward and less developed system than we presently have. For instance, if deregulation comes to the Railbelt, each utility will need to evaluate their individual transmission line needs. Presently, as you know, Chugach is considering extension of the southern transmission line to Soldotna, while Fairbanks is looking to expand the transmission line from Healy to Fairbanks. The State has put up grant funding for each of these projects, but neither amount is sufficient to fully fund either of the transmission lines. Thus the utilities will need to finance the balance of each project using debt capital. Certainly Copper Valley Electric didn't want to take on any more debt to complete the financing of the Sutton to Glennallen transmission line for which the State has made \$35 million available. In order to remain competitive, utilities under deregulation will shun taking on any more new debt that may affect their competitive edge. Thus, it may not come as a surprise if there is a decision to discontinue pursuit of at least one of these Railbelt transmission lines in anticipation of deregulation. The result may well be a loss of overall transmission lines available in the Railbelt to facilitate the very competition that is being sought. Reliability would suffer throughout the Railbelt, and the ability to transfer economical energy from one service area to the next would be diminished. The same may also happen to reserve generation capacity. Utilities will only be building to serve immediate customers and will not invest in the reserve capacity that the industry now expects. In fact this may become a major threat to the entire Lower 48 system under deregulation. Cost cutting measures will result in a diminution of the reserve capacity that makes the system reliable. And putting reliability issues aside, what is the cost to the economy from more frequent power outages? Perhaps the only thing saving the system will be the off peak demands artificially created by the changing time zones.

9. *If the ultimate goal is to lower consumer prices for electricity, is it true that deregulation and competition will be the method?*

- You're asking for a subjective evaluation here. As you know, even Congress is having second thoughts about deregulation of the electric utility industry. While I am a free market person myself, I have serious reservations about a totally deregulated electric utility industry even for the Lower 48 states, let alone Alaska where we are already a largely consumer owned utility state with a relatively uninterconnected utility system. I think that in Alaska, deregulation will just shift the benefits and burdens from one user class to the next, but the average cost of all electricity will remain little changed. The winners will be businesses with enough economic clout to force a lowering of their rates. The losers will be the small residential customers. Winners will also include small upstart dispersed generation providers that will be able to "cherry pick" the best customers in a given service area while the utility shoulders the responsibility of maintaining a grid system and backup generation required of them by their ever-increasing disgruntled member owners, and the APUC.

10. How should the state assure that residential consumers reap the same benefits as large commercial customers and how do we solve the rural/urban problems?

- There is no easy answer here. When one segment of the market has the ability to skew the pricing structure, another segment will have to pick up the slack. Certainly we have attempted to address this situation in HB-235. Deregulation may have a particularly regressive affect in rural Alaska where "cherry picking" could become a fruitfully common event. My own personal belief is that we can gain the greatest economy of scale in rural Alaska if we bring all of the smaller utilities under one master utility such as AVEC which presently provides service to some fifty or more villages. At the same time, the administration should issue a policy stating that any state or federally funded entity in village Alaska shall remain with the utility in the village and that any dispersed generation brought to a village should be administered through the local utility. This would allow small energy providers to come to rural Alaska, but coordinate their efforts through the local utility. In urban Alaska where we have more of a market economy and a bit of an integrated system, this plan probably wouldn't work. Commercial customers already get a rate break in comparison to residential consumers in the Railbelt area. Under deregulation, they would be able to get an even-greater price break; perhaps even greater than would be economically justified. Other ways to insure that rates in both rural and urban areas would not see too much rate shock under deregulation would be for the state to: (1) make provision for utilities to recapture revenue to pay for "stranded costs," (or for the state to pick up that cost since it is changing the rules under which the utilities were led to operate under APUC regulation), (2) have the state pick up the added cost of APUC increased regulation, (3) have the state eliminate the "obligation to serve" within a service area.

11. Can the state control the level of "cherry picking or cream-skimming" and accomplish increased competition at the same time without eliminating competition?

- This could probably be accomplished by vesting APUC with the authority to "control" all aspects of the industry. In so doing, APUC could establish some sort of criteria that allows "cherry picking" up to a point when rates for everyone else reaches a ceiling. It would then stop the practice until the market rates drop back down below a predetermined threshold. Essentially this is what is being attempted under HB-235. The debate is over the threshold.

12. How should the practice of "cherry picking and cream skimming" be defined?

- Cherry picking occurs when a competitor proposes to serve a customer outside of their own service territory at a rate that is less than the tariff approved by the APUC for that service territory. Under deregulation, service territories would eventually go away, and rates would be continually changing. Eventually consolidations would take place and competition would be eliminated. Cherry picking will have become subsumed by the overall practice of cherry picking.

13. When electrical service areas overlap how do we preserve competition without duplication of capital investment?

- This is an excellent question. At the present time there are no overlapping service territories. (The one exception is Klawock, and that is being ruled on by APUC at the present time.) History would indicate that duplication of effort will take place under an unregulated utility environment. APUC was required by the Legislature in 1973 to provide all of the utilities in Alaska with exclusive territories. Before that, however, it was a common practice to see two sets of distribution lines running down each side of the streets in Anchorage, for instance, as the two utilities vied for customers in a specific geographic area. But the basic answer to the question is, there will be duplicate capital investment by dispersed generation providers, and by the utilities themselves to some extent (in order to provide for customer choice and to compete with the independent dispersed generation providers). If on the other hand the utilities were only competing among themselves, there would be little if any new investment in generation as the utilities would not want to take on the new debt and become less competitive.

14. Should the APUC statutes be changed to include timelines for all of its decisions? Or should the statutes just establish a priority system for the commission?

- Frankly, the timeliness of decisions from APUC is so bad now that both the electric and telephone industries are considering asking the legislature to change their statutes to require that they act within prescribed time lines. Under deregulation of the electric industry, their workload will become even heavier.

15. What is the status of the Copper Valley "cherry picking or cream skimming" problem?

- Alaska Power Systems, which has recently received a \$1.5 million state grant to supplement their earlier state grants, has signed up two customers in the Glennallen area, is pursuing the school, and is still pressing for customers in the Valdez area. Copper Valley appealed to APUC for help, but APUC told them to come in with a legal docket request before APUC would consider the situation. That 160-page formal complaint was submitted to APUC on October 7, 1997.

I hope that our responses have been helpful. Please call upon me if I can provide additional information.

Sincerely,



Eric P. Yould
Executive Director

cc: Ken Lancaster
Larry Markley

att.

Attachment 1

Pres/GM	Title	Contact FirstName	LastName	JobTitle	Company	Address1	City	State	ZIP	Phone	Fax
Mr. Corbus	Mr.	William	Corbus	President	Alaska Electric Light & Power Co.	5601 Tonsgard Court	Juneau	AK	99801	907-780-2222	907-463-3304
Mr. Grimm	Mr.	Robert	Grimm	President	Alaska Power & Telephone Co.	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Curtis	Mr.	Helvi	Sandvik	V.P. Operations	Artic Utilities, Inc.	1001 E. Benson Blvd.	Anchorage	AK	99508	265-4100	265-4123
Mr. Eggen	Mr.	Andrew	Eggen	General Manager	Haines Light & Power Inc.	P.O. Box 30	Haines	AK	99827	907-766-2331	907-766-2384
Mr. Eller	Mr.	Don	Eller	General Manager	Tanana Power Company	P.O. Box 873509	Wasilla	AK	99687	907-373-5599	907-373-5599
Mr. Manns	Mr.	Carl	Danielson		Bettles Light & Power, Inc.	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Hanson	Mr.	Ed	Lockhart		Manley Utility Company, Inc.	5450 A Street	Anchorage	AK	99518	561-1674	563-3185
Mr. Linke	Mr.	James	Davenport		Alaska Power Company	2770 Sherwood Ln, Suite 213	Juneau	AK	99801	907-586-7405	907-586-7270
	Mr.	Daniel	Nelson		Napakiak Ircinraq Power Co.	P.O. Box 34030	Napaskiak	AK	99634	907-589-2227	907-589-2412
Mr. Brown	Mr.	Stanley	Brown	General Manager	Paxson Lodge, Inc.	Box 101	Paxson	AK	99737	907-822-3330	
Mr. Leonard	Ms.	Diana	Leonard		Egegik Light & Power Co.	Box 179	Egegik	AK	99579	907-233-2244	907-233-2213
Mr. Mickelson	Mr.	Carl	Danielson		Coffman Cove Electric Utility	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Mager	Mr.	Jack	Mager		Sand Point Electric, Inc.	P.O. Box 209	Sandpoint	AK	99661	907-383-4020	907-383-5320
Mr. Tilbury	Mr.	Tom	Sterrett		Bethel Utilities Corporation	3380 C Street, Suite 210	Anchorage	AK	99503	562-2500	562-2502
Mr. DeMandel	Ms.	Darlene	Holmberg		Aniak Light & Power Co., Inc.	4th & Boundary Avenue	Aniak	AK	99557	907-675-4334	907-675-4334
Mr. Mahon	Mr.	Carl	Danielson		Northway Power & Light	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Whitmarsh	Mr.	Glen	Woods		Pelican Utility Company	P.O. Box 110	Pelican	AK	99832	907-735-2204	907-735-2281
Mr. Helmer	Mr.	Carl	Danielson		Eagle Power Company, Inc.	P.O. Box 222	Port Townsend	WA	99368	360-385-1733	360-385-5177
Mr. Finnesand	Mr.	Martin	Finnesand		Chitna Electric Inc.	P.O. Box 88	Chitna	AK	99566	907-823-2220	
Mr. Kimberlin	Mr.	Ray	Kimberlin		Far North Utilities	P.O. Box 80564	Fairbanks	AK	99708	907-456-4201	907-456-2084
	Mr.	Robert	Enoch		Tuntutuliak Community Service	c/o General Delivery	Tuntutuliak	AK	99680	907-256-2529	907-256-2934
Mr. Ferguson	Mr.	Gary	Ferguson	General Manager	G & K, Inc.	P.O. Box 117	Cold Bay	AK	99571-0117	907-532-2407	907-532-2513
	Mr.	David	Thomas	Power Plant Operator	Gwitchyaa Zhee Utility Company	P.O. Box 09	Fort Yukon	AK	99740	907-662-2322	907-662-2983
Mr. Blodgett	Mr.	Don	Petersen		Teller Power Company	3301 Denali St.	Anchorage	AK	99503	278-8878	278-5779

POWER

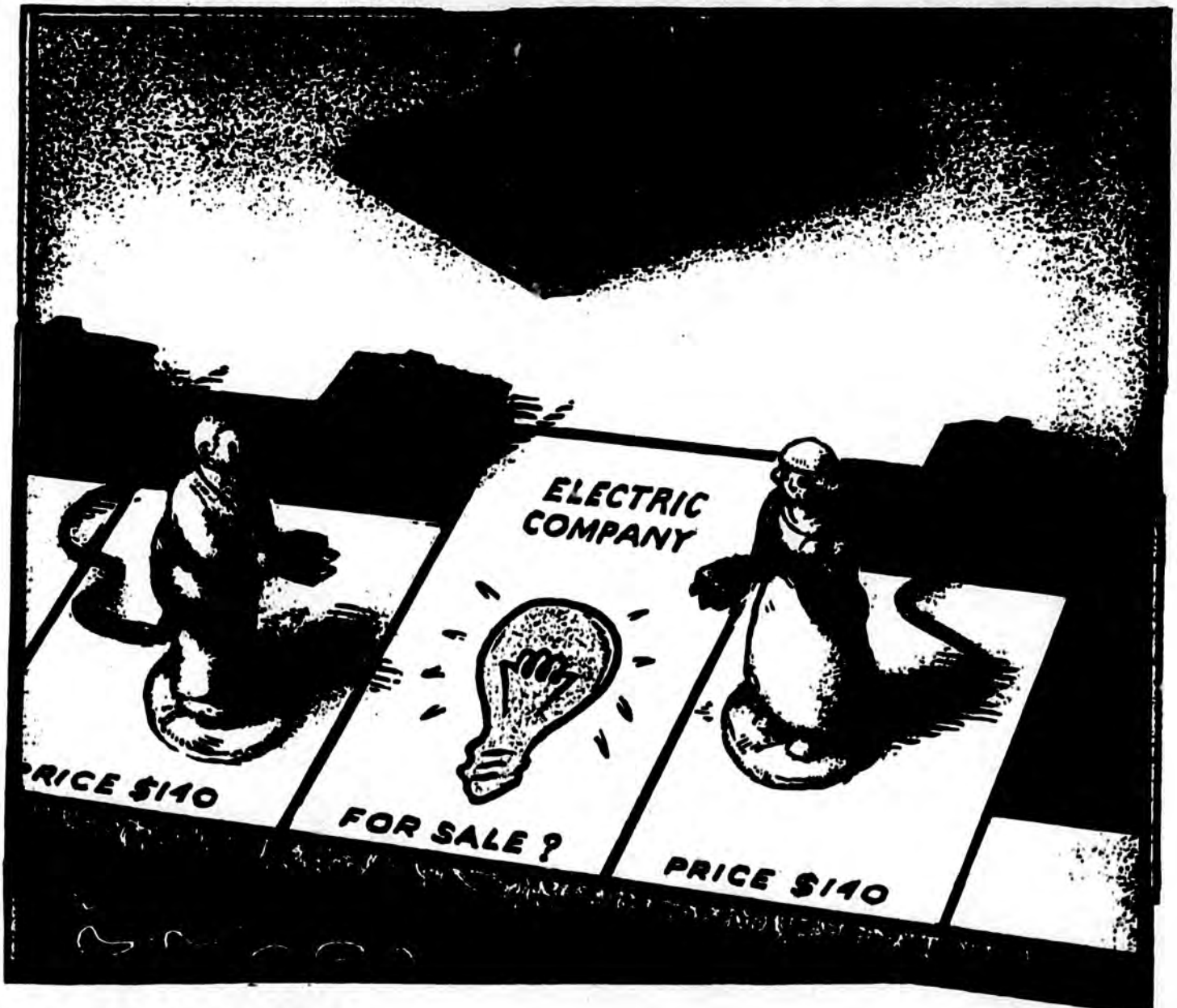
IF YOUR CITY OWNS ITS ELECTRIC utility, chances are there is some talk these days about selling it. The starting point for such conversations is nearly always the topic of electricity deregulation—and the big question that it raises in local officials' minds: Can we compete when our monopoly is gone? But regardless of whether the issue is debated loudly in the

public arena or discussed quietly behind closed City Hall doors, the deliberations all end the same way: without a sale.

Nobody knows this better than Tallahassee Mayor Scott Maddox and Memphis Mayor Willie Herenton. During the past year, they were the ones who initiated the discourse on privatizing public power in their respective communities. Both

mayors expressed concern about the possible impact of competition, and reasoned that a utility sale would absolve their cities of the risks of deregulation. In addition, money from a sale, socked away in a trust fund, could provide a steady revenue stream for years to come.

But like every other sizable municipality that has gone down this road lately, Tal-



POLITICS

lahassee and Memphis eventually turned back. Deregulation may be coming—and in some states it's already here—but city after city is deciding to compete rather than sell out. The interesting thing, in looking at Tallahassee and Memphis, is that deregulation stands to impact the two cities in drastically different ways. Yet both places ultimately concluded it was better not to sell. It seems that while the economics of selling utilities varies widely from place to place, the political roadblocks are the same everywhere.

Indeed, in the brave new world of competition, Tallahassee has everything to lose economically. The city is wedded to its utility revenues, which make up \$32 million of the city's \$100 million budget. That dependence comes largely from the city's status as a state capital. Between the government presence and that of two universities, Tallahassee cannot tax 53 percent of its land. The city charges relatively high electricity rates to compensate, but under deregulation, those same high rates could push big customers to bolt for better deals in the open market. And that, in turn, would further imperil the city's budget.

Memphis, meanwhile, is in a better economic situation. The city collects only \$20 million of its \$335 million budget from its utility. The city's electricity rates are among the nation's lowest. And unlike Tallahassee, Memphis is a distribution-only utility, meaning it owns only the poles and wires. That relieves Memphis of another layer of risk, since under deregulation, it is only the generation side of the business where monopolies are expected to get busted up. Still, the prospect of a windfall approaching \$1 billion has sparked more than a little interest among local officials in exploring a sale.

Of course, at this point, all of this local talk of competitiveness, risk and losing customers is only speculation. Neither Florida nor Tennessee has deregulated its electricity market, and neither is expected to for at least a couple of years. The world around the two states, however, is chang-

ing rapidly. Eighteen states have enacted deregulation plans and are at varying stages of implementing them. Thirty other states are debating or investigating deregulation. The idea of breaking up local electricity monopolies and letting customers choose their electricity provider offers the seductive promise of lower rates.

For the country's 2,000 municipally

Selling off the electric utility may make economic sense in this era of deregulation. But almost everywhere, public sentiment gets in the way.

■ CHRISTOPHER SWOPE

owned electric utilities, however, deregulation—or at least the prospect of it—is inspiring some major soul-searching. Every utility is different, and depending on whom you ask, the years ahead are laced with either opportunity or apprehension. It is this uncertainty that is causing a lot of municipalities to reconsider their role in the electricity business. Selling out is not the only possible approach, however. "This is a time when people are looking at their options," says Deborah Penn, a privatization expert with the American Public Power Association. "That includes changing the way you operate now or adding new services. Some would include the alternative of not staying in business."

In fact, many cities are examining a variety of possibilities, and in some that do not have public power, there is even a counter-

trend: A few towns served by private "investor-owned" utilities are looking at municipalizing those companies, Penn notes. But the list of places that have recently pondered a sale—Lansing, Michigan, Austin, Texas, and Riverside, California, to name a few—is evidence that the privatization idea is being taken very seriously. In countless other localities, officials are no doubt beginning to mull it over. "We should do that," says Barry Moline, head of the Florida Municipal Electric Association. "That's public power. We have an obligation to continually examine that option from time to time."

From the start in Tallahassee, to sell or not to sell was a question with a deadline. At the end of this month, the city is slated to start work on a new power plant. If a sale to a private entity were to happen, it had to occur before any tax-exempt municipal bonds were approved to pay for the \$109 million project.

Well aware of their budget's addiction to electricity revenues, and with the prospect of deregulation around the corner, city officials know that the price of inaction could be devastating. The utility's high rates make it a sitting duck for potential competitors. For example, one of its two biggest customers, Florida State University, is already talking of shopping around if the market opens up.

But Mayor Maddox sees another, more immediate impact from the deregulation already taking place in other states. Among investor-owned utilities, deregulation has unleashed a spree of buying, selling and merging. The companies are looking for economies of scale and to make inroads into new markets, and in many recent cases, they are paying a pretty penny for the privilege. For example, one privately owned utility in Tallahassee's backyard, Florida Power & Light, recently paid an exorbitant \$846 million for another private utility's power plants in Maine. Maddox figured it was a sellers' market and wondered if Tallahassee's utility



Mayor Scott Maddox proposed soliciting bids on Tallahassee's electric utility. But his plan was nixed by the rest of the city commission.

might fetch the same premium. "Several national companies want a foothold in Florida," he says. "And Florida's investor-owned utilities will pay to keep those folks out."

The question of value, and whether it would increase or decrease under deregulation, is a contentious one. Maddox believes that if competition comes and there's a municipal utility fire sale across Florida, the selling price will go down. The value may further decrease if Tallahassee loses its biggest customers.

Others say that if Tallahassee can get its rates competitive, it has nothing to worry about. The area's population is growing, and that should help buffer any lost customers. What's more, they add, the biggest source of future value to the utility is its connection to its 90,000 customers. The poles and wires and rights of way the city owns are essential if the city should decide some day to jump into other businesses, such as telecommunications or cable television.

Currently, the utility's value is believed to lie somewhere in a broad range between \$300 million and \$800 million. But the one sure way to find out what private utilities would pay is to ask. So last winter, Maddox proposed to seek bids, and if any especially juicy offers rolled in, the wheels of a sale could be put in motion.

That, however, is when the political reality of a sale hit. Three city commissioners (a majority) lined up against Maddox, saying the sale option was being pushed too hard and too fast. They believed major concerns—losing local control of the utility, the fate of its 300 workers under private management, and pure sentimentality for an institution as old as electricity itself—were being steamrolled in the deadline rush. The mayor's advisers said that the utility could sell

without going before voters, and many folks found that frightening. "People said, 'We love our electric utility, so don't move too quickly on this,'" recalls Commissioner Deborah Lightsey, a leading sale opponent.

In short, Maddox underestimated the intense feelings residents had about public power. Chief among those is local control: People like the idea that elected local officials essentially act as the utility's board of directors. When the lights go out, a customer can call not just a power outage hotline but also their city commissioner to complain. That would disappear under private ownership. Moreover, as is often the case with public power, the city utility has a good track record with customers. By one common measure—outage rates—Tallahassee's service is four times better than Florida's major investor-owned utilities.

All along, however, the mayor and his advisers viewed a sale not so much in terms of electricity service but in terms of dollars. The sale idea, he says, came about at a strategic planning meeting. "I asked, 'Why are we in the electricity business? Is it to provide electricity? To preserve energy? Or is it for the money?' Everyone agreed it was for generating revenue." If a private suitor was willing to pony up three times the book value, they figured, it would outweigh the local-control concern. Money from a sale could be put into a trust fund and the city could ride into the deregulation sunset living off the interest.

Of course, there was no guarantee a bid would come in at all, let alone an exceptionally high one. For example, Anaheim, California, solicited bids on its utility last year. Anaheim was willing to entertain just about any type of bid, be it an outright offer to buy, to form an alliance with

another utility or to outsource certain operations. It was a fishing expedition, and Anaheim wanted to see what it could catch. The city got 21 bites—all alliance and outsourcing proposals—but nobody was seriously interested in a purchase.

In Tallahassee, however, when it came time to go fishing for offers, the commission punched a hole in the boat. Rather than soliciting bids, commissioners voted 3-2 to investigate options other than a sale. With momentum behind the sale option dead, the boat then sank. The vote on financing the new power plant succeeded 4-1, effectively killing the sale option. Maddox' vote was the only "nay."

The mayor's advisers couldn't help but wonder if the result would have been different if it were a private, rather than public, utility being unloaded. They believed the financial calculus favored a sale. But the protracted public debate that was required once selling became a serious consideration allowed time for opposition to galvanize. "We were clearly handicapped by the requirement to operate under public meetings laws," says City Attorney James English. "The board of directors meetings of our future competitors aren't on live TV."

Memphis officials knew from the very beginning that putting the utility on the block would be a tough sell. Memphis Light, Gas & Water Division is widely respected and considered a model operation among utility experts. Perhaps more important, the company is known for its tradition of giving back to the community in a variety of ways, such as setting up special weekend classes for students of inner-city schools. Given community sentiment about MLG&W, it was clear that doing anything drastic to the utility would require broad political support.

Nevertheless, Mayor Willie Herenton suggested last winter that the city consider selling MLG&W. Like Maddox, he argued that deregulation made it a good time to examine future options for the utility. And in this market, buyers might pay a mint, especially for a well-run utility such as MLG&W. "This is a historic opportunity in the market to do something," says Michael Harris, a managing director at Morgan Keegan & Co., a local investment firm that studied a MLG&W sale. "The key to valuation is the stock market and interest rates. The timing is great."

While the market may be ripe, there was significant doubt about the deregulation

question. Certainly, compared with cities such as Tallahassee, Memphis is well positioned for when the deregulation train rolls into town. Memphis' electricity rates are more competitive, making it less likely to lose big customers. The city's budget is less dependent on utility revenues, and MLG&W already has some experience with deregulation in the market for natural gas. But most important, unlike Tallahassee and a lot of other municipal utilities, MLG&W owns no power plants. That means Memphis won't be subject to the dog-eat-dog competition in the generation side of business, where analysts say the most money will be made and lost.

However, deregulation does pose some risks for MLG&W, mostly inherited from its electricity supplier, the Tennessee Valley Authority. Since TVA's creation in the 1930s, the federal agency has been providing MLG&W and other municipal utilities in the region with cheap power from its vast network of dams and power plants. Memphis, in fact, is TVA's biggest customer. Theoretically, if Congress were to pass deregulation nationally and include TVA, distribution-only municipals like MLG&W could shop for even better deals from other providers. The problem is that TVA's contract locks them in: If Memphis wanted to shop around, it would have to wait a full decade.

The TVA contract, which Herenton describes as "onerous" and "distasteful," is an albatross for another reason. TVA currently carries an enormous \$27 billion debt on its expensive generating facilities. If Congress doesn't significantly bail TVA out of those stranded costs, TVA may have to raise the rates it charges distributors such as MLG&W. That could ripple through to the rates MLG&W charges its customers, making the utility less competitive in the long run. "We're at the mercy of TVA," Herenton says, "Their rates drive our rates."

Still, it was apparent that money, in addition to deregulation, was a driving force behind the sale idea. Morgan Keegan had been pitching the idea of a sale to Herenton for years, arguing that MLG&W was a cash cow waiting to be milked. The firm had conservatively estimated MLG&W's worth at between \$600 million and \$800 million, and other estimates topped \$1 billion. The money, if put in a trust fund, could bring in \$70 million a year in interest.

Mayor Herenton and his staff touted a



Sale opponents complained that Memphis Mayor Willie Herenton had pre-ordained MLG&W's fate.

litany of ways the cash could be spent: pay down the city's debt; hire 200 new teachers and 400 new police officers; get new computer systems for schools and police; provide free trash collection and slash property taxes. Herenton says he looked at the situation as a business would. "I don't know any corporation that would have an asset like the city of Memphis has on its books and not try to secure a bigger dividend from that asset," he says.

To opponents, however, the trust fund wish list showed Herenton's bias toward a sale. The mayor maintained he wanted only to study options for MLG&W, but he was already talking up how to spend the sale money. "If I felt his proposal was about studying the potential of changing the status of MLG&W, then I would've supported him 100 percent," says Councilwoman Pat Vander Schaaf. "But he leapt to those figures and into a different dimension completely."

To be sure, the windfall sounded great, but most residents were leery of the cost. MLG&W is Memphis' most valuable asset. Once it is gone, it would be very difficult for Memphis to get it back. And while the city would have these fat trust funds in its stead, what would keep politicians from dipping into the principal and frittering the funds away?

There were other concerns as well: Would the utility's new corporate owners, with headquarters perhaps thousands of miles from Memphis, give as much back to the community as the old MLG&W had? As to the city's low electricity rates, nearly everyone expected those to go up. After all, new owners would be concerned with mak-

ing a profit, not with providing the lowest-cost service possible. And what about the utility's 2,600 employees? Would some of them be laid off under private ownership? The questions produced enough anxiety that some 74 percent of those polled by a local newspaper, the *Commercial Appeal*, said they opposed the sale.

Herenton, like Maddox in Tallahassee, suggested a possible end-run around the opposition. He found a loophole in the law that could allow a sale without getting the consent of voters. The idea, not surprisingly, was a lightning rod for his adversaries. They claimed it was further proof that the mayor had pre-ordained MLG&W's fate, although Herenton insists he was merely laying all available options on the table.

In the end, however, no vote was necessary. At the same time Vander Schaaf was building city council support to pull the plug on any sale, the mayor's own consultant, Rotan Lee, weighed in with a recommendation against selling. Lee's reasons were somewhat diffuse; he said the utility did not provide him with certain information he needed. His report, however, acknowledged the political pitfalls of pursuing a sale. "Fears of rate increases, loss or replacement of a trusted provider and disruption of the status quo are common and natural," Lee wrote. "Freedom of choice does not automatically supplant the belief that government is a better guardian of the public's interest."

Indeed, perhaps the single greatest political force lined up against the likes of Herenton and Maddox is inertia. "There's a lesson to be learned here," says state Senator Jim Kyle, a Memphis Democrat working on deregulation issues. "It's that when we have a government entity that has the public's confidence, the public as a whole is not interested in change."

Nevertheless, there is widespread agreement in these two cities that as the era of electric deregulation draws closer, the subject of selling off the public utility will be revisited. Florida and Tennessee are only beginning to consider deregulation, and when the time finally arrives to compete—two, four or six years from now—the jitters will no doubt kick in again. "This whole debate is just beginning," says Memphis City Attorney Robert Spence. "I would be surprised if what we decided this spring is the final word." ■

An Electrifying Breakthrough



THIS SPRING, the obscure Pennsylvania-New Jersey-Maryland Interconnection Association, known as PJM, changed the prices it charges to use its power lines. In doing so, it put in place an infrastructure policy so significant that Kennedy School of Government Professor William Hogan, a leading scholar on utility deregulation, describes it as a "major breakthrough" needed to ensure the success of electricity deregulation in several states.

To get a handle on the innovation, it helps to understand how deregulation evolved. In other critical industries, such as telecommunications, aviation and natural gas, services were provided by privately owned companies but regulated by governments as monopolies. Through much of this century, this system worked well. In the 1970s and '80s, however, fuel prices and power-plant construction costs increased dramatically, creating a concern that utilities were being rewarded for making investments, rather than for being efficient. At about the same time, scholars challenged the idea that many regulated industries were natural monopolies.

In the economic doldrums of the times, these ideas resonated. In less than a decade, deregulation swept aside laws governing airlines, railroads, trucking firms, natural gas and telecommunications. Now, the federal government and several states—notably Massachusetts and California—are opening electricity to competition as well.

In pursuing these policies, states and the federal government have followed a model used in natural gas deregulation and telecommunications. Specifically, they are encouraging competition in generation, where it is feasible, while retaining monopolies in transmission lines, where competition is impossible. Doing so requires setting prices for transmission, which in natural gas lines is a relatively straightforward question of calculating existing capacity and the cost of adding additional transmission lines.

It turns out, however, that the physics of power lines make it difficult to follow this approach in electricity because the capacity of the whole system is not fixed. Instead, it varies depending on where power enters the system, where it leaves and the capacity of the lines in between those points. It is possible, for instance, to add 1,000 megawatts from one power plant without creating any problems, while adding the same amount of power at another location could overtax the system.

Historically, when demand for electricity approached the

David Luberoff is assistant director of the Taubman Center for State and Local Government at Harvard's Kennedy School of Government.

transmission system's capacity, consortia of utilities, known as regional power pools, found the combination of power plants that could meet total system demand at the lowest total cost. This approach, however, is not compatible with a deregulated system that allows individual generators to contract with individual consumers for the sale and delivery of power.

One solution, favored by many firms trying to take advantage of utility deregulation, is to give all sellers and buyers unfettered access to the system and set transmission fees at their average cost. This approach, however, could wreak havoc. If deregulated power producers add power at congested spots in the system, the system operator would have to shut down power plants in other locales. This, in turn, could drive up costs for other users or disrupt other direct transactions between buyers and sellers of electricity.

That's where PJM's new pricing system comes in. Last year, PJM, a regional power pool serving mid-Atlantic states, won permission from federal regulators to base transmission fees on the hourly cost of adding power at different points near one or more major power plants—even though some independent power producers feared that the system would lead to higher transmission costs that would make them uncompetitive.

PJM started using the system in April and, contrary to the predictions of those who touted average cost pricing, the difference in costs between various locations has been substan-

A new way of pricing power-line charges is critical to ensuring the success of electric utility deregulation.

tial. When the demand for power is close to the system's capacity, for example, charges for access to the electric lines can range from about \$90 per megawatt hour to a negative \$10 dollars a megawatt hour. (The negative number is because in some cases, adding power at certain points actually increases overall system capacity.) In an industry where price differences of a few dollars a megawatt hour are significant, such cost differences are enormous. It is no surprise, therefore, that the power pool serving New York State is about to implement a similar system and other power pools are considering it.

Ultimately, the PJM story is important in two ways. It is a critical element in ensuring the success of utility deregulation, and it shows that as regulators and policy makers move to bring market-based reforms to fields that range from the sale of water rights to opening local telephone markets to competition, they must be careful to design systems that reflect both underlying economic principles and the physical characteristics of the networks that deliver critical services.

Power Business



MICHAEL L. AMMONSON

The bloated, 120-year-old electric power industry isn't just being deregulated—it's being revolutionized. The impact on business will be huge.

BY BRIAN O'REILL

It seems so incredibly obvious you want to slap your forehead for being so obtuse all these years. Electric power costs a bundle in places like New York and California but barely a third as much in out-of-the-way states like Idaho, West Virginia, and Kentucky. *Why not take all that cheap power the West Virginians aren't using and ship it to Manhattan, Chicago, San Francisco?*

That, vastly oversimplified, is the idea behind the move to deregulate the electric power industry: If your power company is charging too much for electricity, why should you be forced to accept it? Why can't you shop around? Why can't a power company from Pocatello knock on your door and offer a bargain kilowatt or two?

It's coming. There will be far more competition in the electric power business. It is reasonable to expect that deregulation will cause the nation's \$212 billion-a-year electric bill to drop by 20% to 30% or more in the next five to ten years. But not before a vast tangle of technical, economic, and political problems gets solved.

If it works, and it should, the consequences will be enormous. "Electric power is the biggest American industry ever to be deregulated," says Kenneth Lay, chief executive of Enron, a big, aggressive gas and electricity marketer that has led the drive for deregulation. "It's about twice the

size of the long-distance telephone business and dwarfs the gas, airline, trucking, and railroad industries, which were all once regulated." The average homeowner, who uses about \$850 worth of power a year, won't be financing trips to Bermuda with the impending savings. But the potential savings for business are huge: Electricity can account for more than 15% of operating costs for a big company such as Chevron, which spends about \$250 million a year for power in the U.S. Lay notes that industrial and commercial companies consume about 60% of all power sold.

"The billions they stand to save will boost corporate profits and make American companies more competitive internationally," he says. (The upheaval in this once-staid industry will hit investors too: Owning utility stocks isn't just a matter of waiting for dividend checks anymore. For a look at how electricity deregulation affects the market, see *Personal Fortune*.)

All this is small comfort for the big, often bloated electric utilities, which have lived a long, comfortable existence as regulated monopolies. Already the prospect of deregulation is prompting much moaning and groaning, and with good reason: Deregulation will force many utilities to become far smaller. They will have to sell off some or all of their brawnier assets—those massive generating plants—and make a living mostly by operating the wires that run to homes and factories.

BUT WHAT ABOUT GRANNY?

Naturally, utilities are piously declaring that they relish the bracing winds of competition. But with barely a pause, they urge caution, hinting darkly at the havoc any rapid move will bring to this complicated, delicate industry: grandmothers stuck in elevators, hucksters who won't deliver the juice you need on a hot night, novice power plant owners frying transmission lines as they greedily try to ship power to places that can't handle the load.

If the electric power industry is doomed to collapse in a shower of sparks, we'll find

out soon enough. Regulators in California defied the Cassandra and declared that everybody can buy power from anybody, starting next January. Already advance men from all over the country have

descended on the state. None seem particularly worried they'll be stuck in elevators.

If anything, the electric business will run better than before, says Michael Peevey, former president of Southern California Edison, one of the biggest utilities in the country. Under the existing scheme, electric companies go virtually unpunished for power failures, Pee-

vey says, so power outages are far from rare. But Peevey noticed that when a Cal Edison subsidiary built and operated power plants for private customers and was penalized for down time, the plants ran smoothly 95% to 97% of the time—considerably better than Cal's regulated plants. "That's when I began to have creeping doubts about the wisdom of regulation," says Peevey. "I was like a fallen Catholic. I no longer believed." He quit and now runs New Energy Ventures in Los Angeles, which plans to help companies buy inexpensive power.

A QUIRKY INDUSTRY—REALLY

Not that anybody really knows how all this deregulation will work out. For all its apparent blandness, this is, believe it or not, a varied, quirky industry. Unlike the old Ma Bell, which seemed to spawn seven clones of itself at breakup time in 1984, each of the nation's 198 investor-owned utilities seems markedly different from the others in operations, culture, oddball problems, and long-range financial prospects.

How different? Ohio-based American Electric Power runs gigantic power plants right near coal mines in Ohio, West Vir-

ginia, and Kentucky, with boilers so vast they can fit the Statue of Liberty inside. Consolidated Edison in New York City has to run almost all its wires underground, at a cost eight times greater than stringing them on poles. Cinergy, an aggressive midsized utility in Cincinnati, is determined to be one of the five biggest energy traders in the country.

It's hard to say which private utilities will thrive. Each state will devise most of the rules governing the deregulation—and the fate—of its own utilities. In most states, though, regulators have barely begun to tackle deregulation. (The 3,000 or so electric cooperatives and government-owned utilities will be affected by the changes sweeping the industry, but they're exempt from deregulation.)

So in the absence of any simple declarations about the electric power business, herewith a guided tour of the problems, issues, and peculiarities of this soon-to-be-transformed industry.

LET'S REDECORATE!

One of the infuriating practices of most utilities has been their failure to economize. Why should they? Regulators routinely allowed them to earn a fixed rate of return on their assets. The result was a perversity known as "asset-based management." The more money a utility spent



Kenneth Lay, CEO of Enron, has led the fight for deregulation.

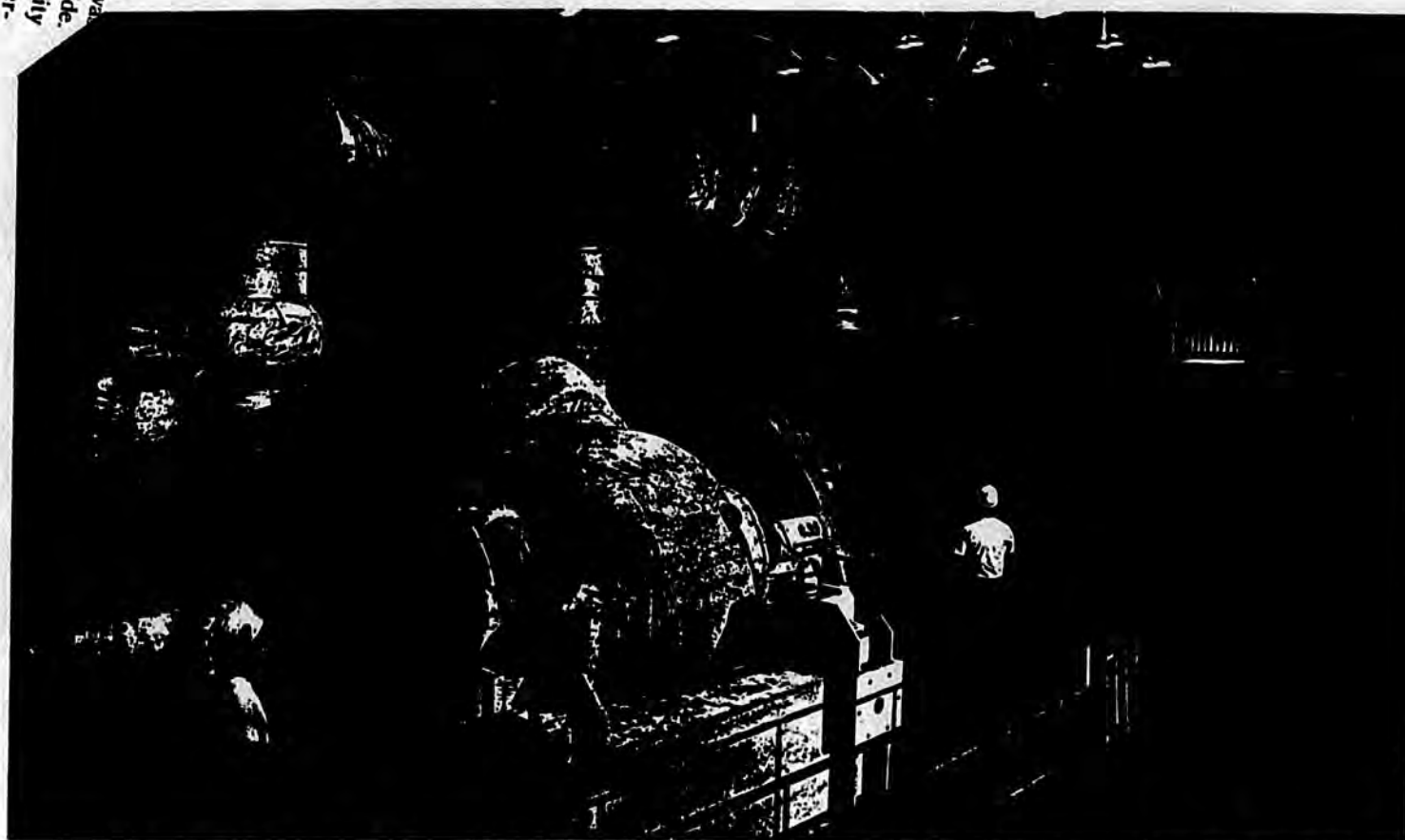
adding generators and other assets to its local power system, the more money the company made. Thus, for instance, cost overruns on nuke plants didn't cause too many sleepless nights for executives.



One of the most infuriating practices of most utilities has been their failure to economize. Why should they?

TRICITY

with boilers so vast
e of Liberty inside.
in New York City
l its wires under-
times greater than
s. Cincy, an ag-
in Cincinnati, is
the five biggest



American Electric Power runs this huge, 1,300-megawatt power plant in West Virginia. It can ship cheap power all the way to New York City.

Michael Peevey says overruns on Cal Edison's nuclear plants "doubled our assets and doubled our earnings." (As the CEO of Wisconsin Power & Light, Erroll B. Davis Jr. once remarked, "This is the only business in the world where you can increase your profits by redecorating your office.") Such gold plating should stop as competition heats up in the industry, particularly with generating equipment.

"BUT WE HAD TO BUILD IT"

The great nightmare for many utilities is what to do with all their high-cost plants once competition begins. It's not a problem now, when every home and business in a power company's franchise area has to pay for the power regardless of price. But Con Edison has an old generating station in Manhattan that produces power at an absurdly expensive 11.7 cents per kilowatt-hour; other utilities run nuclear plants whose kilowatts cost almost as much. What will those plants be worth if someone else can make power for 3 cents and send it to New York? If a plant becomes worthless because competitors can undercut its costs, do Con Ed's stockholders eat the loss, or will Gothamites?

Sorting out which costs were truly wasteful and how to pay for the rest is a major hot potato for state legislators and regulators and will probably delay the full effect of deregulation for years. Rather than label these costs "the tab for our boneheaded overbuilding," utility execs conjured up the academic-sounding term "stranded costs." They tend to blame 1970s-era federal policymakers, who encouraged nuke plants after the Arab oil embargo.

The bonehead/stranded stakes are huge. Early estimates of the write-downs utilities will have to take when competition makes many of their assets and supply contracts uneconomic range from \$100 billion to \$400 billion. In August, California-based Pacific Gas & Electric surprised many observers by paying above book value for a handful of generating plants sold by a New England

utility. But that high price may be an anomaly: Problems at nearby power plants have caused a power shortage in New England, driving up the price PG&E can charge when it sells power to other utilities in the area. It's still not clear who'll pay what for old power plants as they come on the market, but Kit Konolige, an analyst at Morgan Stanley, says power generation assets may concentrate among a few huge companies.



THE VISIBLE, CLUMSY HAND

This won't come as a surprise, but in the past utility regulators occasionally goofed bigtime. About 20 years ago federal regulators mandated that certain kinds of new, private, unregulated generating companies (known as nonutility generators, or "NUGs") could sell their power to utilities. New York regulators foolishly

declared that its utilities had to accept power from anyone who charged 6 cents or less. Scores of sharpies quickly calculated they could make power for far less, and forced 20- and 40-year supply contracts on New York utilities.

Now, with power sometimes available on spot markets for just 2 cents, power companies are screaming bloody murder. Con Ed in New York says the contracts are costing customers \$530 million a year. Niagara Mohawk, an upstate power company, says the contracts nearly pushed it into bankruptcy. Before competition can begin in New York, utilities argue, they must be relieved of their overpriced contracts. As with uneconomic power plants, New Yorkers will be asked to pay up, probably through state-issued bonds; rate payers in California and other states can expect the same. It will cost billions.

REGULATION WAS OKAY ... ONCE

Regulating utilities wasn't always a dumb idea. By the late 1920s, 50 years after Edison invented the light bulb, the industry was a mess. Three big holding companies controlled half the power made in the U.S., and another 13 companies held an additional 25% market share. Often they were byzantine in complexity and dubious in ethics: Subsidiaries paid huge management fees to their parents, asset values were inflated by sales from one subsidiary to another, and companies often issued worthless stock. Many collapsed in the 1929 stock market crash. In 1935 Roosevelt stepped in, breaking up the multistate holding companies, limiting power companies to compact, contiguous service areas, and preventing unregulated companies from selling power. Hit by both the Depression and more effective regulation, average power prices, which peaked at 32 cents per kilowatt in 1932 (in 1992 dollars), declined steadily for more than 40 years before rising again.

A MARKET EXPLODES

Even now, if you think your local utility is charging too much for power, you have no choice but to pay for it. By law, nobody else is allowed to sell power to you. Frustrating, eh?

Utilities themselves had a similar problem. When utilities can't or don't want to generate all the power their customers

need, they often buy surplus power from other utilities. Problem was, the neighboring power company didn't have to sell. It didn't even have to transport power from a faraway utility if it didn't want to. So if a utility in, say, Tennessee, offered cheap electricity to a power-hungry utility in Florida, and asked a utility in Georgia to transport the electricity, the Georgia utility could refuse—and offer Florida its own, more expensive juice instead. All that began to change in 1992, when Congress ordered privately owned utilities to allow

"wheeling," or transporting power from one utility to another across a third's transmission system, if it had enough capacity.

And the market for wheeled power exploded. There is an oversupply of generating capacity in much of the country, but the complexity of shutting down and starting up a power plant means that many have to run constantly, even if customers are few. Therefore, lots of power gets dumped on the market for far less than the average cost of production.

Experienced commodity traders, notably Houston-based Enron, jumped into the act. Enron, formerly a regulated gas pipeline company, made a fortune when the pipeline industry was deregulated in the early 1980s. Because many big gas buyers are electric companies purchasing generator fuel, Enron already knew the players and the market.

Now Enron traders are on the phone 24 hours a day, calling up power plant operators to see who needs power, who's selling it, which transmission lines are at capacity. They can slice a gigawatt of power into pieces and sell the parts faster than an Omaha hog butcher. A utility needs a steady 50 megawatts per hour all day tomorrow? Sold. Need 400 megawatts of reserve capacity in case a generator goes down next week? Got it. All kinds of companies have joined the fray—utilities, Wall Street firms (see box)—but utility executives seem to be



More than 600,000 miles of high-voltage transmission lines crisscross the U.S. These carry cheap power from Oregon to California.

in particular awe of Enron, which now buys and sells more power than anybody.

TECHNICAL DIFFICULTIES

On a map it looks so straightforward. The cheap power is made over here, in coal country; the big city over there is paying a fortune for its power. Can't they send a bunch of econo-gigawatts from the Midwest to New York? Yes, but not easily. Electric utilities all over the country are interconnected. Alas for would-be marketers, this interconnectivity was designed as a way to back up neighboring utilities during emergencies, not as a way to move power easily over long distances. Electricity can't be routed to a particular place like a phone call, and a lot of power gets wasted as heat when it's transmitted over long distances. As a result, a lot of the anticipated price competition among generators won't develop until delivering power gets easier.

Think of all those big overhead transmission lines as a web of interconnected lakes and canals, not as a switched telephone network. Dump enough extra water in your lake, and eventually water levels rise for everybody. Usually.

Say Cinergy, in Cincinnati, agrees to sell extra power to the New York Power Pool (a confederation of interconnected utilities), which sees a heat wave coming. Cinergy starts making more power than its

want to slap
use all these
jumble in places
nia but barely
se-way states
Kentucky. Wh
r the West Vir
Manhattan, C'

aplified, is th
ate the electr
company is el
y should you
you shop
ny from Pl
ter a bargain
ing. There
ne electric
s expect th
n's \$212 b
20¢ to 3
ars. But
economy
It's
be er
Am
K

ELECTRICITY

own customers need. On paper, Cinergy's surplus power travels through Dayton Power & Light's wires, then on Ohio Edison's, then over Duquesne Light's, through the Penn-Jersey-Maryland (PJM) Power Pool's wires, and into New York. In reality, however, the power flows willy-nilly wherever it wants—usually over the path of least resistance (but sometimes on to a neighbor's already-full wires, causing them to overheat, and prompting a mad scramble by the neighbor to shut down generators and reroute power). Often, most of Cinergy's surplus power wanders into the lines owned by neighboring American Electric Power (AEP), whose turf extends toward Pennsylvania, eastern Ohio, and Virginia. The people at AEP, however, are displeased. Under current rules (no pun intended), Dayton Power and all those other utilities will collect a fee for carrying the load, even though most of it goes through AEP. "It's a pain in the neck," says E. Linn Draper Jr., AEP's CEO.

This is not a trivial problem. Since many utilities will have to sell their power plants and make money operating power lines, how will they be able to charge for wheeling a neighbor's power? Can they

charge extra at times of peak demand? No final decisions have been made.

\$32 MILLION PER MILE

If you think driving in New York City is tough, try delivering electrons there. Geography, history, and politics have made the place a power wheeler's nightmare. It sits at the bottom of funnel-shaped New York State, and all the upstate and out-of-state transmission lines that could bring cheap power must go underground at Yonkers, just north of the city, or run through tunnels under the Hudson and other rivers. So even if there are gigawatts of cheap power available elsewhere, little of it can make its way into the city. On a hot day, Con Edison needs 11,000 megawatts of power but can import only 4,500 and must generate the rest in the city.

That helps keep residential prices in New York City, now 16.2 cents per kilowatt, the second highest in the continental U.S., after nuke-beleaguered Long Island. Con Ed, like utilities in many big cities, can't burn cheap coal for environmental reasons and must use natural gas or low-sulfur oil. In addition, its generators are inefficient.

and it pays a ton in state and city taxes. Why not just build more transmission lines? "It's easier to get permission to build a new generating plant than a new transmission line," says Jack Feinstein, a Con Ed vice president. Cheaper too: Running a new 345,000-volt power line underground from Yonkers to midtown Manhattan would cost \$650 million, Feinstein says.

California has similar problems. Nearby states produce vast amounts of cheap power, but California has only two major links with outsiders: a tangle of wires coming down from Oregon and another link that runs from Arizona toward L.A. Only 12,000 of the 40,000 megawatts California needs during peak demand can come from out-of-state generators.

CALIFORNIA DIVES IN

On Jan. 1, Californians will be able to buy power from anybody who offers it. That puts California way ahead of almost all other states, which have, at best, allowed a few trial programs. But getting California utilities to sign on to the plan and drop threats of lawsuits required political horse-trading that exacted a high

The volume of power that utilities sell to one another has boomed. At LG&E in Louisville, traders buy cheap power on the spot market.

Need Electricity? Call Your Broker

Electricity is turning into a commodity, bought and sold like any other.

Soon you'll have *lots* of places to buy your power.

BY BETHANY McLEAN

TRADERS SWIVEL IN THEIR CHAIRS, EYEING THE PHONES and the flashing computer screens. Second by second, they monitor commodity prices and weather conditions across the country. Tension runs high: A slight delay could cost millions. Sounds just like ... Louisville? Here on the trading floor of the local utility, LG&E (Louisville Gas & Electric), they're not swapping stocks and bonds; they're swapping electricity.

The deregulation of the electric utility business isn't merely uprooting ancient monopolies—it's also creating a whole new industry: "power marketing," the buying and selling of electricity on the open market. In fact, this already huge, rapidly developing business may become the biggest commodity market in the country. Scott Spiewak of the Power Marketing Association (yes, there's already an industry association), says about \$50 billion of power is changing hands on trading floors. Within five years, he predicts, power marketing will be a \$2 trillion business. What's especially impressive is that this is an industry that didn't exist a few years ago. Only in 1992 was the wholesale market (i.e., sales of electricity from one utility to another) opened to competition; the biggest part of the business—selling electricity to businesses and homeowners—hasn't even been deregulated yet. In the first half of 1997, almost 380 million megawatt-hours were traded, six times the amount traded during the same period in 1996.

As weird as it sounds, trading electricity isn't much different from trading soybeans, oil, or pork bellies. There are electricity options and futures contracts, for example. As with traditional commodity markets, electricity traders try to lock in prices or speculate on price volatility.

One significant difference from more conventional markets, however, is that there's no real way to store electricity—and that helps make electricity trading a volatile business. And if weather sweeps in or a plant goes down unexpectedly, an immediate shortage may result. Because of these sudden, dramatic imbalances in supply and demand, the price of power can soar from \$20 to \$150 per megawatt-hour almost instantly. Tim O'Neill, a managing director at Goldman Sachs, says that in a fully deregulated market, electricity prices may be more than twice as volatile as the stock market, making electricity the most volatile commodity in existence.

Even though power marketing is still new, it's already transforming the famously stodgy utility culture. Utilities used to do business much like kindergartners—they shared. Now they find themselves wheeling, dealing, and generally acting like competitive businesses.

The biggest culture shock facing utilities has come in the form of a whole new set of big, mean players: Wall Street in-

stitutions. Commodity trading is Wall Street's turf, after all, and electricity is too rich an opportunity to ignore. The biggest power marketing deal to date—a supply agreement for Oglethorpe Power, a cooperative in Georgia—clearly shows that the Street has arrived. Last fall Oglethorpe signed a contract with utility LG&E; in March 1997 it signed a second contract with Morgan Stanley Dean Witter. Each will supply half the electricity Oglethorpe's customers consume—worth well over \$5 billion over the life of the contracts.

This raises a question: Will people buy electricity from fast talkers in very expensive clothing? Customers have to believe their supplier will deliver those electrons every day, which would seem to give an edge to utilities. Morgan Stanley traders certainly can't run power plants. "Power plants give them the wilies—might get their suits all dirty," jokes Robert Hosfeld, Oglethorpe Power's vice president of power marketing.

Then again, soybean traders in Chicago aren't farmers. Oglethorpe has full faith in the electricity-supply capabilities of Morgan Stanley, which won the contract over Enron, the big natural-gas company—and arguably the toughest, most sophisticated power-marketing player of all. Morgan buys and sells the equivalent of 20% of the world's energy products every day, and its executives have no doubt it can handle this electricity deal.

Whoever comes to dominate this new industry, power marketing is changing the way people think about electricity. There are about 300 companies—old-line utilities, gas companies like Enron, investment banks, and others—battling for a share of this business. Soon many of them will be coming after consumers to... Imagine dialing your Morgan Stanley Dean Witter branch and charging your electricity supply for the month to your Discover card. Your broker, your power company. How's that for change?

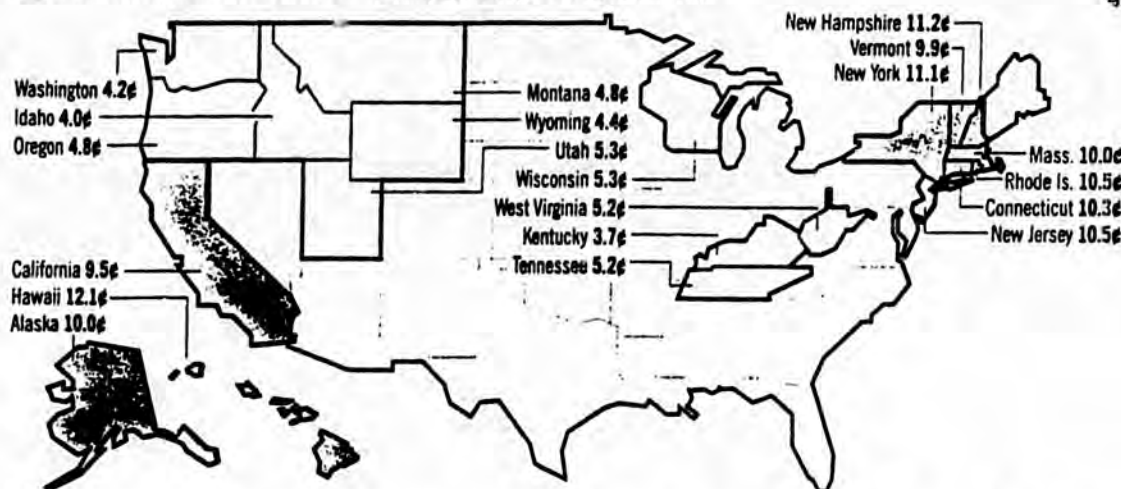


Power marketing in action

ELECTRICITY

THE 20 STATES WITH THE CHEAPEST—AND COSTLIEST—POWER

□ LOWEST rates per kilowatt-hour in 1996 □ HIGHEST rates per kilowatt-hour in 1996



price: direct, producer-to-user price competition will be thwarted for years.

Here's what's happening in California. First, to make sure the state's utilities don't overwhelm would-be competitors on the generation side of the business, regulators have pushed the utilities to sell off their gas-fired generating plants. California also rolled back rates the big private utilities can charge homeowners to what they were in June 1996. At about a dime, that's better than the 12 to 13 cents Californians had been paying, so complaints are few. Lower rate freezes apply for commercial and industrial customers.

Are the utilities screaming? No, because regulators also devised a process to help them recover losses on those "stranded," or devalued-by-competition, assets. Their costs will drop sharply in the next few years. Remember that California utilities, like others elsewhere, were forced to sign contracts for overpriced power generated by independent producers; many of these contracts were already due to expire in the next few years. If, as expenses drop, it then costs the utilities, say, only 7 cents to deliver a kilowatt, they get to pocket the 3 cents and use it to write off their overpriced, stranded assets. They have four years to make, buy, and deliver power as cheaply as possible. In 2002, the fixed price disappears, and California's big three utilities—Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric—will have a harder time recovering any remaining stranded costs. (Some version of California's plan will probably be adopted in other states.)

"Whoa," a California resident might say, "now that I can buy from anybody, why

can't I buy some of that 2.5-cent power, instead of the 10-cent stuff from SCE or PG&E?" Simple. That 2.5-cent or so cost of generating power is only about a quarter of your total bill. The rest is pretty well fixed. The new laws say California homeowners will still have to pay their utility for: transmission (0.7 cents), the wires and poles distributing electricity to your house (2.4 cents), and state-mandated help for the poor (0.1 cents). Billing and other services typically add another 0.4 cents. And everybody will have to pay an additional 3 to 4 cents to help the power companies pay off their stranded costs.

CALIFORNIA AUCTION

Even if you wanted to, you might not find cheaper electricity. Under the new rules in California, that power company in Utah with cheap electricity has no incentive to sell it to you at a bargain. More likely, those in Utah will get a better price by selling it to the soon-to-be-created California Power Exchange (PX), a nonprofit clearinghouse mandated by state officials.

Here's how it will work. Every day, the PX will take bids on the power it will need for each hour of the following day, and take the cheapest power offered. Anybody can buy or sell on the exchange. However, Cal-

ifornia's three big utilities must sell and buy all their electricity through the PX. Let's say that a company we'll call Cheapo Electric offers and sells ten megawatts of power at a penny per kilowatt for 7 A.M. the following day. But for 8 A.M., demand is expected to rise to 15 megawatts. Cheapo won't be able to provide enough one-penny power to meet all demand, but Outtastate Heat & Light offers the additional five megawatts at the next lowest price: 2 cents. Under the PX rules, both Cheapo and Outtastate get paid 2 cents for that hour of power, even though one offered power at a lower price.

By 3 P.M., with hot winds blowing in off the desert, California will need all the power it can find, and the out-of-state transmission lines are full. So ElectroGouge Illuminating, a startup that bought old, inefficient power plants when the California utilities auctioned them off, offers \$1.50 per kilowatt. If the PX pays ElectroGouge \$1.50 per kilowatt for that last bit of power, everybody else, even Cheapo, will get paid \$1.50. So in one day, exchange prices have fluctuated between \$0.01 and \$1.50.

Negotiating megawatts with a beady-eyed trader won't be much fun for the average corporate facilities manager.

LOWBALLERS FRUSTRATED

The Power Exchange is not great news for Enron, PacificCorp, and other

big power providers that hoped to come to California, offer cheap out-of-state power, and develop a cozy relationship with big industrial customers. Indeed, the PX is another inconvenient product of politics, a stopgap measure to help utilities cover stranded costs. "It will not be easy for a customer to beat the PX price," says Alex Miller, vice president for California operations at PacificCorp, an Oregon utility

with coal plants in several Western states. That's because with Edison and PG&E buying from the PX and tacking on the same transmission and stranded-cost charges as other providers, everybody's price will be about the same.

Lincoln Anderson, the head of Enron's operations in California, is rethinking how Enron will attack the California electricity business. He can't succeed for now, he says, by treating retail electricity as a commodity to be sold at the lowest price. Instead, Enron intends to build relationships with customers by delivering energy-related services. They can, for instance, finance and install new heating, cooling, and lighting equipment.

California's retail electricity business will change sharply in 2002, though, says Anderson. By then prices will move freely. The 3- or 4-cent surcharge to help the utilities pay stranded costs will disappear, and the PX may be disbanded. With rapidly fluctuating prices, he says, Enron will flourish. Want a guaranteed flat rate per kilowatt for two years? Want one contract price for your factory's steady electric load, and another that limits the top price you'll pay per kilowatt during peak periods? Enron, and others, will offer that.

AlliedSignal's \$15,000, refrigerator-sized generator will let small companies make their own power and could threaten many utilities.

BE PREPARED

Negotiating megawatts with a beady-eyed Enron trader won't be much fun for the average corporate facilities managers.

So get ready now, says Catherine Luthin, a consultant whose work includes managing Columbia University's \$11-million-per-year electric bill. Big commercial and industrial power users should analyze how their buildings and factories use electricity, she says. "You should have at least a year's worth of data, gathered in 15-minute increments." Most utilities will collect the information for a small fee. Of what use is this data? Power prices will probably fluctuate wildly, every hour, once competition starts. You may have negotiated a flat fee with Enron for up to two megawatts of power a day, but could have to pay a fortune for anything extra you use on a hot August afternoon.

By studying how and when each facility uses electricity, a company will know how to cut power consumption appropriately or negotiate favorable power-supply contracts. Several firms already sell software that helps companies analyze their electricity usage.

THE MIGHTY MICROTURBINE

If you think the utilities get to relax once they've sold off their generators, cozy in the thought of all those billions' worth of power lines running down Main Street, you're wrong. There is a new threat: the microturbine.

In big cities, where the cost of providing electricity on wires be-

low ground is eight times higher than providing it on poles, an overwhelming portion of every customer's electric bill is for distribution—the wires connected to

your house or office. What if you decide you don't want to pay those distribution charges anymore?

AlliedSignal, the jet engine and auto parts company, hopes you will detach from the power lines and make your own electricity. The company has developed a line of small generators, including one for \$15,000

There is a new threat that will come to haunt utilities. It is the microturbine. Con Edison executives pooh-pooh it.



that can produce power for 3.5 to 4.3 cents per kilowatt-hour. It appears to be a masterpiece of simplicity: a turbine, with one moving part, that emits virtually no noise or pollution and can burn natural gas. Heat from the exhaust can be used to boil water or warm a building. It probably won't be economical for a home, but a Taco Bell stand in Brooklyn, say, which probably uses 75 kilowatts an hour, could pay it off in two years, claims Tony Prophet, an Allied executive.

Executives at Con Ed pooh-pooh the threat. New York real estate is too valuable to waste on generator space, says one. Apartment dwellers wouldn't want a high-pressure gas line running to a rooftop generator, scoffs another. Con Ed's counterpart in Chicago, however, is not so sanguine. When the Allied generators are mass-produced next year, Commonwealth Edison's parent company will have an exclusive franchise to sell them in the territory of all rival utilities in ten neighboring states.

The electricity business hasn't changed much over the past 60 years, so it isn't surprising that there is still a strain of denial among those—certain utility officials in New York, say—who'd rather see things continue as they were. But when a supposedly quiescent, fossilized utility like Commonwealth Edison contemplates assaulting its neighbors, it seems inevitable that competition will wring every inefficiency from this long-protected industry. This is a revolution, it's already begun, and it's about time. ■

STEVE LABOWITZ

COLUMBIA STEEL CASTING CO., INC., an
Oregon corporation, Plaintiff-Appellee,
v.
PORTLAND GENERAL ELECTRIC COMPANY,
an Oregon corporation, Defendant-Appellant.
COLUMBIA STEEL CASTING CO., INC., an
Oregon corporation, Plaintiff-Appellant,
v.
PORTLAND GENERAL ELECTRIC COMPANY,
an Oregon corporation; Public Utility
Commission of the State of Oregon, Defendants-
Appellees.

Nos. 93-35902, 93-35958.

United States Court of Appeals,
Ninth Circuit.

Argued and Submitted May 3, 1995.

Decided July 20, 1995.

Opinion Withdrawn Dec. 27, 1996.

Decided Dec. 27, 1996.

As Amended on Denial of Rehearing
and Rehearing En Banc
April 3, 1997.

Industrial customer brought action against electric utilities and Oregon Public Utility Commission (PUC), alleging that utilities had conspired to divide market for electricity in city in violation of Sherman Antitrust Act, and that purported division of city into exclusive service territories was beyond scope of PUC order. Cross-motions for summary judgment were filed. The United States District Court for the District of Oregon, Helen J. Frye, J., 770 F.Supp. 562 and 1993 WL 36071, granted summary judgment for customer, rejecting utility's contention that it was entitled to federal antitrust immunity under state-action doctrine. Utility moved for reconsideration. The District Court, 1992 WL 161031 and 1993 WL 191637, denied motions. Utility appealed, and customer cross-appealed and moved for attorney fees on appeal. The Court of Appeals, William A. Norris, Circuit Judge, held that: (1) PUC did not forthrightly state policy of state that was clear in its purpose to displace competition in city market with territorial monopolies and, thus, utility was not protected under state-action doctrine from liability to customer under Act section governing combinations in

restraint of trade; (2) under Oregon law, PUC's subsequent order, declaring that it had intended in its order issued 20 years earlier to displace competition in city with regulation, was not entitled to preclusive effect as to issue of availability of antitrust state-action doctrine; (3) alleged foreseeability of territorial division of city market, as result of PUC order approving exchange of property and customers between utilities in city, did not render utility entitled to immunity under state-action doctrine; (4) utility's refusal to wheel another utility's electricity to customer's plant was overt act that restarted statute of limitations on customer's claim against refusing utility; (5) utility was not entitled to regulatory justification defense or business justification defense; (6) antitrust immunity under Noerr-Pennington doctrine for attempt to influence legislation or public officials was inapplicable to utility; (7) filed rate doctrine did not apply so as to bar customer from recovering damages for utility's violation of Act; and (8) customer was entitled to damages from utility beginning with other utility's earlier refusal to sell customer power at its lower rates, rather than beginning with that utility's later entry into contract with customer for provision of electricity to customer's plant.

Affirmed in part, vacated in part, and motion for attorney fees on appeal granted.

Opinion, 103 F.3d 1446, superseded.

[1] MONOPOLIES $\S$ 12(1.5)

265k12(1.5)

Agreement among competitors to allocate territories is per se violation of Sherman Antitrust Act section governing combinations in restraint of trade. Sherman Act, $\S$ 1, as amended, 15 U.S.C.A. $\S$ 1.

[2] MONOPOLIES $\S$ 12(15.6)

265k12(15.6)

State-action doctrine cloaks anticompetitive conduct with antitrust immunity only if state's intent to displace competition with regulation is clearly articulated and affirmatively expressed as state policy. Sherman Act, $\S$ 1 et seq., as amended, 15 U.S.C.A. $\S$ 1 et seq.

[3] MONOPOLIES $\S$ 12(15.6)

265k12(15.6)

Midcal test for federal antitrust state-action doctrine is rigorous one that ensures that private parties can claim state-action immunity from Sherman Antitrust Act liability only when their anticompetitive acts are truly product of state regulation. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[4] MONOPOLIES ⇨ 12(15.6)

265k12(15.6)

Midcal test for federal antitrust state-action doctrine guarantees that private party's anticompetitive conduct promotes state policy, rather than merely party's individual interests, and limits spread of immunity that is disfavored, much as are repeals of antitrust laws by implication, because of Congress' overarching and fundamental policies protecting competition. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[5] MONOPOLIES ⇨ 12(16)

265k12(16)

Under state-action doctrine, to the extent that public utility provider obtains lawful and valid contract for allocation of territories and customers through provisions of Oregon territorial allocation statutes, that provider is immune from federal antitrust violations. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.; ORS 758.400-758.475.

[6] MONOPOLIES ⇨ 12(16)

265k12(16)

For protection under federal antitrust state-action doctrine, under Oregon statutory provisions authorizing Oregon Public Utility Commission (PUC) to approve contracts between public utilities allocating exclusive service territories, utility companies must enter into contract which allocates service territories and designates service to customers, and utility companies must make application to and receive order from PUC approving and establishing allocation of these territories; these requirements must be met to receive immunity which is provided by state statutory scheme from federal antitrust laws. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.; ORS 758.400-758.475.

[6] PUBLIC UTILITIES ⇨ 114

317Ak114

For protection under federal antitrust state-action doctrine, under Oregon statutory provisions authorizing Oregon Public Utility Commission

(PUC) to approve contracts between public utilities allocating exclusive service territories, utility companies must enter into contract which allocates service territories and designates service to customers, and utility companies must make application to and receive order from PUC approving and establishing allocation of these territories; these requirements must be met to receive immunity which is provided by state statutory scheme from federal antitrust laws. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.; ORS 758.400-758.475.

[7] MONOPOLIES ⇨ 12(16)

265k12(16)

Oregon Public Utility Commission (PUC) did not forthrightly state policy of state that was clear in its purpose to displace competition in city market with territorial monopolies, either in its initial order approving exchange of property, facilities, and customers between electric utilities in city or in its subsequent orders, and, thus, utility was not protected under state-action doctrine from liability to industrial customer under Sherman Antitrust Act section governing combinations in restraint of trade; neither initial order nor agreement it approved said anything about exclusive service territories in city, initial order did not cite statutory provisions governing PUC authority to approve contracts allocating exclusive service territories in approving exchange of property, and subsequent orders did not amend initial order to clarify it as expression of state policy to displace competition but, at best, recited that utilities had stopped competing within territories they had defined. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480, 758.400-758.475; Portland, Or., Ordinance 134416 (Apr. 26, 1972).

[8] MONOPOLIES ⇨ 12(16)

265k12(16)

Oregon statutory provisions authorizing Oregon Public Utility Commission (PUC) to approve contracts between public utilities allocating exclusive service territories did not themselves satisfy clear articulation prong of Midcal test for state-action immunity from liability under Sherman Antitrust Act section governing combinations in restraint of trade, for purposes of industrial customer's action against electric utility, which had agreed to territorially divide city with another electric utility, alleging that first utility and other utility had conspired to divide market for electricity in city; state's clearly

articulated policy was to have Commission decide whether to sanction anticompetitive conduct and, thus, Court of Appeals had to look to decisions of Commission to determine whether first utility's conduct was part of clearly articulated state policy. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 758.400-758.450.

[9] MONOPOLIES ⇨ 12(15.6)
265k12(15.6)

Clear articulation and active supervision Midcal elements for federal antitrust state-action doctrine are both directed at ensuring that particular anticompetitive mechanisms operate because of deliberate and intended state policy. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[10] MONOPOLIES ⇨ 12(15.6)
265k12(15.6)

Under federal antitrust state-action doctrine, mere state authorization, approval, encouragement, or participation in restrictive private conduct confers no antitrust immunity. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[11] ELECTRICITY ⇨ 8.1(4)
145k8.1(4)

Under Oregon law, order of Oregon Public Utility Commission (PUC), declaring that it had intended, in its order issued 20 years earlier, to displace competition in city with regulation, was not entitled to preclusive effect as to issue of availability of antitrust state-action doctrine in industrial customer's action against electric utility, alleging violation of Sherman Antitrust Act section governing combinations in restraint of trade; issue decided in order was whether earlier PUC had intent to approve allocation of exclusive service territories, but state-action immunity issue turned on whether displacement of competition with monopolies was clearly articulated and affirmatively expressed as state policy. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480, 758.400-758.475; Portland, Or., Ordinance 134416 (Apr. 26, 1972).

[12] JUDGMENT ⇨ 715(1)
228k715(1)

Under Oregon law, one tribunal may give preclusive effect to prior determination of issue by another tribunal only if issue in the two proceedings is identical.

[13] JUDGMENT ⇨ 713(1)
228k713(1)

Under Oregon law, second tribunal may give preclusive effect to earlier decision on issue by another tribunal only if party sought to be precluded has had full and fair opportunity to be heard on that issue.

[14] MONOPOLIES ⇨ 12(15.6)
265k12(15.6)

State-action immunity is question of federal antitrust law that turns on clarity of state's expression of its policy, not subjective intent of its policymakers. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[15] MONOPOLIES ⇨ 12(15.6)
265k12(15.6)

Federal antitrust state-action immunity is not issue of fact, and cannot be decided simply by ferreting out extrinsic evidence in effort to ascertain subjective intent of state; issue of state-action immunity must be decided by applying rigorous test of whether state clearly articulated and affirmatively expressed its intent to displace competition with regulation as matter of state policy. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[16] JUDGMENT ⇨ 815
228k815

Order or judgment is not entitled to full faith and credit if issuing tribunal had no subject matter jurisdiction over matter before it. U.S.C.A. Const. Art. 4, § 1.

[17] MONOPOLIES ⇨ 12(16)
265k12(16)

Alleged foreseeability of territorial division of city market, as result of Oregon Public Utility Commission (PUC) order approving exchange of property and customers between electric utilities in city, did not render utility entitled to immunity under state-action doctrine from liability to industrial customer under Sherman Antitrust Act section governing combinations in restraint of trade, where, in its order, PUC did not expressly authorize utility to maintain exclusive service territory but, rather, merely approved exchange of property and customers. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480, 758.400-758.475; Portland, Or., Ordinance 134416 (Apr. 26, 1972).

[18] FEDERAL COURTS ⇨612.1
170Bk612.1

Court of Appeals would exercise its discretion to consider issue raised for first time on appeal by electric utility and Oregon Public Utility Commission (PUC), that federal antitrust state-action immunity applied to utility because territorial division of city market was foreseeable result of PUC's prior order approving exchange of property and customers between electric utilities in city, in industrial customer's action against utility, alleging violation of Sherman Antitrust Act section governing combinations in restraint of trade, where foreseeability issue was pure issue of law, and consideration of issue would not prejudice customer. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480, 758.400-758.475; Portland, Or., Ordinance 134416 (Apr. 26, 1972).

[19] FEDERAL COURTS ⇨612.1
170Bk612.1

Court of Appeals will review issue that has been raised for first time on appeal under certain narrow circumstances, including when issue is purely one of law.

[20] MONOPOLIES ⇨12(15.6)
265k12(15.6)

Express authorization is necessary predicate for foreseeability test regarding reach of federal antitrust immunity under state-action doctrine. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

[21] MONOPOLIES ⇨12(16)
265k12(16)

In absence of state-action immunity, agreement between electric utilities to territorially divide city market for electricity constituted per se violation of Sherman Antitrust Act section governing combinations in restraint of trade. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1.

[22] LIMITATION OF ACTIONS ⇨58(1)
241k58(1)

Electric utility's refusal to wheel another utility's electricity to industrial customer's plant was overt act that restarted statute of limitations on customer's claim against refusing utility under Sherman Antitrust Act section governing combinations in restraint of trade, based on prior agreement between utilities to territorially divide city between them;

utility's refusal was not mere reaffirmation of utilities' agreement to stop competing, because agreement was not permanent and final decision that controlled utility's later act. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1.

[23] MONOPOLIES ⇨12(2)
265k12(2)

Electric utility was not entitled to regulatory justification defense or business justification defense in industrial customer's action against utility, alleging violation of Sherman Antitrust Act section governing combinations in restraint of trade, arising from utility's refusal to wheel another utility's electricity to customer's plant after Oregon Public Utility Commission (PUC) order approving exchange of property and customers between utilities in city, where order did not approve allocation of exclusive service territories, and language of order was permissive. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480, 758.400-758.475, 758.450(2); Portland, Or., Ordinance 134416 (Apr. 26, 1972).

[24] MONOPOLIES ⇨12(16.5)
265k12(16.5)

Antitrust immunity under Noerr-Pennington doctrine was inapplicable to electric utility in industrial customer's action alleging violation of Sherman Antitrust Act section governing combinations in restraint of trade, arising from utility's refusal to wheel another utility's electricity to customer's plant after Oregon Public Utility Commission (PUC) order approving contract for exchange of property and customers between utilities in city; applying to agency for approval of anticompetitive contract was not "lobbying activity" within meaning of doctrine, and liability was not based on filing application that resulted in order approving contract but, but on agreeing with other utility to replace competition with area monopolies. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1; ORS 757.480; Portland, Or., Ordinance 134416 (Apr. 26, 1972). See publication Words and Phrases for other judicial constructions and definitions.

[25] MONOPOLIES ⇨12(16.5)
265k12(16.5)

Applying to administrative agency for approval of anticompetitive contract is not "lobbying activity" within meaning of Noerr-Pennington doctrine governing federal antitrust immunity for attempt to

influence legislation or public officials. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

See publication Words and Phrases for other judicial constructions and definitions.

[26] MONOPOLIES ⇨ 12(2)

265k12(2)

Filed rate doctrine did not bar industrial customer from recovering damages for electric utility's violation of Sherman Antitrust Act section governing combinations in restraint of trade, based on utility's refusal to wheel another utility's electricity to customer's plant due to agreement between utilities to territorially divide city, despite contention that refusing utility could not charge rate offered by other utility or transfer customer to other utility without Oregon Public Utility Commission (PUC) approval; conduct challenged was not refusal to sell electricity to customer at lower rate but, rather, noncompetition agreement between utilities that prevented customer from buying electricity at other utility's lower prices. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1.

[27] MONOPOLIES ⇨ 12(2)

265k12(2)

"Filed rate doctrine" generally forbids recovery of treble damages under Sherman Antitrust Act based on payment of rates that are established by regulated tariffs, even if defendants engaged in illegal price-fixing. Sherman Act, § 1 et seq., as amended, 15 U.S.C.A. § 1 et seq.

See publication Words and Phrases for other judicial constructions and definitions.

[28] MONOPOLIES ⇨ 12(2)

265k12(2)

Industrial customer's requirements contract to purchase electricity from electric utility did not bar customer from suing utility under Sherman Antitrust Act for agreeing with another electric utility to stop competing in city market. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1.

[29] MONOPOLIES ⇨ 28(9)

265k28(9)

Industrial customer was entitled to damages beginning with electric utility's earlier refusal to sell customer power at its lower rates, rather than beginning with that utility's later entry into contract with customer for provision of electricity to

customer's plant, in customer's action against another electric utility, arising from other utility's refusal to wheel first utility's electricity to plant due to agreement between utilities to territorially divide city, alleging violation of Sherman Antitrust Act section governing combinations in restraint of trade; first utility was coconspirator at time of its initial refusal, and other utility was liable for acts of first utility in furtherance of their conspiracy not to compete in city. Sherman Act, § 1, as amended, 15 U.S.C.A. § 1.

*1431 Allan M. Garten and Barbee B. Lyon, Tonkon, Torp, Galen, Marmaduke & Booth, Portland, Oregon, for Portland General Electric Company.

Michael C. Donen, Heller, Ehrman, White & McAuliffe, Portland, Oregon, for Columbia Steel Casting Co., Inc.

Jas. J. Adams, Assistant Attorney General, Oregon Department of Justice, Salem, Oregon, for the Public Utility Commission of Oregon.

Robert B. Nicholson and David Seidman, United States Department of Justice, Washington, DC, for the United States as amicus curiae.

Appeals from the United States District Court for the District of Oregon, Helen J. Frye, District Judge, Presiding. D.C. Nos. CV-90-00592-HJF, CV-90-00524-HJF.

*1432 ORDER

The opinion filed on December 27, 1996, 103 F.3d 1446, is amended as follows:

[Editor's Note: Amendments incorporated for purpose of publication.]

With the above amendments, the panel, as constituted above, has voted unanimously to deny the petition for rehearing. Judge Browning has voted to reject the suggestion for a rehearing en banc, and Judges Reavley and Norris have recommended the same.

The full court has been advised of the suggestion for en banc rehearing and no judge of the court has requested a vote on the suggestion for rehearing en banc. Fed.R.App.P. 35(b).

The petition for rehearing is DENIED, and the suggestion for a rehearing en banc is REJECTED.

Before: BROWNING, REAVLEY (FN*), and NORRIS, Circuit Judges.

FN* The Honorable Thomas M. Reavley, Senior Circuit Judge, United States Court of Appeals for the Fifth Circuit, sitting by designation.

ORDER

The Petition for Rehearing, filed August 3, 1995, is hereby GRANTED.

The Opinion filed July 20, 1995, and reported at 60 F.3d 1390, 1396 (9th Cir.1995), is WITHDRAWN and the attached Opinion is ordered filed instead.

OPINION

WILLIAM A. NORRIS, Circuit Judge:

TABLE OF CONTENTS

I. Facts and Procedural History	1433
II. State-Action Immunity	1436
A. The Midcal Clear Articulation Requirement	1436
B. Issue Preclusion	1441
C. Foreseeability: PGE's New Argument on Appeal	1442
III. PGE's Other Defenses	1444
A. Statute of Limitations	1444
B. Justification Defenses	1445
C. The Noerr-Pennington Doctrine	1445
D. The Filed Rate Doctrine	1446
IV. Damages	1446
V. Columbia Steel's Cross-Appeal on Damages	1447
VI. Conclusion	1447

This appeal arises out of an antitrust action that Columbia Steel Casting Co., a large consumer of electric power in Portland, Oregon, brought against two electric utilities, Portland General Electric (PGE) and Pacific Power & Light (PP & L), charging them with dividing the city of Portland into exclusive service territories in violation of the Sherman Act, 15 U.S.C. §§ 1-2. (FN1) PGE raised a state-action immunity defense on the basis of a 1972 order of the Oregon Public Utility Commission which, PGE argued, approved a division of the Portland market into exclusive service territories. See *Parker v. Brown*, 317 U.S. 341, 63 S.Ct. 307, 87 L.Ed. 315 (1943). The district court rejected this state-action immunity defense and awarded summary judgment to Columbia Steel. PGE appeals the summary judgment in favor of Columbia Steel and

the denial of its own motion for summary judgment. Columbia Steel cross-appeals the amount of its damage *1433 award. We affirm the summary judgment in favor of Columbia Steel on PGE's antitrust liability and vacate and remand the damage award for further proceedings.

FN1. Only PGE is a party to this appeal.

I. Facts and Procedural History

The facts are undisputed. Until 1972, PGE and PP & L competed for customers throughout Portland. This competition resulted in the duplication of transmission lines and poles, substations, and transformers throughout the city. For many years the two utilities attempted to gain regulatory approval for a division of the Portland market into exclusive service territories. In 1962, for example,

PGE applied to Oregon's Public Utilities Commission (OPUC) for an allocation of an exclusive service territory in the city of Portland. [FN2] These efforts to secure exclusive service territories within Portland were unsuccessful, however, in part because of opposition from the city. Portland had a longstanding policy of encouraging competition among utilities, and the city charter provided that "[n]o exclusive franchises shall be granted." Portland City Charter, § 10-206. See, e.g., Portland, Or., Resolution 28879 (1962) (opposing PGE's 1962 application to the OPUC for an "allocation of exclusive areas for electric service within ... Portland").

FN2. In 1961, the Oregon legislature enacted a statute vesting in the OPUC exclusive authority to approve the creation of exclusive service territories in order to promote "[t]he elimination and future prevention of duplication of utility facilities." Or.Rev.Stat. § 758.405. The statute authorizes the OPUC to approve contracts between competitors that divide markets into exclusive service territories. Or.Rev.Stat. §§ 758.410-758.425, 758.450.

In 1972, PGE and PP & L jointly submitted to the city of Portland a plan to eliminate competition between them by dividing the city into exclusive service territories. This plan provided, inter alia, that "[s]ubject to the necessary regulatory approvals ... it is proposed that Parcels A & B [two defined areas within the city of Portland] be served exclusively by PP & L," and that "[s]ubject to the necessary approvals, it is proposed that Parcel C [a defined area within the city of Portland] ... be exclusively served by PGE." CR 269, exh. 47 at 2-3.

The Portland City Council disapproved the utilities' 1972 plan to displace competition with territorial monopolies in Portland. The City Council agreed, however, that the duplication of facilities should be eliminated for aesthetic, safety, and economic reasons. In the ordinance it passed, the City Council declared, "both [PGE and PP & L] operate under non-exclusive franchises and ... the obligation to supply properties within the City must remain binding upon both companies." Portland, Or., Ordinance 134416 (Apr. 26, 1972). The only action that the ordinance approved was "the sale, transfer and exchange of plant and property between PGE and PP&L." [FN3] *Id.*

FN3. The Ordinance states, in part:

An Ordinance consenting to exchange of certain property within the City between [PGE] and [PP & L] on certain conditions in order to permit reduction of poles and wires and duplication of facilities in various areas of the City.

The City of Portland ordains: Section 1. The Council finds that both [PGE] and [PP & L] operate electric power systems which serve patrons within the City, that both companies operate under non-exclusive franchises and that the obligation to supply properties within the City must remain binding upon both companies; that at the present time, however, in many areas of the City poles and wires are duplicated between the companies for service purposes; that to reduce the visual impact of duplicating facilities, to promote safety, to promote economy, to simplify subsequent undergrounding and to work toward the lowest possible rates for users within the City, an interchange of properties between the companies should be permitted as hereinafter set forth; ... now, therefore, the City does by this ordinance consent to the sale, transfer and exchange of plant and property between [PGE] and [PP & L] as follows

....
Portland, Or., Ordinance 134416 (Apr. 26, 1972) (emphasis added).

After securing the City Council's approval of the exchange of utility properties, but not the establishment of exclusive service territories, PGE and PP & L entered into an agreement, dated July 18, 1972 (the "1972 Agreement"), which they submitted to the OPUC for approval. In contrast to the plan submitted to the Portland City Council, the 1972 Agreement said nothing about exclusive service territories in Portland. The "whereas" *1434 clauses of the 1972 Agreement recited that one of its purposes was to comply with the terms of the Portland ordinance, which had approved an exchange of plant and property, but had disapproved exclusive service territories. The 1972 Agreement recited:

WHEREAS, [PGE] and [PP & L] wish to provide for the elimination of duplicating electric facilities in [the city of Portland]; and

WHEREAS, the City of Portland, by Ordinance No. 134416, passed April 26, 1972, effective May 26, 1972, consented to the exchange by [PGE] and [PP & L] of certain properties located within the city;

NOW, THEREFORE, in order to implement the elimination of said duplicating facilities and to comply with Ordinance 134416, it is agreed....

1972 Agreement at 1-2.

The 1972 Agreement used the following language to effect the exchange of facilities:

1. Exchange of Facilities

(a) [PP & L] shall transfer and convey to [PGE] and [PGE] shall acquire from [PP & L] all of the electric distribution plant, including distribution substations, poles, lines, transformers, meters, related distribution facilities, and all easements necessary for the operation thereof, owned, operated and maintained by [PP & L] in ... the area [in Portland] designated as Parcel C....

(b) [PGE] shall transfer and convey to [PP & L] and [PP & L] shall acquire from [PGE] all of the electric distribution plant, including distribution substations, poles, lines, transformers, meters, related distribution facilities, and all easements necessary for the operation thereof, owned, operated and maintained by [PGE] in the areas [in Portland] designated as Parcels A and B....

1972 Agreement at 2-3.

The 1972 Agreement was approved by an order of the OPUC issued in December 1972. The 1972 Order provided, in relevant part:

The Commissioner's approval is needed prior to the sale, lease, assignment or other disposition of public utility property pursuant to ORS 757.480.... On July 18, 1972, [PP & L] and [PGE] entered into an agreement whereby an exchange of property and utility facilities would be made between [PGE and PP & L] in the City of Portland.... This exchange ... also involves the transfer of customers from one party to the other.

....
ORDERED that [PP & L] may transfer to [PGE] electric distribution plant ... situated within or used for providing utility service within the boundaries of Parcel A ... [and] Parcel B....

ORDERED that [PGE] may transfer to [PP & L] all electric distribution plant ... used for providing utility service within the boundaries of [Parcel C]....

....
ORDERED that the manner and method of accomplishing the transfer and exchange of property, facilities and customers, and the terms and conditions governing this transfer, shall be provided by that agreement between the companies herein, dated July 18, 1972.

Pub. Util. Comm'n of Or., Order 72-970 (Dec. 15,

1972) (the "1972 Order"). [FN4]

FN4. The only reference to customer accounts in the 1972 Agreement is in Section 7, which provides in relevant part:

7. Transfer of Customer Accounts

The transfer of customer accounts between [PGE] and [PP & L] shall commence on July 24, 1972, and shall be coordinated so that the revenues from the sales of electricity of each company will remain substantially the same over the period required to accomplish transfer of all customers involved....

There is no reference to customer accounts in Section 1 of the 1972 Agreement, which provides for the exchange of facilities. In referring to the transfer of customers, Section 7 does not use the "shall transfer and convey" language used in Section 1. Thus the language and structure of the 1972 Agreement, as well as the language of the 1972 Order quoted in the text, suggest that the transfer of customers was treated as a necessary incident to the exchange of facilities. For a further discussion of the transfer of customers, see *infra* pp. 1456-57.

In approving the exchange of property in the city of Portland, the OPUC did not cite any of the statutory provisions that give the OPUC its authority to approve contracts between *1435 utility companies allocating exclusive service territories. See Or.Rev.Stat., ch. 758 ("Utility ... Territory Allocation ..."). [FN5] Unlike the Portland City Council ordinance—which had expressly disapproved exclusive service territories—but like the 1972 Agreement, the 1972 Order said nothing about exclusive service territories in Portland. The OPUC cited as authority for its approval of the 1972 Agreement Chapter 757 of the Oregon Revised Statutes ("Utility Regulation Generally"), specifically Or.Rev.Stat. § 757.480, [FN6] which gives the OPUC authority to approve the sale, lease, assignment or other disposition of public utility property.

FN5. Chapter 758 of the Oregon Revised Statutes speaks of "allocated" territories and defines that term in a way that means exclusive service territories. Section 758.400(1) defines "allocated territory" as "an area with boundaries established by a contract between persons furnishing a similar utility service and approved by the commission or established by an order of the commission approving an application for the allocation of territory". Or.Rev.Stat. § 758.400(1). Section 758.410(1) permits "[a]ny person providing a utility service [to] contract with any other person providing a similar

utility service for the purpose of allocating territories and customers between the parties and designating which territories and customers are to be served by which of said contracting parties." Or.Rev.Stat. § 758.410(1). Section 758.425 authorizes the OPUC to approve the "contract as filed" and provides that "[i]f the commission approves [the] contract ... the contract shall be deemed to be valid and enforceable...." Or.Rev.Stat. § 758.425. Section 758.450(2) provides that "no other person shall offer, construct or extend utility service in or into an allocated territory." Or.Rev.Stat. § 758.450(2).

FN6. Section 757.480 provides in pertinent part:

(1) No public utility doing business in Oregon shall, without first obtaining the commission's approval of such transaction:

(a) Sell, lease, assign or otherwise dispose of the whole of the property of such public utility necessary or useful in the performance of its duties to the public or any part thereof of a value in excess of \$10,000, or sell, lease, assign or otherwise dispose of any franchise, permit, or right to maintain and operate such public utility or public utility property, or perform any service as a public utility;

...

(2) Every such sale, lease, assignment, mortgage, disposition, encumbrance, merger or consolidation made other than in accordance with the order of the commission authorizing the same is void.

Or.Rev.Stat. § 757.480.

After the OPUC issued its 1972 Order, PGE and PP & L stopped competing with each other in Portland. Each utility served customers exclusively in the parcels in which it had acquired the electric distribution facilities of the other.

Columbia Steel operates a steel casting plant located in the area which PGE began serving exclusively after the issuance of the 1972 Order. In 1987, Columbia Steel asked PP & L to service its plant because PP & L's rates were lower than PGE's. PP & L refused, citing the fact that the plant was located in the territory being served exclusively by PGE.

In 1989, Columbia Steel again asked PP & L to service its casting plant. This time, PP & L agreed and offered to enter into a supply contract with Columbia Steel. PGE objected, however, citing its 1972 Agreement with PP & L. PGE took the position that the 1972 Agreement gave it the

exclusive right to service Columbia Steel's plant because it was located in the service territory allegedly "allocated" to PGE by the 1972 Agreement. Undeterred, Columbia Steel wrote PGE on May 30, 1990, asking it to "wheel" electricity generated by PP & L to the casting plant until PP & L could build a substation which would enable it to deliver power directly to the plant. PGE refused, reasserting that it had the exclusive right to service Columbia Steel's plant.

[1] On June 19, 1990, Columbia Steel filed this antitrust action against PGE, PP & L, and the OPUC, on the theory that the division of Portland into exclusive service territories violated the Sherman Act, 15 U.S.C. §§ 1- 2. [FN7] The defendants raised the *1436 state-action doctrine as an affirmative defense, contending that the division of the Portland market was cloaked with antitrust immunity by the 1972 Order of the Oregon OPUC approving the 1972 Agreement.

FN7. An agreement among competitors to allocate territories is a per se violation of § 1 of the Sherman Act. E.g., *Palmer v. BRG of Georgia, Inc.*, 498 U.S. 46, 49-50, 111 S.Ct. 401, 402-03, 112 L.Ed.2d 349 (1990); *Outer Tail Power Co. v. United States*, 410 U.S. 366, 378, 93 S.Ct. 1022, 1030, 35 L.Ed.2d 359 (1973) (contracts that purported to restrict defendant's ability to wheel power "were 'in reality, territorial allocation schemes,' " and "were per se violations of the Sherman Act") (citation omitted).

In July 1990, PP & L entered into a contract with Columbia Steel and began servicing the casting plant in July 1991, when PGE began transmitting PP & L's power to the plant over PGE's power line. Columbia Steel later dismissed all its claims against PP & L, which explains why PP & L is not a party to this appeal.

On July 3, 1991, the district court rejected PGE's state-action defense in an order granting Columbia Steel's motion for partial summary judgment. *Pacificorp v. Portland Gen. Elec. Co.*, 770 F.Supp. 562 (D.Or.1991). The district court held that the OPUC's 1972 Order did not articulate a state policy to allocate exclusive service territories in Portland as required by *California Retail Liquor Dealers Ass'n v. Midcal Aluminum, Inc.*, 445 U.S. 97, 105, 100 S.Ct. 937, 943, 63 L.Ed.2d 233 (1980). *Pacificorp*, 770 F.Supp. at 569-71. As the district court

interpreted the OPUC's 1972 Order, it approved a one-time exchange of property and customer accounts, but not an allocation of exclusive service territories. *Id.* at 570-71.

On February 4, 1993, the district court granted summary judgment for Columbia Steel on the remaining issues, ruling that PGE had violated section 1 of the Sherman Act in agreeing with PP & L not to compete in the Portland market. The court awarded Columbia Steel \$508,425 in treble damages and \$901,671.62 in attorneys' fees and costs.

II. State-Action Immunity

A. The Midcal Clear Articulation Requirement

[2][3][4] The state-action doctrine cloaks anticompetitive conduct with antitrust immunity only if the state's intent to displace competition with regulation is "clearly articulated and affirmatively expressed as state policy." *Midcal*, 445 U.S. at 105, 100 S.Ct. at 943 (upholding state wine pricing system because "[t]he legislative policy is forthrightly stated and clear in its purpose to permit resale price maintenance"). The *Midcal* test is a "rigorous" one that "ensure[s] that private parties [can] claim state-action immunity from Sherman Act liability only when their anticompetitive acts [are] truly the product of state regulation." *Patrick v. Burget*, 486 U.S. 94, 100, 108 S.Ct. 1658, 1662, 100 L.Ed.2d 83 (1988). It guarantees that the "private party's anticompetitive conduct promotes state policy, rather than merely the party's individual interests," *id.* at 101, 108 S.Ct. at 1663, and limits the spread of an immunity that is "disfavored, much as are repeals [of the antitrust laws] by implication." *FTC v. Ticor Title Ins. Co.*, 504 U.S. 621, 636, 112 S.Ct. 2169, 2176, 119 L.Ed.2d 410 (1992), because of Congress's "overarching and fundamental policies" protecting competition. *City of Lafayette v. Louisiana Power & Light Co.*, 435 U.S. 389, 398-99, 98 S.Ct. 1123, 1129, 55 L.Ed.2d 364 (1978). See also Phillip Areeda & Donald F. Turner, *Antitrust Law* ¶ 214e (1978).

[5][6] The district court acknowledged that the provisions of chapter 758 of the Oregon Revised Statutes, which authorize the OPUC to approve contracts between public utilities allocating exclusive service territories, "articulate the policy of the State of Oregon to remove market competition as the basis

for determining the customers of the providers of electricity." *Pacificorp*, 770 F.Supp. at 570. As the district court put it:

To the extent that a public utility provider obtains a lawful and valid contract for the allocation of territories and customers through the provisions of the territorial allocation statutes, [Or.Rev.Stat.] 758.400 to 758.475, that provider is immune from antitrust violations.

....
[Or.Rev.Stat.] 758.400(1) states that "[a]llocated territory" means an area with boundaries established by a contract between persons furnishing a similar utility service and approved by the commission or established by an order of the commission approving an application for the allocation of territory." In order to lawfully displace competition as the method of allocating customers for electric service in a particular area, utility companies must enter into "1437 a contract which allocates service territories and designates service to customers, and the utility companies must make application to and receive an order from the [O]PUC approving and establishing the allocation of these territories. These requirements must be met in order to receive the immunity which is provided by the state statutory scheme from the federal antitrust laws.

Id.

Notwithstanding the clarity with which chapter 758 expresses a legislative policy of authorizing the OPUC to approve allocations of exclusive service territories, the district court rejected PGE's state-action immunity defense because the OPUC failed to exercise that authority in issuing the 1972 Order. *Id.* at 571. The district court explained that the 1972 Agreement between PGE and PP & L, which the 1972 Order approved, did not establish exclusive service territories in the city of Portland. As the district court read the 1972 Agreement, PGE and PP & L had agreed "only to an exchange of facilities within the area relevant to this action." *Id.* at 571. In other words, the state did not approve the displacement of competition with territorial monopolies in the Portland market with the clarity required by *Midcal*.

[7][8][9] We agree with the district court that the 1972 Order fails to "speak" with sufficient clarity to satisfy the *Midcal* test. [FN8] Neither the 1972 Order nor the 1972 Agreement it approved says

anything about exclusive service territories in the city of Portland. This omission becomes glaring when the language of the 1972 Order as it pertained to Portland is compared with the language of the same order as it pertained to the city of Rainier. Although the 1972 Order said nothing about exclusive service territories in approving the exchange of property in Portland, it expressly used such language in approving a provision of the 1972 Agreement which transferred to PGE an area within the city of Rainier that had previously been served exclusively by PP & L. See 1972 Order at 8 ("ORDERED that the application of [PP & L] to transfer certain of its exclusively served area allocated to it and lying in and around Rainier, Oregon, to [PGE] is approved.") (emphasis added). The contrast between the "transfer and exchanging of utility property and facilities and customers" language used in the 1972 Order to describe the utilities' agreement with respect to the city of Portland, 1972 Order at 8, and the "exclusively served territory" language used in the 1972 Order to describe the utilities' agreement *1438 with respect to the Rainier area, *id.*, is striking.

FN8. PGE argues that the clear articulation prong of the Midcal is satisfied because Or.Rev.Stat. §§ 758.400-758.450 "encourage exactly the kind of division that PGE and PP & L carried out," and that whether or not the OPUC clearly authorized PGE's challenged conduct is relevant only to the active supervision prong of Midcal. 445 U.S. at 105, 100 S.Ct. at 943 (state action immunity only applies if the state actively supervises the challenged anticompetitive conduct). Resp. of Portland General Elec. Co. to Appellant's Pet. for Reh'g and Amicus Brief of United States at 18. In making this argument, PGE relies on *Praxair, Inc. v. Florida Power & Light Co.*, 64 F.3d 609, 612 (11th Cir.1995) ("If [the defendant engaged in anticompetitive conduct] presumably because of a territorial agreement, but the area in question was never approved by the Commission, the [defendant's] action would not merit state action immunity because of the lack of 'active state supervision.'") (quoting *FTC v. Ticor Tide Ins. Co.*, 504 U.S. 621, 636, 112 S.Ct. 2169, 2178, 119 L.Ed.2d 410 (1992)), cert. denied, — U.S. —, 116 S.Ct. 1678, 134 L.Ed.2d 781 (1996).

Praxair does not help PGE. As the Court explained in *Ticor*, the case on which *Praxair* relies, "Midcal's two elements ... [are both] directed at ensuring that particular anticompetitive mechanisms operate because of a deliberate and intended state policy." *Ticor*, 504 U.S. at 636, 112 S.Ct. at 2178. *Praxair*

is nothing more than a fact specific application of the Midcal test. The anticompetitive conduct had been authorized by a Florida Public Service Commission order approving an allocation of service territories, and the Eleventh Circuit merely held that the order was intended to include a particular county in the exclusive service territories created. See *Praxair*, 64 F.3d at 613. Since the Oregon statute speaks solely of authorizing the OPUC to approve exclusive service territories, the state's clearly articulated policy is to have the OPUC decide whether to sanction anticompetitive conduct. It follows, therefore, that we must look to the decisions of the OPUC to determine whether PGE's conduct was part of a clearly articulated state policy. Cf. *Ticor*, 504 U.S. at 636-37, 112 S.Ct. at 2178-79 (first prong of Midcal test intended to ensure state has not acted through inadvertence).

Like the part of the 1972 Order relating to Rainier, the ordinance passed by the Portland City Council earlier in 1972 also referred to exclusive service territories. It did so, however, in disapproving, not approving, the elimination of competition in favor of a territorial division between PGE and PP & L. The ordinance reminded the utilities that they "operate under non-exclusive franchises and that the obligation to supply properties within the City must remain binding upon both companies." Portland, Or., Ordinance 134416 (1972).

Our second reason for agreeing with the district court is that in approving the exchange of property in Portland, the 1972 Order does not cite any of the statutory provisions governing the allocation of exclusive service territories. Rather than citing chapter 758 or any of its provisions, the OPUC cited a provision of chapter 757, the chapter governing "Utility Regulation Generally," specifically Or.Rev.Stat. § 757.480, which authorizes the approval of exchanges of utility facilities. We are struck by the precision and care with which the OPUC cited various statutory provisions in issuing the 1972 Order. As authority for approving the transfer to PGE of the exclusively served territory in Rainier previously allocated to PP & L, the OPUC cited the statutory provision governing transfers of previously allocated service territories (Or.Rev.Stat. § 758.460 [FN9]). It did not cite any section of chapter 758 in approving the provisions of the 1972 Agreement relating to Portland. [FN10] As authority for approving the exchange of facilities in Portland, the OPUC cited only the statutory provision governing transfers of utility facilities

(Or.Rev.Stat. § 757.480).

FN9. Section 758.460 provides in relevant part:

(1) The rights acquired by an allocation of territory may only be assigned or transferred with the approval of the commission after a finding that such assignment or transfer is not contrary to the public interest.

Or.Rev.Stat. § 758.460.

FN10. In particular, there is no reference in the 1972 Order to Or.Rev.Stat. § 758.410, which permits utilities to contract with each other "for the purpose of allocating territories and customers between the parties." Nor is there any reference to § 758.425, which gives the OPUC its authority to approve such contracts, even though an exclusive service territory can be established only "by a contract between persons furnishing a similar utility service and approved by the commission or ... by an order of the commission approving an application for the allocation of territory." Or.Rev.Stat. § 758.400(1) (defining "allocated territory").

In sum, the OPUC did not "forthrightly state[]" a policy of the state of Oregon that was "clear in its purpose" to displace competition in the Portland market with territorial monopolies. [FN11] *Midcal*, 445 U.S. at 105, 100 S.Ct. at 943.

FN11. Columbia Steel argues that PGE and PP & L intentionally introduced ambiguity into the 1972 Agreement in order to slip a monopolistic agreement past the city of Portland. We need not address this argument because, whether or not ambiguity was introduced into the contract for the self-serving purpose of making it less politically vulnerable, the utilities' failure to include the "exclusively served" language in the 1972 Agreement that had been included in the plan submitted to the City Council certainly had the effect of creating ambiguity in the 1972 Order.

The OPUC argues that, despite the failure of the 1972 Order to say anything about exclusive service territories in the city of Portland, the Order nonetheless immunized the division of the Portland market because the "statutory import of the 1972 Order was necessarily an allocation of service territory in the City of Portland as between PGE and PP & L." Opening Brief of Pub. Util. Comm'n of Or. at 9. The OPUC asserts that the 1972 Agreement "effectively" allocated exclusive service territories because "[e]xchanging customers is logically the only way to reallocate established

service territory into exclusive zones." *Id.* at 9-10. The OPUC adds that "[t]he only way that the OPUC could lawfully have approved the transfer of customers between existing utilities was under the authority of the territorial allocation statutes." *Id.* at 10. See also Resp. of Portland General Elec. Co. to Appellant's Pet. for Reh'g and Amicus Brief of United States at 7 ("The allocation statutes speak of the allocation of 'territories and customers.' The 1972 Agreement and the 1972 Order explicitly allocate customers, whether they explicitly allocate *1439 territories or not.") (citation omitted) (emphasis in original).

In response, Columbia Steel argues that nothing in the relevant statutory provisions rules out a one-time exchange of customers as an incident of an exchange of facilities without the establishment of permanent territorial monopolies. According to Columbia Steel, such a one-time exchange of customers is a practical consequence of an exchange of facilities:

When, as in this case, a utility sells the power line that distributes electricity directly to a customer, it makes sense that the account of the customer served by that line would be transferred to the new owner of the line. Thus, the transfer of customer accounts was only an incident of the transfer of utility property. It is the practical consequence of a transfer of facilities, but it is not the perpetual grant of monopoly power. As a practical matter, unless another source of electricity is available, the customer will take service from the utility that owns the facilities connected to that customer's premises. But the utility serves that customer because it is practical to do so, not because the utility has an exclusive right to serve that customer.

Pet. for Reh'g at 13-14.

Columbia Steel's argument has considerable force. It is buttressed by the fact that PP & L was able to take a good customer away from PGE simply by building a substation in PGE's "territory" to transmit power to Columbia Steel's plant at rates that were more competitive than PGE's. Thus, although the transfer of facilities, and the transfer of customers incidental thereto, gave each utility a temporary competitive advantage, it did not immunize them from competition forevermore. That PGE's advantage proved to be transitory is not surprising given the competitive pressures that technology and deregulation have been exerting on utility markets

where monopolies have traditionally reigned.

In any case, we need not resolve the dispute over whether, as the OPUC argues, an exchange of customer accounts is, as a practical matter, the factual equivalent of an allocation of exclusive service territories. Even if this were the case, it would merely be evidence that might tend to support a permissive inference that the OPUC intended to approve a displacement of competition in Portland with monopolies, and any such inference could not transform the 1972 Order into the forthright and clear statement that it takes to satisfy Midcal's stringent requirements.

PGE and the OPUC also argue that the OPUC's failure to cite any provision of chapter 758 as authority for the 1972 Order as it pertains to Portland renders the 1972 Order nothing more than an "imperfect regulation" which may still confer state-action immunity, citing *Llewellyn v. Crothers*, 765 F.2d 769, 774 (9th Cir.1985) ("actions otherwise immune should not forfeit that protection merely because the state's attempted exercise of its power is imperfect in execution under its own law").

PGE and the OPUC's reliance on *Llewellyn* is misplaced. In *Llewellyn*, the administrator of a state agency promulgated a fee schedule for health care providers, as he was authorized to do under state statute, but bypassed statutory rulemaking procedures. We held that although the administrator had acted in a "procedurally improper manner," the state government was nonetheless entitled to state-action immunity. *Id.* at 773. *Llewellyn* is inapposite here. There the state legislature had clearly articulated an intention to authorize the administrator to promulgate a fee schedule, and the administrator had exercised that authority in clearly articulating his intent to adopt such a fee schedule, notwithstanding that he did not follow the required rulemaking procedures of the state's Administrative Procedure Act. *Id.* at 772. In contrast, the OPUC did not clearly exercise its statutory authority to approve the allocation of exclusive service territories in Portland; indeed, it did not speak to the issue at all. So rather than exercising its authority "imperfectly," the OPUC failed altogether to exercise its authority to approve exclusive service territories with any clarity whatsoever.

Finally, PGE and the OPUC argue that even if the

1972 Order did not clearly authorize *1440 an allocation of exclusive service territories within the city of Portland, later orders issued by the OPUC clarify the 1972 Order. In particular, the PGE and the OPUC rely upon a 1974 Order of the OPUC, which, they assert, confirmed that the 1972 Order did, in fact, confer state-action immunity. [FN12]

FN12. PGE also cites Pub. Util. Comm'n of Or., Orders 73-688 (Oct. 25, 1973), 75-704 (Aug. 13, 1975), and 79-055 (Jan. 12, 1979).

None of the OPUC orders relied on by PGE establishes state-action immunity. First, to the extent that there is language in the orders relevant to the division of the Portland market, it merely recognizes the undisputed fact that PGE and PP & L had stopped competing with each other in that city. [FN13] For instance, the 1974 Order, on which PGE relies most heavily, states that PGE and PP & L "no longer competitively serve the same areas. Their respective areas of service within Portland have been defined." Pub. Util. Comm'n of Or., Order 74-658 (Sept. 3, 1974), *aff'd sub nom. American Can Co. v. Davis*, 28 Or.App. 207, 559 P.2d 898 (1977) (the "1974 Order"), at 25; see also Pub. Util. Comm'n of Or., Order 75-704 (Aug. 13, 1975) (noting that PP & L serves customers "in parts of Portland"). That language is merely a description of the status quo; it is not an expression of a state policy to replace competition with regulation. Although the quoted language might tend to support a permissive inference that the commissioners in 1974 thought that the commissioners in 1972 had defined exclusive service territories in Portland when they issued the 1972 Order, the OPUC can not confer state-action immunity by forming an intent that is not expressed forthrightly and clearly.

FN13. As *Columbia Steel* puts it, "(w)hether, as a matter of fact, the utilities competed is an entirely different inquiry from whether, as a matter of law, the utilities secured lawful allocations of exclusive service territory." *Columbia Steel Reply Brief* at 11.

Second, the "respective areas of service" language in the 1974 Order, as well as the language in the other OPUC orders stating that PGE and PP & L had stopped competing in Portland, cannot be construed as a product of the OPUC's exercise of its statutory authority to approve contracts allocating

exclusive service territories. Because there were no such contracts before the OPUC when it issued these later orders, the orders were not issued pursuant to the provisions of Or.Rev.Stat. ch. 758 authorizing approval of such contracts. The 1974 Order, for example, was issued pursuant to Or.Rev.Stat. §§ 757.205, 757.210, and 757.215, which pertain to changes in tariffs charged by utilities. The 1974 Order approved PP & L's revised tariff schedule, which equalized PP & L's rates in Portland with the higher rates it charged in other areas of the state. As a result, PP & L's rates for customers in Portland became higher than the rates charged by PGE. The "respective areas of service" language in the 1974 Order was recited merely to establish a rationale for the OPUC's action approving the new rates:

A rate differential between Portland and [other areas] was formerly justified on the basis of competing electric service in Portland between [PP & L] and [PGE]. For various reasons, it was believed that in the Portland metropolitan area rates between two similar utilities serving the same area should be the same.

The two companies no longer competitively serve the same areas. Their respective areas of service within Portland have been defined. Thus, with the lack of competition, the justification for rate uniformity is said to have disappeared.

1974 Order at 25.

[10] As a matter of law, then, neither the 1974 Order nor any of the other subsequent orders of the OPUC amend the 1972 Order to clarify that Order as an expression of state policy to displace competition with regulation. At best, these orders recite that the utilities have stopped competing with each other within territories they have defined. As our court has said, mere "state authorization, approval, encouragement, or participation in restrictive private conduct confers no antitrust immunity." *Phonetele, Inc. v. American Tel. & Tel. Co.*, 664 F.2d 716, 736 (9th Cir.1981) (quoting *Cantor v. Detroit Edison Co.*, 428 U.S. 579, 592-93, 96 S.Ct. 3110, *1441 3118-19, 49 L.Ed.2d 1141 (1976)), cert. denied, 459 U.S. 1145, 103 S.Ct. 785, 74 L.Ed.2d 992 (1983).

In sum, we agree with the district court that the elimination of competition between PGE and PP & L in Portland was not cloaked with state-action immunity. As the district court put it, the OPUC did

not "specifically and clearly authorize[] by the relevant statutory process" a division of the Portland market into exclusively served territories. *Pacificorp*, 770 F.Supp. at 571.

B. Issue Preclusion

After Columbia Steel filed this antitrust action in federal district court, PGE applied to the OPUC for a declaration that the 1972 Order allocated exclusive service territories in Portland. In response, the 1992 OPUC issued an order declaring that the 1972 OPUC had intended to do so, and amended the 1972 Order, *nunc pro tunc*, to that effect. In its 1992 Order, the OPUC acknowledged that "perhaps [the 1972 Order] did not unambiguously allocate exclusive service territories to PGE and PP & L." Pub. Util. Comm'n of Or., Order 92-557 (Apr. 16, 1992) (the "1992 Order"), at 14. [FN14]

FN14. The 1992 Order states, in relevant part:

[B]ecause [the 1972 Order] did not expressly refer to ORS Chapter 758 with respect to future service in Portland under the allocation statutes and because the order did not say that exclusive territorial allocations are being created in Portland, ... perhaps it did not unambiguously allocate exclusive service territories to PGE and PP & L. However, the order did create boundaries that the utilities observed as if they were allocated territories until Columbia Steel's attempt to switch utilities in 1989. The Commission made the required statutory findings to allocate exclusive service territories and acted as if it had approved a territorial allocation in its 1972 order. The behavior of the utilities and the Commission demonstrates an understanding that exclusive service territories had been created.

For the foregoing reasons, it appears to the Commission that [the 1972 Order] is not a complete and accurate memorial of the 1972 decision of the Commissioner the order omits a reference to the statute under which its findings were actually made when the Commissioner approved the PGE/PP & L contract. Pursuant to ORS 756.568, the Commission will amend [the 1972 Order], *nunc pro tunc*, to conform to the actual decision intended and followed.

1992 Order at 14-15.

[11] Armed with the OPUC's 1992 Order, PGE moved for reconsideration of the district court's summary judgment rulings in favor of Columbia Steel, arguing that the OPUC's 1992 Order was entitled to full faith and credit. The district court denied the motion, reasoning that:

[t]he availability of the defense of state action immunity depends upon the satisfaction of the objective standards set forth in *Parker* [v. Brown, 317 U.S. 341, 63 S.Ct. 307, 87 L.Ed. 315 (1943)] and the authorities which have interpreted *Parker*. ... The fact that the [O]PUC did not do what it now concludes that it intended to do in the 1972 Order does not alter the fact that the claim of PGE to a monopoly was not specifically and clearly authorized at the time that this court decided that Columbia Steel was entitled to a declaration that [the 1972 Order] neither empowers nor authorizes PGE to monopolize the service of electric power to Columbia Steel.

Unpublished Opinion, filed June 29, 1992, at 7-9.

[12][13][14] We agree and hold that the 1992 Order is not entitled to preclusive effect because the issue decided by the OPUC in that order is not identical to the state-action immunity issue. [FN15] The issue decided by the *1442 1992 OPUC is whether the 1972 OPUC had the intent to approve the allocation of exclusive service territories in the city of Portland. The state-action immunity issue is different. It does not turn on the fact issue of the subjective intent of the OPUC at the time it issued the 1972 Order. Rather, the state-action immunity question is one of law that turns on whether the displacement of competition with monopolies in the Portland market was "clearly articulated and affirmatively expressed as state policy," *Midcal*, 445 U.S. at 105, 100 S.Ct. at 943. As the district court said, "the availability of the defense of state-action immunity depends upon the satisfaction of the objective standards set forth in *Parker* [and its progeny]." Unpublished Opinion, filed June 29, 1992, at 7-8. In other words, state-action immunity is a question of federal antitrust law that turns on the clarity of a state's expression of its policy, not the subjective intent of its policymakers.

FN15. Oregon law provides that one tribunal may give preclusive effect to the prior determination of an issue by another tribunal only if "the issue in the two proceedings is identical." *Hickey v. Senesier*, 318 Or. 196, 864 P.2d 372, 375 (1993).

Oregon law also provides that the second tribunal may give preclusive effect to an earlier decision only if "the party sought to be precluded has had a full and fair opportunity to be heard on that issue." *Id.* Columbia Steel argues that it was not given such

an opportunity before the OPUC issued the 1992 Order. Columbia Steel denies having waived its right to a hearing on the merits, pointing to record evidence that it only agreed to postpone the submission of evidence to the OPUC until the OPUC ruled on Columbia Steel's motion to dismiss for lack of jurisdiction. We need not decide whether Columbia Steel was denied a fair opportunity to be heard in the proceeding before the OPUC because, as we explain in the text, the issue in that procedure is not "identical" to the issue of state-action immunity in this federal antitrust action. *Id.*

[15] In declaring what the 1972 OPUC intended to do, the 1992 OPUC approached the 1972 Order as though it were interpreting a contract. After finding ambiguity in the 1972 Order, the 1992 OPUC went on to decide, as an issue of fact, the intent of the 1972 OPUC by looking to extrinsic evidence such as the behavior of the parties between 1972 and 1990. See 1992 Order at 12-15. To repeat, state-action immunity is not an issue of fact. It cannot be decided simply by ferreting out extrinsic evidence in an effort to ascertain the subjective intent of the state. The issue of state-action immunity must be decided by applying the "rigorous" test, *Patrick*, 486 U.S. at 100, 108 S.Ct. at 1662-63, of whether the state "clearly articulated and affirmatively expressed" its intent to displace competition with regulation as a matter of state policy. *Midcal* 445 U.S. at 105, 100 S.Ct. at 943. [FN16]

FN16. For the same reason, there can be no issue preclusion based on the judgment of the Marion County Court affirming the 1992 Order on the ground that the it was "supported by substantial evidence." See *Columbia Steel Casting Co. v. Public Util. Comm'n of Or.*, Marion County Circuit Court No. 92C-12005, judgment affirming Public Utility Commission of Oregon Order Nos. 92-557 & 92-1135, at 2, *aff'd without opinion*, Oregon Ct. of Appeals (Dec. 15, 1993).

[16] In sum, the 1992 OPUC could not satisfy the *Midcal* test retroactively by amending the 1972 Order years after PGE entered into the monopolistic agreement it now seeks to cloak with federal antitrust immunity. [FN17] In other words, the state of Oregon cannot satisfy the objective *Midcal* clear articulation test by declaring that it had intended to displace competition with regulation 20 years earlier. [FN18]

FN17. It is fundamental that an order or judgment is

not existed to full faith and credit if the issuing tribunal had no subject matter jurisdiction over the matter before it. *Underwriters Nat'l Assurance Co. v. North Carolina Life & Accident & Health Ins. Guar. Ass'n*, 455 U.S. 691, 704-05, 102 S.Ct. 1357, 1365-66, 71 L.Ed.2d 558 (1982). We do not know whether the OPUC and the Marion County Court had subject matter jurisdiction as a matter of state law to amend the 1972 Order retroactively. We believe, however, that it is questionable whether either had subject matter jurisdiction to decide the federal antitrust question of state-action immunity that is now before us. We need not decide this jurisdictional question because the lack of identity between the issue decided in the 1992 Order and the issue of state-action immunity deprives the 1992 Order of any preclusive effect in this federal antitrust action.

FN18. PGE's reliance on *California Aviation, Inc. v. City of Santa Monica*, 806 F.2d 905 (9th Cir.1986), and the cases on which it relies, for the proposition that Midcal can be satisfied retroactively is misplaced. In *California Aviation*, the later statute "articulate[d] and affirm[ed] a pre-existing state policy of allowing [particular anticompetitive conduct]." *Id.* at 909 (emphasis added). In contrast, there was no pre-existing state policy to eliminate competition in the Portland market for the OPUC to articulate or affirm in its 1992 Order.

C. Foreseeability: PGE's New Argument on Appeal

[17][18][19] PGE, joined by the OPUC, argues for the first time on appeal that state-action immunity applies because the division of the Portland market was a foreseeable result of the 1972 Order. According to PGE, "state action immunity must apply where the [challenged] conduct is the 'foreseeable result' of the state's policy." Opening Brief of Appellant Portland General Elec. Co. at 23 (citing *Nugget Hydroelectric, L.P. v. Pacific Gas & Elec. Co.*, 981 F.2d 429 (9th Cir.1992), cert. denied, 508 U.S. 908, 113 S.Ct. 2336, 124 *1443 L.Ed.2d 247 (1993)). "We will review an issue that has been raised for the first time on appeal under certain narrow circumstances," including "when the issue is purely one of law." *Parks Sch. of Business v. Symington*, 51 F.3d 1480, 1488 (9th Cir.1995). Because the foreseeability issue raised by PGE and the OPUC is a pure issue of law, and because consideration of it will not prejudice Columbia Steel, see *Aronson v. Resolution Trust Corp.*, 38 F.3d 1110, 1114 (9th Cir.1994), we exercise our

discretion to consider it.

In our original opinion, we agreed with PGE. We held that "[u]nder [*Nugget and Medic Air Corp. v. Air Ambulance Auth.*, 843 F.2d 1187 (9th Cir.1988)], private conduct is immunized if it is a foreseeable result of state agency action and if circumstances justify an inference that the agency intended to authorize the conduct." *Columbia Steel Casting Co. v. Portland General Elec. Co.*, 60 F.3d 1390, 1396 (9th Cir.1995), herewith withdrawn. Although we said that "the 1972 Order is not particularly clear regarding the [OPUC]'s intention to permit a permanent division of the Portland market, as opposed to a one-time exchange of facilities and customer accounts," *id.* at 1396, we nonetheless "conclude[d] that the elimination of competition between PGE and PP & L was a natural and foreseeable result of the 1972 Order," *id.* at 1399, "justify[ing] the inference that it was intended by the [OPUC]." *Id.* Accordingly, we held that PGE's conduct enjoyed state-action immunity from Sherman Act liability.

We are persuaded by Columbia Steel's petition for rehearing and an amicus curiae brief filed by the Antitrust Division of the Department of Justice that we erred in allowing a foreseeability test to be substituted for the clear articulation test of Midcal. In doing so, we misconstrued *Medic Air* and *Nugget*. In *Medic Air*, we used Midcal's clear articulation test, not a foreseeability test, in deciding that state-action immunity shielded a monopoly granted to Air Ambulance Authority in the market of dispatching air ambulances in Washoe County, Nevada. 843 F.2d at 1189. We did use a foreseeability test in *Medic Air*, but only in deciding the reach of the antitrust immunity that protected Air Ambulance Authority's monopoly in the dispatching market. Specifically, we held that Air Ambulance Authority was not shielded from antitrust liability in using its immunized monopoly power to gain a competitive advantage in a different market, the market for air ambulance services. *Id.* We reasoned that Air Ambulance Authority's antitrust immunity in the dispatching market did not extend to the ambulance service market because anticompetitive conduct in the service market was "not a 'necessary or reasonable consequence' of the decision to establish an exclusive dispatcher." *Id.* (citation omitted). As we explained, "[t]he state and its agencies have not granted Air Ambulance an

exclusive [ambulance service] franchise. That they might have done so is irrelevant. The state must act if immunity is to exist.... The Protocols [governing dispatching procedures] did not interfere with existing competition. The District Board did not seek to displace competition or limit entry into the ambulance market. The District Board did not even consider the dispatch program's effect upon competition." *Id.*

The anticompetitive conduct at issue in *Nugget* was also expressly authorized by state action independently of any foreseeability inquiry. A California statute authorized the California Public Utility Commission to "specify the prices, terms, and conditions" for the sale of power by a private power producer like *Nugget* to a utility." 981 F.2d at 434 (quoting statute). In exercising that statutory authority, the California PUC clearly expressed an intention to regulate such sales in detail. The California PUC's implementing Guidelines provided that private power producers would "generally bear the risk of failing to develop their power facility before the five year deadline and that only rarely will permitting delays qualify as force majeure events." *Id.* The Guidelines specified that a utility was "expect [ed] ... [to] negotiate [force majeure claims] only in instances where it is convinced that a settlement, versus adjudication, is in the ratepayers' best interest." *Id.* (quoting Guidelines). We held in *Nugget* that state-action immunity extended to the anticompetitive effects of a utility's rejection of a private power supplier's force majeure claim for an extension of *1444 the contract period because the anticompetitive effects were a foreseeable result of the California PUC's implementing Guidelines. *Id.*

Our rejection of PGE's argument that it is entitled to state-action immunity because the division of the Portland market was a foreseeable result of the 1972 Order is consistent with *Town of Hallie v. City of Eau Claire*, 471 U.S. 34, 105 S.Ct. 1713, 85 L.Ed.2d 24 (1985), upon which we relied in *Nugget*. The issue in *Town of Hallie* was whether the city's anticompetitive activities were protected by state-action immunity "when the activities are authorized, but not compelled, by the State." *Id.* at 36, 105 S.Ct. at 1715 (emphasis added). The Supreme Court held that the challenged action of the city was protected by the state-action immunity doctrine because the city's conduct was "a foreseeable result of empowering the City to refuse

to serve unannexed areas." *Id.* at 42, 105 S.Ct. at 1718. However, the Court held that this result was foreseeable because the state expressly authorized the city's anticompetitive behavior. See *Id.* In contrast, the OPUC did not expressly authorize PGE to maintain an exclusive service territory; it merely approved the exchange of property and customers.

[20] In sum, neither *Medic Air* nor *Nugget* applies a foreseeability test as a substitute for the threshold Midcal clear articulation test. As the Antitrust Division puts it, "express authorization [is] the necessary predicate for the Supreme Court's foreseeability test." Brief of Amicus Curiae United States at 9. PGE cites no case to the contrary and we know of none.

III. PGE's Other Defenses

[21] In the absence of state-action immunity, an agreement between PGE and PP & L to divide the Portland market for electricity constitutes a per se violation of § 1 of the Sherman Act. See, e.g., *Palmer v. BRG of Georgia, Inc.*, 498 U.S. 46, 49-50, 111 S.Ct. 401, 402-03, 112 L.Ed.2d 349 (1990) (agreement among competitors to allocate territories to diminish competition is a per se § 1 violation). There is no genuine issue of material fact regarding the existence of such an agreement that would prevent the entry of summary judgment against PGE on liability. See *Abdul-Jabbar v. General Motors Corp.*, 85 F.3d 407, 410 (9th Cir.1996). We therefore address PGE's affirmative defenses other than state-action immunity. Although the district court found only one of these defenses worthy of discussion, we discuss each of them in turn.

A. Statute of Limitations

[22] PGE argues that Columbia Steel's antitrust action, which was filed on June 19, 1990, is time-barred because it was filed four years after any overt act in furtherance of PGE and PP & L's agreement to divide the Portland market. See 15 U.S.C. § 15(b) (establishing 4-year limitations period for Sherman Act violations); *Pace Indus., Inc. v. Three Phoenix Co.*, 813 F.2d 234, 237 (9th Cir.1987) ("even when a plaintiff alleges a continuing violation, an overt act by the defendant is required to restart the statute of limitations and the statute runs from the last overt act"). PGE argues that the

acts relied upon by the district court in finding Columbia Steel's antitrust claims timely were insufficient to restart the running of the statute because they were merely "reaffirmations" of the original 1972 Agreement to divide the Portland market. See *id.* at 238.

On May 30, 1990, Columbia Steel wrote to PGE and stated that it would terminate its contract with PGE and take power from PP & L as of July 1, 1990, if PGE would agree to wheel power for PP & L so it could serve Columbia Steel's casting plant. PGE said no, declaring in a letter dated May 30, 1990, that "[Columbia Steel] is within PGE's exclusive territory. If it desires to purchase electricity, it must do so from PGE." The district court held that PGE's refusal to wheel PP & L's electricity to Columbia Steel's casting plant was an overt act that restarted the statute of limitations.

We agree with the district court. PGE's refusal was not a mere reaffirmation of PGE and PP & L's 1972 Agreement to stop competing in the Portland market because the 1972 Agreement was not a permanent and final decision that controlled the later act. *1445 See *Hennegan v. Pacifico Creative Serv., Inc.*, 787 F.2d 1299, 1300-01 (9th Cir.) (limitations period restarted each time tour guides shepherded tourists away from plaintiff's souvenir shop in furtherance of antitrust conspiracy between tour operators and other vendors) (quoting and distinguishing *In re Multidistrict Vehicle Air Pollution*, 591 F.2d 68, 72 (9th Cir.), cert. denied, 444 U.S. 900, 100 S.Ct. 210, 62 L.Ed.2d 136 (1979), in which later acts were mere affirmations of earlier "irrevocable, immutable, permanent and final" decisions that "completely and permanently excluded [plaintiff] from the market"), cert. denied, 479 U.S. 886, 107 S.Ct. 279, 93 L.Ed.2d 254 (1986). [FN19] *Hennegan* also distinguishes *David Orgell, Inc. v. Geary's Stores, Inc.*, 640 F.2d 936 (9th Cir.), cert. denied, 454 U.S. 816, 102 S.Ct. 92, 70 L.Ed.2d 84 (1981), the only Ninth Circuit case other than *Multidistrict Air Pollution* that is cited by PGE on the statute of limitations issue, on the same ground. *Hennegan*, 787 F.2d at 1301-02.

[FN19. Columbia Steel also argues that the refusal in 1987 of PGE's coconspirator PP & L to service the steel casting plant over the objection of PGE was also an overt act that restarted the statute of limitations. We need not consider the significance of the events in 1987 to the statute of limitations

question because we hold that the statutory period was restarted in 1990. The 1987 events are, however, relevant to Columbia Steel's cross-appeal regarding damages, which we address in Part V, *infra*.

B. Justification defenses

[23] PGE asserts that the 1972 Order required it to stop competing with PP & L in the city of Portland, and that "had PGE failed to conform to the commands of the OPUC ... it could have subjected itself to treble damages for violation of Oregon utility law." Opening Brief of Appellant Portland Gen. Elec. Co. at 29. PGE argues that as a result it is entitled to raise a regulatory justification defense, see *Phonezele, Inc. v. American Tel. & Tel. Co.*, 664 F.2d 716, 737-38 (9th Cir.1981) (no antitrust liability when defendant reasonably concludes that its actions are necessitated by concrete factual imperatives recognized as legitimate by the regulatory authority), cert. denied, 459 U.S. 1145, 103 S.Ct. 785, 74 L.Ed.2d 992 (1983), and a business justification defense, see, e.g., *City of Anaheim v. Southern Cal. Edison*, 955 F.2d 1373, 1381 (9th Cir.1992) (utility not liable for using high-powered transmission line to the exclusion of competitors in order to keep rates low).

These justification defenses are not available to PGE. When it stopped competing with PP & L in Portland after the 1972 Order issued, it was under no compulsion to do so because the 1972 Order did not approve the allocation of exclusive service territories. Had the 1972 Order done so, a justification defense would arguably have been available to PGE because the Oregon statutes provide that only the utility that has been allocated a territory may serve that territory. See *Or.Rev.Stat. § 758. 450(2)* ("Except [under circumstances not relevant here], no other person shall offer, construct or extend utility service in or into an allocated territory."). In light of this provision, it is significant that in approving an exchange of facilities, the 1972 Order used permissive language. See 1972 Order at 8-9 ("ORDERED that [PP & L] may transfer to [PGE] all electric distribution plant ... that [PGE] may transfer to [PP & L] all electric distribution plant ... that the manner and method for accomplishing the transfer and exchange of property ... and the terms and conditions governing this transfer, shall be as provided by [the 1972 Agreement]") (emphasis added). Because the

language of the 1972 Order was permissive, it did not require PGE and PP & L to perform the 1972 Agreement and did not prevent them from rescinding it before the property was exchanged. Given the statutory prohibition against serving a territory allocated to another utility, see Or.Rev.Stat. § 758.450(2), the permissive language in the 1972 Order would have been incongruous if the 1972 Order had approved an allocation of exclusive service territories.

C. The Noerr-Pennington Doctrine

[24][25] PGE argues that it is entitled to antitrust immunity under the Noerr-Pennington doctrine. *Eastern R.R. Presidents Conference v. Noerr Motor Freight, Inc.*, 365 U.S. 127, 136, 81 S.Ct. 523, 529, 5 L.Ed.2d 1446 464 (1961) (the Sherman Act does not prohibit competitors from "associating together in an attempt to persuade the legislature or the executive to take particular action with respect to a law that would produce a restraint or a monopoly"); *United Mine Workers of America v. Pennington*, 381 U.S. 657, 670, 85 S.Ct. 1585, 1593, 14 L.Ed.2d 626 (1965). The Noerr-Pennington doctrine, which is rooted in the First Amendment protection of political activity, see *Continental Ore Co. v. Union Carbide & Carbon Corp.*, 370 U.S. 690, 707, 82 S.Ct. 1404, 1414-15, 8 L.Ed.2d 777 (1962), does not apply here. Applying to an administrative agency for approval of an anticompetitive contract is not lobbying activity within the meaning of the Noerr-Pennington doctrine. In any case, PGE is not being held liable for filing the application that resulted in the 1972 Order. PGE is being held liable for agreeing with PP & L to replace competition with area monopolies in the Portland market.

D. The Filed Rate Doctrine

[26][27] PGE argues that the filed rate doctrine bars Columbia Steel from recovering damages even if PGE did violate the Sherman Act. The filed rate doctrine generally forbids the recovery of treble damages under the Sherman Act based on the payment of rates that are established by regulated tariffs, even if the defendants engaged in illegal price-fixing. See, e.g., *Keogh v. Chicago & Northwestern Ry.*, 260 U.S. 156, 162, 43 S.Ct. 47, 49, 67 L.Ed. 183 (1922). According to PGE, the filed rate doctrine applies in this case as follows:

(1) Because PGE could charge only the rates approved by the OPUC, it could not charge the same rate offered by PP & L to Columbia Steel; (2) PGE could not "transfer" its customer Columbia Steel to PP & L without OPUC approval; (3) thus, the district court could not award damages based on the difference between the rate charged by PGE and the "rate that might have been approved absent the conduct at issue." Opening Brief of Appellant Portland General Electric Co. at 32.

We reject PGE's reasoning. The conduct challenged in this case is not PGE's refusal to sell electricity to Columbia Steel at a lower rate. Rather, the challenged conduct is the non-competition agreement that prevented Columbia Steel from buying electricity at PP & L's lower rates. The filed rate doctrine is inapplicable. To hold that it is applicable would be to "allow a blockade of a competitor to escape scrutiny. This would overextend Keogh's reach and could produce a rule that one who pays for services governed by [a regulatory body's] tariffs is foreclosed from asserting that antitrust violations prevented use of a less expensive, equivalent service." *In re Lower Lake Erie Iron Ore Antitrust Litig.*, 998 F.2d 1144, 1159 (3d Cir.1993).

IV. Damages

[28] PGE argues that Columbia Steel suffered no damages at any time because (1) at all relevant times, Columbia Steel was obligated on its requirements contract with PGE to purchase electricity from PGE, and (2) PGE could not transfer Columbia Steel as a customer to PP & L without prior OPUC approval. These arguments are to no avail. First, Columbia Steel's requirements contract with PGE did not bar it from suing PGE under the Sherman Act for agreeing with PP & L to stop competing in the Portland market. See, e.g., *Perma Life Mufflers v. International Parts Corp.*, 392 U.S. 134, 139-40, 88 S.Ct. 1981, 1984-85, 20 L.Ed.2d 982 (1968) (franchise agreement does not defeat franchisee's standing to bring antitrust suit against franchisor); *Hanover Shoe, Inc. v. United Shoe Machinery Corp.*, 377 F.2d 776, 781 (3d Cir.1967) ("captive customer" having valid lease agreement with defendant for use of certain equipment could nonetheless sue for antitrust violation based on defendant's refusal to sell the equipment), *aff'd* on other grounds, 392 U.S. 481,

OFFICE COPY

U.S.A.

STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners:

Sam Cotten, Chairman
Alyce A. Hanley
Dwight D. Ornquist
Tim Cook
James M. Posey

In the Matter of the Complaint Filed)
by the MUNICIPALITY OF ANCHORAGE)
d/b/a MUNICIPAL LIGHT & POWER)
DEPARTMENT Against CHUGACH ELECTRIC)
ASSOCIATION, INC., and the Cross-)
Complaint Filed by CHUGACH ELECTRIC)
ASSOCIATION, INC., Against the)
MUNICIPALITY OF ANCHORAGE d/b/a)
MUNICIPAL LIGHT & POWER DEPARTMENT)

U-97-201

ORDER NO. 3

ORDER GRANTING ML&P'S MOTION FOR SUMMARY
JUDGMENT DISMISSING CHUGACH'S CROSS-COMPLAINT:
DENYING CHUGACH'S MOTION FOR SUMMARY JUDGMENT:
AND REQUIRING ADDITIONAL BRIEFING

BY THE COMMISSION:

Background

On October 13, 1997, the MUNICIPALITY OF ANCHORAGE d/b/a
MUNICIPAL LIGHT AND POWER DEPARTMENT (ML&P)¹ filed a complaint
alleging that CHUGACH ELECTRIC ASSOCIATION, INC. (Chugach), offered
to provide electric power to customers located in ML&P's service
area, outside the service area specified in Chugach's Certificate
of Public Convenience and Necessity (Certificate) No. 8. ML&P

¹ML&P is authorized to provide electric public utility service
in Anchorage under Certificate No. 121.

1 contends that Chugach's actions are illegal and in violation of
2 Chugach's tariff and AS 42.05.221(a).

3 In its complaint, ML&P requests that the Commission
4 institute an investigation into Chugach's customer recruitment
5 practices to determine where else Chugach has offered to provide
6 electric service outside the service area specified in its
7 Certificate. Additionally, ML&P requests that the Commission
8 declare that Chugach's provision of electric service outside the
9 service territory specified in its Certificate is illegal and order
10 Chugach to desist from contacting any person about providing retail
11 electric service outside its certificated service area. Lastly,
12 ML&P requests that the Commission order Chugach to pay all costs
13 incurred by the Commission and ML&P relating to this proceeding and
14 order Chugach to conduct "goodwill advertising" for a period of at
15 least one year to compensate ML&P for the harm allegedly caused by
16 Chugach's actions.

17 On November 3, 1997, Chugach filed its answer to ML&P's
18 complaint and, additionally, filed a cross-complaint against ML&P.
19 In its answer, Chugach admits that it has offered to sell electric
20 power to the Boardwalk Condominiums Owners Association and to
21 Columbia Alaska Regional Hospital, customers located in ML&P
22 certificated service area. (Chugach Answer ¶¶ 5-6.) Chugach
23 contends, however, that its sales to these customers are legal. In
24 its cross-complaint, Chugach contends that ML&P's refusal to wheel
25 power over the latter's transmission and distribution systems on
26

1 Chugach's behalf to customers located in ML&P's certificate
2 service area violates federal antitrust law.

3 Chugach requests that the Commission (1) declare tha
4 neither Alaska law nor any of the Commission's Orders in Docket
5 U-71-16 clearly articulate a policy permitting ML&P to monopoliz
6 sales of electric power in ML&P's certificated service area
7 (2) order ML&P to immediately commence transmission and distribu
8 tion services on behalf of Chugach to deliver power to customers i
9 ML&P's certificated service area; and (3) order ML&P to immediatel
10 submit a tariff setting forth the terms and conditions for deliver
11 services over its transmission and distribution system.

12 On November 10, 1997, Chugach filed a motion for summar
13 judgment seeking a declaratory ruling on the relief it requests i
14 its cross-complaint. Chugach contends that there are no dispute
15 facts and that the Commission can rule on the motion as a matter o
16 law.

17 On December 4, 1997, ML&P filed its opposition to
18 Chugach's motion for summary judgment and cross-moved for summar
19 judgment to dismiss Chugach's cross-complaint. In its oppositio
20 and cross-motion for summary judgment, ML&P agrees that for
21 purposes of ruling on the pending motions there are no disputed
22
23
24
25
26

1 issues of fact.² On January 20, 1998, the Commission heard oral
2 argument from the parties on the pending motions.

3
4 Issues

5 Chugach argues that federal antitrust law, in particular
6 the state action doctrine, is the starting point for analyzing
7 whether the Commission may allow ML&P to retain an exclusive right
8 to sell power in its service territory. Chugach then applies the
9 principles of this doctrine and contends that there is no clearly
10 articulated state policy expressed in Alaska statutes that would
11 allow the Commission to restrict competition implemented through
12 retail-wheeling arrangements. (Chugach Memorandum at 16-24.)
13 Hence, Chugach concludes that principles of federal antitrust law
14 require the Commission to declare that ML&P is not authorized to
15 refuse Chugach's requests for retail wheeling.

16 Based on this argument and ML&P's opposition, the
17 Commission will address in its discussion below the following legal
18 issues:

19 (1) Is federal antitrust law the starting point for
20 analyzing whether the Commission may authorize ML&P to
21 retain an exclusive right to serve customers in its
22 certificated service area?

23
24
25 ²In its opposition, ML&P identified various factual issues in
26 dispute concerning the difficulty ML&P would have if ordered to
wheel power on behalf of Chugach over ML&P's transmission and
distribution system. (See Affidavit of Robert R. Regan, ¶¶ 15-17.)

1 (2) Does the Commission have authority under state
2 law to require Chugach to apply for a certificate of
3 public convenience and necessity (certificate) before
4 seeking to sell retail power outside its service terri-
5 tory through retail-wheeling arrangements?

6 (3) Does the Commission have authority under state
7 law to allow ML&P to retain an exclusive right to sell
8 power in its service area?

9 (4) Under principles of federal antitrust law, will
10 a Commission decision allowing ML&P to retain an exclu-
11 sive right to serve the customers in its service terri-
12 tory satisfy the state action doctrine?

13 Discussion
14

15 I. The Starting Point Is State Law, Not Federal Antitrust Law

16 Chugach argues that principles of federal antitrust law
17 particularly the state action doctrine, should control the
18 Commission's interpretation of its authority to make policy
19 determinations in this Docket. However, the Commission finds that
20 this would be contrary to the U.S. Supreme Court's purpose for
21 creating the state action defense.

22 The state action doctrine was first enunciated by the
23 Supreme Court of the United States in the case of *Parker v. Brown*
24 317 U.S. 343 (1943). The *Parker* case concerned a producer and
25 packer of raisins who filed suit under the Sherman Act to enjoin
26

1 the California State Director of Agriculture and other state
2 officials from administering a state marketing program designed to
3 restrict competition among raisin growers. The issue before the
4 Supreme Court was whether the Sherman Act restrains state action.
5 The Supreme Court held that "[t]here is no suggestion of a purpose
6 to restrain state action in the [Sherman] Act's legislative
7 history." *Id.* at 351. Accordingly, the Court held that the
8 California state official's administration of the marketing program
9 was not prohibited by the Sherman Act. The Court explained that:

10 It is the state which has created the machinery for
11 establishing the prorate program. Although the organiza-
12 tion of a prorate zone is proposed by producers, and a
13 prorate program, approved by the Commission, must also be
14 approved by referendum of producers, it is the state,
15 acting through the Commission, which adopts the program
16 and which enforces it with penal sanctions, in the
17 execution of a governmental policy.

18 *Id.* at 352 (emphasis added).

19 Subsequent U.S. Supreme Court decisions have confirmed
20 that the state action doctrine is based on principles of federalism
21 and respect for state sovereignty. *City of Columbia v. Omni*
22 *Outdoor Advertising, Inc.*, 499 U.S. 365, 372 (1991). The Supreme
23 Court created the doctrine to allow state officials (like this
24 Commission) to freely administer and develop state policy in
25 accordance with state law free from restraint under the Sherman
26 Act. Of course, the Commission's policy decisions must be
authorized by state law, but this is true for any action by the
Commission.

1 If the Commission accepts Chugach's assertion that
2 federal antitrust law controls the Commission's decisions in this
3 Docket, then the Supreme Court's purpose for creating the state
4 action doctrine is defeated, and the principles of federalism and
5 state sovereignty underlying the doctrine are undermined. *Id.* at
6 371-72. The fact that the Commission's decisions subsequently may
7 be reviewed in the context of a federal antitrust lawsuit against
8 a utility, like ML&P, does not mean that federal antitrust law now
9 should control how the Commission interprets its authority or
10 otherwise makes policy determinations in this Docket.

11
12 II. ML&P Shall Retain an Exclusive Right To Serve the Customers in
13 Its Service Territory until the Commission Determines Other-
14 wise

15 There is no Alaska statute that specifically addresses
16 the issue of retail competition in the electric industry and retail
17 wheeling. The Commission's authority to decide these matters
18 derives from its general powers to regulate utilities
19 (AS 42.05.141), to require certificates (AS 42.05.221(a)), and to
20 eliminate competition that it finds is not in the public interest.
21 (AS 42.05.221(d)).

22 The Legislature has given the Commission broad authority
23 to regulate public utilities in this state. In AS 42.05.141, the
24 Legislature has delegated to the Commission broad authority "to do
25 all things necessary or proper to carry out the purposes and
26 exercise the powers expressly granted or reasonably implied in this
chapter, including:

1 (1) regulate every public utility engaged or
2 proposing to engage in a utility business inside the
3 state, except to the extent exempted by AS 42.05.711. .

3

4 (3) make or require just, fair, and reasonable
5 rates, classifications, regulations, practices, services,
6 and facilities for a public utility.

6 The Legislature has broadly defined "public utility" or "utility"
7 to include:

8 [E]very corporation whether public, cooperative, or
9 otherwise, company individual, or association of individ-
10 uals, their lessees, trustees, or receivers appointed by
11 a court, that owns, operates manages, or controls any
12 plant, pipeline, or system for

11 (A) furnishing, by generation,
12 transmission, or distribution, electrical
13 service to the public for compensation; . . .

13 AS 42.05.990(4).

14 With few exceptions,³ the Legislature requires all public
15 utilities operating in the state to apply for a certificate before
16 providing an intrastate "commodity" or a "service" to the public.

17 The certificate requirement in AS 42.05.221(a) states that:

18 A public utility may not operate and receive compensation
19 for providing a commodity or service without first having
20 obtained from the commission under this chapter a
21 certificate declaring that public convenience and
22 necessity require or will require the service. Where a
23 public utility provides more than one type of service, a
24 separate certificate of convenience and necessity is
25 required for each type. A certificate must describe the
26 nature and extent of the authority granted in it,

24 ³Some exceptions to the certificate requirement can be found
25 in AS 42.05.711(e) (an electric or telephone utility grossing less
26 than \$50,000 annually) or AS 42.05.325 (a utility operating
strictly as an alternate operator service would only need to
register with the Commission).

1 including, as appropriate for the services involved, a
2 description of the authorized area and scope of operations of the public utility.

3 The Legislature did not define the term "commodity" but defined the
4 term "service" broadly to generally include "commodity":

5 unless the context indicates otherwise, every commodity,
6 product, use, facility, convenience or other form of
7 service that is offered for and provided by a public
8 utility for the convenience and necessity of the public.

AS 42.05.990(6).

9 The restrictions on the Commission's authority to grant
10 a certificate are set forth in AS 42.05.241. This statute provides
11 that:

12 A certificate may not be issued unless the commission
13 finds that the applicant is fit, willing and able to
14 provide the utility services applied for and that the
15 services are required for the convenience and necessity
16 of the public. The commission may issue a certificate
17 granting an application in whole or in part and attach to
18 the grant of it the terms and conditions it considers
19 necessary to protect and promote the public interest
20 including the condition that the applicant may or shall
21 serve an area or provide a necessary service not contemplated
22 by the applicant. The commission may, for good
23 cause, deny an application with or without prejudice.

24 The issue of competition is addressed generally in AS
25 42.05.221(d), which states that:

26 In an area where the commission determines that two or
more public utilities are competing to furnish identical
utility service and that this competition is not in the
public interest, the commission shall take appropriate
action to eliminate the competition and any undesirable
duplication of facilities. This appropriate action may
include, but is not limited to, ordering the competing
utilities to enter into a contract that, among other
things, would:

(1) delineate the service area boundaries of each
in those areas of competition;

1 (2) eliminate existing duplication and paralleling
2 to the fullest reasonable extent;

3 (3) preclude future duplication and paralleling;

4 (4) provide for the exchange of customers and
5 facilities for the purposes of providing better public
6 service and of eliminating duplication and paralleling;
7 and

8 (5) provide such other mutually equitable arrange-
9 ments as would be in the public interest.

10 The Legislature's charge in AS 42.05.221(d) to the
11 Commission to eliminate competition that the Commission finds is
12 not in the public interest impliedly authorizes the Commission to
13 grant monopolies when competition is not in the public interest.
14 The Legislature is fully aware of the Commission's authority to
15 grant monopolies as evidenced by AS 45.50.572(d), which provides
16 that the state's antitrust laws do not apply to utilities operating
17 pursuant to a certificate issued by the Commission.

18 In the Commission's view, the statutory framework,
19 discussed above, provides it with comprehensive control over public
20 utilities and the services they provide to the public in this
21 state. Importantly, they give the Commission policymaking
22 authority to determine when and how to implement competition among
23 public utilities in the public interest. The Commission may decide
24 that it is in the public interest to allow only one electric
25 utility to serve a community, as it recently decided in Docket
26 U-94-2, in which it granted Alaska Power Company the exclusive
right to serve Klawock. See Order U-94-2(19); see also Order

1 U-95-9(3)/U-95-30(3) (allowing the City of Thorne Bay to retain an
2 exclusive right to serve the customers in its service territory)

3 Or, the Commission may decide to grant multiple certifi-
4 cates and allow competition in an area as it has done on pas-
5 occasions once it finds that competition is in the public interest.
6 See Re: Far North Sanitation Service, Inc., 3 APUC 333 (1981); Re
7 Matanuska Telephone Association, Inc., 3 APUC 348 (1981); Re
8 Colville Environmental Services, 4 APUC 131 (1982); Re: Claude C
9 Bailey d/b/a Valley Refuse, 7 APUC 97 (1985).

10 Chugach seeks to circumvent the Commission's certifica-
11 tion requirement by characterizing its proposed sales of electric
12 power as "commodity" sales, and then arguing that AS 42.05.221(a)
13 does not allow the Commission to restrict this category of sales.
14 Chugach reaches this conclusion by arguing that the absence of the
15 word "commodity" in the last sentence of AS 42.05.221(a) demon-
16 strates that the Legislature intended to authorize the Commission
17 to establish an "authorized area" for the provision of a "service,"
18 but not for a "commodity." (Chugach Memorandum at 21-22.)

19 The Commission rejects Chugach's unsupported assertion
20 that its proposed sales of electric power through retail-wheeling
21 arrangements with ML&P constitute a "commodity" rather than a
22 "service." Neither the Legislature nor the Commission has defined
23 the term "commodity." On the other hand, the Legislature has
24 broadly defined a "service" to generally include every type of
25 commodity, product, use, facility, or form of service "unless the
26

1 context indicates otherwise." AS 42.05.990(6). The Commission is
2 not persuaded that the absence of the word "commodity" in the last
3 sentence in AS 42.05.221(a) evidences a legislative intent to
4 restrict the Commission's authority to regulate electric power
5 sales implemented through retail-wheeling arrangements, which
6 Chugach characterizes as "commodity" sales. Because the Legisla-
7 ture broadly defined the term "service" in AS 42.05.990(6)
8 generally to include every type of commodity, the Legislature
9 logically may have decided that it was unnecessary to include the
10 word "commodity" in the last sentence.

11 Even assuming that Chugach's proposed sales of electric
12 power through retail-wheeling arrangements may be characterized as
13 a "commodity" sale rather than a "service," the Commission still
14 rejects Chugach's interpretation of AS 42.05.221(a) because it
15 contradicts the primary purpose for imposing a certificate
16 requirement expressed in the first sentence of the statute, which
17 is that a public utility may not provide either a "commodity" or a
18 "service" to the public without first having obtained a certificate
19 from the Commission.⁴

20 Additionally, Chugach does not cite any legislative
21 history to support its novel interpretation of AS 42.05.221(a), and
22

23
24 ⁴The Commission questions how any of Chugach's arguments
25 regarding the distinction it makes between a "commodity" sale
26 versus a "service" would give it a right to serve customers located
in ML&P's certificated service territory since Chugach is only
authorized pursuant to its Certificate to furnish "ELECTRIC
SERVICE."

1 the Commission has found none either. This statute and most of AS
2 42.05 was substantially rewritten in 1970, and there have been
3 relatively minor amendments since then. See ch. 113 SLA 1970 (SC
4 CSHB 202). In general, the 1970 amendments were designed to
5 strengthen the Commission's jurisdiction over utilities, including
6 municipal utilities, in part, to allow the Commission to resolve
7 conflicts between competing utilities. *APUC v. Chugach Electric*
8 *Ass'n*, 580 P.2d 687, 693 (Alaska 1978) (holding that whatever
9 property right Chugach may have had in its Certificate prior to
10 1970 was extinguished by the Legislature in 1970 to allow the
11 Commission to modify certificates as needed to resolve conflicts
12 between competing utilities).

13 Chugach's interpretation of AS 42.05.221(a) would
14 restrict the Commission's control over competing utilities and
15 create a loophole with respect to an undefined category of power
16 sales Chugach describes as "commodity" sales. In the Commission's
17 view, this result is contrary to the Legislature's intent in 1970
18 of expanding the Commission's regulatory powers over public
19 utilities and the conflicts that can arise between them.

20 Furthermore, the Commission finds that Chugach's
21 interpretation of AS 42.05.221(a) would not serve the public
22 interest because it would deny the Commission the opportunity to
23 determine whether the retail-wheeling arrangements Chugach proposes
24 are in the public interest. One of the most effective means of
25 ensuring Commission review and regulation of utility service to a
26

1 area is the certificate requirement in AS 42.05.221(a), which
2 Chugach seeks to bypass with its novel interpretation.

3 Chugach also argues that the Commission's authority to
4 eliminate competition in AS 42.05.221(d) is restricted to
5 situations involving only the duplication of facilities, and it
6 contends that its proposed sales of power to customers in ML&P's
7 service territory through retail wheeling would not result in the
8 duplication of facilities. (Chugach Memorandum at 22-23.)

9 Assuming as true Chugach's factual assertion that its
10 proposed sales of power to customers located in ML&P's certificated
11 service territory will not result in a duplication of facilities,
12 the Commission still rejects Chugach's interpretation because it is
13 contrary to the plain language in AS 42.05.221(d). The fallacy in
14 Chugach's interpretation is that it is the duplication of "ser-
15 vices" between competing utilities, not the duplication of
16 "facilities" as Chugach would have it, that triggers Commission
17 action in AS 42.05.221(d). When competing utilities provide
18 identical service to an area and the Commission finds that this
19 competition is not in the public interest, the Commission is
20 required to eliminate the competition and any "undesirable
21 duplication of facilities." The Commission may take additional
22 "appropriate action" to eliminate the competition as described in
23 AS 42.05.221(d)(1)-(5).

24 Chugach attempts to support its interpretation of
25 AS 42.05.221(d) by referring to the Commission's regulations at
26

1 3 AAC 52.110 - 3 AAC 52.150, which Chugach argues underscore the
2 focus on the elimination of duplicative facilities. (Chugach
3 Memorandum at 22.) These regulations though are broader than
4 Chugach suggests. For example, 3 AAC 52.110 states broadly that:

5 The purpose of 3 AAC 52.110 - 3 AAC 52.150 is to prevent
6 duplication of electric facilities and services in those
7 geographical areas of the state in which two or more
8 electric utilities compete.

9 (Emphasis added.)

10 The provisions of 3 AAC 52.120(a) specifically prohibit
11 an electric utility from competing with another electric utility to
12 provide an electric service connection for a customer without
13 approval from the Commission or otherwise complying with the
14 requirements in 3 AAC 52.120(b).

15 Therefore, the Commission concludes that AS 42.05.221(a)
16 applies to Chugach's proposed sales of electric power to customers
17 located in ML&P's certificated service territory through retail
18 wheeling and that if Chugach wishes to serve these customers, it
19 will have to apply in accordance with the statute to serve them.
20 The Commission further concludes that AS 42.05.221(d) does not
21 restrict its authority to eliminate competition between electric
22 utilities to situations where a duplication of facilities might
23 result. Together, AS 42.05.221(a) and AS 42.05.221(d) ensure that
24 the Commission will review and regulate all forms of utility
25 service to an area and determine when and how competition among
26 utilities may be implemented in the public interest.

1 Lastly, following from the conclusions just discussed,
2 it is evident that unless the Commission concludes that it is in
3 the public interest to authorize a second utility to provide retail
4 electric service to customers in ML&P's certificated service
5 territory, ML&P is the exclusive provider of retail electric
6 service to customers in its certificated service territory.

7
8 **III. The Commission's Decision in This Docket Should Satisfy the
 State Action Doctrine**

9 The last issue for discussion is whether the Commission's
10 decision herein confirming ML&P's exclusive right to serve
11 customers in its service territory will satisfy the state action
12 doctrine. Although the Commission is not empowered to and surely
13 cannot guarantee immunity to utilities like ML&P from the federal
14 antitrust laws, the Commission feels compelled to elaborate on its
15 views regarding the state action doctrine, given the considerable
16 arguments Chugach has made on the subject in this Docket.⁵

17 As discussed in section I above, the U.S. Supreme Court
18 carved out an exception to liability under the federal antitrust
19 law referred to as the "state action" doctrine. In respect of the
20

21
22 ⁵The parties have presented divergent views on whether the
23 Sherman Act would apply to ML&P's retail electric operations. For
24 purposes of analysis only, the Commission will assume that there is
25 a sufficient nexus between ML&P's retail sales of electric power
26 and interstate commerce to satisfy the jurisdictional prerequisites
 necessary to support Sherman Act jurisdiction. See *McLain v. Real
 Estate Board of New Orleans, Inc.*, 444 U.S. 239, 243 (1980); *Musick
 v. Burke*, 913 F.2d 1390, 1394-95 (9th Cir. 1990). The Commission
 recognizes that this is a complicated jurisdictional issue that
 ultimately would need to be resolved by the courts.

1 principles of federalism and state sovereignty, the Court create
2 the exemption to allow state policy makers (like this Commission
3 the freedom to develop and administer state policy free from
4 federal antitrust concerns. *Columbia v. Omni Outdoor Advertising*
5 *Inc.*, 499 U.S. 365, 370 (1991).

6 In *California Liquor Dealers Assn. v. Midcal Aluminum*
7 445 U.S. 97 (1980), the U.S. Supreme Court articulated the two
8 prong test used today for determining whether private action will
9 be immune from antitrust liability under the state action doctrine
10 The Court explained that:

11 First, the challenged restraint must be "one clearly
12 articulated and affirmatively expressed as state policy";
13 second, the policy must be "actively supervised" by the
14 State itself.

15 *Id.* at 105.

16 In *Midcal*, Midcal Aluminum, a wine distributor, success-
17 fully challenged California's wholesale wine-pricing program under
18 the Sherman Act. The Court held that the wine-pricing program
19 satisfied the first prong of the test but failed the second prong
20 because the California statutes did not provide for state oversight
21 of the price schedules and did not otherwise monitor the program
22 *Id.* at 105-06.

23 In explaining the *Midcal* test to the Commission, Chugach
24 has asserted that the first prong of the test can only be satisfied
25 if Alaska statutes clearly and affirmatively express a legislative
26 policy against competition. (Chugach Memorandum at 17-18.)
Chugach then argues that the only statute that speaks to the issue

1 of eliminating competition is AS 42.05.221(d), which as discussed
2 above, Chugach narrowly interprets. Chugach thus concludes that no
3 state statute authorizes the Commission to allow ML&P to refuse
4 Chugach's requests for retail wheeling; and, therefore, a Commis-
5 sion decision allowing ML&P to retain an exclusive right to serve
6 customers in its certificated service territory would not satisfy
7 the state action doctrine in the context of a federal antitrust
8 lawsuit. Chugach's discussion of the first prong of the *Midcal*
9 test, however, is misleading.

10 Since the *Midcal* decision, the U.S. Supreme Court has
11 provided additional guidance regarding how the first prong of the
12 *Midcal* test may be satisfied. Critical to an understanding in this
13 Docket, is the Supreme Court's decision in *Southern Motor Carriers*
14 *Rate Conference, Inc. v. U.S.*, 471 U.S. 48 (1985). In *Southern*
15 *Motor*, the U.S. Dept. of Justice filed a lawsuit against the
16 Southern Motor Carriers Association, Inc., and North Carolina Motor
17 Carriers Association, Inc., for engaging in collective ratemaking
18 activities. These entities were "rate bureaus" operating in four
19 states (North Carolina, Georgia, Mississippi, and Tennessee), which
20 were authorized by each of the states to submit joint rate
21 proposals to the public service commissions in each state to
22 establish the common carriers' intrastate rates for the transporta-
23 tion of goods. The public service commission in each state would
24 make the final decision regarding the intrastate rates.

1 The U.S. Dept. of Justice argued that the rate bureau
2 had violated the Sherman Act by conspiring with their members t
3 fix the intrastate rates. The rate bureaus argued that thei
4 conduct was exempt from the federal antitrust laws by virtue of th
5 state action doctrine. The Supreme Court applied the *Midcal* tes
6 to determine whether the rate bureaus were exempt from the federa
7 antitrust laws and explained that because the government ha
8 conceded that the state public service commission supervised th
9 collective ratemaking activities of the rate bureaus, the secon
10 prong of the *Midcal* test was satisfied. *Southern Motor*, 471 U.S
11 at 62.

12 The critical issue, therefore, was whether the collectiv
13 ratemaking activities supervised by the four public servic
14 commissions were authorized by their respective state legislature
15 and would satisfy the first prong of the *Midcal* test. With respec
16 to North Carolina, Georgia, and Tennessee, their state legislature
17 explicitly permitted collective ratemaking by common carriers
18 With respect to Mississippi, however, its legislature had no
19 passed a statute that specifically authorized its public servic
20 commission to permit collective ratemaking. The Supreme Cour
21 therefore articulated the issue in the following way:

22 We therefore must consider whether, in the absence of a
23 statute expressly permitting the challenged conduct, the
24 first prong of the *Midcal* test can be satisfied.

25 *Southern Motor*, at 63.

26

1 On this issue, the Court observed that the Mississippi
2 statutes provided the state public service commission with general
3 authority to regulate common carriers and to prescribe "just and
4 reasonable" rates for the intrastate transportation of goods. *Id.*
5 On this basis, the Supreme Court held that:

6 The legislature thus made clear its intent that intra-
7 state rates would be determined by a regulatory agency,
8 rather than by the market. The details of the inherently
9 anticompetitive rate-setting process, however, are left
10 to the agency's discretion.

11

12 If more detail than a clear intent to displace
13 competition were required of the legislature, States
14 would find it difficult to implement through regulatory
15 agencies their anticompetitive policies. Agencies are
16 created because they are able to deal with problems
17 unforeseeable to, or outside the competence of, the
18 legislature. Requiring express authorization for every
19 action that an agency might find necessary to effectuate
20 state policy would diminish, if not destroy, its useful-
21 ness. . . . Therefore, we hold that if the State's
22 intent to establish an anticompetitive regulatory program
23 is clear, as it is in Mississippi, the State's failure to
24 describe the implementation of its policy in detail will
25 not subject the program to the restraints of the federal
26 antitrust laws.

18 *Id.* at 64-65 (emphasis added).

19 The *Southern Motor* case makes it clear that for purposes
20 of satisfying the state action doctrine, the Alaska Legislature's
21 intent to displace competition in the utility industry may be
22 evidenced by the general regulatory structure it has created for
23 utilities in AS 42.05, which this Commission administers. It is
24 not necessary, as Chugach has asserted, that the Alaska Legislature
25 set forth the details of the state's policy in the Alaska statutes
26

1 regarding how or when competition may be limited; this matter may
2 be generally delegated to the Commission, which, subject to some
3 exceptions,⁵ the Legislature has done in AS 42.05.221(d). See also
4 AS 4..50.572(d) (which exempts from the state's antitrust laws
5 public utilities operating pursuant to a certificate issued by the
6 Commission).

7 In *City of Columbia v. Omni Outdoor Advertising, Inc.*,
8 499 U.S. 365 (1991), the U.S. Supreme Court elaborated further on
9 this issue and observed that if the first prong of the *Midcal* test
10 were applied too restrictively by federal courts, then federal
11 courts then would become the standard reviewer of state agency
12 action. This, the Court explained, would undermine the very
13 interests of federalism the state action doctrine was designed to
14 protect. *Id.* at 372. Accordingly, the Court held that the City
15 of Columbia's general grant of zoning authority, which the City
16 relied on to promulgate anti-competitive ordinances restricting the
17 location, size, and space of billboards, satisfied the first prong
18 of the *Midcal* test. In so holding, the Court explained that:

19 Besides authority to regulate, however, the *Parker*
20 defense also requires authority to suppress competition
21 -- more specifically, 'clear articulation of a state
22 policy to authorize anticompetitive conduct' by the
23 municipality in connection with its regulation. . . . We
24 have rejected the contention that this requirement can be
met only if the delegating statute explicitly permits the
displacement of competition, . . . It is enough, we have

25 ⁵When the Legislature wishes to require the Commission to
26 implement competition, it has explicitly stated so as in the case
with intrastate long distance telephone service. See AS 42.05.800-
890.

1 held, if suppression of competition is the 'foreseeable
2 result' of what the statute authorizes

3 Id. at 372-73 (emphasis added).

4 For the reasons discussed in section II above and in
5 accordance with the U.S. Supreme Court's decisions in *Southern*
6 *Motor* and *City of Columbia*, the Commission concludes that the
7 Alaska Legislature has evidenced its intent to displace competition
8 in the utility industry by creating a comprehensive regulatory
9 structure, which the Commission administers, and furthermore
10 delegating to the Commission the power to determine when to
11 eliminate or implement competition in the public interest pursuant
12 to AS 42.05.221(d). The Commission believes its decision to allow
13 ML&P to retain an exclusive right to sell power to customers in its
14 certificated service territory should satisfy the state action
15 doctrine in the context of a federal antitrust lawsuit.

16 The Ninth Circuit decision in *Columbia Steel Casting Co.*
17 *Inc. v. Portland General Electric Company*, 111 F.3d 1427 (9th Cir.
18 1997), which Chugach relies on, does not contradict the U.S.
19 Supreme Court precedent discussed above. In *Columbia Steel*,
20 Portland General Electric (PGE) refused to wheel power on behalf of
21 Pacific Power & Light (PP&L) to Columbia Steel Casting Co.
22 (Columbia Steel) on the ground that PGE held an exclusive right to
23 provide service to Columbia Steel that derived from a 1972
24 Agreement in which PGE and PP&L agreed to exchange facilities in
25 Portland. In a written order, the Oregon Public Utility Commission
26 (Oregon PUC) had approved the utilities' agreement in 1972. When

1 sued by Columbia Steel, PGE asserted immunity under the state
2 action doctrine based on the Oregon PUC's 1972 approval and
3 subsequent course of conduct and correspondence with the Oregon
4 PUC.

5 The Ninth Circuit held that the Oregon PUC had not stated
6 clearly enough in its 1972 order its policy intent to displace
7 competition. *Id.* at 1438. The Ninth Circuit rejected the Oregon
8 PUC's 1992 order, which attempted to clarify the Oregon PUC's
9 intent in 1972 to displace competition. The Ninth Circuit reasoned
10 that the state action doctrine can only be satisfied based on a
11 objective reading of the Oregon PUC's 1972 order. *Id.* at 1442.

12 The *Columbia Steel* decision does not bar this Commission
13 from making policy decisions, including anti-competitive ones, that
14 it is authorized to make in accordance with state law. Nor is the
15 Commission confining itself in this Docket to an interpretation of
16 its prior Orders in Docket U-71-16. To avoid the problems that
17 arose in the *Columbia Steel* case, the Commission hopes that the
18 decision herein will make it absolutely clear for purposes of
19 satisfying the state action doctrine that its policy decision in
20 this Docket is to confirm ML&P's exclusive right to provide retail
21 electric service to customers in its certificated service territory
22 unless the Commission decides otherwise.

23 Chugach also relies on an Idaho district court decision
24 in *Snake River Valley Elec. Ass'n v. PacifiCorp*, 1997 WL 241086 (D
25 Idaho, April 25, 1997). In that decision, the defendant PacifiCorp
26

1 refused to sell power to Snake River Valley Electric Association
2 (SRVA) on the ground that Idaho's Electric Supplier Stabilization
3 Act (ESSA) permitted such refusal. The ESSA apparently was
4 designed to promote harmony among electric suppliers in Idaho by
5 prohibiting one supplier from serving the customer of a second
6 supplier without the latter's consent. *Id.* at 3. SRVA argued that
7 PacifiCorp's refusal to sell it power violated the Sherman Act
8 because SRVA then was unable to compete and sell power to customers
9 in PacifiCorp.'s service territory.

10 The district court agreed with PacifiCorp that the
11 utility could, in accordance with the ESSA, lawfully refuse to sell
12 power to SRVA. The district court therefore easily found that the
13 first prong of the *Midcal* test was satisfied. *Id.* at 3-4. The
14 district court, however, found that the second prong of the *Midcal*
15 test was not satisfied because the court determined that Idaho did
16 not actively administer and supervise the ESSA. The district court
17 stated that "there was no provision for an agency review or any
18 other type of supervision" of the anticompetitive conduct. *Id.*
19 at 4. Therefore, the district court held that PacifiCorp was not
20 entitled to immunity under the state action doctrine. *Id.* at 6.

21 The *Snake River* decision does not pose a problem since
22 this Commission regularly supervises and monitors the conduct of
23 utilities in the state, including ML&P's retail electric opera-
24 tions. One of the most effective means of ensuring Commission
25 review of utility service to an area is the certificate requirement
26

1 in AS 42.05.221, which Chugach seeks to bypass. The review
2 procedures are in place, and Chugach must comply with them.
3 Furthermore, Chugach has not even alleged that the Commission's
4 review procedures would fail to satisfy the second prong of the
5 Midcal test.

6 In view of the above conclusions, the Commission has
7 determined that the parties should be required to file briefs on
8 the issue of what relief, if any, should be provided to ML&P, and
9 what sanctions, if any, should be imposed on Chugach for its
10 attempts to sell power to customers located in ML&P's certificated
11 service territory. The briefing requirement shall consist of both
12 utilities filing briefs and reply briefs, and the deadlines for
13 filing the briefs will be simultaneous.

14
15 ORDER

16 THE COMMISSION FURTHER ORDERS:

17 1. The motion by Chugach Electric Association, Inc.,
18 for declaratory judgment (summary judgment) is denied.

19 2. The motion by the Municipality of Anchorage d/b/a
20 Municipal Light & Power Department for summary judgment to dismiss
21 the cross-complaint filed by Chugach Electric Association, Inc., is
22 granted.

23 3. By 4 p.m., June 10, 1998, the parties shall submit
24 briefs addressing the issue of what relief, if any, should be
25 provided to the Municipality of Anchorage d/b/a Municipal Light &
26 Power Department and what sanctions, if any, should be imposed or

1 Chugach Electric Association, Inc., for its attempts to sell power
2 to customers located in the certificated service territory of the
3 Municipality of Anchorage d/b/a Municipal Light & Power Department.

4 4. By 4 p.m., June 25, 1998, the parties shall submit
5 reply briefs in response to the briefs required by Ordering
6 Paragraph No. 3 of this Order.

7
8 DATED AND EFFECTIVE at Anchorage, Alaska, this 20th day of May,
1998.

9 BY DIRECTION OF THE COMMISSION



17
18
19
20
21
22
23
24
25
26

Alaska Public Utilities Commission
1016 West Sixth Avenue, Suite 400
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

1

2

3

4

5

6

7

8

9

0

1

2

3

4

5

6

7

8

9

0

1

2

3

4

[illegible]

4
5
6
7
8
9
0
1
2
3
4
5
6
7
8
9
0
1
2
3
4

4
5
6
7
8
9
0
1
2
3
4
5
6
7
8
9
0
1
2
3
4

7
8
9
0
1
2
3
4
5
6
7
8
9
0
1
2
3

8
9
0
1
2
3
4
5
6
7
8
9
0
1
2
3
4

[illegible]

4
5
6
7
8
9
0
1
2
3
4

[illegible]6
7
8
9
0
1
2
3
4
5

8

9

0

1

2

3

4

5

9
0
1
2
3
4

0
1
2
3
4
5

3

Alaska Public Utilities Commission
1016 West Sixth Avenue, Suite 400
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

1 in the proceeding identified above to the persons indicated on the
2 attached service list.

3 DATED at Anchorage, Alaska, this 21st day of May, 1998.
4

5
6 Brenda J. Miller
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

SERVICE LIST
U-97-201

May 20, 199
Page 1 of

Donald W. Edwards, Esq.
General Counsel
Chugach Electric Association, Inc.
P. O. Box 196300
Anchorage, AK 99519-6300

Kirk H. Gibson, Esq.
Ronald L. Saxton, Esq.
Ater Wynne Hewitt et. al.
Counsel for Golden Valley Electric
Association, Inc.
Suite 1800
222 S.W. Columbia Street
Portland, OR 97201-6618

James L. Walker, Esq.
Assistant Municipal Attorney
Office of the Municipal Attorney
Counsel for Municipal Light &
Power, Municipality of Anchorage
d/b/a
P.O. Box 196650
Anchorage, AK 99519-6650

COURTESY LIST
U-97-201

Daniel M. Dieckgraeff
Assistant Treasurer and
Manager, Rates and Planning
ENSTAR Natural Gas Company
P. O. Box 190288
Anchorage, AK 99519-0288

James Patras
Manager of Rates
Alaska Electric Generation &
Transmission Cooperative, Inc.
3380 C Street, Suite 110
Anchorage, AK 99503

Martin M. Weinstein, Esq.
Assistant Attorney General
Alaska Public Utilities Commission
1031 West Forth Avenue, Suite 200
Anchorage, AK 99501

Julian L. Mason, Esq.
Ashburn and Mason
1130 West Sixth Avenue, Suite 100
Anchorage, AK 99501

Robin O. Brena, Esq.
Brena, Bell, and Clarkson
310 K Street, Suite 601
Anchorage, AK 99501

Eugene N. Bjornstad
General Manager
Chugach Electric Association, Inc.
P. O. Box 196300
Anchorage, AK 99519-6300

Michael C. Dotten, Esq.
Eric R. Todderud, Esq.
Heller Ehrman White & McAuliffe
Counsel for Chugach Electric
Association, Inc.
Suite 1750
200 S. W. Market Street
Portland, OR 97201-5718

Michael P. Kelly
General Manager
Golden Valley Electric
Association, Inc.
P. O. Box 71249
Fairbanks, AK 99707-1249

Hank Nikkels
Acting General Manager
Municipal Light & Power,
Municipality of Anchorage d/b/a
1200 East First Avenue
Anchorage, AK 99501-1685



NATIONAL CONFERENCE OF STATE LEGISLATURES

1560 BROADWAY SUITE 700 DENVER, COLORADO 80202-5140

PHONE 303-830-2200 x186 FAX 303-863-8003

~INCOMING FAX~**Telecopy to:** Rep. Norman Rokeberg c/o Janet

907-258-2916

From: Johanna Woelfel

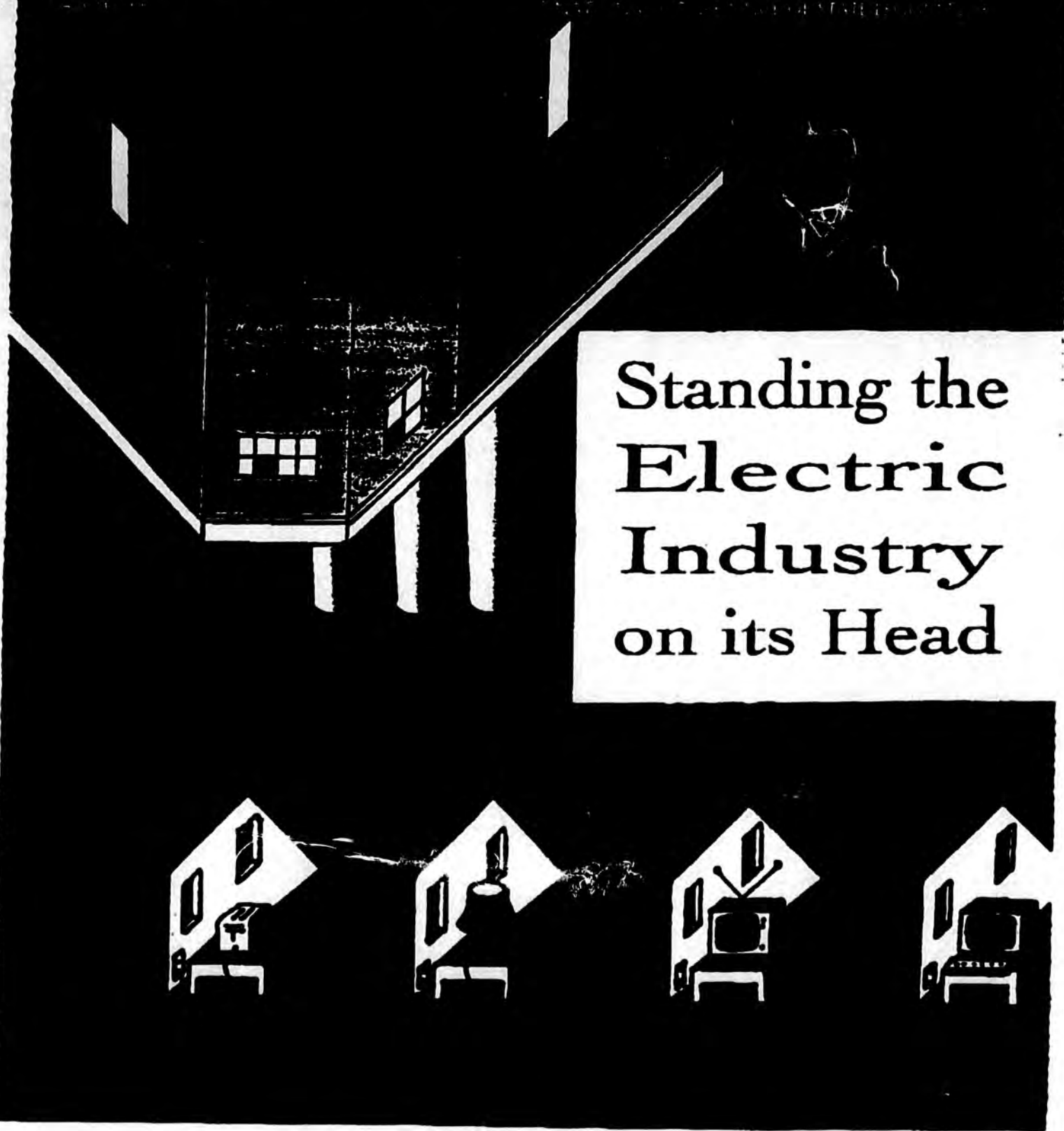
Environment, Energy & Transportation

Message: Here are two brief articles which offer a brief outline of electric industry restructuring. More information will follow by mail. Please call me if you have any questions. Thank you.

Note: Since these articles were written, The total number of states who have passed restructuring legislation has increased to 13. These states are: AZ, CA, CT, IL, ME, MA, MT, NV, NH, OK, PA, RI + VA.

Number of Pages: 8**Date Sent:** July 9, 1998

STATE LEGISLATURES



Standing the
Electric
Industry
on its Head

Standing the Electric Industry on its Head

After years as a regulated monopoly, the electric industry is on unfamiliar competitive ground and so are the states that are letting it happen.

By Matthew H. Brown

In June 1995 the New Hampshire legislature did something that would have been unthinkable a year before. It passed a law to let 17,000 New Hampshire residents choose their electric company. Frustrated with electric rates that were among the highest in the nation and believing that the state's monopoly utilities should face some real competition for their business, the legislature was the first in the nation to establish this kind of experimental program.

It was a harbinger of things to come around the country. Now a few states have passed far-reaching legislation to let all electric customers in the state choose where they want to buy their electricity. And almost every other state is considering the merits of taking the nation's most capital intensive industry from monopoly to competition. Known as "retail wheeling," this move to let customers choose their electric company, just as we all now choose our long distance phone company, is already putting the electric industry through some of its most fundamental changes in half a century.

The traditionally stodgy and predictable electric industry will look different five to 15 years from now, but no one knows just how it will look. Between now and the time that new industry emerges from today's confusion, it will have become very clear just how much the electric industry permeates every aspect of our lives. Legislators will have to make decisions that affect their states' economy, jobs, environment, tax revenue and the reliability of the electric system.

Matthew H. Brown runs the NCSL Energy Project, which offers remote assistance on utility restructuring to state legislatures, a national e-mail discussion group and an array of other resources. Call him to participate in the discussion group or to arrange technical assistance, (303) 830-2200.

A GLIMPSE OF THE NEW INDUSTRY

Close to two years after the New Hampshire legislature passed HB 168, the state's experiment with retail wheeling has taken off and gives a glimpse of the shape of tomorrow's electric industry. "Only by trying it could we see how a competitive electric industry might work," says Representative Clifton Below. The pilot experiment took place at the same time legislators were working on much more

comprehensive legislation to restructure the electric industry, Below says. "This gave us a chance to incorporate some of the lessons from the program into our legislation."

In New Hampshire, 31 different electricity suppliers wooed the pilot program's 17,000 customers with marketing ploys and incentives. Some offered electricity at extraordinarily low prices of less than 1.5 cents per kilowatt hour, others offered savings bonds or different prices for buying different amounts of electricity. One power supplier offered free birdhouses to those who signed up. A few

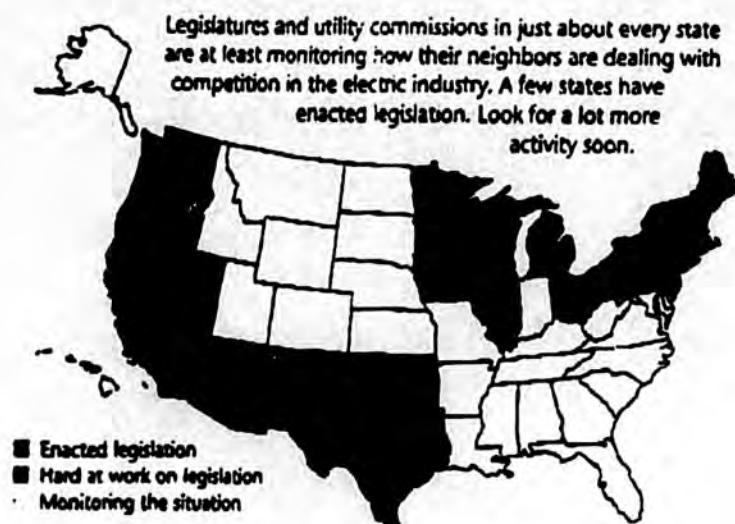
companies tried to identify themselves as clean or "green" power providers, guaranteeing that they would supply power that was generated only from certain "clean" sources, although the definition of what was clean varied from one company to another.

What was new about this was associating a brand name and identity with electrons. Companies began to try to distinguish themselves from each other by becoming the "cheap" power company, the "green" power company or the power company that was a responsible corporate citizen. At no other time has anyone needed to or tried to associate electricity with brand identity. This change alone was a fundamental shift in the character of the previously staid industry.

It was not only the old power companies that were



GIVING THE GO-AHEAD TO ELECTRIC INDUSTRY COMPETITION



competing for customers. Working Assets, the company that made its name by offering a credit card associated with environmentalism, became one of the "power marketers" competing for customers. Working Assets signed long-term contracts to buy power that came from environmentally friendly sources rather than, for instance, big polluter plants. It then sold that power through traditional mass marketing techniques. Working Assets and the other power marketers selling in New Hampshire were typical of a new breed of company in the electric business; they own no utility plants and no power lines, but make money by buying power cheaply from an open market of electricity, and selling it for more.

Elsewhere across the country, hundreds of wholesale power marketers, some of them affiliates of the nation's old utilities, and some of them companies that have not before tried to sell electricity, are buying and selling power. That is, they buy power on the open market and sell it to utilities. These power marketers claim that they can offer savings by selling directly to customers if states allow retail wheeling.

The new choices of services and companies were not necessarily what New Hampshire's customers wanted to see, and sometimes they engendered confusion. Some customers grew tired of having to think about their power company and the large array of options available to them. Others expected that their power rates would be lower than they actually were. Although the companies had advertised their electricity at rock-bottom prices, the final bill read an average of 10 cents per kilowatt hour—still a substantial reduction from what they had been paying, but much higher than what they had expected.

The difference between the 1.5 cents that was advertised and the 10 cents that most of the 17,000 New Hampshire customers ended up paying was partly made up of what has become known as "stranded costs." In New Hampshire's case, Public Service New Hampshire, one of New Hampshire's dominant electric companies, had built Seabrook, an expensive nuclear power plant, as well as a number of other power plants that produced power at rates higher than the market price for electricity. These power plants could become "stranded." That is, they might not be able to compete in a highly competitive power market. Saddled with the costs of these expensive power plants, Public Service New Hampshire could be in big financial trouble.



But Public Service New Hampshire pointed out that the state had approved the building of the power plants years ago, and that all these plants had been built as a result of a planning process in which the state had been heavily involved. Although some people still claim that these decisions to build expensive plants were simply bad business choices, the state elected to let the utilities recover most of the stranded costs that arose from the pilot program. These stranded costs, and the cost of sending the power over electric lines from power plants to customers, made up the difference between the low advertised cost of energy and the 10 cents per kilowatt hour or so that the customers were paying.

These stranded costs will not be limited to New Hampshire. Depending on who is doing the estimating, the nation's electric utilities could face a total of between \$50 billion and \$250 billion in stranded costs, mostly from expensive and noncompetitive power plants. In some cases, the stranded costs exceed the equity value of the utility that owns the stranded power plants. When these utilities make the transition from monopoly to competition, a few could go belly-up unless the states step in to help them. Yet the cost of helping some of these utilities through the transition could be enormous. Connecticut, with four problem-ridden nuclear power plants that will have lots of trouble producing power to compete with other cheap sources of electricity, is a prime example of a state in this dilemma.

An experimental program like New Hampshire's creates a

model of how an electric industry would change and what obstacles might arise in the transition from monopoly to competition in a state with very high electric rates. Not every state has

electric rates as high as New Hampshire's, and some states have far lower rates and a vastly different electric industry. Although it is instructive, not all of New Hampshire's experience is helpful to every other state. A few other states have begun pilot programs akin to New Hampshire's. Almost every other state is considering whether and how to make its electric energy business competitive and is facing issues that the pilot program did not address. Now legislation that several states have enacted and others are considering begins to deal with some of these other important issues, like taxation, the role of municipal utilities, rural electric cooperatives and

ANOTHER FEDERAL "SOLUTION?"

Although the states have gotten a jump on the federal government in moving toward a plan that lets customers choose their electricity suppliers, the final word may come from Washington. Congress and federal regulators are seriously considering preemption of state authority over electric utilities. A "one size fits all" federal solution could be imposed that extends federal control to retail markets.

The federal role in electric utility regulation up to this point has been limited and largely focused on the wholesale market. The passage of the Public Utilities Regulatory Policy Act (PURPA) in 1978 set in motion the federal effort to increase competition. PURPA sought to encourage development of power sources that did not use fossil fuels as a way of mitigating U.S. dependence on foreign oil. The federal efforts to spur competition increased markedly with the adoption of the Energy Policy Act of 1992. The Federal Energy Regulatory Commission (FERC) established rules for the sale of wholesale electricity between utilities. The rules require utilities to allow other companies to send electricity over their power lines for a reasonable, non-discriminatory price.

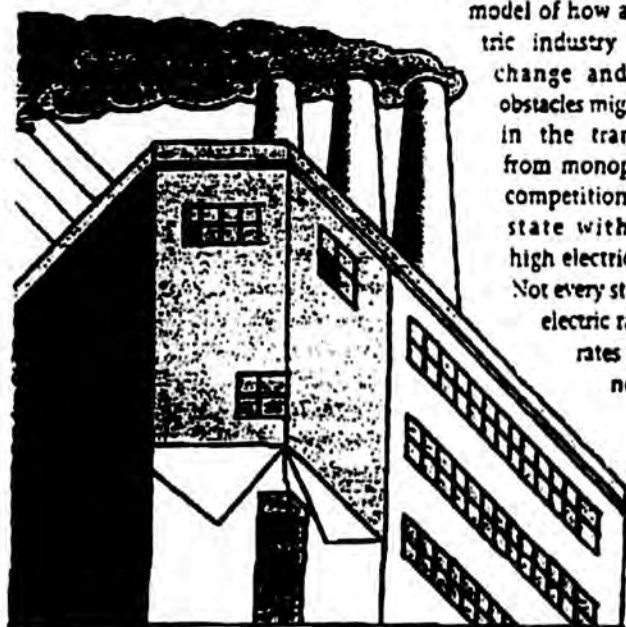
Now Congress and federal regulators are considering more broadly based efforts to open the retail electricity market to consumer choice. During the 104th Congress, bills surfaced not only to reform PURPA, but also, in the case of a proposal by Congressman Dan Schaefer, to require states to allow competition in the retail electricity market. The Schaefer proposal would give FERC authority to impose retail wheeling on any states that did not enact legislation to allow the practice themselves.

Over the course of the 104th Congress, a dozen or so hearings on these proposals were held by both House and Senate committees and drew the attention of a variety of well-financed stakeholders who stepped up both their lobbying efforts and their contributions to candidates for Congress. They are expected to be influential in any action taken this session.

Former Senator Bennett Johnson of Louisiana will be a player representing a group of utilities seeking retail wheeling. Schaefer's efforts are likely to be bolstered by the Commerce Committee chair, Congressman Tom Bliley of Virginia, who has expressed sympathy for "breaking up monopolies of utilities."

Major power outages during the summer of 1996 pushed the Clinton administration to get involved. It established a multi-agency team to develop the president's legislative initiative on the issue. As a result, the U.S. Department of Energy has been drafting a comprehensive package of federal legislation that would let customers throughout the country choose their electricity supplier.

States have a lot to lose in the battle that is sure to take place in Washington this session as special interests jockey for market advantages. The issue is not simply whether the electric retail market is deregulated, but who does it.



other so-called "public power" firms in competitive markets, and the role of energy efficiency and renewable energy in competitive markets.

WHAT ABOUT TAXES?

"We are very nervous about going full tilt at retail wheeling without making sure the tax piece is taken care of," says Representative Carl Holmes of the Kansas task force committee on electric industry reform. "We could see some big tax revenue losses if we jump into utility reform without thinking hard about how to do it. I am also convinced that some tax policy will ultimately have a big effect on how competitive these markets really are."

In fact Representative Holmes' predictions about tax revenue are already ringing true in Wilmington, Vt. New England Power, one of New England's largest utilities, recently sent Wilmington's town manager a letter notifying her that it was about to sell all its power plants, including a plant located there. That power plant contributes more than \$250,000 in property tax revenue to the town budget; if New England Power sells that plant, the town could see its property tax revenues decline by 50 percent or more because of revaluation. In another example, the Ohio school board association recently released a study that predicted property tax revenues could decline by as much as \$275 million statewide if the state decides to open the doors to competition.

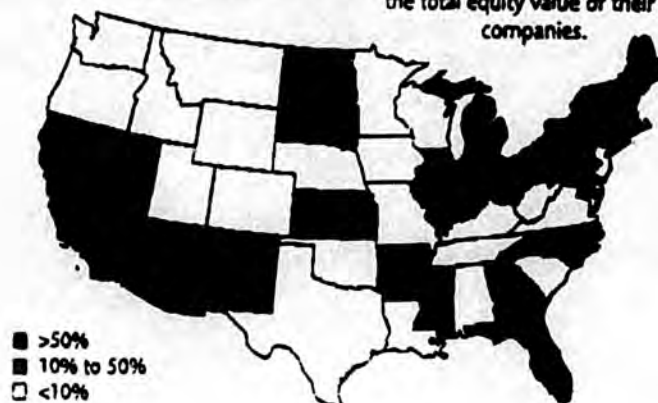
HOW TO DEAL WITH ENERGY EFFICIENCY

States are finding new ways to keep energy efficiency and renewable energy programs alive in competitive markets.

- Massachusetts has suggested that everyone pay 0.4 cents per kwh to fund energy efficiency and renewable energy programs.
- Rhode Island's law requires everyone to make a 0.23 cent per kwh contribution.
- California requires customers to pay up to 0.3 cents per kwh to create a \$500 million fund over four years.
- Vermont is looking at a requirement that retail sellers of electricity include among their portfolio of generating resources some renewable energy such as wind or solar power. If a retailer doesn't happen to have any renewables in its portfolio, it could buy tradeable credits from a company that has such resources.

STRANDABLE COSTS

Some utilities stand to lose a lot of money if they have to face competition. Because of differences in the way people estimate these losses, or strandable costs, the national figure ranges from \$50 to \$238 billion. But the potential for big losses varies from region to region and state to state. Utilities in some states face losses of more than 50 percent of the total equity value of their companies.



Source: L. Baxter and E. Hirst, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, Oak Ridge, Tenn: Oak Ridge National Laboratory, 1995.

Property tax revenues are not the only revenue source that could decline. A recent study by Deloitte and Touche, sponsored jointly by the National Conference of State Legislatures and the National Association of Regulatory Utility Commissioners, noted that utilities are often taxed on the basis of their total revenues while power marketers and other companies competing with utilities are taxed on the basis of total revenues minus expenses. These latter taxes on income are lower and generate less revenue for state budgets as a result. Other states and localities may also have to change their franchise fee structure, or face the loss of franchise fee revenues. At this point, no state has passed legislation that tries to solve these tax problems, although Minnesota, Ohio, New Hampshire, Kansas, Oklahoma, Nevada and a few others have spent some time working on it.

PUBLIC POWER

Of the close to 3,200 utilities in the United States, only about 225 are investor-owned. The remainder are a mixture of small rural electric cooperatives, municipal utilities, state-run authorities and federal power agencies. But because these 225 investor-owned utilities generate 75 percent of the electricity in the nation, they tend to dominate the discussions in many parts of the country.

U.S. INDUSTRIAL POWER PRICES

Electricity costs for businesses vary across the country. The cheapest electricity is in states with cheap coal or hydro-power such as Idaho, Wyoming, Utah and Kentucky. States with the highest costs (in red) are apt to be the ones looking seriously at doing away with regulated monopolies.



Up to 4 ¢/kWh
Between 4 ¢/kWh and 5 ¢/kWh
Between 5 ¢/kWh and 9 ¢/kWh

Particularly in the West, however, public power agencies have become an important part of the industry structure. But they have a different history, a different financial structure, a different set of regulations and customer base from many investor-owned utilities. Some of these small utilities feel threatened by competition, fearing that the well-heeled large competitors will pick off their best customers, leaving them to serve only the remaining small customers, without the financial resources to do so. In Colorado's 1996 legislative session a consortium of public power agencies blocked restructuring legislation before it even left committee.

California's AB 1890, enacted in the fall of 1996, required that all electric customers pay a fee of up to 0.3 cents per kWh through their electric bill to support renewable energy, energy efficiency and research and development programs. California is set to raise about \$500 million over the four years for renewable energy (like wind, solar, hydro or biomass power) alone.

California devised this plan at the end of a lengthy set of negotiations because the Legislature became convinced that without outside funding, renewable energy, energy efficiency and research and development programs would wither and disappear when faced with competition from cheap fossil fuels. Because renewable energy sources are marginally more expensive than, for instance, a natural gas fired power plant, the competitive market would shut them out without a subsidy. This subsidy in California and other states may allow these programs to continue.

California devised this plan at the end of a lengthy set of negotiations because the Legislature became convinced that without outside funding, renewable energy, energy efficiency and research and development programs would wither and disappear when faced with competition from cheap fossil fuels. Because renewable energy sources are marginally more expensive than, for instance, a natural gas fired power plant, the competitive market would shut them out without a subsidy. This subsidy in California and other states may allow these programs to continue.

A HARBINGER OF THINGS TO COME?

Now that almost every state is looking at its electric business with an eye to using competition to lower costs, is it a sure thing that every state will follow in the footsteps of those few that have passed legislation? Legislators in New Hampshire, Rhode Island, California and Pennsylvania became convinced that retail wheeling would make their states more attractive to industry, bring efficiency to the industry and lower costs to everyone. Other states aren't so sure, but the 1997 legislative session is witnessing even more legislation than in the past two years.

State legislatures are forced to perform a balancing act as they try to replace monopoly and regulation with competition. "Without any experience with full-blown retail wheeling to draw on," says Senator Michael Sanchez of New Mexico, "we don't know for sure whether competition will result in lower rates, or simply more volatile rates. We don't know for certain if competition might do little more than bring the nation back to an age of unregulated monopolies that control electricity markets at the expense of true competition. And, we don't know whether the environment or the nation's diversity of fuel resources will suffer or improve as companies begin to base their business decisions more heavily on short-term economic considerations."

The transition to competition is a leap of faith, in hopes that competitive markets will be able to manage a complex, capital-intensive industry better than regulation. It will be years before we know if it has worked.

PILOT PROGRAMS

Before launching statewide initiatives, eight states are running pilot programs to see how a competitive electric market might work. Most of these programs are just beginning.

Watch what happens in these small-scale applications of a big idea in:

Idaho
Illinois
Massachusetts
Michigan
New Hampshire
New York
Pennsylvania
Washington

STATESTATS

Electric Monopoly Shifting to Competition

In the past two years 10 states—New Hampshire, Rhode Island, California, Pennsylvania, Oklahoma, Montana, Maine, Nevada, Illinois and Massachusetts—have passed legislation allowing consumers to choose their electricity provider. This fundamental change in the nation's most capital intensive industry follows fast on the heels of new federal regulations that encourage competition among utilities for wholesale electricity sales to one another.

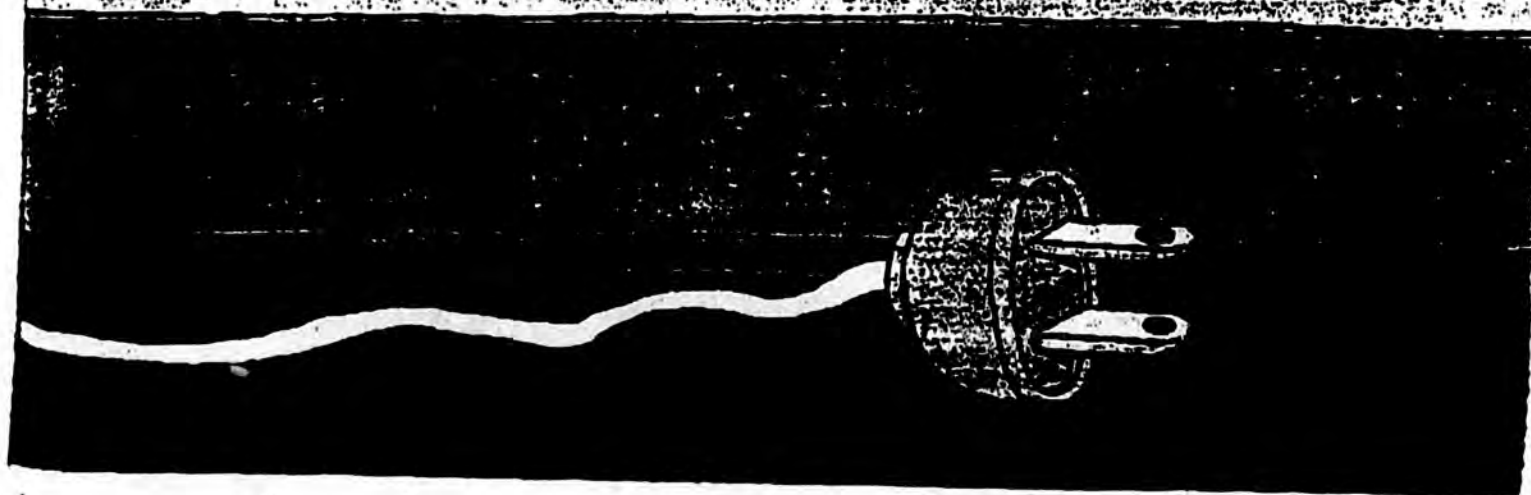
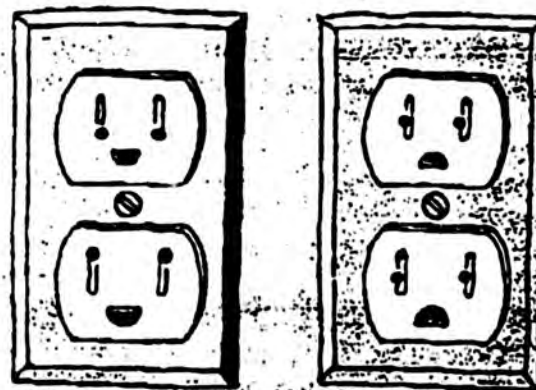
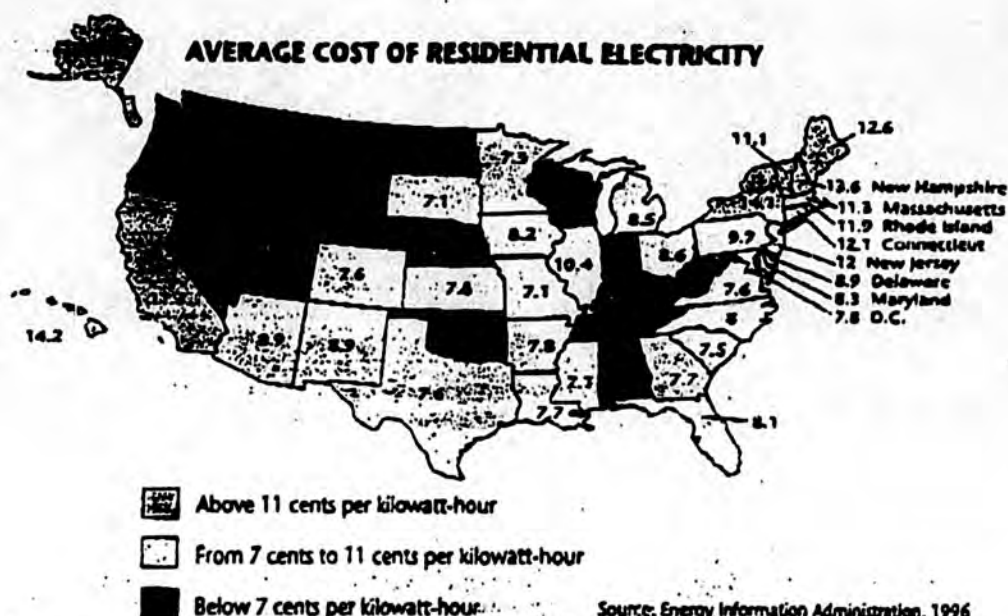
With the exception of Oklahoma and Montana, residents in the states that passed electric industry restructuring legislation pay electricity prices that are above the national average of 8.39 cents per kilowatt-hour. Electricity rates also have been on an upward trajectory in these high-cost states. Their state legislatures hope that competition will reduce electric rates by 10 percent to 20 percent over the next few years.

Residents of Oklahoma and Montana pay below average electric rates that have been trending downward for the past five years. State legislatures there hope to reduce electric rates still further while preparing their home utilities for competition in what

until now has been a monopoly.

This move to competition will mean that at least 25 million customers around the country will be able to choose their electric company at the beginning of 1998. By 2002, at least three times that number will be choosing their electric company. Watch closely as the nation's last heavily regulated industry begins its most fundamental shift in 50 years.

AVERAGE COST OF RESIDENTIAL ELECTRICITY



Glossary

One of the difficulties with discussing restructuring the electric industry is that terms mean different things to different people. This results in poor communication and misunderstandings about the proposals being discussed. To avoid some of this confusion, the following glossary is provided to clarify what the Council means when it uses certain terms. The glossary from the NARUC publication "Affected with the Public Interest" was used as the base of this list. Supplemental material was taken from many sources, including the Public Utilities Commission of Ohio, and a report by the Texas Ratepayers' Organization to Save Energy, Inc. titled "Electric Utility Restructuring, Can the Small Consumer Afford It?"

- Access Charge
- Aggregator
- Average Cost
- Avoided Cost
- Bilateral Contract
- Bottleneck Facility
- BPA
- Broker
- Bulk Power Supply
- Buy Through
- Capacity Release
- Captive Customer
- Commercialization
- Contract Path
- Contracts for Differences (CfD)
- Co-op
- Deintegration
- Demonstration
- Deregulation
- Derivatives
- Direct Access
- Disaggregation
- Distributed Generation
- Distribution
- Distribution Utility (Disco)
- Divestiture
- DSM (Demand-Side Management)
- Economic Efficiency
- Economies of Scale
- EEL
- ELCON
- Electric Utility
- Embedded Costs Exceeding Market Prices (ECEMP)
- Energy Efficiency
- EPA
- EPAct
- ESCO
- Exempt Wholesale Generator (EWG)
- Feebates
- Federal Energy Regulatory Commission (FERC)
- Forwards
- FPA
- Futures Market
- Generation Company (Genco)
- Generation Dispatch and Control

From NCS L
Web Site

- Grid
- Hedging Contracts
- IOU
- Integrated Resource Planning (IRP)
- Integrated Resource Planning Principles
- IPP
- ISDN
- ISO
- Load Centers
- Marginal Cost
- Market-Based Price
- Marketer
- Monopoly
- Monopsony
- Municipalization
- Municipal Utility
- NARUC
- NASUCA
- Natural Monopoly
- NCSL
- NOPR
- NRTA
- NUG
- Obligation to Serve
- Oligopoly
- Options
- Parallel Path Flow
- Peak Load or Peak Demand
- Performance-Based Regulation (PBR)
- Portfolio Management
- Power Authorities
- Power Pool
- Poolco
- Provider of Last Resort
- Public Interest Goals
- PURPA
- PUHCA
- Qualifying Facility (QF)
- Real-Time Pricing
- Reliability
- Renewable Resources
- Reregulation
- Research and Development (R&D)
- Resource Efficiency
- Restructuring
- Retail Competition
- Retail Market
- Retail Wheeling
- RD&D
- RTG
- Rules of Conduct
- Securitize
- Self-Generation
- Self-Service Wheeling
- Special Contracts
- Stranded Costs/Stranded Assets
- Stranded Benefits
- Sunk Cost

- Supply-Side
- Sustained Orderly Development
- SWRTA
- System Integration (of new technologies)
- Taking
- Tariff
- Time-of-Use (TOU) Rates
- Transition Costs
- Transmission-Dependent Utility
- Transmitting Utility (Transco)
- Unbundling
- Universal Service
- Utility
- Vertical Integration
- Volumetric Wires Charge
- WATSCO
- Wheeling
- Wholesale Competition
- Wholesale Power Market
- Wholesale Transmission Services
- Wires Charge
- WRTA
- WSSCC
- WSSP

Access Charge A charge levied on a power supplied, or its customer, for access to a utility's transmission or distribution system. It is a charge for the right to send electricity over another's wires.

Aggregator -- An entity that puts together customers into a buying group for the purchase of a commodity service. The vertically integrated investor owned utility, municipal utilities and rural electric cooperatives perform this function in today's power market. Other entities such as buyer cooperatives or brokers could perform this function in a restructured power market. This is opposed to marketer which will be defined as an entity that represents different suppliers.

Average Cost The revenue requirement of a utility divided by the utility's sales. Average cost typically includes the costs of existing power plants, transmission, and distribution lines, and other facilities used by a utility to serve its customers. It also included operating and maintenance, tax, and fuel expenses.

Avoided Cost The cost the utility would incur but for the existence of an independent generator or other energy service option. Avoided cost rates have been used as the power purchase price utilities offer independent suppliers (Qualifying Facilities).

Bilateral Contract A direct contract between the power producer and user or broker outside of a centralized power pool or POOLCO.

Bottleneck Facility A point on the system, such as a transmission line, through which all electricity must pass to get to its intended buyers. If there is limited capacity at this point, some priorities must be developed to decide whose power gets through. It also must be decided if the owner of the bottleneck may, or must, build additional facilities to relieve the constraint.

BPA -- Bonneville Power Administration. One of five federal power marketing administrations that sell low-cost electric power produced by federal hydro electric dams to agricultural and municipal users. BPA serves Idaho, Oregon, and Washington as well as parts of Nevada and Wyoming.

Broker -- A retail agent who buys and sells power. The agent may also aggregate customers and arrange for transmission, firming and other ancillary services as needed.

Bulk Power Supply -- Often this term is used interchangeably with wholesale power supply. In broader

terms, it refers to the aggregate of electric generating plants, transmission lines, and related-equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

Buy Through -- An agreement between utility and customer to import power when the customer's service would otherwise be interrupted.

Capacity Release -- A secondary market for capacity that is contracted by a customer which is not using all of its capacity.

Captive Customer A customer who does not have realistic alternatives to buying power from the local utility, even if that customer had the legal right to buy from competitors.

Commercialization -- Programs or activities that increase the value or decrease the cost of integrating new products or services into the electricity sector. (See "Sustained Orderly Development.")

Contract Path -- The most direct physical transmission tie between two interconnected entities. When utility systems interchange power, the transfer is presumed to take place across the "contract path," notwithstanding the electrical fact that power flow in the network will distribute in accordance with network flow conditions. This term can also mean to arrange for power transfer between systems. (See also Parallel path flow)

Contracts for Differences (CfD) -- A type of bilateral contract where the electric generation seller is paid a fixed amount over time which is a combination of the short-term market price and an adjustment with the purchaser for the difference. For example, a generator may sell a distribution company power for ten years at 6/kWh. That power is bid into Poolco at some low /kWh value (to ensure it is always taken). The seller then gets the market clearing price from the pool and the purchaser pays the producer the difference between the Poolco selling price and 6/kWh (or vice versa if the pool price should go above the contract price).

Co-op -- This is the commonly used term for a rural electric cooperative. Rural electric cooperatives generate and purchase wholesale power, arrange for the transmission of that power, and then distribute the power to serve the demand of rural customers. Co-ops typically become involved in ancillary services such as energy conservation, load management and other demand- side management programs in order to serve their customers at least cost.

Deintegration -- (See disaggregation)

Demonstration -- The application and integration of a new product or service into an existing or new system. Most commonly, demonstration involves the construction and operation of a new electric technology interconnected with the electric utility system to demonstrate how it interacts with the system. This includes the impacts the technology may have on the system and the impacts that the larger utility system might have on the functioning of the technology.

Deregulation -- The elimination of regulation from a previously regulated industry or sector of an industry.

Derivatives A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

Direct Access -- The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility. (See also Retail Competition)

Disaggregation -- The functional separation of the vertically integrated utility into smaller, individually owned business units (i.e., generation, dispatch/control, transmission, distribution). The terms "deintegration," "disintegration" and "delamination" are sometimes used to mean the same thing. (See also "Divestiture.")

Distributed Generation -- A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

Distribution The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

Distribution Utility (Disco) -- The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The Disco can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.

Divestiture -- The stripping off of one utility function from the others by selling (spinning-off) or in some other way changing the ownership of the assets related to that function. Most commonly associated with spinning-off generation assets so they are no longer owned by the shareholders that own the transmission and distribution assets. (See also "Disaggregation.")

DSM (Demand-Side Management) -- Planning, implementation, and evaluation of utility-sponsored programs to influence the amount or timing of customers' energy use.

Economic Efficiency -- A term that refers to the optimal production and consumption of goods and services. This generally occurs when prices of products and services reflect their marginal costs. Economic efficiency gains can be achieved through cost reduction, but it is better to think of the concept as actions that promote an increase in overall net value (which includes, but is not limited to, cost reductions).

Economies of Scale Economies of scale exist where the industry exhibits decreasing average long-run costs with size.

EEI -- Edison Electric Institute. An association of electric companies formed in 1933 "to exchange information on industry developments and to act as an advocate for utilities on subjects of national interest."

ELCON -- Electricity Consumers Resources Council. ELCON is an association of 28 large industrial consumers of electricity. ELCON members account for over five percent of all electricity consumed in the United States. ELCON was formed in 1976 "to enable member companies to "work cooperatively for the development of coordinated, rational and consistent policies affecting electric energy supply and pricing at the federal, state, and local levels."

Electric Utility -- Any person or state agency with a monopoly franchise (including any municipality), which sells electric energy to end-use customers; this term includes the Tennessee Valley Authority, but does not include other Federal power marketing agency (from EPAct).

Embedded Costs Exceeding Market Prices (ECEMP) -- Embedded costs of utility investments exceeding market prices are: 1) costs incurred pursuant to a regulatory or contractual obligation; 2) costs that are reflected in cost-based rates; and 3) cost-based rates that exceed the price of alternatives in the marketplace. ECEMPs may become "stranded costs" where they exceed the amount that can be recovered through the asset's sale. Regulatory questions involve whether such costs should be recovered by utility shareholders and if so, how they should be recovered. "Transition costs" are stranded costs which are charged to utility customers through some type of fee or surcharge after the assets are sold or separated from the vertically-integrated utility. "Stranded assets" are assets which cannot be sold for some reason. The British nuclear plants are an example of stranded assets which no one would buy. (Also referred to as Transition Costs.)

Energy Efficiency -- Using less energy/electricity to perform the same function. Programs designed to use electricity more efficiently -- doing the same with less. For the purpose of this paper, energy efficiency is distinguished from DSM programs in that the latter are utility-sponsored and -financed, while the former is a broader term not limited to any particular sponsor or funding source. "Energy conservation" is a term which has also been used but it has the connotation of doing without in order to save energy rather than using less energy to do the same thing and so is not used as much today. Many people use these terms interchangeably.

EPA -- The Environmental Protection Agency. A federal agency charged with protecting the environment.

EPAct -- The Energy Policy Act of 1992 addresses a wide variety of energy issues. The legislation creates a new class of power generators, exempt wholesale generators (EWGs), that are exempt from the provisions of the Public Utilities Holding Company Act of 1935 and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid.

ESCO -- Efficiency Service Company. A company that offers to reduce a client's electricity consumption with the cost savings being split with the client.

Exempt Wholesale Generator (EWG) Created under the 1992 Energy Policy Act, these wholesale generators are exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935.

Feebates -- A feebate is a revenue neutral strategy which imposes a fee on polluting resources and rebates those fees to cleaner technologies. This can be accomplished directly through the revenue paid to generators by the Poolco or through incorporation of these values into the dispatch/pricing mechanism of the pool.

Federal Energy Regulatory Commission (FERC) -- The Federal Energy Regulatory Commission regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.

Forwards A forward is a commodity bought and sold for delivery at some specific time in the future. It is differentiated from futures markets by the fact that a forward contract is customized, non-exchange traded, and a non-regulated hedging mechanism.

FPA -- Federal Power Act of 1935. Established guidelines for federal regulation of interstate energy sales. It is the primary statute governing FERC regulation of the electric sector.

Futures Market -- Arrangement through a contract for the delivery of a commodity at a future time and at a price specified at the time of purchase. The price is based on an auction or market basis. Standardized, exchange-traded, and government regulated hedging mechanism.

Generation Company (Genco) -- A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The Genco may own the generation plants or interact with the short term market on behalf of plant owners. In the context of restructuring the market for electricity, Genco is sometimes used to describe a specialized "marketer" for the generating plants formerly owned by a vertically-integrated utility.

Generation Dispatch and Control -- Aggregating and dispatching (sending off to some location) generation from various generating facilities, providing backup and reliability services. Ancillary services include the provision of reactive power, frequency control, and load following. (Also see "Power Pool" and "Poolco" below.)

Grid A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

Hedging Contracts -- Contracts which establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose. (See Contracts for Differences, Forwards, Futures Market, and Options.)

IOU -- An investor owned utility. A company, owned by stockholders for profit, that provides utility services. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives.

Integrated Resource Planning (IRP) -- A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost-effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act Amendments of 1992.

Integrated Resource Planning Principles -- The underlying principles of IRP can be distinguished from the formal process of developing an approved utility resource plan for utility investments in supply- and demand-side resources. A primary principle is to provide a framework for comparing a variety of supply- and demand-side and transmission resource costs and attributes outside of the basic provision (or reduction) of electric capacity and energy. These resources may be owned or constructed by any entity and may be acquired through contracts as well as through direct investments. Another principle is the incorporation of risk and uncertainty into the planning analysis. The public participation aspects of IRP allow public and regulatory involvement in the planning rather than the siting stage of project development.

IPP -- Independent Power Producer. An private entity that operates a generation facility and sells power to electric utilities for resale to retail customers.

ISDN -- Integrated Services Digital Network. A 128 Kbps (kilobytes per second) digital telephone service available in many parts of the country though not universally available that may be able to substitute for fiber optic cable in every respect except possibly television transmission.

ISO -- Independent System Operator. A neutral operator responsible for maintaining instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

Load Centers A geographical area where large amounts of power are drawn by end-users.

Marginal Cost In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.

Market-Based Price A price set by the mutual decisions of many buyers and sellers in a competitive market.

Marketer -- An agent for generation projects who markets power on behalf of the generator. The marketer may also arrange transmission, firming or other ancillary services as needed. Though a marketer may perform many of the same functions as a broker, the difference is that a marketer represents the generator while a broker acts as a middleman.

Monopoly -- The only seller with control over market sales.

Monopsony -- The only buyer with control over market purchases.

Municipalization -- The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.

Municipal Utility A provider of utility services owned and operated by a municipal government.

NARUC -- The National Association of Regulatory Utility Commissioners. An advisory council composed of governmental agencies of the fifty States, the District of Columbia, Puerto Rico and the Virgin Islands engaged in the regulation of utilities and carriers. "The chief objective is to serve the consumer interest by seeking to improve the quality and effectiveness of public regulation in America."

NASUCA -- The National Association of Utility Consumer Advocates. NASUCA includes members from 38 states and the District of Columbia. It was formed "to exchange information and take positions on issues affecting utility rates before federal agencies, Congress and the courts."

Natural Monopoly -- A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries which exhibit decreasing average long-run costs due to size (economies of scale). According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

NCSL -- The National Conference of State Legislatures. A national advisory council which provides services to state legislatures "by bringing together information from all states to forge workable answers to complex policy questions."

NOPR -- A Notice of Proposed Rulemaking. A designation used by the FERC for some of its dockets.

NRTA - Northwest Regional Transmission Association. A subregional transmission group within the Western Regional Transmission Association.

NUG -- A non-utility generator. A generation facility owned and operated by an entity who is not defined as a utility in that jurisdictional area.

Obligation to Serve The obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates set for that service. Traditionally, utilities have assumed the obligation to serve in return for an exclusive monopoly franchise.

Oligopoly -- A few sellers who exert market control over prices.

Options An option is a contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period of time. May either be standardized, exchange-traded, and government regulated, or over-the-counter customized and non-regulated.

Parallel Path Flow -- As defined by NERC, this refers to the flow of electric power on an electric system's transmission facilities resulting from scheduled electric power transfers between two other electric systems. (Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance.)

Peak Load or Peak Demand The electric load that corresponds to a maximum level of electric demand in a specified time period.

Performance-Based Regulation (PBR) -- Any rate-setting mechanism which attempts to link rewards (generally profits) to desired results or targets. PBR sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost-of-service. Other definitions include light-handed regulation which is less costly and less subject to debate and litigation. A form of rate regulation which provides utilities with better incentives to reduce their costs than does cost-of-service regulation.

Portfolio Management -- The functions of resource planning and procurement under a traditional utility structure. Portfolio management can also be defined as the aggregation and management of a diverse portfolio of supply (and demand-reduction) resources which will act as a hedge against various risks that

may affect specific resources (i.e., fuel price fluctuations and certainty of supply, common mode failures, operational reliability, changes in environmental regulations, and the risk of health, safety, and environmental damages that may occur as a result of operating some supply resources). Under a more market-driven power sector with a "power pool" or POOLCO wholesale market structure, a portfolio manager would: aggregate and manage a diverse portfolio of spot-market purchases, contracts-for-differences, futures contracts and other market-hedging-type contracts and mechanisms.

Power Authorities Quasi-governmental agencies that perform all or some of the functions of a public utility.

Power Pool -- An entity established to coordinate short-term operations to maintain system stability and achieve least-cost dispatch. The dispatch provides backup supplies, short-term excess sales, reactive power support, and spinning reserve. Historically, some of these services were provided on an unpriced basis as part of the members' utility franchise obligations. Coordinating short-term operations includes the aggregation and firming of power from various generators, arranging exchanges between generators, and establishing (or enforcing) the rules of conduct for wholesale transactions. The pool may own, manage and/or operate the transmission lines ("wires") or be an independent entity that manages the transactions between entities. Often, the power pool is not meant to provide transmission access and pricing, or settlement mechanisms if differences between contracted volumes among buyers and sellers exist.

Poolco -- Poolco refers to a specialized, centrally dispatched spot market power pool that functions as a short-term market. It establishes the short-term market clearing price and provides a system of long-term transmission compensation contracts. It is regulated to provide open access, comparable service and cost recovery. A poolco would make ancillary generation services, including load following, spinning reserve, backup power, and reactive power, available to all market participants on comparable terms. In addition, the Poolco provides settlement mechanisms when differences in contracted volumes exist between buyers and sellers of energy and capacity.

Provider of Last Resort A legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

Public Interest Goals -- Public interest goals of electric utility regulation include: 1) inter- and intra-class and intergenerational equity; 2) the equal treatment of equals (horizontal equity); 3) balancing long- and short-term goals that have the potential to affect intergenerational balance; 4) protecting against the abuse of monopoly power; and 5) general protection of the health and welfare of the citizens of the state, nation, and world. Environmental and other types of social costs are subsumed under the equity and health and welfare responsibilities.

PURPA The Public Utility Regulatory Policy Act of 1978. Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity.

PUHCA -- The Public Utility Holding Company Act of 1935. This act prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The legislation also restricts ownership of an electric business by non-utility corporations.

Qualifying Facility (QF) Under PURPA, QFs were allowed to sell their electric output to the local utility at avoided cost rates. To become a QF, the independent power supplier had to produce electricity with a specified fuel type (cogeneration or renewables), and meet certain ownership, size, and efficiency criteria established by the Federal Energy Regulatory Commission.

Real-Time Pricing -- The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Reliability -- Electric system reliability has two components -- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

Renewable Resources -- Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Reregulation -- The design and implementation of regulatory practices to be applied to the remaining regulated entities after restructuring of the vertically-integrated electric utility. The remaining regulated entities would be those that continue to exhibit characteristics of a natural monopoly, where imperfections in the market prevent the realization of more competitive results, and where, in light of other policy considerations, competitive results are unsatisfactory in one or more respects. Reregulation could employ the same or different regulatory practices as those used before restructuring.

Research and Development (R&D) -- Research is the discovery of fundamental new knowledge. Development is the application of new knowledge to develop a potential new service or product. Basic power sector R&D is most commonly funded and conducted through the Department of Energy (DOE), its associated government laboratories, university laboratories, the Electric Power Research Institute (EPRI), and private sector companies.

Resource Efficiency -- The use of smaller amounts of physical resources to produce the same product or service. Resource efficiency involves a concern for the use of all physical resources and materials used in the production and use cycle, not just the energy input.

Restructuring -- The reconfiguration of the vertically-integrated electric utility. Restructuring usually refers to separation of the various utility functions into individually-operated and -owned entities.

Retail Competition a system under which more than one electric provider can sell to retail customers, and retail customers are allowed to buy from more than one provider. (See also Direct Access)

Retail Market -- A market in which electricity and other energy services are sold directly to the end-use customer.

Retail Wheeling -- See Direct Access.

RD&D -- Research, development and demonstration (see definitions above for "Research and Development" and "Demonstration").

RTG -- A Regional Transmission Group. A voluntary organization of transmission owners, users, and other entities interested in coordinating transmission planning, expansion, operation, and use on a regional and inter-regional basis. Such groups are subject to FERC approval.

Rules of Conduct -- Rules set in advance to delineate acceptable activities by participants, particularly participants with significant market power.

Securitize -- The aggregation of contracts for the purchase of the power output from various energy projects into one pool which then offers shares for sale in the investment market. This strategy diversifies project risks from what they would be if each project were financed individually, thereby reducing the cost of financing. Fannie Mae performs such a function in the home mortgage market.

Self-Generation -- A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

Self-Service Wheeling -- Primarily an accounting policy comparable to net-billing or running the meter backwards. An entity owns generation that produces excess electricity at one site, that is used at another site(s) owned by the same entity. It is given billing credit for the excess electricity (displacing retail electricity costs minus wheeling charges) on the bills for its other sites.

Special Contracts -- Any contract that provides a utility service under terms and conditions other than those listed in the utility's tariffs. For example, an electric utility may enter into an agreement with a large customer to provide electricity at a rate below the tariffed rate in order to prevent the customer from taking advantage of some other option that would result in the loss of the customer's load. This generally allows that customer to compete more effectively in their product market.

Stranded Costs/Stranded Assets -- See Embedded Costs Exceeding Market Prices.

Stranded Benefits -- Public interest programs and goals which could be compromised or abandoned by a restructured electric industry. These potential "stranded benefits" might include: environmental protection, fuel diversity, energy efficiency, low-income ratepayer assistance, and other types of socially beneficial programs.

Sunk Cost In economics, a sunk cost is a cost that has already been incurred, and therefore cannot be avoided by any strategy going forward.

Supply-Side Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load through energy efficiency measures or on-site generation on the customer side of the meter.

Sustained Orderly Development -- A condition in which a growing and stable market is identified by orders that are placed on a reliable schedule. The orders increase in magnitude as previous deliveries and engineering and field experience lead to further reductions in costs. The reliability of these orders can be projected many years into the future, on the basis of long-term contracts, to minimize market risks and investor exposure. (See also "Commercialization.")

SWRTA -- The Southwest Regional Transmission Association. A subregional RTG within WRTA, and awaiting FERC approval.

System Integration (of new technologies) -- The successful integration of a new technology into the electric utility system by analyzing the technology's system effects and resolving any negative impacts that might result from its broader use.

Taking -- Reducing the value of someone's property through government action without just compensation.

Tariff -- A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

Time-of-Use (TOU) Rates -- The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Transition Costs -- See Embedded Costs Exceeding Market Prices.

Transmission-Dependent Utility A utility that relies on its neighboring utilities to transmit to it the power it buys from its suppliers. A utility without its own generation sources, dependent on another utility's transmission system to get its purchased power supplies.

Transmitting Utility (Transco) -- This is a regulated entity which owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide non-discriminatory connections, comparable service and cost recovery. According to EPAct, any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale. (See also "Generation Dispatch & Control" and "Power Pool.")

Unbundling -- Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

Universal Service -- Electric service sufficient for basic needs (an evolving bundle of basic services) available to virtually all members of the population regardless of income.

Utility -- A regulated entity which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

Vertical Integration An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system, and distribution lines to provide all aspects of electric service.

Volumetric Wires Charge A type of charge for using the transmission and/or distribution system that is based on the volume of electricity that is transmitted.

WATSCO -- The Western Association for Transmission System Coordination.

Wheeling -- The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission.

Wholesale Competition A system whereby a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Power Market -- The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wholesale Transmission Services -- The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce (from EPAct).

Wires Charge A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

WRTA -- The Western Regional Transmission Association, an RTG.

WSSCC -- The Western System Coordinating Council. A voluntary industry association created to enhance reliability among western utilities.

WSSP -- The Western Systems Power Pool. A FERC approved industry institution that provides a forum for short-term trades in electric energy, capacity, exchanges and transmission services. The pool consists of approximately 50 members and serves 22 states, a Canadian province and 60 million people. The WSSP is headquarter in Phoenix, Arizona.

88 S.Ct. 2224, 20 L.Ed.2d 1231 (1968).

As for PGE's second argument, the only authority it cites is the 1972 Order stating that "[t]here can be no question that the Commissioner has regulatory approval over any such transfers or exchanges of customers," 1972 Order at 6. However, when read in context, this statement refers only to the joint application by PGE and PP & L for the transfer of tens of thousands of customers without the customers' permission. It has *1447 no application, therefore, to Columbia Steel's request to be transferred, as a customer, from PGE to PP & L. In the absence of any further analysis or authority for PGE's argument that OPUC approval was necessary for Columbia Steel to become a customer of PP & L, we cannot hold that it has any merit.

V. Columbia Steel's Cross-Appeal on Damages

[29] Columbia Steel argued to the district court, and now argues on its cross-appeal, that it was entitled to damages beginning with PP & L's refusal in 1987 to sell Columbia Steel power at its lower rates. The district court rejected this argument, stating that "Columbia Steel cannot recover damages from PGE for actions taken or not taken by PP & L. Even where officials of PP & L contacted officials of PGE and discussed the request for service, the refusal of service was an act by PP & L and not an act by PGE." Unpublished Opinion, filed Feb. 5, 1993, at 24. The district court therefore limited recovery of damages to the period from July 1990, when Columbia Steel entered into a contract with PP & L and was thus "willing and able to actually purchase power at a lower rate from PP & L," and

July 1991, when PGE began wheeling PP & L's power to Columbia Steel over PGE's transmission lines. *Id.* at 25.

We agree with Columbia Steel that the district court erred in not awarding damages beginning in 1987. The district court mistakenly held that PGE could not be liable for PP & L's refusal to sell power to Columbia Steel in 1987. PP & L was a coconspirator in 1987, and PGE is liable for the acts of PP & L in furtherance of their conspiracy not to compete in Portland. See *Beitz Travel Serv., Inc. v. International Air Transport Ass'n*, 620 F.2d 1360, 1367 (9th Cir.1980) ("If [plaintiff] can establish the existence of a conspiracy in violation of the antitrust laws and that [defendants] were a part of such a conspiracy, [defendants] will be liable for the acts of all members of the conspiracy in furtherance of the conspiracy, regardless of the nature of [defendants'] own actions.").

VI. Conclusion

The partial summary judgment holding PGE liable to Columbia Steel under § 1 of the Sherman Act is **AFFIRMED**. The partial summary judgment awarding Columbia Steel \$508,425 in treble damages is **VACATED** and the case is remanded to the district court for a redetermination of Columbia Steel's damages in accordance with this opinion. Columbia Steel's motion for attorney's fees on appeal pursuant to 15 U.S.C. § 15 is **GRANTED**. The amount of the fees shall be determined by the district court.

END OF DOCUMENT

ALASKA STATE LEGISLATURE

Joint Committee on Electric Utility Restructuring

Senate Members:

Sentor Bert Sharp, Co-Chairman

Senator Loren Lemmon

Senator Robin Taylor

Senator Al Adams

Address: 119 N. Cushman, #201

Fairbanks, AK 99701-2879

Telephone: (907) 452-7885

FAX: (907) 456-4221



House Members:

Rep. Norman Rokeberg, Co-Chairman

Rep. Alan Austerman

Rep. Fred Dyson

Rep. John Davies

Address: 716 W. 4th Avenue, #640

Anchorage, AK 99501-2133

Telephone: (907) 258-8191

FAX: (907) 258-2916

TO: Members, Joint Committee on Electric Utility Restructuring

FROM: Janet Seitz *Janet*
Rep. Rokeberg's Office

DATE: July 30, 1998

RE: Packets for August 6, 1998 Meeting

Enclosed are two additional items for your review:

- a. NCSL's "Comparison of Selected Electric Restructuring Legislation"
- b. IBEW's "Will Deregulation Short-Circuit North America's Electric Power Supply". [Note: IBEW's Washington, DC, office is sending additional copies of the pamphlet. As soon as they are received, you will receive one (the original pamphlet is in color and the graphs show up better).]

Comparison Of Selected Electric Restructuring Legislation



National Conference of State Legislatures

COMPARISON OF SELECTED ELECTRIC RESTRUCTURING LEGISLATION

(Revised March 31, 1998)

Start Date of Retail Competition

Nevada A.B. 366 July 16, 1997	Customers may begin obtaining generation, aggregation, and any other potentially competitive services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest. (Section 39, p. 12)
California H.B. 1890 August 31, 1996	3/31/98 (p. 30, 42)
Maine H-568 (LD 1804) May 23, 1997	Beginning on 3/1/00, all consumers have the right to purchase generation services from competitive providers. (p. 1)
Montana S.B. 390 May 2, 1997	On or before 7/1/98, customers with loads greater than 1000 kW must have opportunity to choose an electric supplier. Co-ops may file notice with PSC, within one year after effective date of Act, electing not to participate in retail access. (p. 4, 11)
New Hampshire H.B. 1392 May 21, 1996	PUC to implement in most expeditious manner and no later than 1/1/98. PUC may delay to 7/1/98 but not longer without legislative approval. (p. 9)
Oklahoma S.B. 500 April 25, 1997	All retail customers are permitted to choose their retail electric energy suppliers by 7/1/02. (p. 3-4)
Pennsylvania H.B. 1509 November 26, 1996	Transition period to begin on 1/1/97. All customers to have retail access by 1/1/01. (p. 39, 84)
Rhode Island 96-H 8124 Substitute B August 7, 1996	By 1/1/97 each distribution company shall file with PUC a plan for transferring ownership of generation, transmission, and distribution facilities into separate affiliates. Company shall implement plan within 3 months after retail access is available to 40 percent of kWh sales in New England. PUC may extend time if necessary. (p. 17-18)
Massachusetts H.B.5117	3/1/98 for all customers

COMPARISON OF SELECTED ELECTRIC RESTRUCTURING LEGISLATION

(Revised March 31, 1998)

Illinois H.B. 362	10/99 All large industrial customers, 33% of nonresidential customers 12/00 Remaining 66% of nonresidentials 5/02 All residentials
Phase-in of Retail Competition	
Nevada A.B. 366	PUC may establish different dates for different services and different geographic areas and authorize retail competition in gradual phases. Utilities shall submit to PUC plan for compliance with Act, including information PUC needs to: set rates (e.g., utilities' cost to provide service and estimate of required revenue), allocate costs of service among customers, and adopt regulations for potentially competitive services. PUC may exempt sellers from certain portions of Act if necessary to achieve effective competition. (Section 39, p. 12; Section 49, p. 20)
California H.B. 1890	Full retail access for all customers no later than 1/1/02; phase-in to be equitable to all classes as determined by PUC. (p. 5, 42, 91)
Maine H-568 (LD 1804)	Beginning 3/1/02, electric billing and metering services are subject to competition. The PUC may establish an earlier date except in no case may the date be prior to 3/1/00. (p. 3)
Montana S.B. 390	Transition period begins 7/1/98 for customers with loads greater than 1000 kW; all customers eligible by 7/1/02, unless the PSC determines added time is needed because workable competition does not exist. Full implementation may not be delayed beyond 7/1/04, however, for customers with loads greater than 1000 kW and not beyond 7/1/06 for all other customers. Participating co-ops must adopt transition plans on or before 7/1/01, and the transition period may not extend beyond 7/1/02, although the transition plan may be altered under certain circumstances. (p. 3-5, 9, 12-13)
New Hampshire H.B. 1392	On the effective date of the Act, PUC shall undertake a generic proceeding to develop a statewide industry restructuring plan in accordance with the legislative principles in the bill. Final order is due by 2/28/97. PUC shall require all utilities to submit compliance filings. No utility shall be required, however, to commence implementation until filings representing 70 percent of retail sales have been implemented. (p. 9-10)

COMPARISON OF SELECTED ELECTRIC RESTRUCTURING LEGISLATION

(Revised March 31, 1998)

Oklahoma S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative Task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. A defined period for transition shall be established. (p. 4)
Pennsylvania H.B. 1509	As of 1/1/99, maximum of 33 percent of peak load in each customer class will have direct access; 66 percent by 1/1/00; 100 percent by 1/1/01. PUC may extend 1/1/99 implementation date for 6 months. PUC to conduct milestone reviews to ensure technically workable and equitable transition. (p. 35, 39-41)
Rhode Island 96-H 8124 Substitute B	On 7/1/97, distribution companies required to offer retail access from non-regulated power producers to all new commercial and industrial customers with anticipated annual demand of 200 kW or more, all existing manufacturing customers over 1500 kW, and all state accounts, not to exceed 10 percent of total kW sales. On 1/1/98 access to include all existing manufacturers over 200 kW and all towns in state, not to exceed 20 percent of total kW sales. Access for all customers within 3 months after access is available to 40 percent or more of the kW sales in all New England states, but not later than 7/1/98. PUC may extend final deadline up to 6 months. (p. 24-25)
Massachusetts H.B.5117	No phase-in
Illinois H.B. 362	(see above start date info)
Pilot Program	
Nevada A.B. 366	
California H.B. 1890	

COMPARISON OF SELECTED ELECTRIC RESTRUCTURING LEGISLATION

(Revised March 31, 1998)

Maine H-568 (LD 1804)	
Montana S.B. 390	Beginning 7/1/98, utilities shall conduct pilot programs using samples of residential and small commercial customers. Utilities must file a report with the PSC and the transition advisory committee on or before 7/1/00 analyzing the results of the pilot programs. Co-ops may also establish pilot programs for customers with loads less than 1000 kW. (p. 3-4, 9)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	PUC has authority to require utilities to submit proposals for pilots to begin 4/1/97. Program must commit 5 percent of peak load for each customer class. Minimum period for pilot is 1 year and shall include an evaluation process as directed by PUC. (p. 42-45)
Rhode Island 96-H 8124 Substitute B	
Massachusetts H.B.5117	
Illinois H.B. 362	

Primary Responsibility for Implementation of Retail Competition

Nevada A.B. 366	PUC shall promulgate regulations to implement Act and shall determine which electric services are potentially competitive. Such services are defined as ones that: will not harm one or more customer classes; will decrease cost; increase quality or innovation, where effective competition is likely to develop; will advance competitive position of state; and won't jeopardize safety or reliability. If PUC determines that market for potentially competitive service does not include effective competition, it shall establish method for determining prices, terms, and conditions of service. Effective competition means an individual seller can't significantly influence the price of service. (Sections 39-52, p. 12-22; Section 337, p. 149)
California H.B. 1890	PUC. (p. 42)
Maine H-568 (LD 1804)	PUC. PUC may impose by rule any additional requirements necessary to carry out the purposes of the Act, except PUC may not regulate the rates of competitive providers. (p. 5)
Montana S.B. 390	All public utilities shall submit a transition plan to the PSC not later than 1 year before retail choice is offered. PSC shall develop a procedural schedule for considering transition plans and issue a final order within 9 months after the plan is filed. On approval of plan, PSC shall enforce the plan in its final order. PSC may extend the transition period if workable competition does not exist. Workable competition exists if competition is sufficient to inhibit monopoly pricing or anti-competitive price leadership. (p. 5, 12-13)
New Hampshire H.B. 1392	PUC authorized to order such charges and other service provisions and to take such other actions substantially consistent with the legislative principles in the bill that are necessary to implement restructuring. (p. 3, 11)

Oklahoma S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. (p. 4)
Pennsylvania H.B. 1509	PUC. (p. 28-29)
Rhode Island 96-H 8124 Substitute B	PUC and the Division of Public Utilities and Carriers. (p. 2)
Massachusetts H.B.5117	Department of Telecommunications and Energy (DTE), Division of Energy Resources (DOER)
Illinois H.B. 362	Public Utility Commission
Independent System Operator (ISO)	
Nevada A.B. 366	
California H.B. 1890	Control of transmission system given to ISO. Utilities cannot collect CTC unless they commit control of their transmission assets to ISO. ISO governed by Oversight Board selected by governor and legislature. (p. 30, 36-39, 87, 90)
Maine H-568 (LD 1804)	The governance of any ISO with responsibility for operations of the regional transmission system must be fully independent of influence by market participants. The PUC shall use all means within its authority and resources to advocate for and promote the interests of Maine ratepayers in any FERC proceeding involving the development, governance, operations, or conduct of an ISO. PUC shall monitor events in the region pertaining to the development of an ISO, the management of competitive access to the regional transmission system, and rights to negotiate potential contracts

	between buyers and sellers. If the PUC determines that there is insufficient independence on the part of the ISO, the PUC shall provide a report to the joint standing committee of the legislature with recommendations to remedy the problem. (p. 20, 22-23)
Montana S.B. 390	
New Hampshire H.B. 1392	
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	All participants encouraged to coordinate plans and transactions through ISO or functional equivalent. ISO should, and PUC shall, set and enforce inspection, maintenance, and repair standards. (p. 23)
Rhode Island 96-H 8124 Substitute B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of ISO. (p. 22)
Massachusetts H.B.5117	Established as of 3/1/98. Monitored and analyzed by DOER.
Illinois H.B. 362	As of enactment of bill, each electric utility company will file a request to join an ISO. If by 3/31/99, FERC has not approved the ISO application; or if by 6/30/99, all utilities have not applied to be a part of the ISO, an Oversight Board will be formed to oversee creation of ISO.
Power Pool	
Nevada A.B. 366	
California H.B. 1890	Power Exchange established to operate an efficient, competitive auction for electricity open to all suppliers on a nondiscriminatory basis. (p. 5, 39)
Maine H-568 (LD 1804)	

Montana S.B. 390	
New Hampshire H.B. 1392	New England Power Pool should be reformed to compliment restructuring on a regional basis. Any pool structure should not preclude bilateral contracts and should not preclude ancillary pool services from being obtained from non-pool sources. (p. 8)
Oklahoma S.B. 500	Legislative task force is authorized to retain consultants to study the benefits of establishing a Power Exchange which would operate as a power pool allowing power producers to compete on common ground in the state. (p. 9)
Pennsylvania H.B. 1509	PUC to take all necessary steps to encourage interstate power pools. PUC and utilities to work with federal and state governments, regional reliability councils, and interstate power pools to ensure reliable service. (p. 37)
Rhode Island 96-H 8124 Substitute B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of voluntary power exchange. PUC shall establish regulations for non-regulated power producers selling into state that are necessary to meet operating and reliability standards of regional power pool. (p. 22)
Massachusetts H.B.5117	New England Power Pool should be used to provide strong coordination and enforceable protocols for all users of the power grid and to promote the use of the interconnected regional transmission systems.
Illinois H.B. 362	
Mandatory Rate Reductions or Rate Caps	
Nevada A.B. 366	Rates charged for residential services must not exceed the rate charged for the service on 7/1/97. The rate cap remains in effect until 2 years after the date the PUC repeals the regulations that established the pricing method for the service. The PUC may approve an increase in the rate for residential service in an amount that does not exceed the increase necessitated to ensure the recovery by the utility of just and reasonable costs. (Section 45, p. 18)
California H.B. 1890	Small customers receive at least 10 percent reduction on 1/1/98 and no less than 20 percent by 4/1/02. Can be financed with rate reduction bonds. (p. 5, 28, 49)

Maine H-568 (LD 1804)	When retail access begins, PUC shall ensure that standard-offer service is available to all consumers of electricity. By 2/15/98, PUC shall provisionally adopt rules establishing terms and conditions for standard-offer service. If qualifying bids for standard-offer service in any service territory, when combined with the regulated rates of transmission and distribution service and any stranded costs charge exceed, on average, the total rate for electricity immediately before the implementation of retail access, PUC shall investigate whether implementation of retail access remains in the public interest or whether other mechanisms to achieve the public interest and to adequately protect consumer interests need to be put in place. PUC shall notify legislature of results of its investigation and its determination. (p. 17-18)
Montana S.B. 390	Rate moratorium during transition period: 7/1/98 thru 6/30/00, utilities may not charge more than rates in effect on 7/1/98; 7/1/00 thru 6/30/02, utilities may not increase the increment of rates normally allocated to electric supply-related costs above those associated with such costs in effect on 7/1/98. From 7/1/00, utilities may propose increases to rate increments normally allocated to T&D costs. Increased costs related to universal system benefit programs greater than those in effect on passage are exempt from rate caps, as are increased costs necessary to implement full customer choice including metering, billing, and technology. Certain other exemptions are allowed in extraordinary cases. (p. 6-8)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	Rates capped at 1/1/97 levels for 54 months or until stranded costs are recovered and all customers have retail access, whichever is shorter. Additionally, generation component of rates is capped for 9 years or until distribution utility has collected stranded costs and all customers have direct access, whichever is shorter. (p. 30-31)

Rhode Island 96-H 8124 Substitute B	Within 3 months after retail access is available to 40 percent of the kW sales in New England and extending through 2009, distribution companies must arrange power contracts for their customers who have not contracted for their own power supply such that the average revenue per kWh received from the customer shall equal the price for the 12-month period ending 9/30/96, with certain inflationary adjustments. No customer who chooses this standard offer and subsequently contracts with their own supplier shall be required to pay an exit fee (p. 26)
Massachusetts H.B.5117	2.8 cent/kWh standard offer charge for generation offered by energy producers affiliated with established distribution companies. 10% rate reduction for all customers off rates in effect 8/97. Proceeds from securitization, if chosen and approved, can be used toward further reducing rates by additional 5%.
Illinois H.B. 362	<u>ComEd and IP residential rate reductions:</u> 8/98 15% 5/02 5% 10/02 0% <u>Other suppliers except CILCO's residential rate reductions:</u> 8/98 5% (2% CILCO) 5/02 Max. 5% 10/02 reflective of the Midwest avg. CILCO has had historically low rates compared to the Midwest avg, therefore, it doesn't have to offer as substantial rate reductions as ComEd and IP. Non-residential customers get no rate reduction.
Financing Rate Reductions and Stranded Costs	
Nevada A.B. 366	
California H.B. 1890	Provides for rate reduction bonds to finance rate reductions and stranded ("transition") costs. (p. 5-6, 75-87)

Maine H-568 (LD 1804)	
Montana S.B. 390	PSC may authorize the imposition and collection of fixed transition amounts and the issuance of transition bonds. After 7/1/97, a utility may apply to the PSC for a determination that certain transition costs may be recovered through the issuance of transition bonds. If such bonds are not issued within 4 years of the PSC order, the order must terminate. A utility may apply for an extension or renewal of the order. Order must set forth the term over which transition bonds are to be paid—not to exceed 20 years. Upon issuance of transition bonds, the financing orders and fixed transition amounts must be irrevocable. Cost savings associated with and resulting from the bonds must benefit customers. Proceeds from bonds must be used to recover, reimburse, finance or refinance transition costs, and to acquire transition property. Bonds may not constitute an indebtedness or loan of credit against the state or a political subdivision thereof. Co-ops may fully recover transition costs approved by local governing body. (p. 2-3, 6-7, 10,16-21)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	All transition costs shall be recovered by virtue of savings generated by increased efficiency in markets brought about by restructuring. All classes of consumers shall share in the transition costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring. Study shall include but is not limited to examination of IOU financing and any other financial issues Commission deems appropriate. Final report shall be provided to legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania H.B. 1509	PUC may approve utility request for issuance of transition bonds for some or all of its stranded costs. If approved, the utility's rates or its CTC must be reduced by an amount equal to the revenue requirement of the stranded costs for which transition bonds have been issued. (p. 52-53, 69-84)
Rhode Island 96-H 8124 Substitute B	
Massachusetts H.B.5117	As of 7/1/98, DTE will review purchase power contracts to determine if utility companies have made efforts to reduce or renegotiate them in order to reduce stranded costs. Non-mitigable stranded costs can be collected through a transition charge.

	Customers can only bypass transition charge if they have already notified utility company of intention to cogenerate. No exit fee would be charged that customer in that case.
--	--

Illinois H.B. 362	Utilities may use securitization to finance transitional costs or stranded costs. Commission must approve of securitization as long as the proceeds of sale will be used to: 1)refinance debt, equity or both reducing capital; 2)retire fuel contracts for nukes; or 3)fund debt services to pay for costs associated with above. Funding charges for securitization can only be collected until 12/31/08.
------------------------------------	---

Divestiture of Generation Assets

Nevada A.B. 366	A vertically integrated electric utility shall not provide a potentially competitive service except through an affiliate. The PUC shall establish limitations on ownership, operation, and control of the assets of a provider of an electric service to prevent anti-competitive conduct and ensure the development of effective competition. Such conditions and limitations may include limitations on the ownership, operation, and control of transmission facilities and any generation necessary to the reliable and economic operation of such transmission facilities. An affiliate may provide a potentially competitive service if PUC finds there is an arm's length transaction that will not adversely affect effective competition and the risk of anti-competitive behavior, and the regulatory expense to prevent such behavior, is minimal; PUC shall adopt procedure to process an affiliate request to provide potentially competitive service and shall make any required findings no later than 6 months before authorizing retail competition. (Section 39, p. 12; Sections 41-43, p. 15-16)
----------------------------------	--

California H.B. 1890	Essential to separate monopoly transmission function from competitive generation operations by use of ISO. PUC must approve retention of generation assets in same corporation with distribution assets after market valuation. (p. 29, 61)
---------------------------------------	--

Maine H-568 (LD 1804)	On or before 3/1/00, each investor-owned utility shall divest all generation assets and generation-related business activities other than contracts with QFs or demand side management providers, facilities located outside the U.S., or generation assets PUC determines necessary for the utility to perform its transmission and distribution obligations. No later than 1/1/99, each utility shall submit to the PUC a plan to accomplish divestiture. PUC
--	---

	shall review the plans and, by 7/1/99, issue an order approving or modifying the plan. Utility may apply for an extension beyond 3/1/00. PUC shall grant an extension if the extension would improve the sale value of the assets. If extension is granted, utility shall transfer generation assets to a distinct corporate entity by 3/1/00. After 2/28/00, each utility shall sell rights to capacity and energy from all generation assets except those necessary to perform its transmission and distribution obligations. PUC shall adopt rules governing the procedure for divestiture. PUC shall require distribution utility to divest an affiliated competitive provider if the utility or the affiliate has knowingly violated provisions of the Act and the violation resulted in or had the potential to result in substantial injury to retail consumers. If, after the effective date of the Act, 10 percent or more of the stock of a distribution utility is purchased by an entity, the purchasing entity and any affiliate may not sell or offer generation service to any retail customer and, if the PUC determines that an affiliated provider obtains an unfair market advantage as the result of such a purchase, the PUC shall order the distribution utility to divest the affiliate. If PUC orders a distribution utility to divest an affiliate, the distribution utility may not have an affiliated interest in a competitive provider after the divestiture. (p. 2, 7, 11-12)
Montana S.B. 390	To the extent a utility is vertically integrated, it shall functionally separate electricity supply, retail transmission, and distribution. PSC may approve functional separation but may not order divestiture or prohibit it. Utilities shall prevent undue discrimination in favor of own power supply and prevent any form of self-dealing that could result in noncompetitive electricity prices. Utilities must grant customers and suppliers access to the utilities' retail transmission and distribution systems on a nondiscriminatory, comparable basis. Utilities may satisfy these provisions if they adopt a code of conduct consistent with the FERC-approved code of conduct. Similar provisions apply to co-ops. (p. 2, 5, 9)
New Hampshire H.B. 1392	Restructuring should require at least functional separation of generation from transmission and distribution services. However, distribution companies should not be entirely precluded from owning small-scale distributed generation resources. PUC authorized to require that distribution and power supply services be provided by separate affiliates. (p. 2, 4, 11)
Oklahoma S.B. 500	A primary goal of a restructured electric industry is to encourage development of competition through separation of generation services from transmission and distribution services. Entities that own both transmission and distribution, as well as generation facilities, shall not be allowed to use any monopoly position in these services as a barrier to competition. Generation services shall be functionally separated from transmission and distribution services. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring, which shall include but not

	be limited to examination of unbundling of generation, transmission and distribution services, and market power. (p. 2-4, 6)
Pennsylvania H.B. 1509	PUC may permit but cannot require a utility to divest facilities or reorganize its corporate structure. (p. 33-34)
Rhode Island 96-H 8124 Substitute B	By 1/1/97, distribution companies must file plan with PUC to transfer ownership of generation facilities to separate affiliates. Every wholesale power supplier receiving contract termination fees must subject its generating facilities to market valuation through lease, sale, spin-off or other method. At least 15 percent of such facilities must be disposed of through this process. If company is subject to a higher requirement in another state's restructuring proceeding, same amount will apply in Rhode Island. Implementation methodology must be filed with PUC by 7/1/97. Employees of distribution company must function independently of affiliated non-regulated power company under detailed standards of conduct. (p. 17, 31-32, 35-38)
Massachusetts H.B.5117	Optional divestiture, although encouraged by DTE as a good way for utility to rid itself of nuclear related stranded costs. Non-nukes must be sold at auction or sale. Proceeds from sale of generation, net of tax effects, should be applied to reduce amount of transition costs. Affiliates must be separate entities.
Illinois H.B. 362	During the transition period to full competition, utilities are authorized to reorganize, retire generation from service, sell, lease, assign assets to affiliated or unaffiliated entities, enter into power purchase agreements as long as they will be approved of by the FERC, and/or use accelerated cost recoveries, without the approval of the Commission. Commission may investigate the need for and adopt rules for functional separation between generation services and delivery services. After 1/1/03, the Commission may investigate the need for separation between competitive and non-competitive services offered by a utility.
Treatment of Stranded Costs	
Nevada A.B. 366	When PUC determines an electric utility providing noncompetitive service cannot meet the conditions to also provide a potentially competitive service, utility has reasonable opportunity to recover previously incurred costs of those services it elects not to provide in future. The PUC shall determine the recoverable costs associated with assets and obligations documented in the

	accounting records of a vertically integrated electric utility that are properly allocable to a particular potentially competitive service as of the date alternative sellers begin providing such service in this state. Shareholders of the utility must be fully compensated for all such costs determined by the PUC. In determining the recoverable costs, the PUC shall take into account extent utility was legally required to incur cost; extent market value exceeds costs for assets and obligations; mitigation efforts; extent to which previous rates have already compensated shareholders for risk of non-recovery; tax effects; and, where utility had discretion to incur costs, its performance relative to similar utilities. PUC may impose a non-bypassable mechanism for recovery and determine time period for recovery. Such determinations and procedures must not discriminate against a market participant. (Section 43, p. 16; Section 46, p. 18)
California H.B. 1890	Fair opportunity to fully recover costs of PUC approved generation-related assets, including work force realignments and buyouts of certain existing power contracts. PUC to identify and determine costs and categories that may become uneconomic. Such costs are recoverable from all customers on a non-bypassable basis. Calculation based on book cost net against market value. Departing customers pay a severance fee; remaining customers pay a competitive transition charge (CTC) based on customer usage. CTC ends for most costs on 12/31/01; employee related cost recovery extends to 12/31/06. "Firewall" protects customers in one class from absorbing CTC exemptions granted in other classes. If local publicly owned utility elects not to allow retail competition, it cannot recover stranded costs. (p. 5, 31, 45-53, 60, 89-90)
Maine H-568 (LD 1804)	Stranded costs are defined as a utility's legitimate, verifiable, and unmitigable costs made unrecoverable as a result of restructuring and determined by the PUC. For each utility, PUC shall determine the sum of the following to the extent they qualify as stranded costs: costs of utility's regulatory assets related to generation; difference between net plant investment associated with generation assets, and the market value of generation assets; difference between future contract payments and market value of the utility's purchased power contracts. When determining market value of generation assets and purchased power contracts, PUC shall rely to the greatest extent possible on market information. PUC may not include any costs for obligations incurred on or after 4/1/95, except: regulatory assets created after 4/1/95 and prior to 3/1/00, for amortization of costs associated with restructuring a QF contract; costs deferred pursuant to rate plans; energy conservation costs; obligations incurred after 4/1/95, and prior to 3/1/00, that are beyond the control of the utility; and obligations incurred after 4/1/95, to reduce potential stranded costs. Utility must pursue all reasonable means to reduce potential stranded costs and to receive highest possible value for assets and contracts. PUC shall consider utility's efforts to mitigate when determining amount of stranded costs. PUC shall provide utility a reasonable opportunity to recover stranded costs through rates of transmission and distribution. Nothing in the Act may be construed to give

a utility a greater or lesser opportunity to recover stranded costs than existed prior to retail access. Before retail access begins, PUC shall estimate stranded costs of each utility. PUC shall use these estimates as the basis for a stranded costs charge to be charged by each transmission and distribution utility when retail access begins. In 2003, and every 3 years thereafter until utility is no longer recovering adjustable stranded costs, PUC shall correct any substantial inaccuracies in the estimates and adjust the charges to reflect the correction. Any change will be prospective only and may not reconcile past estimates to reflect actual values. PUC shall set an amount of recoverable, stranded costs after calculating the net aggregate value of all divested assets that had proceeds exceeding book costs against the aggregate value of all other stranded generation assets. Commission may not shift cost recovery among customer classes in a manner inconsistent with existing law. PUC shall conduct separate adjudicatory proceedings to determine stranded costs for each utility. In the same proceeding, PUC shall establish stranded cost charges for each utility. Customer who significantly reduces or eliminates consumption due to self-generation, conversion to alternative fuel or DSM, may not be assessed an exit or entry fee in any form. Absent other just cause, a layoff after 3/1/00 is deemed to be a result of retail competition. Each utility must file a plan with the PUC prior to the beginning of retail access providing transition services and benefits for eligible employees. Such benefits include programs to assist employees in maintaining fringe benefits, up to 2 years of retraining and out-placement services, full tuition for 2 years at the University of Maine or a comparable technical school at the discretion of the employee, 24 months of continued health care insurance, and severance pay equal to 2 weeks of base pay for each year of full-time employment. The plan may include provisions for early retirement benefits. PUC shall allocate the reasonable accrual incremental cost of such benefits to ratepayers through charges collected by the transmission and distribution utility. All charges must be transferred to a system benefits administrator in the transmission and distribution utility and used to provide the benefits and services provided for in the Act.

(p. 13-15, 21-22)

**Montana
S.B. 390**

PSC shall allow recovery of transition costs including unmitigatable costs of QFs such as reasonable buyout or buy down, unmitigatable costs of energy supply-related regulatory assets and deferred charges, unmitigatable transmission costs related to generation and other power purchase contracts, except recovery of those costs is limited to the amount accruing during the first 4 years after the PSC approves a transition plan. Value of generation-related assets must be reasonably demonstrable and considered on a net basis. Methods for determining value include estimating future market values, independent third-party appraisal, and competitive bid sale. Transition charges must be imposed within a transition cost recovery period approved by the PSC on a case-by-case basis. Certain transition costs may have varying transition cost recovery periods.

(p. 3, 6-7, 10)

New Hampshire H.B. 1392	Defined as costs, liabilities, and investments utilities would reasonably expect to recover under existing regulatory scheme but which they will not recover in a competitive market. Such costs limited to existing, PUC-approved renegotiated, or new PUC-mandated, commitments. It is legislative intent to give PUC appropriate tools and guidance to address stranded costs. PUC shall balance interests of ratepayers and utilities. Nothing is intended to provide greater recovery than present law provides. Utilities should recover net nonmitigatable costs of environmental mandates and federally mandated QF contracts. Costs should be on net basis, verifiable, exclusive of transmission and distribution assets, periodically trued up. Recovery should be by nondiscriminatory, appropriately structured charge, fair to all customer classes, limited in duration, consistent with promotion of competitive markets, applied only to customers within the distribution utility's service territory. Entry and exit fees are not preferred mechanisms. PUC may establish interim recovery charge good for 2 years after compliance filing, to be netted against final recovery charges. Interim charge sets no precedent for amount of final recovery charge. (p. 4, 7-8, 10-11)
Oklahoma S.B. 500	A procedure shall be established for identifying and quantifying stranded costs and for allocating such costs. Mechanisms shall be proposed for recovery of an appropriate amount of prudently incurred, unmitigatable, verifiable stranded costs. Each entity must propose a recovery plan that establishes its unmitigatable, verifiable stranded costs and a limited recovery period designed to recover costs expeditiously, provided that the recovery period and amount of transition costs shall yield a transition charge that shall not cause total price, including transmission and distribution services, for any consumer to exceed the cost per kW hour paid on the date of this Act during the transition period. Transition charge shall be applied to all consumers including direct access consumers, shall not disadvantage one class or supplier over another, shall not impede competition, and shall be allocated over a period of not less than 3 nor more than 7 years. No later than 1/1/99, Commission shall commence a study of financial issues related to restructuring, which shall include but not be limited to the examination of stranded costs and their recovery, and a final report shall be provided to the legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania H.B. 1509	Fair opportunity to fully recover amount of stranded costs PUC determines to be just and reasonable. PUC determines level of each utility's stranded costs to be collected through a non-bypassable CTC applied to all customers accessing transmission and distribution systems. PUC must adhere to specifically enumerated principles in determining amount. Calculation based on utility's known and measurable net generation-related cost determined on net present value basis over life of asset that may become uneconomic despite mitigation efforts. Includes prudently incurred costs of work force realignments and power contract buyouts and excludes any costs previously disallowed by PUC as imprudent. (p. 21-22, 24, 26-27, 35-36, 49-52)

Rhode Island 96-H 8124 Substitute B	Utilities should have a reasonable opportunity to recover prudently incurred transition costs. Distribution companies who purchase wholesale power under an all-requirements contract are authorized to terminate the contract and pay a termination fee. Such payments are recoverable from all customers through a non-bypassable transition charge. Charge may include costs of regulatory assets, nuclear obligations, buyout of above market power contracts, net unrecovered commitments, and capital costs of generating plants. Charge continues until liabilities are satisfied, with true up calculations. Recovery time for certain specified components is limited to period from 7/1/97 to 12/31/09. From 7/1/97 to 12/31/00, charge shall recover 2.8¢/kWh, thereafter in an amount set by PUC. (p. 3, 20, 28-30)
Massachusetts H.B.5117	Use of securitization by distribution company would require approval by DTE and is subject to achievement of mitigation efforts satisfactory to DTE. But, use of securitization may only be used if distrib. co. demonstrated that rate reductions stemming from securitization would not be financially viable without securitization.
Illinois H.B. 362	<u>Residential</u> Graduated transition chg. decreases annually during the period 2002-2006 <u>Non-Residential</u> .05 cents/kWh in '99 increases to .9 cents/kWh in 2006. Intangible transition assets can be securitized. Collection of transition costs can continue to 2008, 2010, if determined to be in public interest. The amt. Securitized cannot exceed 50% of total capitalization (\$7 billion for ComEd, \$1.8 billion for IP)
Reciprocity	
Nevada A.B. 366	PUC to issue a quarterly report to legislature evaluating, among other issues, opportunities to cooperate, formally or informally, with other states or with the Federal Government in the implementation of competition. (Section 53, p. 23)
California H.B. 1890	For a utility to sell to another utility's customers, it must allow access to its own customers. Out-of-state utilities must enter into a compact to adhere to enforceable reliability protocols to be allowed to sell to California retail customers. (p. 29, 90-91)

Maine H-568 (LD 1804)	
Montana S.B. 390	All suppliers must be afforded open, fair, and nondiscriminatory access to customers and a comparable opportunity to compete. Distribution service providers or affiliates may not use another distribution service provider's facilities unless the first provider offers comparable, nondiscriminatory access to its distribution facilities. Co-ops that elect not to participate in retail access may not use utilities' distribution systems unless there is a pre-existing contract. (p. 11, 14)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	Any municipal corporation may voluntarily become subject to the provisions of the Act through a non-revocable election. Any municipal corporation that elects not to participate shall be prohibited from extending retail electric distribution service beyond its corporate limits with the exception that it may continue to offer retail distribution service from lines owned on the Act's effective date. (p. 4, 9)
Pennsylvania H.B. 1509	No entity regulated by the PUC may use the transmission or distribution system of another PUC regulated entity to supply electricity to an end-use customer unless the first entity allows the other entity to sell to its customers. (p. 38-39)
Rhode Island 96-H 8124 Substitute B	
Massachusetts H.B.5117	-All suppliers must be given open access to customers and the ability to compete. -The Commonwealth should enter into compact with other New England state and N.Y. that provides incentives to sell electricity to MA retail customers. But protects reliability of regional transmission and distribution
Illinois H.B. 362	Alternative suppliers may not: 1) deny service or offer different terms, rates, etc. to anyone or group 2) deny service based on locality or change rates etc. based on locality Electric Co. may serve customer outside service territory as long as customer is eligible for service from alternative and has expressed desire

for alt. Service. They may also sell to customers previously served by municipal company.

Municipal CO's are exempt from state jurisdiction.

Customer Aggregation

Nevada
A.B. 366

Customers may begin obtaining aggregation services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest.
(Section 29, p. 11; Section 39, p. 12)

California
H.B. 1890

All customer classes are entitled to aggregation on a voluntary basis. Can be done by private parties, or governmental entities. Public bodies acting as residential aggregators must offer to include everyone within the jurisdiction.
(p. 43)

Maine
H-568
(LD 1804)

When retail access begins, consumers may aggregate in any manner they choose. If a public entity serves as an aggregator, it may not require consumers within its jurisdiction to purchase generation service from that entity.
(p. 2-3)

Montana
S.B. 390

Aggregators may be licensed by the PSC to aggregate retail customer purchases. Aggregators take title to electric energy as an intermediary for sale to retail customers.
(p. 2)

New Hampshire
H.B. 1392

Oklahoma
S.B. 500

Pennsylvania
H.B. 1509

Permits PUC licensing of aggregators, brokers and marketers as suppliers of electric energy, including municipal corporations selling outside their municipal limits, to serve all customer classes.
(p. 24, 53-56)

Rhode Island
96-H 8124 Substitute B

Massachusetts H.B.5117	Municipalities can aggregate, but cannot solicit customers of municipal companies. Cities and towns can aggregate on behalf of citizens.
Illinois H.B. 362	Groups of customers can aggregate power needs and purchase electricity at bulk rates. However, customers included in aggregation must have become eligible for choice.
Unbundling	
Nevada A.B. 366	PUC to determine which electric services are potentially competitive using a set of specified criteria. Retail customers will have direct access to such services. (Section 39, p. 12-13)
California H.B. 1890	Each electric corporation shall propose a stranded cost recovery plan to the PUC, which must provide identification and separation of individual rate components. Bills shall disclose each component of the total charge. (p. 49, 62, 71)
Maine H-568 (LD 1804)	Beginning 1/1/99, utility shall issue bills that state the current cost of electric capacity and energy separately from transmission and distribution charges and other charges for electric service. By 1/31/98, each utility shall file an unbundling proposal with PUC. Beginning 3/1/02, billing and metering services are subject to competition. PUC may establish an earlier date for competitive billing and metering services, but beginning date may not be prior to 3/1/00. (p. 3, 19)
Montana S.B. 390	Electrical bills must disclose each component of the electrical bill in accordance with the rules promulgated by PSC. Bills must disclose distribution and transmission charges, electricity supply charges, competitive transition charges, and universal system benefits charges. (p. 14)
New Hampshire H.B. 1392	Restructuring should require unbundling of prices and services. Customers should be able to choose options such as levels of reliability, real time pricing, and generation source. There should be clear price information on generation, transmission, distribution, and ancillary services. (p. 2, 4)
Oklahoma S.B. 500	A primary goal of a restructured industry is to encourage unbundling of prices. Consumer choice means retail consumers shall be allowed to purchase different levels and quality of electric supply. When consumer choice is introduced, rates shall be unbundled to provide clear price information on generation, transmission, distribution, and ancillary charges. Bills for all classes shall be unbundled, utilizing line itemization to reveal various component costs of services. Charges for public benefit programs

	shall be unbundled and appear in line item format for all classes of consumers. (p. 3-5)
Pennsylvania H.B. 1509	PUC must require unbundling of electric services, tariffs, and bills to separate charges for generation, transmission and distribution, and may require unbundling of other services. Customer bills must contain unbundled charges sufficient to enable consumer to determine basis for the charges. (p. 29-30, 47)
Rhode Island 96-H 8124 Substitute B	On or before 1/1/97, and effective 7/1/97, distribution companies shall file unbundled rates separately stating transmission, distribution and transition charges. Customer bills shall conspicuously display specified information, including transition and conservation charges, taxes, number of kWh consumed, cost of power, cost of distribution, and other costs. (p. 27, 49)
Massachusetts H.B.5117	As of 1/1/98, unbundled bills were sent to customers.
Illinois H.B. 362	Three years from effective date of this Act, Commission will investigate the need for unbundling.
Consumer Education	
Nevada A.B. 366	The PUC shall establish minimum standards for the form and content of all disclosures, explanations, or sales information disseminated by sellers of competitive services to ensure that consumers receive adequate, accurate, and understandable information about the service that enables them to make an informed decision relating to the source and type of electric service purchased. Such standards must not be unduly burdensome, must not unnecessarily delay or inhibit competition, and may establish different requirements for disclosures, explanations, or sales information relating to different services or similar services to different classes of customers wherever appropriate. Before commencement of direct access, the PUC shall carry out an educational program for consumers to inform them of changes in the provision of electric service, inform them of the requirements relating to disclosures, explanations, or sales information, and provide assistance in understanding and using the information to make reasonably informed choices. The PUC shall expend up to \$500,000 from its reserve account to provide education and informational services to educate and inform residents. The PUC shall contract with an independent person to provide such services. (Section 48, p. 19; Section 57, p. 24)

California H.B. 1890	Electric corporations, in conjunction with PUC, shall devise and implement a customer education program. (p. 72)
Maine H-568 (LD 1804)	PUC shall establish standards for publishing and disseminating, through any means considered appropriate, information that enhances consumers' ability to effectively make choices in a competitive market. PUC shall adopt rules implementing a consumer education program including the immediate organization of a consumer education advisory board to investigate and recommend methods to educate the public about retail access and its impact on consumers. PUC shall ensure broad representation from all customer classes including public agencies on the advisory board. Members serve without compensation. The advisory board must address level of funding for adequate educational efforts and source of such funding; aspects of retail access on which consumers need education; most effective means of accomplishing education of consumers; appropriate entities to conduct education efforts; and any other relevant issue regarding education of consumers. PUC shall consider the recommendations of the advisory board when adopting rules to implement a consumer education program. (p. 5, 19)
Montana S. B. 390	Public utilities shall educate customers about choice so customers can make informed choices. The education process must give special emphasis to efforts during the transition period.
New Hampshire H.B. 1392	PUC should ensure customer confusion is minimized and consumers will be well informed about changes. (p. 4)
Oklahoma S.B. 500	Commission shall ensure that consumer confusion will be minimized and consumers will be well informed about changes resulting from restructuring and increased choice. (p. 4)
Pennsylvania H.B. 1509	Each distribution company, in conjunction with PUC, must implement a consumer education program. PUC shall establish regulations to ensure suppliers provide adequate and accurate information to enable consumers to make informed choices. Information must be in an understandable format that enables comparison of price and service on a uniform basis. (p. 47-48)
Rhode Island 96-H 8124 Substitute B	Distribution companies to notify customers of retail options at least 90 days prior to eligibility for retail access. (p. 25)

Massachusetts H.B.5117	DOER will be primary agency in charge of consumer ed. DOER will provide a toll free hot-line for customers, and provide educational materials. Educational services will be approved by DTE to ensure they're not duplicative of educational/protection services provided by DTE's Consumer Division. Portfolio standards and disclosure of fuel sources, emissions etc. will be provided in standardized form for consumers to make supplier choices.
Illinois H.B. 362	-Commission of Consumer Education, through the Consumer Education Program, is responsible for consumer education. This Commission consists of a representational array of stakeholders in the restructuring process, such as utility representatives, consumer rights specialists etc. The Commission is charged with producing written materials on consumer education by 3/1/99 for residential customers and by 11/1/01 for commercial customers. Disclosure of energy fuel sources, emissions produced etc. on quarterly basis to all customers to help them choose their supplier. -Establishment of customer information centers. All suppliers will be required to maintain customer call centers where customers can get information and talk to a representative.
Consumer Protection	
Nevada A.B. 366	Any alternative seller must have a PUC license, which may be limited, suspended, or revoked to protect the public interest. By 1/1/99, PUC to establish conditions alternative sellers must satisfy before selling to retail customers. Conditions relate to safety, electric reliability, financial reliability, fitness to serve customers, billing practices, and terms for establishing and terminating service. PUC to establish and implement standards of conduct related to activities inconsistent with goals of Act, including appropriate penalties for violation and procedures for imposing such penalties and referring potential violations to Attorney General or Justice Department. PUC shall establish procedures to ensure no customer is switched to another seller without reliable confirmation. (Section 40, p. 14; Section 42, p. 15-16; Section 48, p. 19)

California H.B. 1890	Every entity offering power to small customers must register with PUC. All offers of service must include written notice of price and terms, including amount of CTC and right to rescind contract. Consumers can recover actual and punitive damages, including attorney's fees, for violations. No residential or small commercial customer's account can be switched to another provider without confirmation by an independent third party verification company. (p. 6, 43-44, 72-73)
Maine H-568 (LD 1804	PUC shall establish minimum standards to protect consumers. PUC shall license competitive electric providers. To issue a license, PUC must receive evidence of financial capability, ability to enter into binding interconnection arrangements with transmission and distribution utilities, disclosure of all pending legal actions and customer complaints filed during the prior 12 months, evidence of ability to satisfy the renewable resource portfolio standards, and disclosure of names and corporate addresses of all affiliates. PUC may also require a bond as evidence of financial ability to withstand market disturbances. PUC shall establish rules governing information disclosure for competitive providers. As a condition of licensure, provider supplying customers with a demand of 100 kW or less may not terminate generation service without 30 days' prior notice, must offer service for a minimum period of 30 days, must allow customer to rescind selection of competitive provider within 5 days of initial selection, may not telemarketing services to a customer who has filed a written request not to receive such services, and must provide a customer with specified disclosure information within 30 days of contracting. PUC may limit the duration and scope of a license or may revoke a license in the public interest. PUC shall establish by rule consumer protection standards to protect and promote market competition and to prevent fraud or other unfair and deceptive business practices. PUC may impose a penalty of up to \$5,000 for each violation of any consumer protection rule. Each day of a violation constitutes a separate offense. If PUC has reason to believe that utility has violated any provision of law for which a criminal prosecution is provided or has violated any antitrust law of the state or the US, PUC shall notify the attorney general. Attorney general shall promptly institute any appropriate actions. A distribution utility may not release any proprietary customer information without the prior written authorization of the customer. Employees of a distribution utility may not state or provide any customer or potential customer opinion regarding reliability, experience, qualifications, financial capability, managerial capability, operations capability, customer service record, consumer practices, or market share of any affiliated competitive provider or nonaffiliated competitive provider. (p. 4-6, 9-10, 12)
Montana S.B. 390	Public interest requires continued protection of consumers through licensure, provision of information, and a process for investigating and

	resolving complaints. Utilities shall maintain standards of safety and reliability of the electric delivery system. PSC may require proof of financial integrity, adequate reserves, and a license bond. PSC may revoke or suspend a license of an electric supplier or impose a penalty or both. If the supplier intentionally provided false information to PSC, switched electricity customer without written permission, failed to provide reasonably adequate supply of electricity, committed fraud, or engaged in deceptive practices, fine is not less than \$100 or more than \$1,000 for each violation. Each day of each violation constitutes a separate violation. PSC shall promulgate rules establishing procedures to prevent unauthorized switching of customers. Transitional advisory committee shall file annual report in 2000 that addresses the need, if any, for additional consumer protection including protection from abusive or anti-competitive practices. (p. 1, 11, 13-14, 16)
New Hampshire H.B. 1392	Retail suppliers who do not own transmission and distribution facilities should at a minimum be registered with PUC. (p. 5)
Oklahoma S.B. 500	Appropriate rules shall be promulgated ensuring that reliable and safe electric service is maintained. Minimum residential consumer service safeguards and protections shall be ensured. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring including but not limited to reliability and safety. Final report shall be provided to legislative task force no later than 12/31/98. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of consumer safeguards and licensing of retail suppliers. Final report shall be provided to legislative task force no later than 8/31/00. All retail suppliers shall be required to meet certain minimum standards designed to ensure reliability and financial integrity and be registered with Commission. There shall be no customer switching between distribution providers from the date of this Act until 7/1/02, except by mutual consent of all affected parties. (p. 4-7, 9)
Pennsylvania H.B. 15	Each generation supplier required to obtain PUC license and post bond or other security to ensure financial responsibility. PUC to establish regulations to prevent customer account transfer without direct oral confirmation or written consent. PUC to monitor market for anti-competitive conduct; investigate complaints or potential violations and refer them as necessary to the appropriate state or federal prosecutors; deny proposed mergers, acquisitions, dispositions, or other transactions that are anti-competitive or discriminatory. (p. 21, 47, 53, 67-69)

Rhode Island 96-H 8124 Substitute B	By 1/1/97, electric licensing committee to submit proposals to legislature for consumer protection. All non-regulated power producers must file registration application with division listing specified information and showing evidence of financial soundness such as surety bonds or other mechanisms specified by division. On request, distribution company must release names and addresses of customers to power producers who will be eligible for retail access within next 60 days, unless customer has requested in writing that information not be released. (p. 22, 24, 26)
Massachusetts H.B.5117	DTE's Consumer Division will continue to protect consumers and ensure that distribution companies adhere to rules and regulations concerning billing and termination procedures. Alternative supplier can only serve customers after receiving a Letter of Affirmation stating that the customer desires the alternative supplier.
Illinois H.B. 362	Utility companies retain obligation to serve residential and small commercial customers. -If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. -Supplemental low-income Energy Assistance Fund will be established from surcharge on bills (\$.40/mo for residential, \$4.00/mo for non-residential and \$300/mo for large industrials). -Energy Assistance Program Design Group will design low-income energy efficiency programs.
Universal Low-Income Assistance Program	
Nevada A.B. 366	An electric distribution utility shall provide all noncompetitive services within its territory unless the PUC authorizes another entity to provide the noncompetitive service. PUC to establish minimum terms and conditions under which any customer not using an alternate seller will receive electric service. PUC shall designate utility to provide service to customers who do not elect or are unable to obtain alternative seller. Procedures may include, but are not limited to, requiring utility to serve such customers, requiring each alternative seller to serve a share of such customers, competitive bidding to select one or more providers. If the provider is an electric utility, the service shall be provided through an affiliate whose sole business is provision of basic service. (Section 44, p. 17; Section 45, p. 18)
California H.B. 1890	Such programs must continue to be funded at not less than the 1996 authorized levels. (p. 6, 65-67)

Maine H-568 (LD 1804)	The policy of the state is to ensure adequate provision of financial assistance. In order to continue existing levels of financial assistance for low-income households and to meet future increases in need, PUC shall receive funds collected by all transmission and distribution utilities at a rate set by the commission in periodic rate cases and set initial funding for programs based on an assessment of aggregate customer need. If legislature appropriates financial support for households and individuals receiving assistance from the general fund, PUC may not terminate the assistance provided by transmission and distribution utilities unless the general fund source has completely replaced such assistance. On or before 1/1/98, PUC and state planning office shall provide the legislature with recommendations to fund assistance to low-income consumers through the general fund or through a tax on all energy sources in the state. (p. 19-20, 26)
Montana S.B. 390	Universal system benefits programs include cost effective local energy conservation, low-income customer weatherization, renewables and low-income energy assistance. Programs are paid for by a non-bypassable universal system benefits charge assessed at the meter. Programs are established to ensure continued funding of, and new expenditures for, conservation, renewables, and low-income assistance during the transition period and into the future. From 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for the calendar year ending 12/31/95 establishes the minimum annual funding level. Utilities receive credit for internal programs or activities that support renewables, conservation, or low energy assistance. Credits can be carried forward to future years. Minimum annual funding for low-income and weatherization is established at 17 percent of the utility's annual universal system benefits funding level. The utility's transition plan must describe proposals for benefit programs, including methodologies such as cost effectiveness and need determination used to measure the utility's level of contribution to each program. Customers with loads greater than 1000 kW pay a charge equal to the lesser of \$500,000, less credits, or .9 mills per kWh x the customer's kWh purchases, less credits. Utilities must submit an annual summary report relating to system benefit programs to the PSC and the transition advisory committee. Co-ops may collectively pool statewide credits to satisfy annual funding requirements. On or before 7/1/02, transition advisory committee and PSC shall reevaluate system benefits programs and make recommendations to the legislature regarding future need for such programs. On or before 11/1/98, the transition advisory committee shall make recommendations to the governor and legislature regarding low-income assistance programs. Recommendations may include assignment of agency or private nonprofit entity to administer fund. (p. 2-4, 11-12, 16)

New Hampshire H.B. 1392	Distribution utility has obligation to connect all customers and to maintain minimum residential service safeguards, including low income assistance. A non-bypassable, competitively neutral system benefits charge applied to distribution may be used to fund low income programs. (p. 5)
Oklahoma S.B. 500	"Public benefit programs" means all social, economic, and environmental programs currently funded through rates charged to consumers. Entities providing distribution services shall be relieved of their traditional obligation to provide electric supply but shall have a continuing obligation to provide distribution service to all consumers within existing service territories. Firm service territories shall be fixed by a date certain if not currently established in law. Minimum residential consumer service safeguards and protections shall be insured including programs and mechanisms that enable residential consumers with limited incomes to obtain affordable essential electric service and the establishment of a default provider for any distribution customer who has not chosen an alternative supplier. Commission shall consider establishment of a distribution access fee assessed to all consumers to cover social costs, capital costs, and operating costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring including but not limited to stranded benefits and their funding. Final report shall be provided to legislative task force no later than 12/31/99. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect. Final report shall be provided to legislative task force no later than 8/31/00. (p. 3, 5, 7)
Pennsylvania H.B. 1509	State must at a minimum continue current protections and policies to assist low-income customers. PUC shall ensure that universal service is appropriately funded in each distribution territory and shall encourage the use of community-based organizations with necessary experience to be direct providers of programs that assist low-income customers. PUC shall establish an appropriate cost recovery mechanism for each utility to fully recover universal service costs. Distribution company remains provider of last resort unless PUC approves alternative. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. (p. 20, 22, 28, 34-35, 48-49)

Rhode Island 96-H 8124 Substitute B	Current special rates and protections shall continue. Within 3 months after 40 percent of kWh sales in New England are available for retail access, distribution company shall arrange a last resort power supply for customers unable to receive power under the standard offer or elsewhere. Company shall periodically solicit bids for power at market prices plus a fixed contribution from the company, subject to PUC approval. Company's fixed contribution is recoverable in rates charged all other customers. Company can terminate for nonpayment pursuant to PUC regulations. Authorized performance-based rate increases for distribution companies between 1/1/97 to 12/31/98 cannot be applied to low-income customers. (p. 3, 27-28, 35, 43)
Massachusetts H.B.5117	Default service will ensure that customer will be served by incumbent supplier. Rate shall never exceed the avg. monthly market price of electricity. Payment options and rates charged for default service will remain uniform for up to 6 months. Ratepayer Parity Trust Fund will be established to subsidize low-income rates from monthly benefits surcharge on customers' bills.
Illinois H.B. 362	Utility companies retain obligation to serve residential and small commercial customers. -If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. -Supplemental low-income Energy Assistance Fund will be established from surcharge on bills (\$.40/mo for residential, \$4.00/mo for non-residential and \$300/mo for large industrials). -Energy Assistance Program Design Group will design low-income energy efficiency programs.
Renewable Energy, Conservation, and Environmental Issues	
Nevada A.B. 366	The PUC shall establish portfolio standards for domestic energy that set forth the minimum percentage of the total electricity sold during each calendar year that must be derived from renewable energy resources. The portfolio standards must require two-tenths of 1 percent of the total amount of electricity annually consumed by customers in this state as of 1/1/01 to come from renewables. This standard must be increased biannually thereafter by two-tenths of 1 percent of the total annual electric consumption until the standard reaches a total of 1 percent of the total amount of electricity consumed. The electricity must be derived from not less than 50 percent renewable energy resources and be derived from not less than 50 percent solar renewable energy systems. Tradable renewable energy credits are allowed. Reporting requirements are established to ensure that all providers comply with the standards. A vertically integrated

	electric utility that has 9 percent of its electricity furnished by renewable energy resources on 1/1/97 is deemed to be in compliance until 1/1/05. Between 1/1/05 and 12/31/09, such a utility shall reach a total of one-half of 1 percent of the annual amount of electricity consumed, in annual increments of one-tenth of 1 percent, from solar energy resources. (Section 52, p. 22-23)
California H.B. 1890	PUC must require each electric corporation to identify a rate component to fund energy efficiency, public interest research and development, and demand side management in specified yearly amounts that total \$540 million through 3/31/02. The funds are to be held by the Energy Commission until further legislative action. Consumers can make voluntary contributions through their monthly bills to support such programs. (p. 6, 61-67)
Maine H-568 (LD 1804)	Renewable resources are defined as total power production capacity not exceeding 100 mW and relying on fuel cells, tidal power, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste generators. Each competitive provider must demonstrate that no less than 30 percent of its portfolio of supply sources is derived from renewable resources. PUC shall review the 30 percent requirement and make a recommendation for any change to the joint standing legislative committee no later than 5 years after the beginning of retail competition. PUC shall require utilities to implement energy conservation programs. (p. 15-17)
Montana S.B. 390	Public interest requires continued protection of consumers through funding for public purpose programs for energy conservation, weatherization, and renewable resource projects and applications. Such programs are paid for with a universal system benefits charge assessed at the meter. Beginning 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for the calendar year ending 12/31/95, is the minimum annual funding level for total system benefits programs, and 17 percent of that minimum must be used for low-income assistance programs, including weatherization. The balance may be used for other benefit programs such as energy conservation and renewables. Customers with loads greater than 1000 kW pay a system benefit program charge equal to the lesser of \$500,000, less credits, or .9 mills per kW hour x the customer's kWh purchases, less credits. Credits can be carried forward into future years. Customers are entitled to credits for expenditures on renewable energy or conservation-related activities that are part of internal utility programs or activities. Utilities must submit an annual summary report to PSC and transition advisory committee detailing activities relating to all system benefit programs. On or before 7/1/02, PSC and transition advisory committee shall reevaluate ongoing need for such programs and make future needs recommendation to legislature. (p. 2-4, 11-12, 16)
New Hampshire H.B. 1392	Overall policy goal is to implement restructuring with minimum adverse consequences to environment. Continued environmental protection and

	long-term environmental sustainability should be encouraged. A non-bypassable, competitively neutral system benefits charge applied to distribution may be used to fund energy efficiency, research and development, and investments in new technologies, as determined by the PUC. Increased future commitments to renewables should be consistent with existing state energy policy and be balanced against impact on rates. Over the long term, renewables can have significant environmental, economic, and security benefits. Customers should be able to pay a premium for renewables. Incentives should be provided for demand side management. (p. 2, 5-7)
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	
Rhode Island 96-H 8124 Substitute B	From 1/1/97 until 12/31/01, each distribution company must include a 2.3 mills per kWh charge to fund demand side management and renewables. PUC shall determine allocations of funds between the two categories. PUC, at its own discretion, may increase the sums after notice and public hearing. City where a generation plant has been proposed may request builder to fund study of environmental effects of proposed facility, up to lesser of \$100,000 or .1 percent of estimated capital cost of project. (p. 43, 52-53)
Massachusetts H.B.5117	<u>Energy efficiency</u> benefits charge assessed to all by muni electric company customers for DSM over five years starting 3/1/98 (\$.0033/kwh in '98, to \$.0025/kwh by 2002). Competitive procurement process must be used. DOER will oversee and coordinate energy efficiency programs. <u>Renewables</u> will be funded by vacillating annual rate of \$.00075/kwh to \$.0005/kwh by 2002. Funds would be deposited in "Massachusetts Renewable Energy Trust Fund". Renewables portfolio will be established by DOER. DOER will oversee and coordinate ee programs. Customers purchasing renewable energy in excess of minimum requirements under renewables portfolio standard, can take tax deduction of 50% of above market price. Business customers get 25% tax deduction. Individual or business purchasing energy efficiency equipment will be eligible for a 20% deduction up to \$10,000. Businesses will be eligible for 10% up to \$50,000.

	Performance standards for fossil fuel plants will be drawn up by EPA with adoption by at least 3 other northeast states. Assessment against all nukes will be at least \$90,000 to be used for radiation control program.
Illinois H.B. 362	Renewable Energy Resources Program will be administered by Dept. of Commerce and Community Affairs. Grants, loans and other incentives for investment in renewable energy resources. Report will be made to the General Assembly on the use and potential of renewables. As of 1/198 "Renewable Energy Resources and Coal Technology Development Assistance Charge" will be assessed customers. \$.05/mo for residential, non-residential and gas customers; \$37.5/month for non-residential electric and gas customers. <u>Environmental protection</u>: \$100 million over 10 years for development of renewable energy resources and coal technology. \$10 million in annual funding through surcharge on bills. <u>Energy Efficiency Trust Fund</u>: As of 1/1/98, this trust fund will consist of the pro-rata share of \$3 million based on kWh sales from each supplier. By 4/1/99, every supplier with nuclear generation must file a tariff indicating the kWh sales for those facilities for decommissioning expense purposes.

Treatment of Transmission and Distribution (T&D)

Nevada A.B. 366	A public entity does not become subject to the provisions of Sections 28-53 solely because the entity provides transmission or distribution service to an alternative seller except that the public entity shall provide such transmission and distribution services on an open and nondiscriminatory basis to alternative sellers in accordance with standards the PUC may establish by regulation. The PUC shall require each provider of a noncompetitive service that is necessary to the provision of a potentially competitive service to make its facilities or services available to all alternative sellers on equal and nondiscriminatory terms and conditions. The PUC may establish standards of conduct to prevent anti-competitive activities and such standards of conduct may include limitations on the ownership, operation, and control of transmission facilities and any generation necessary to reliable and economic operation of such transmission facilities. The PUC shall adopt regulations ensuring that a person who owns a transmission or distribution facility makes the facilities available on equal and nondiscriminatory terms and conditions to all alternative sellers or customers of alternative sellers. The Colorado River Commission may sell electricity or provide transmission or distribution service to customers who it was not serving or with whom it did not have a contract on the effective date of the relevant provisions of the Act, if the Colorado River Commission allows its system for transmission and
--	--

	distribution to be utilized by other alternative sellers pursuant to such terms and conditions as the PUC may establish. PUC may conduct an investigation of the effect on the market of transmission congestion or constraints. (Section 40, p. 14; Section 41, p. 15; Section 42, p. 15; Section 44, p. 17; Section 50, p. 20)
California H.B. 1890	Continues to be regulated. All customers and suppliers to receive open, nondiscriminatory, and comparable access. (p. 29-30)
Maine H-568 (LD 1804)	Upon request from a competitive provider, PUC shall provide load data on a class basis that is in the possession of a T&D utility, subject to reasonable protective orders to protect confidentiality. Except as otherwise permitted, on or after 3/1/00, an IOU T&D may not own, have a financial interest in, or otherwise control generation or generation-related assets. After commencement of retail access, a large investor-owned T&D utility serving more than 50,000 retail customers may not sell electricity to any retail customer. An affiliated provider may sell to retail customers outside the service territory of the distribution utility with which it is affiliated and within the service territory of the distribution utility with which it is affiliated, except that the affiliate may not sell more than 33 percent of the total kWh sold within the service territory of the distribution utility. No later than 1/1/05, based on its evaluation of the development of the competitive retail sales market, PUC shall complete an evaluation of the need for the market share limitation and shall report its findings to the legislature. A distribution utility may not engage in joint advertising or marketing programs of any sort with its affiliated competitive provider. Employees of a distribution utility may not be shared with and must be physically separated from those of an affiliated competitive provider. A distribution utility and its affiliated competitive provider must keep separate books and records. All regulated products and services offered by a distribution utility, including any discount, rebate, or fee waiver, must be available to all customers and competitive providers simultaneously and without undue or unreasonable discrimination. (p. 3, 8-12)
Montana S.B. 390	Distribution services providers must make distribution facilities available to all suppliers, providers, and customers on a nondiscriminatory, comparable basis; and be the emergency supplier of electricity and related services. When a distribution services provider acts as emergency supplier, the supplier that should have provided the power must reimburse the distribution company according to a prescribed formula. Distribution services providers are not required to purchase reserve supply to fulfill emergency obligations. Transmission services must also be available on a nondiscriminatory, comparable basis. If a co-op offers electricity competitively to customers using a utility's distribution facilities, the co-op must create an affiliated for-profit entity to serve those customers that allows the entity to be taxed at the same level as other for-profit suppliers. PSC shall regulate retail transmission and distribution services including

	designed to modify the Act consistent with the public interest. The joint standing legislative committee having jurisdiction over utility and energy matters may report out legislation concerning electric energy restructuring to future legislative sessions. (p. 22, 26)
Montana S.B. 390	Transition advisory committee consists of eight voting members, equally balanced by party: 4 appointed by Speaker and 4 appointed by Senate President. Non-voting advisory members include: the director of dept. of environmental quality; one public utilities appointee; and 1 representative each from consumers, cooperatives, and PSC. Governor appoints 1 each non-voting member from: industry, non-industrial consumers, organized labor, environmental/ conservation, low-income program provider, Indian tribes, power market industry. PSC, legislative counsel, and agencies provide staff. Committee meets quarterly and dissolves on earlier of date full transition is completed or 12/31/04 and shall: provide an annual report on or before 11/1/01 to governor, speaker, Senate president, and PSC; provide quarterly reports to legislature thru 1/1/99; analyze and report on transition to effective competition. Annual report in 2000 must evaluate pilot programs with loads under 1000 kWh and include legislative recommendations about best means to further encourage choice, market access, and need for additional consumer protection revisions. Criteria for evaluating effective competition are specified. On or before 7/1/02, committee and PSC shall reevaluate need for ongoing universal system benefits programs and make recommendations. On or before 11/1/01, committee shall determine whether Montana utilities have an opportunity to market outside the state comparable to the reverse. On or before 11/1/98, committee shall make recommendations to governor and legislature regarding low-income assistance programs. (p. 4, 12, 15-16, 27)
New Hampshire H.B. 1392	Establishes 14-member legislative oversight committee, seven from each house, with 2-year terms. Committee to report annually on or before 11/1 to governor, legislature, and PUC. In conjunction with PUC, report shall address new legislation and proposed amendments to existing law to promote restructuring. (p. 12)
Oklahoma S.B. 500	Act creates Joint Electric Utility Task Force composed of 14 members of the legislature, 7 each selected by Senate President and House Speaker. Task force may appoint advisory councils made up of representatives of interested parties. Task force shall direct and oversee studies by the Commission and the Tax Commission. Task force shall remain in effect until termination, which shall be no later than 1/1/03. Commission shall make reports to task force on independent system operator issues, technical issues, financial issues, and consumer issues no later than 2/1/98, 12/31/98, 12/31/99, and 8/31/00, respectively. Task force may make final recommendations to the governor and the legislature. The task force is authorized to retain consultants and experts to study the creation of an ISO and the benefits of establishing a Power Exchange, which would operate as a power pool. All

	studies and recommendations relating to the ISO shall be submitted to the task force on or before 2/1/98, and shall conform to FERC Order No. 888. (p. 8-9)
Pennsylvania H.B. 1509	
Rhode Island 96-H 8124 Substitute B	On 1/1/98, and annually for next 4 years, PUC to file report with governor and legislature detailing developments in competitive supply market, estimated savings from retail competition, progress towards regional transmission agreement, reforms instituted by regional power pool, and status of restructuring in surrounding states. (p. 23)
Massachusetts H.B.5117	Legislature will be reported to on an annual basis, or as necessary, by DTE, DOER and any other agencies, task forces involved with the restructuring process.
Illinois H.B. 362	-On or before 12/31/99, and once every three years thereafter, the Commission shall monitor and analyze patterns of entry and exit to the market and report its findings to the General Assembly. During 2001 through 2006, the Commission will prepare annual reports regarding the development of electric markets. -Utility companies must report annually to legislature on their collection of transition charges, efforts to mitigate stranded costs and use of transition funding mechanisms. A Policy Advisory Council, established by the legislature, will analyze restructuring and ensure that requirements of the Act are met and advise legislature on the spending of the Fund monies.

Taxes

Nevada A.B. 366	If two or more persons perform separate functions collectively needed to supply electricity to final customer and the property would be centrally assessed if owned by one person, it shall be centrally valued and apportioned. Proportion of the tax levied by each county shall be determined according to valuation of contribution of each person to aggregate valuation of property. However, this provision does not apply to QFs built before 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 278, p. 114-116; Section 335, p. 148)
----------------------------	---

	establishment of just and reasonable rates, which may include performance-based rates. (p. 2, 6, 9-10, 12-13, 22)
New Hampshire H.B. 1392	T&D should remain regulated for the foreseeable future. PUC to take necessary measures to ensure nondiscriminatory, comparable, and open access to T&D. (p. 4-5)
Oklahoma S.B. 500	A primary goal of a restructured industry is to enable suppliers to engage in fair and equitable competition through open, equal, and comparable access to T&D systems. Entities which own both T&D as well as generation facilities shall not be allowed to use any monopoly position in these services as a barrier to competition. Generation shall be functionally separated from T&D services, which shall remain regulated. Comparable access for retail suppliers competing with affiliates of entities supplying T&D shall be assured. Commission shall monitor companies providing T&D and take necessary measures to ensure no supplier of such services has an unfair advantage in offering and pricing such services. Benefits associated with implementing an independent system planning committee composed of owners of electric distribution systems to develop and maintain planning and reliability criteria for distribution facilities shall be evaluated. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect, as well as rates for regulated services. Final report shall be provided to the legislative task force no later than 8/31/00. (p. 3-7)
Pennsylvania H.B. 1509	Continues to be regulated as a natural monopoly. Distribution company remains provider of last resort unless PUC approves alternative. PUC shall require all transmission and distribution facilities to provide comparable open access to all customers and suppliers. There is a rebuttable presumption the distribution company can accommodate all requests for service from suppliers but does not have to install nonstandard equipment unless customer pays full cost of such facilities. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. Company must accept returning customer on same terms and conditions as new applicant. Distribution company shall implement procedures to require suppliers to deliver sufficient power to meet supplier's customer obligations. Subject to PUC approval, company may require customer to pay for enhanced metering capability. (p. 22, 28, 34, 46, 48-49)

Rhode Island 96-H 8124 Substitute B	T&D companies must provide nondiscriminatory access on reasonable terms consistently applied to all customers. Distribution companies must terminate all requirements contracts with generators no later than 3 months after 40 percent of the kWh sales in New England are available for retail access and can only own or operate generation or transmission facilities through affiliates, with some specific exceptions. (p. 6, 17-19, 21)
Massachusetts H.B.5117	-T&D companies must provide nondiscrimination access on reasonable terms for all suppliers and customers. -Transmission and distribution assets as of 12/31/96, or acquired thereafter, shall be transferred to transmission or distribution companies, respectively. Distribution companies will be prohibited from selling electricity at retail and from owning or operating transmission services. As of 3/1/98, DTE will designate service territories for distribution companies.
Illinois H.B. 362	To ensure system reliability, the Commission, within 180 days of the Act must adopt rules and regs for T&D that establish the procedures for restoring T&D to customers.
Legislative Oversight	
Nevada A.B. 366	PUC shall issue a quarterly report to the legislature assessing developments in electric industry in Nevada. Report shall evaluate, at a minimum, effectiveness of competition, compatibility of direct access with environmental goals, impacts of competition on each customer class relative to present structure, and opportunities to cooperate with other states or the Federal Government in implementation of competition. In the quarterly report for the first quarter of 1999, the PUC shall provide a comprehensive evaluation of the development of the markets for potentially competitive services since 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 53, p. 23; Section 335, p. 148; Section 336, p. 148)
California H.B. 1890	Five-member oversight board composed of three gubernatorial appointees, one Senator, and one Assemblyman. Board oversees the ISO and Power Exchange and serves as the appeal board from ISO decisions. (p. 5, 34-36)
Maine H-568 (LD 1804)	On December 31 of each calendar year, PUC shall submit to the joint standing legislative committee a report describing the PUC's activities in carrying out the requirements of the Act, and include draft legislation

California H.B. 1890	
Maine H-568 (LD 1804)	On or before 1/1/98, the PUC and the state planning office shall provide the legislature with recommendations concerning funds to assist low-income consumers through general fund appropriations or through a tax on all energy sources in the state. (p. 26)
Montana S.B. 390	During 4-year transition period, utilities may accelerate amortization of accumulated deferred investment tax credits associated with T&D and general plant if earnings fall below 9.5 percent earned return on average equity. Revenue oversight committee shall analyze state and local tax revenue derived from previously regulated electricity suppliers that will enter the competitive market and report to legislature annually on how revenue to state and local government is changed by restructuring and competition. On or before 11/30/98, revenue oversight committee shall recommend legislative changes, if any, to address comparable state and local taxation burdens on all market participants. (p. 8, 10, 16, 21-22)
New Hampshire H.B. 1392	
Oklahoma S.B. 500	The Tax Commission shall study and fully assess the impact of restructuring on state tax revenues and all other facets of current utility tax structure both on the state and all other political subdivisions. Study shall include feasibility of a uniform consumption tax or other method of taxation. Tax Commission is expressly prohibited from promulgating any rule or order without prior express authorization from the legislature or legislative task force. In the event a uniform tax policy, which allows all competitors to be taxed on a fair and equal basis, has not been established on or before 7/1/02, effective date for customer choice shall be extended until such time as a uniform tax policy has been established. (p. 8)
Pennsylvania H.B. 1509	Restructuring to be accomplished in a revenue neutral manner at a level necessary to recoup losses that may result from restructuring. (p. 57-66)
Rhode Island 96-H 8124 Substitute B	By 1/1/97, retail electric licensing committee shall submit plan to legislature for taxing and/or assessing distribution and transmission companies and non-regulated power producers. (p. 22)
Massachusetts H.B.5117	Requires parent, affiliate, subsidiary to pay transition payments to municipality impacted by devaluing of power plant in which generation

	facility is located. Transition payments are calculated on a declining rate from 1998-2009 (percentage difference between local property tax value of the property as of 1/1/96 and the fair cash value of the property as of 1/1 of the year previous to the year during which calculation is made). Generation facilities would be subject to the full fair cash valuation by localities. Tax payment would be a payment-in-lieu-of-taxes.
Illinois H.B. 362	-Sale, pledge, assignment or other transfer of intangible transition property shall be exempt from state and local taxes. -A per/kWh use tax will be implemented, except for municipal corporations owning and operating a local transportation system for public service.

Performance Based Rates (PBR)

Nevada A.B. 366	PUC shall adopt regulations permitting innovative methods of pricing noncompetitive services upon a finding that such methods would improve performance or lower costs. (Section 44, p. 17)
California H.B. 1890	
Maine H-568 (LD 1804)	
Montana S.B. 390	PSC shall establish just and reasonable rates, through established rate making principles, for distribution and transmission services and shall regulate these services. PSC may approve performance-based rate making on a demonstration by utilities that the alternative methods comply with the utilities' transition plans. (p. 13)
New Hampshire H.B. 1392	Performance-based or incentive regulation should be considered for transmission and distribution services. (p. 4)
Oklahoma S.B. 500	
Pennsylvania H.B. 1509	PUC has authority to approve flexible rates, including negotiated, contract-based tariffs and to use performance based rates. (p. 45)

Rhode Island 96-H 8124 Substitute B	It is in the public interest to establish performance based rate making. To hold overall rate increases to the level of inflation, for the period 1/1/97 to 12/31/98, distribution companies shall implement a PBR plan in accordance with specified provisions, subject to PUC approval. However, rates for low-income customers cannot increase. (p. 3, 33-35)
Massachusetts H.B.5117	-DTE has authority to promulgate rules and regs to establish and require PBR for each distribution, transmission, and gas company organized and doing business in the Commonwealth. Service quality standards will be established for customer service performance. Each company will file a report with DTE by 3/1 of each year comparing performance during the previous year to DTE's standards. DTE will be able to levy a penalty against any company failing to meet standards up to 2% of revenues for the previous calendar year.
Illinois H.B. 362	An Electric Utility Property Tax Assessment Task Force will be established. From the 1997 assessment year through the 1999 assessment year, fair cash value for any electric generating plant shall be determined using original cost less depreciation, and depreciation rates shall be equal to those in effect on 11/1/97.

Residential Electricity Rates (¢/kWh)
(Source: Resource Data International, Inc.)

	1991	1995
Nevada A.B. 366	5.89	7.11
California H.B. 1890	10.79	11.61
Maine H-568 (LD 1804)	10.45	12.51
Montana S.B. 390	7.39	7.26
New Hampshire H.B. 1392	10.38	13.50
Oklahoma S.B. 500	7.03	6.82
Pennsylvania H.B. 1509	9.58	9.72

Rhode Island 96-H 8124 Substitute B	10.99	11.61
Massachusetts		11.3 (1996)
Illinois		10.4 (1996)

Compiled by the Research Division of Nevada's Legislative Counsel Bureau

Portions added by the National Conference of State Legislatures

S.Com.Lab:August.27Rev.StateComparison

August 5, 1998

Representative Norman Rokeberg
Co-Chair Joint Committee on Electric Utility Restructuring
716 West 4th Avenue
Anchorage, Alaska 99501-2133

AUG 03 1998

Dear Representative Rokeberg:

I had intended to testify in person on the following points but cannot. I am submitting this letter as written testimony. I would appreciate your consideration of the following points and I would encourage your committee to recommend immediate restructuring in the Anchorage Bowl

- Alaska businesses are not able to achieve savings to our electricity costs because we are not being allowed to exercise our rights to choose our electric power provider.
- Alaska businesses large and small make every effort to hold down overhead costs while still providing the best products and services.
- As a business organization in one of the most competitive areas of the economy I know that competition helps keep prices down and it keeps us on our toes to meet customer needs.
- We have a choice on every product and service we buy EXCEPT electricity.
- Government has some necessary functions but it should not be in a position to tell the private sector business community who they can or cannot buy electricity from.
- We would like the opportunity to choose our electricity provider.
- Gas costs have been cut because of the competitive market on the large commercial gas level.
- In a deregulated environment the lowest cost provider could serve us.
- Restructuring will insist that service levels rise and products available will be increased.

Thank you for your consideration about a product/service that affects all of us in almost every facet of our lives every single day.

Sincerely,

Dail Chambers
REGIONAL PROPERTY DIRECTOR
WEIDNER INVESTMENT SERVICES
561-5211

**Governmental decisions
are being made which will
affect your electric service
for decades to come.**

Voice your concerns

**YOU CAN
MAKE THE
DIFFERENCE!**

Will Deregulation Short-Circuit North America's Electric Power Supply

How the coming deregulation of the
electric power industry may impact consumers,



Did You Know?

There's a battle being waged right now that could jeopardize your electric service and drastically impact the quality of your life. It's a fight over the future structure of the deregulated electric power industry. You must get involved now to ensure that an equitable structure prevails. If you don't actively voice your concerns —

your rates could rise,

your electric service could become less reliable, and environmental and conservation programs could vanish.

Consider the Following:

- In the summer of 1996, two massive power system failures in the transmission grid covering at least 12 Western states caused blackouts affecting millions of customers, some for extended periods.
- In June 1996 thousands of doctors and other citizens in Connecticut were notified that electric power may not be guaranteed 24 hours a day.
- Outages seem to be longer and more frequent.
- Electric power companies are shedding thousands of employees.
- Merger activity is on the rise, leading to fewer companies having greater control.
- Some electric power companies are threatened with bankruptcy in the face of a deregulated industry.

Rapid, Radical Deregulation May Cause ...

- ... electric power companies to cherry-pick their rivals' most attractive customers who buy large quantities of power, to the detriment of the local company, its rate payers and the community;
- ... electric power companies to neglect to maintain equitable service to smaller customers (residential, small business and rural); and
- ... electric power companies to continually restructure their business functions, resulting in constant anxiety in the work force and financial instabilities in the industry and communities.

There are many vital issues at stake concerning rapid, radical deregulation.

ISSUE 1: Reliability — Electric power companies are cutting costs, resulting in systems so overstretched they may not be able to operate efficiently in times of peak demand or during storms.

ISSUE 2: Cost to Consumers — Electric rates may increase due to profiteering, temporary shortages and the shifting of costs from large industrial users to small commercial and residential energy users.

ISSUE 3: Societal Impacts — Valuable community-based programs currently funded by local power companies are likely to disappear. These programs include lighting for playgrounds and athletic fields, holiday lighting, lifeline energy assistance, and wildlife preservation.

ISSUE 4: Universal Access — Deregulated electric power companies may not be obligated or motivated to serve customers needing electricity in remote areas or in regions suffering economic trouble.

ISSUE 5: Tax Revenues — Currently, your local electric power company contributes significantly to your local tax base. In a deregulated industry, this tax revenue may dry up as power companies located outside the community serve local customers but pay taxes elsewhere.

ISSUE 6: Stranded Costs — Because of prudent government regulations, companies built generating plants to meet projected electrical demand in their areas. Under rapid, radical deregulation, some companies may not be able to recover those investment costs, thus threatening local economies.

ISSUE 7: Mega-Mergers and Market Dominance — Ongoing consolidation of existing electric utilities and other energy industry companies will create opportunities for the abuse of economic power and manipulation of energy markets to maximize profits at the expense of consumers.

ISSUE 8: Environment — Environmental and conservation programs voluntarily implemented by electric power companies could be dropped in a deregulated industry. Emissions from power generation will be geographically redistributed, adversely affecting states and regions currently in compliance with clean-air policies.

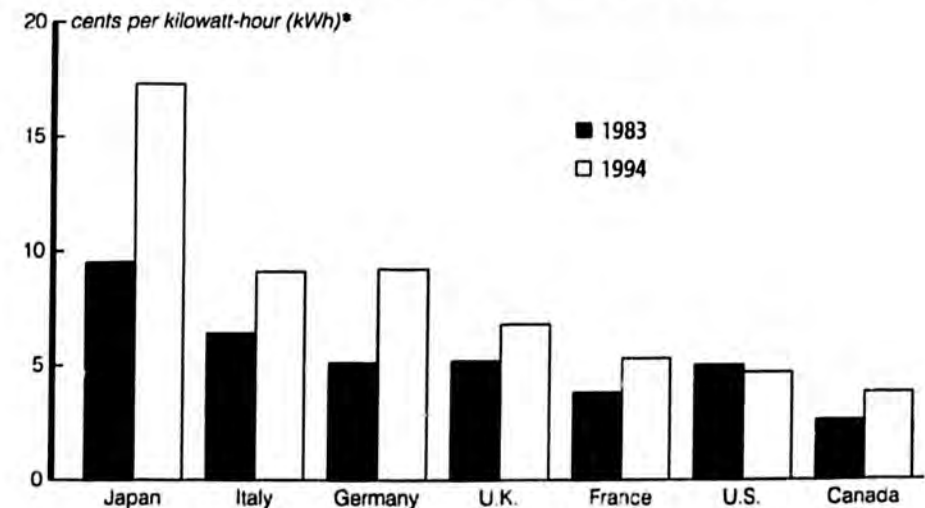
ISSUE 9: Safety and Employment — Cost-cutting measures and work force reductions are being implemented throughout the electric power industry. As a result, the existing work force and the electric systems are stressed to a point that threatens worker safety and public safety.

This booklet provides you with background on the issues at stake now and on the context of regulation and competition in the industry.

At the back of the booklet is a list of practical guidelines to help you get involved in ensuring the continuation of affordable, safe, reliable and secure electric power service.

Many of us take for granted the electric power industry's history of providing universal, quality service. Currently, the North American system is the best in the world, with industrial rates lower than those of the largest industrial countries, the highest level of service reliability and a tremendous safety record. Fast-paced abandonment of the current electric power system and the reckless overturning of responsible regulation in pursuit of greater profits will put all of this in jeopardy.

Worldwide Industrial Electricity Prices



Source: OECD, International Energy Agency Statistics, Energy Prices and Taxes (Fourth Quarter 1995).
* Prices converted to 1990 U.S. dollars.

Industrial electric prices in North America are the lowest of the world's leading industrial countries. Electric prices have increased in every major industrial country except the United States.

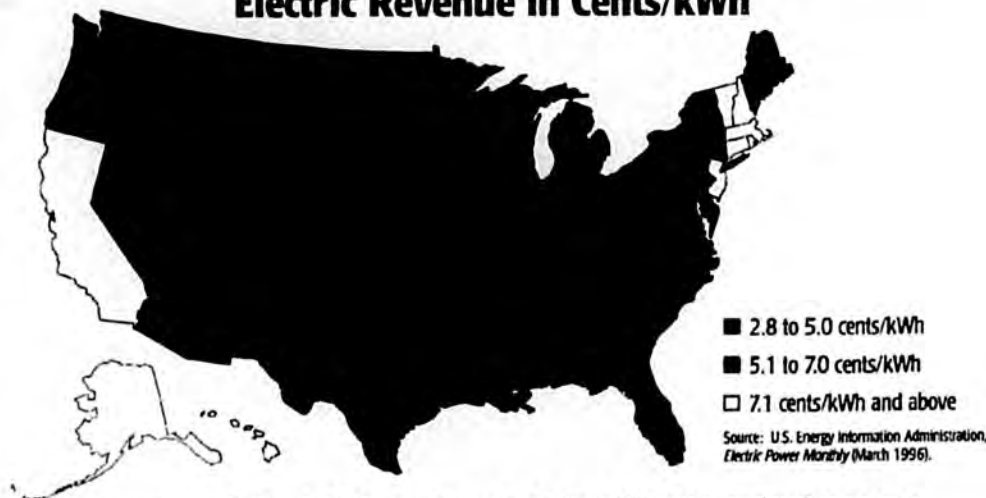
Who Wants Rapid, Radical Change?

There are only a few groups responsible for the push toward rapid, radical change to the electric power industry structure. The most influential and outspoken are the large industrial consumers of electric energy who are motivated by the lure of increased profits; a few utilities which may benefit financially from the proposed radical changes; power marketers; and a coalition of certain politicians and special interest groups that reject government rules and regulation in favor of a private, free-market philosophy that is completely profit-driven.

Large industrial consumers are pushing for rapid deregulation because electric rates vary substantially across regions of the United States, and they want access to the cheapest rates. There are many economic, political and social reasons for these rate disparities. The rates in each area reflect the regulations of its citizenry in trying to reach the proper balance among the interests of all stakeholders.

Commodity traders want to radically change the electric power industry to create a new market for their services. These Wall Street traders seek to profit by merely buying and selling contracts that anticipate the movement of electric prices. Similarly, power marketing companies want rapid, radical change so they will have the ability to act as middlemen in the buying and selling of electricity at the wholesale level.

Disparity in 1995 Average Industrial Electric Revenue in Cents/kWh



States use regulation to balance the cost of electricity with societal concerns. Examples are universal access to all residents, the research and development of energy-efficient products, maintaining environmental standards such as air quality, and determining what kinds of fuel should be used to generate electricity.

The economists and politicians who call for the dismantling of the current electric power industry base their arguments on theory and questionable economic models rather than real-world experiences. These advocates maintain that society's interests are hampered by government rules and regulations and are best served by completely open markets.

Rapid, Radical Change Is Shortsighted.

Advocates of rapid, radical deregulation neglect to address numerous issues, such as the risks involved, who will actually benefit and who will end up paying. Similar deregulation in other industries has resulted in a tremendous increase in customer complaints, harassing and sometimes misleading telemarketing schemes, cost shifting, and cost-cutting measures that threaten safety and quality. The irony of unbridled competition has been the evolution of a few dominant, mammoth corporations through mergers and takeovers, thereby eliminating competition and the benefits it was supposed to create. Unquestionably, the remaining companies and their shareholders benefit. Unfortunately, consumer concerns such as service, safety and reliability are sacrificed to market pressures. For example, deregulation in the airline industry has produced some cheaper fares but at a significant cost to safety and quality. Some cities have suffered loss of service and significantly higher airfares.

Consumer groups, as well as energy conservation and environmental groups, fear that completely opening access to all electric power companies will simply bring about a reallocation of costs that will benefit large industrial users to the detriment of smaller commercial and residential customers. Competitive pressures may make it difficult for electric power companies to take the long-term perspective; and failure to do so may lead to inappropriate resource choices and higher power supply costs, particularly to residential customers. Further, deregulation may end comprehensive planning for energy consumption and conservation programs.

As electricity consumers, we need to remind ourselves of the fundamental reason for industry regulation: to ensure that a fair balance exists between customers and the companies that provide the service. If we hastily implement radical changes to the regulations governing the electric power industry, we will also radically change who and what has priority in our system.

ISSUE 1: Reliability

When electric power companies are subject to prudent local and federal control and regulatory oversight, they are responsible for operating and maintaining a reliable, efficient electricity system. The incentive to invest in reliability protections becomes less likely when profits are the primary consideration. In fact, the incentive to cut costs may result in systems so overstretched they may not be able to operate efficiently in times of peak demand or during storms.

Electricity, unlike goods, cannot be stored or inventoried; it must be used when produced. Mechanisms must be developed to provide financial incentives to ensure that capacity will always meet demand. **Electricity is an essential service, not merely a commodity.** Customers will not tolerate less reliable service.

Reliability of electric service is also a public safety issue and a matter of national security. Society relies on the smooth operation of electrically based technologies. If power brownouts or blackouts occur more often, will civil unrest and rioting become the price for such periods of unreliable power?

ISSUE 2: Cost to Consumers

No one can predict with certainty what will happen to the price of electricity in an open market. Supporters of radical deregulation speculate prices will fall, yet they do not take into account some factors particular to electric power:

- With fewer operating reserves, temporary shortages may become more frequent. This will make prices vulnerable to fluctuating demands.
- It takes several years to plan, design and build new generation capacity. As a result, companies will lose the ability to adjust prices quickly in response to a shortage.

Most educated observers claim that customer choice will be of little or no value to residential consumers or small businesses in terms of the price of electricity. Large industrial consumers will command any or all lower-cost electricity, leaving higher-cost supplies to residential and small business users.

ISSUE 3: Societal Impacts

Local utilities currently support a number of beneficial community programs. In an environment motivated solely by profits, many of these programs will disappear as costs are cut.

Lifeline energy assistance programs, community activities, and numerous conservation and economic development activities are funded through electric rates, mainly because of strong identification between the local electric power

company and its community. The ability and desire on the part of companies to voluntarily cooperate to achieve state-level social objectives will be impaired under an environment motivated solely by profit.

ISSUE 4: Universal Access

Under deregulation, electric power companies may not be obligated or have an incentive to serve those customers who are considered a financial risk. Electricity is a necessity, and methods will have to be found to assure that these customers still have electric power companies to serve them at reasonable prices.

ISSUE 5: Tax Revenues

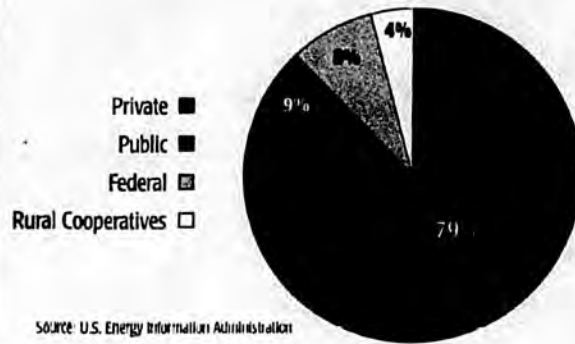
The electric power industry currently pays billions in state and local taxes. What will be the impact of deregulation on these vital revenues, particularly in states and localities where power plants may be shut down when power is brought in from distant areas? Residential consumers and small businesses might be expected to pay more in taxes to make up the shortfall.

ISSUE 6: Stranded Costs

The electric power industry is the most capital-intensive industry in North America. Hundreds of billions of dollars have been invested in plants and facilities. In response to prudent government regulations, private utilities built large generating plants to provide universal service and meet projected demand for electric power. Companies expected to recover the costs of these long-term investments through rates paid by a defined customer base. In a deregulated industry, these electric power companies will be unfairly burdened with those investment costs, compared to other providers who were not required to make similar investments. Who will compensate the companies for these stranded costs?

Since the 1930s the United States has greatly benefited from a decentralized electric power industry consisting of four distinct types of ownership systems: **private** (investor owned); **public** (municipals, power districts, irrigation districts, state authorities and other state organizations); **rural cooperative** (consumer owned); and **federal** (primarily hydroelectric projects such as Tennessee Valley Authority, Bureau of Reclamation, Bonneville Power Administration, etc.). This structure has provided safe, reliable, affordable service to all customers and has allowed flexibility for communities to address their local concerns and preferences.

1993 Net Electricity Generation in U.S. by Type of Utility



In general, private serve large, consolidated markets; public serve communities and nearby customers at the lowest possible cost; rural cooperative serve people in rural areas; and federal sell most of their power to non-profit preference customers for resale.

ISSUE 7: Mega-Mergers and Market Dominance

Numerous mergers have occurred since restructuring and deregulation initiatives first surfaced in the industry. Many more mergers can be expected. In a recent industry survey, 93% of surveyed power companies anticipated greater consolidation. A key consumer concern is the potential for abuse of market power by energy behemoths to manipulate prices. With almost 90% of generating capacity provided by the largest 200 systems, can competition grow with deregulation, or will there be merger mania to gain an even higher percentage of the electric generation market?

Electric power companies play a unique role in state and local communities. They are often engines of economic development, and they have traditionally maintained local offices to ensure customer contact and quality service. Much of this regional involvement may be lost when the local company merges with another which has no historical concern for the community. Governmental policymakers have made little effort to effectively analyze and protect communities against the potential adverse effects of mergers.

ISSUE 8: Environment

Through their control over local utility rates, states have been able to meet numerous environmental goals through stringent pollution controls, mandatory use of renewable sources of energy, energy-saving programs, etc. The present balance of environmental concerns associated with electrical energy is threatened, and environmentally beneficial programs may ultimately be dropped.

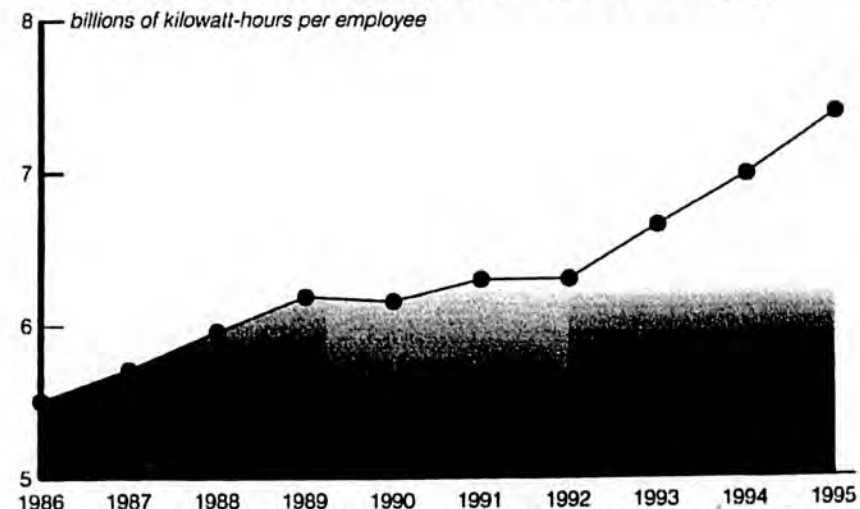
Effective energy-saving programs provide customers with direct financial incentives to invest in measures and equipment to promote energy efficiency. Successful programs have encouraged installation of reduced-flow shower heads, additional insulation, heater wraps and load-control devices. These energy-saving programs have been shown to be highly cost-effective, allowing the sponsoring company to save fuel, cut transmission and distribution costs, and generate capacity reserves. As a trade-off, the company sacrifices increased sales and related earnings. In an environment motivated solely by profits, the electric power supplier will have no reason to conduct these energy-saving programs.

ISSUE 9: Safety and Employment

Electricity must be transmitted in relatively close proximity to the general public and can be extremely dangerous unless properly produced, delivered and used. In general, workers, management and regulators in the existing industry have achieved an exemplary safety record. This is due to a long history of proper training and appropriate investments in public safety and worker safety.

Staffing levels and training programs have been the first areas cut where deregulation has occurred in other industries. Quality of work life has declined, and employees have found themselves in a race to the bottom on wages and benefits.

U.S. Electric Utility Worker Productivity



Source: Calculations based on data from the Bureau of Labor Statistics and the Energy Information Administration. The economy had been growing slowly for a year and a half before the recession, which lasted from approximately September 1990 through March 1991. Slow economic growth resumed in the final three quarters of 1991.

The electric power output per employee in the United States has been steadily increasing. What will be the effect on worker safety and service reliability if the work force continues to be overstretched as a result of downsizing?

Evolution of the U.S. Regulatory Framework

For more than 60 years, regulation of the electric power industry in the United States has been based upon a "compact" between electricity customers and companies which generate, transmit and distribute electric power. The regulatory compact has tried to ensure that a fair balance exists between the interests of the companies, which want to maximize profits, and their customers, who want safe, reliable, affordable power while respecting environmental concerns.

This compact is managed at both federal and state levels. Legislative and regulatory changes have periodically altered this regulatory compact, dramatically affecting the balance of interests between companies and customers.

THE REGULATORY COMPACT

OBLIGATIONS OF PUBLIC UTILITIES

- To provide safe, reliable, affordable power within their service area.
- To serve all customers throughout the authorized service area.
- To charge fair rates for power.

RIGHTS OF PUBLIC UTILITIES

- To invest in plant and equipment necessary to provide safe, reliable, affordable power.
- To operate exclusively within an authorized area.
- To expect a fair rate of return for providing service.

Public Utility Holding Company Act (PUHCA) of 1935

Congress Creates Regulated Monopolies

Prior to regulation the industry comprised a network of operating electric power companies controlled by about 15 large holding companies. They were so massive and powerful that they were able to ignore customer needs. Companies dictated price and refused service to any customer not willing to pay that price. Essentially, these companies were unregulated monopolies in their areas of operation.

In 1935 Congress restricted utility holding companies through PUHCA and other legislation which established a mechanism for interstate regulation of electricity and gave states greater power and authority to regulate utilities. The act granted utilities regulated monopoly control of their service areas, but required them to serve customers in the public interest. In return, state boards or citizen regulatory bodies ensured a reasonable rate of return for utilities at a reasonable cost to the customer.

FEDERAL ENERGY REGULATORY COMMISSION

regulates wholesale power and transmission sales between utilities and between utilities and nonutility generators.

STATE UTILITY COMMISSIONS

regulate power sales and services to retail customers.

Public Utility Regulatory Policies Act (PURPA) of 1978

Congress Introduces Wholesale Competition

In the 1970s large industrial consumers lobbied Congress to introduce electric power competition at the wholesale level. PURPA required utilities to purchase power from "qualifying facilities," regardless of their location. Qualifying facilities include nonutility generators (NUGs) and independent power producers (IPPs) which generally build near a factory or large commercial business. Industrial consumers may use power generated by these facilities instead of power produced by the local utility. The number of qualifying facilities subsequently surged. By 1995 nearly 60% of new electricity generation came from nonutility generators.

Energy Policy Act (EPA) of 1992

The Move to Rapid, Radical Deregulation

In the 1980s corporate interests (not necessarily within the electric power industry) pushed for access to the vast, lucrative markets and huge capital assets accumulated by the traditional power companies. These markets and assets were off-limits—unless the regulatory system were dismantled. Citing the advantages of increased "consumer choice" and lower electricity prices, these corporate interests lobbied for rapid deregulation of the electric power industry.

Congress obliged, in part, by enacting EPA, which removed many regulatory functions from federal oversight and in many ways rendered PUHCA obsolete.

- EPA relieved the Securities and Exchange Commission of many of its obligations to restrict certain practices of retail utilities and to monitor mergers and acquisitions. These changes helped create the destabilizing merger mania prevalent in the power industry. Aggressive companies, many with little interest in supplying power to the public, are now drawn to this industry by the promise of huge profits to come.
- EPA authorized the Federal Energy Regulatory Commission (FERC) to set conditions for wholesale wheeling and to mandate utilities owning transmission systems to open such systems for use by other utilities, exempt wholesale generators and other entities. In addition, EPA opened the door for FERC to assert broad authority to establish rules for the operation and pricing of open transmission systems.

- States are now considering whether and how to implement retail wheeling. Retail wheeling allows retail customers to bypass the local utility and purchase from the energy supplier of their choice. This issue is being debated in almost every state. The changes permitted by EPAct and the prospect of customer choice have spawned a new industry, power marketing, through which electric power suppliers hope to lure retail customers from the local utility. Telemarketing is one method power marketers will use to solicit retail customers.

Can There Be Equitable Deregulation?

*Problems will surely arise in a new environment.
We will have to find solutions.*

Consider the Following:

- ✓ Electrical service must remain reliable, safe and efficient. There must be assurances that there will be sufficient operating reserves for crisis situations.
- ✓ The price of electricity in a competitive market must remain stable for all classes of customers, and the quality of the power must remain high.
- ✓ Societal and community programs should not be abandoned as local government revenues decline due to utilities paying less tax.
- ✓ Universal access must be preserved, because electricity is a necessary service.
- ✓ Individual consumers and local communities should not be expected to bear the full burden of making up for lost tax revenue.
- ✓ Utilities should be compensated for their stranded assets. They invested in plants and equipment based on the current regulatory framework, which included oversight by local communities.
- ✓ Mechanisms should be put in place to protect against the potential adverse effects of mergers and acquisitions which will result from new competitive pressures.
- ✓ Environmental protections and conservation programs must not be abandoned for the sake of enhanced profits and competitiveness.
- ✓ Public safety and worker safety must be maintained, as electric power companies cut staffing levels to enhance profitability.

What Can You Do?

The issues that have been highlighted should inspire all electric power consumers to get involved in the process to voice their concerns within their communities.

You can get involved in many ways at the grass-roots level to protect yourself from rapid, radical deregulation.

Write a letter to, or telephone, your local elected officials, state legislators or federal senators/congressional representatives to voice your concerns.

Network within your affiliations (e.g., church/synagogue, civic groups, professional associations, recreational activities, educational programs, social groups, etc.) to voice your concerns and help educate others.

Meet one-on-one with your neighbors to discuss implications for your community.

Submit an opinion piece or letter to the editor of your local newspaper to express your concerns or respond to those advocating radical change.

Attend public meetings and political rallies to challenge all candidates to clarify their positions on these issues as they campaign for upcoming elections.

Every electric consumer has an opportunity to influence the outcome of electric power deregulation, but only if we get involved at the local, state and national levels. It is important to act now. Governmental decisions are being made which will affect everyone for decades to come. It is important that your concerns be heard. When all is said and done, the electric power industry must continue to provide safe, reliable, affordable service to all consumers.

a public service by the
Committee on Electric Power Industry Restructuring
International Brotherhood of Electrical Workers
1125 Fifteenth Street, N.W., Washington, D.C. 20004

August 5, 1998

Representative Norman Rokeberg
Co-Chair Joint Committee on Electric Utility Restructuring
716 West 4th Avenue
Anchorage, Alaska 99501-2133

AUG 03 1998

Dear Representative Rokeberg:

I had intended to testify in person on the following points but cannot. I am submitting this letter as written testimony. I would appreciate your consideration of the following points and I would encourage your committee to recommend immediate restructuring in the Anchorage Bowl

- Alaska businesses are not able to achieve savings to our electricity costs because we are not being allowed to exercise our rights to choose our electric power provider.
- Alaska businesses large and small make every effort to hold down overhead costs while still providing the best products and services.
- As a business organization in one of the most competitive areas of the economy I know that competition helps keep prices down and it keeps us on our toes to meet customer needs.
- We have a choice on every product and service we buy EXCEPT electricity.
- Government has some necessary functions but it should not be in a position to tell the private sector business community who they can or cannot buy electricity from.
- We would like the opportunity to choose our electricity provider.
- Gas costs have been cut because of the competitive market on the large commercial gas level.
- In a deregulated environment the lowest cost provider could serve us.
- Restructuring will insist that service levels rise and products available will be increased.

Thank you for your consideration about a product/service that affects all of us in almost every facet of our lives every single day.

Sincerely,

Dail Chambers
REGIONAL PROPERTY DIRECTOR
WEIDNER INVESTMENT SERVICES
561-5211



REGAL ALASKAN HOTEL

August 3, 1998

AUG 03 1998

Representative Norm Rokeberg
Fax 258-2916

Dear Representative Rokeberg,

I had intended to testify in person on the following points but cannot. I am submitting this letter as written testimony. I would appreciate your consideration of the following points and I would encourage your committee to recommend immediate restructuring in the Anchorage Bowl.

- Alaska businesses are not able to achieve savings to our electricity costs because we are not being allowed to exercise our rights to choose our electric power provider.
- Alaska businesses large and small make every effort to hold down overhead costs while still providing the best products and services.
- As a business organization in one of the most competitive areas of the economy I know that competition helps keep prices down and it keeps us on our toes to meet customer needs.
- We have a choice on every product and service we buy EXCEPT electricity.
- Government has some necessary functions but it should not be in a position to tell the private sector business community who they can or cannot buy electricity from.
- We would like the opportunity to choose our electricity provider.

A REGAL INTERNATIONAL HOTEL.

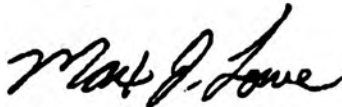
4800 SIYHARD ROAD • ANCHORAGE, ALASKA 99517-3236
PHONE 907.243.2300 • FAX 907.243.6615 • WORLDWIDE RESERVATIONS 800.222.8888
www.regal-hotels.com/anchorage • e-mail: regal@alaska.net

REGAL ALASKAN HOTEL

- Gas costs have been cut because of the competitive market on the large commercial gas level.
- In a deregulated environment the lowest cost provider could serve us.
- Restructuring will insist that service levels rise and products available will be increased.

Thank you for your consideration about a product/service that affects all of us in almost every facet of our lives every single day.

Sincerely,



Max J. Lowe, CHA
General Manager

MJL:ta

Alaska Electric Utility Restructuring

Joint Committee on Electric Utility Restructuring
Alaska State Legislature
HCR No. 34



Donn T. Wonnell, *Counsel for*
Municipal Light & Power
Municipality of Anchorage
August 6, 1998

Alaska Electric Utility Restructuring

- Basic Principles
- Industry Restructuring Outside
- Alaska Is Different
- Additional Problems
- Recommendations



1. Basic Principles

- Competition

- Public interest test (sustainable; demonstrable)

- Non-discrimination

- Deregulation (asymmetry)

- Competition v. competitors



1. Basic Principles

“Second only to the temptations on regulators to show results in the form of quick rate reductions is the temptation to produce some competitors, even competitors less efficient than the incumbents, by extending to them special preferences or protections and restraining efficient responses by the incumbents.”

Alfred E. Kahn

“Deregulation: Micromanaging the Entry and Survival of Competitors”

The Edison Electric Institute

Washington, D.C. (February 1998)



1. Basic Principles

- Change = Improvement
 - Ubiquitous effects
 - Continuous effects
 - Safety, reliability, and availability
 - Unintended consequences
 - Enhancing consumer benefits



1. Basic Principles

“Power Trader’s Default Sends Tremors Through Markets

...That default caused a chain reaction of fears and unmet promises that on June 23 drove Midwest electricity prices to as high as \$3,200 a megawatt-hour, 125 times the average price last year. The Federal Energy story shows how changes in the buying and selling of U.S. electricity have created a wild-fire market filled with new dangers for the power industry.”

© 1998 Bloomberg L.P.
AOL, July 8, 1998



1. Basic Principles

- Change = Nondiscrimination
 - Effects of market forces
 - Consumer benefits/absence of detriments
 - “Windfall” benefits, other inequities
 - Availability and affordability



1. Basic Principles

- Alaskan Issues/Solutions
 - “We don’t care how they do it outside.”
 - Unique internalities and externalities
 - Programs elsewhere are new
 - Results elsewhere are mixed
 - Limited ability to absorb policy failures





- Basic Principles
- Industry Restructuring Outside
- Alaska Is Different
- Additional Problems
- Recommendations

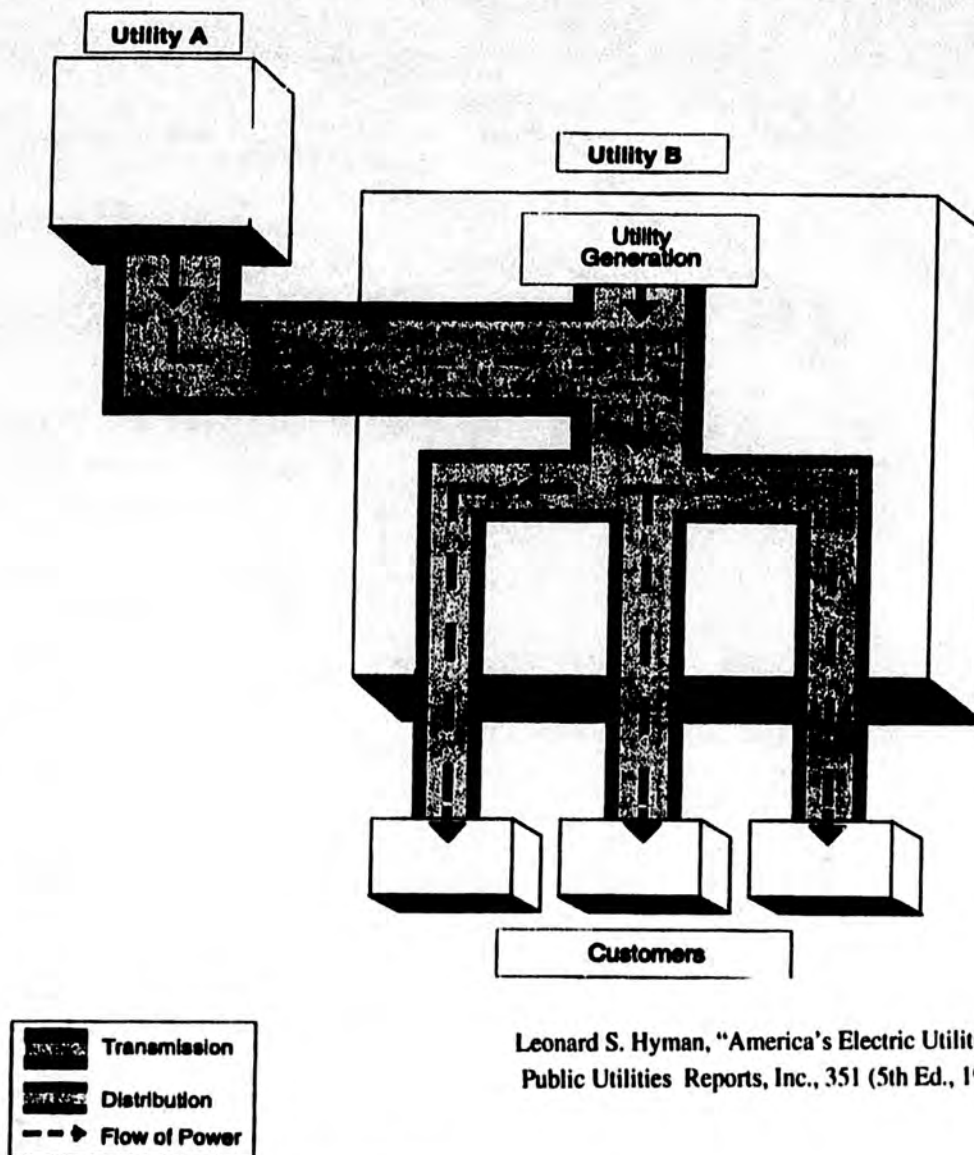
Alaska Electric Utility Restructuring

2. Industry Restructuring Considerations

- **Generation**
 - Multiple sources
 - Physically interconnected
- **Transmission**
 - “Bottleneck facilities”
 - Comparable access
 - Comparable information
- **Local Distribution**
 - Unbundled service
 - Regulatory issues



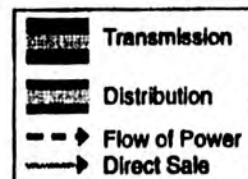
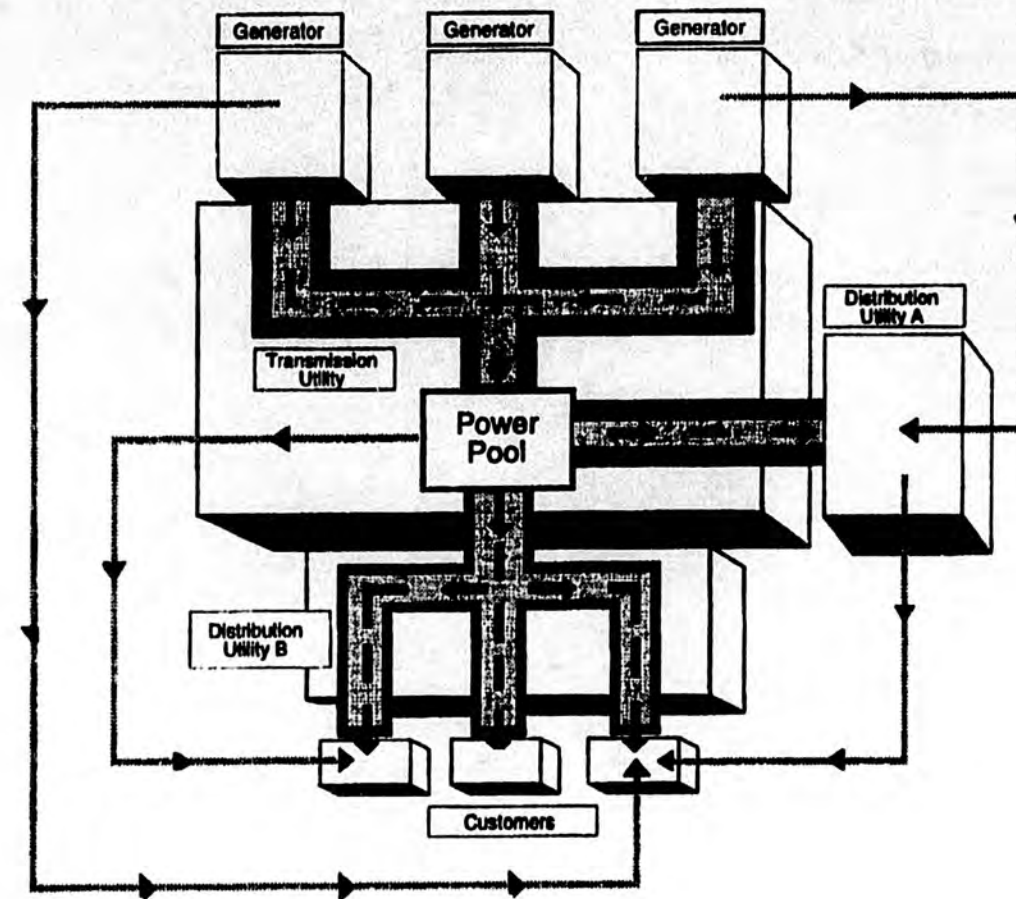
2. Industry Restructuring Outside



Leonard S. Hyman, "America's Electric Utilities,"
Public Utilities Reports, Inc., 351 (5th Ed., 1994)



2. Industry Restructuring Outside



Leonard S. Hyman, "America's Electric Utilities,"
Public Utility Reports, Inc., 355 (5th Ed. 1994)



Alaska Electric Utility Restructuring

- Basic Principles
- Industry Restructuring Outside
- *Alaska Is Different*
- Additional Problems
- Recommendations



3. Alaska Is Different

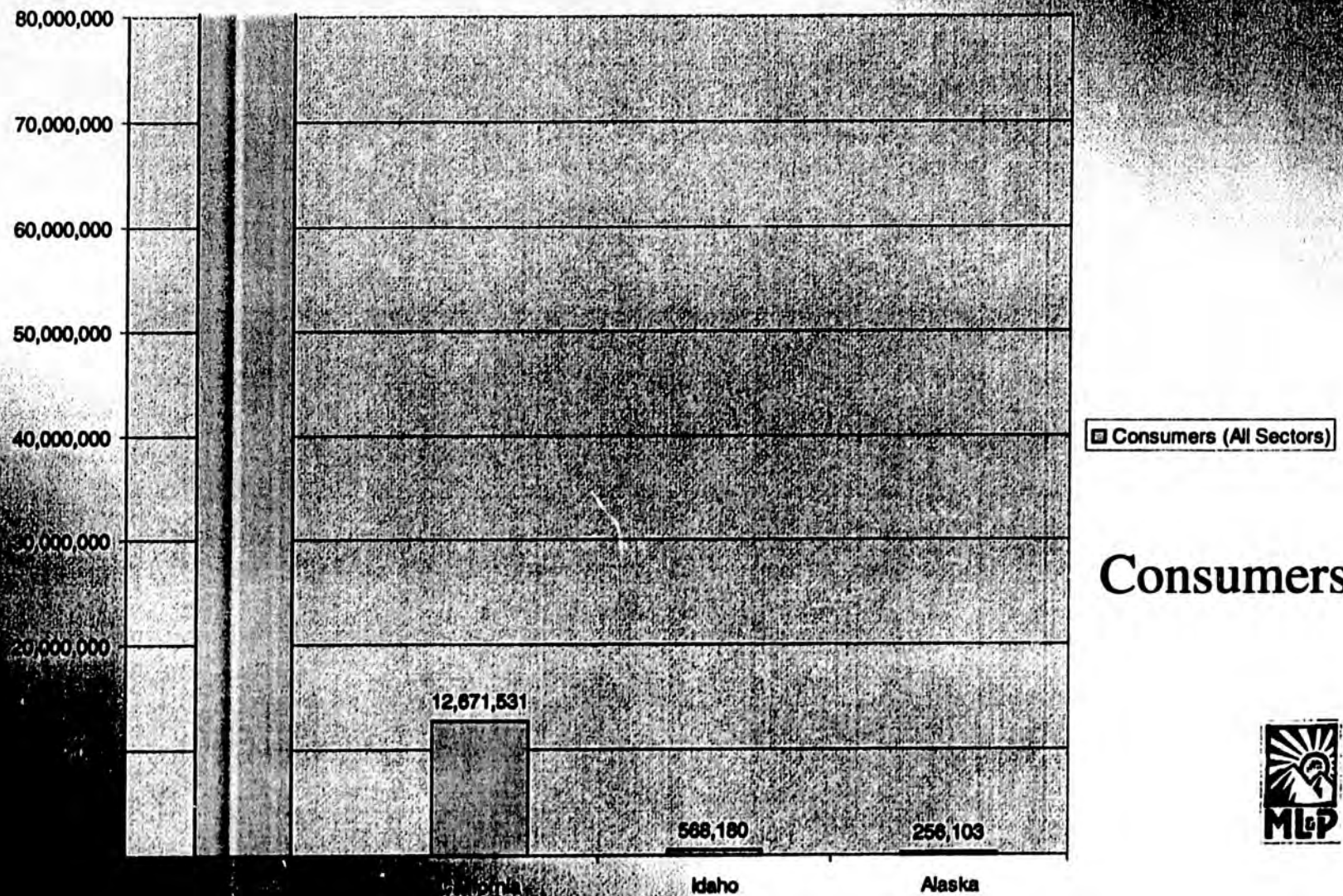
- Total market is extremely small
- Physical isolation from lower-48
- Grid limitations
- Insignificant non-utility generation
- No competitive wholesale market structure



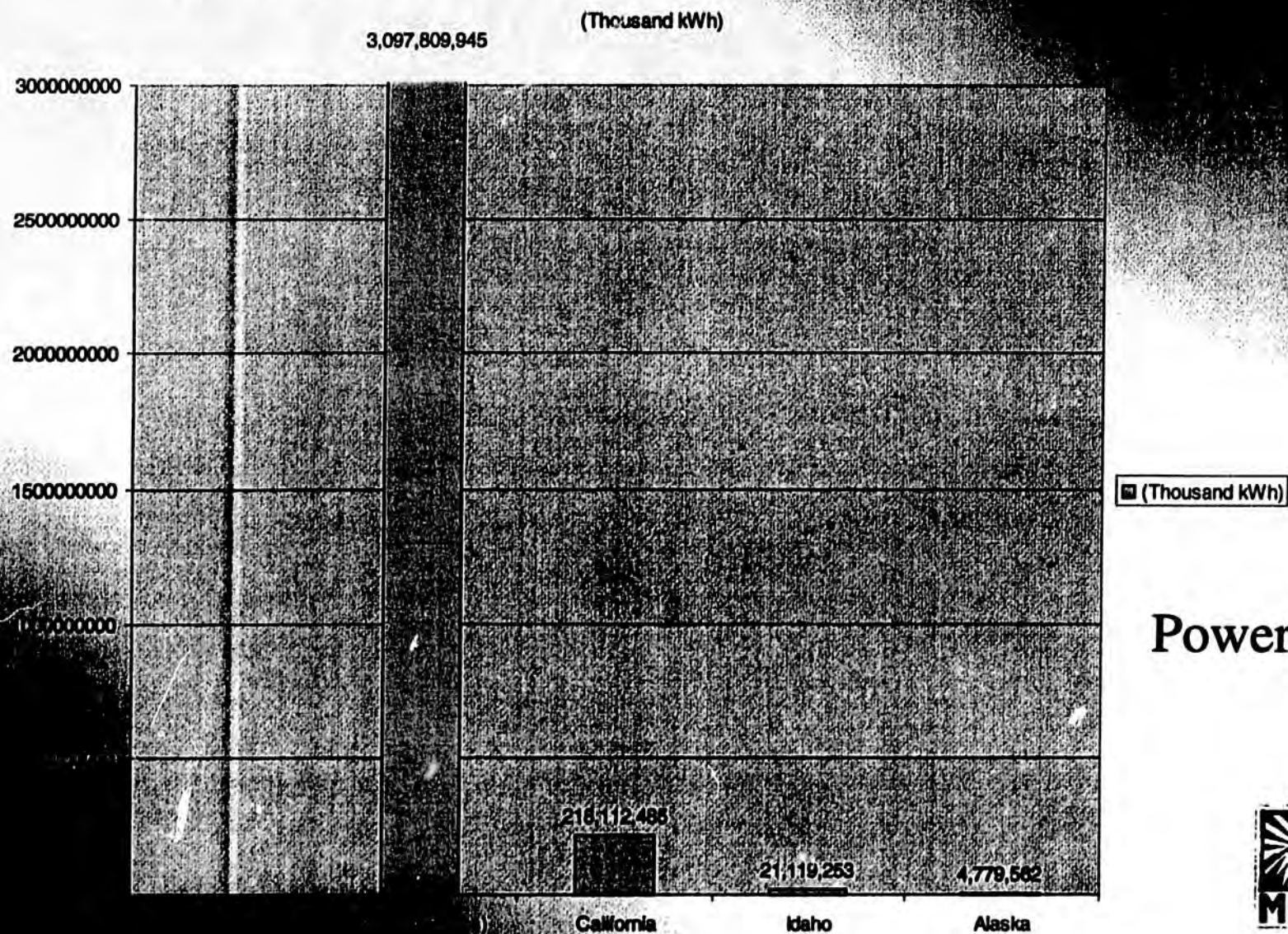
3. Alaska Is Different

120,002,093

Consumers (All Sectors)



3. Alaska Is Different



Alaska Electric Utility Restructuring

- Basic Principles
- Industry Restructuring Outside
- Alaska Is Different
- *Additional Problems*
- Recommendations



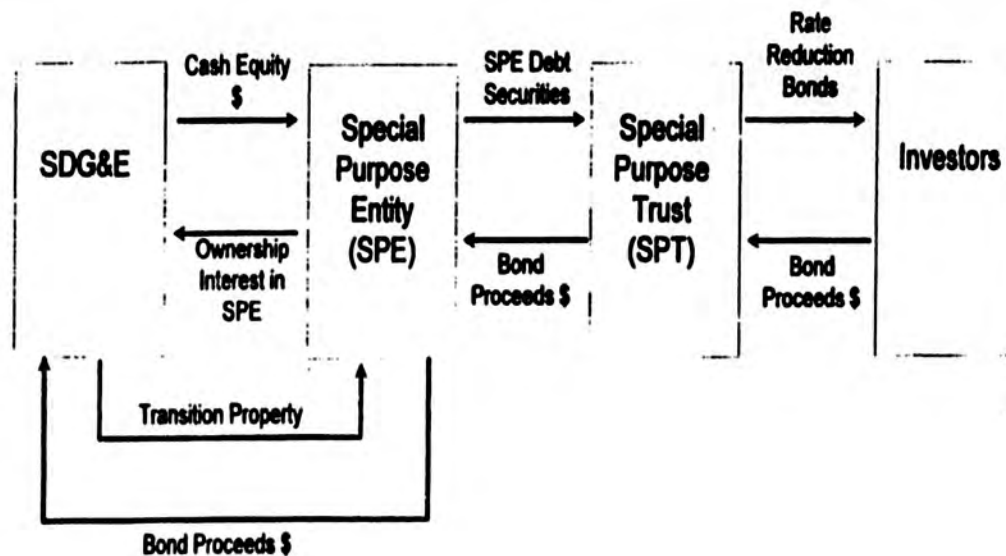
4. Additional Problems

- **Stranded Investment**
 - Defining, measuring, verifying, and collecting
 - \$30- 40 million/year for railbelt
- **Consumer-owned utilities**
 - No IOUs in railbelt
 - ML&P is capitalized through MOA-issued revenue bonds
 - Privatization as precondition for divestiture
- **Rate Impacts**
 - Discrimination
 - Universal availability



4. Additional Problems

Rate Reduction Bonds Transaction Structure



Frank H. Ault, San Diego Gas & Electric 19
NARUC Presentation, Subcommittee on Accounts
San Diego, California (March 16, 1998)



Alaska Electric Utility Restructuring

- Basic Principles
- Industry Restructuring Outside
- Alaska Is Different
- Additional Problems
- Recommendations



5. Recommendations

- Study economic impacts
- Take steps in an orderly sequence
 - Stage 1: Power Pooling
 - Stage 2: Wholesale Competition
 - Stage 3: Retail Competition
 - Retail demonstration projects
 - Broader measures, if warranted

Utilize APUC expertise

97-140

communications experience

non-combatants, not combatants



**Preliminary Comments of Municipal Light & Power
Concerning the Commission Inquiry into Electric Restructuring Issues**

(APUC Docket R-97-10)

**Meera Kohler, General Manager
Daniel B. Helmick,
Financial Services Manager
Donn T. Wonnell, *Counsel for***

**Municipal Light & Power
1200 East 1st Avenue
Anchorage, Alaska 99501**

April 24, 1998



**Preliminary Comments Concerning Alaska Restructuring Issues
Re: APUC Docket R-97-10**

The following outline presents the initial comments and observations of Municipal Light & Power (ML&P) concerning the process to be followed in considering Alaska electric industry restructuring issues. These remarks respond to the invitation of the Alaska Public Utilities Commission (APUC or Commission) to address six matters concerning the process to be invoked in Docket U-97-10, upon which comment is sought (see Attachment B).

ML&P appreciates the opportunity to provide input for the Commission's consideration on this important subject. The scope of electric restructuring issues can be extremely broad. It has proved to be so in the many state and federal proceedings transpiring to date in the lower-48. That breadth places additional importance on the process to be employed in this docket. Of necessity, ML&P's points here must be general and preliminary in nature. Commission consideration of these matters, however, will promote a comprehensive review of the relevant issues and lead to reasoned consideration of the public interest issues implicated by any restructuring proposal.

A. Basic Principles.

ML&P recommends that the Commission embrace four basic principles in assessing whether, to what degree, and how to restructure the electric industry in Alaska.

1. Competition: ML&P favors the principle of competition. Competition promotes diversity of service offerings, stimulates efficient production, and tends toward reduced market prices for goods and services. Competition, however, requires that certain economic and legal conditions exist in order to be sustainable. Further, in the context of a pre-existing monopoly market structure, competition is unlikely fully and fairly to develop without at least some transitional structure and period. Such a transition promotes a level playing field and prevents an inadvertent, asymmetrical distribution of burdens and benefits among both industry participants and energy consumers. Inquiry into both the conditions necessary for competition and, if competition is indicated, the structure necessary to transition to competition should be a part of this process.

2. Universal service: The introduction of competition into the industry should benefit consumers in a non-discriminatory fashion. It should not disadvantage those in the rural areas of the state, nor should it provide windfall benefits to specific classes of customers, at the expense of other classes of customers. Further, under competition, price is driven in the direction of cost. To the extent existing rate structures and cost recognition mechanisms are based upon factors other than cost (for example, implicit subsidies in current rate designs), those subsidies may evaporate. As a result, some consumers could well face rate increases rather than reductions, which could impose severe financial burdens on those customers. Quality service, at affordable rates, should remain available or become available universally within the state.

3. System safety, reliability, and quality: The Commission should ensure that industry restructuring does not become the occasion for degradation in the quality and reliability of electric power. Further, competition, if adopted, must function within the bounds of incentives and/or minimum mandatory standards necessary to secure the safety of the system, for customers and employees alike.



4. Unique Alaskan conditions: The experience of the lower-48 states provides a wealth of precedent and insight into the issues implicated by Alaska electric restructuring. ML&P believes the Commission should take advantage of this knowledge and incorporate it into the proposed process. But ML&P also believes that many conditions inherent in the lower-48 experience do not obtain here. Consequently, the Commission's process should ensure that all relevant aspects of Alaska's unique circumstances are developed and recognized in any final plan adopted by the Commission as a result of this process. Since the current market structure is meeting extant needs in a satisfactory manner, the Commission should resist special interest pressures to implement any particular market change for the sake of change, alone.

B. ML&P Responses to Identified Issues.

1. Determining whether there should be competition in the electric industry in Alaska.

To date, state and federal agencies have taken a variety of positions on and approaches to the issue of introducing competition. They generally have not decided, and the Commission should not decide a priori for or against competition without reference to the public interest. In assessing whether to introduce competition into the Alaska electric industry, the Commission should consider the following course:

- a. **Identify segments of the electric industry potentially subject to competitive service provisioning.** This could include subdividing the industry into operational or economic segments for further analysis; e.g.,
 - Generation
 - Transmission
 - Distribution
 - Ancillary services
- b. **Identify the conditions necessary to promote and to sustain competitive markets in one or more segments.** Competition at the federal level currently exists in wholesale generation because of the existence of multiple, alternative power sources. Open access to transmission facilities (but not distribution facilities) is an indispensable part of such competition. In some states, competition in energy sales at the retail level is being initiated or studied. Such retail competition involves related issues of independent system operation, power exchange creation and management, regulation of new industry participants, and so on. In virtually all cases, state implementation of restructuring has been preceded by a prudent, thoughtful analysis of the problems and solutions implicit in each restructuring proposal under consideration. It would prove instructive to examine such precedent, e.g., FERC Order No. 888, to determine what conditions or issues impact the creation and maintenance of competitive markets.
- c. **Identify the public interest issues and benefits attending alternative market structures.** Identification of the public interest issues inherent in restructuring must be a core concern of the Commission in any proposed process. That interest can be analyzed, and the prospective benefits of any particular course identified and quantified. In this manner, the Commission can begin to determine whether the introduction of specific changes to the existing structure are, in fact, likely to promote the public interest.
- d. **Establishing the procedural context for developing these and other issues related to the desirability of industry restructuring.** ML&P believes that this docket provides an appropriate vehicle for Commission inquiry into the fundamental issues of restructuring. The process for developing these issues is addressed in the following section.



2. Educating the public, the industry, and the Commission on possible issues.

ML&P supports both Items A and B of the outline of issues, and recommends the following matters for Commission consideration:

- a. **The Commission should establish a substantive agenda.** This agenda would identify the substantive issues, such as those suggested in 1, above, concerning which industry and consumer input would be sought. The Commission should propose a basic list of such issues and afford any interested party an opportunity to comment upon or add to that list.
- b. **The Commission should establish a procedural agenda.** In parallel with the foregoing, the Commission should establish a timetable for advancing the development, analysis, and evaluation of restructuring alternatives. This procedural agenda would incorporate such matters as:

Public notices identifying issues and opportunities for participation;
Public forums for presenting issues to the public and for soliciting public concerns and perspectives;
Industry workshops to pool knowledge and ideas of industry participants;
Multi-party (staff, industry, and public) workgroups to address specific issues identified by this process, as the Commission finds appropriate;
Record hearings to develop the statutory basis for further Commission action.

ML&P commits to being an active participant in these proceedings. It is our desire to utilize the knowledge and expertise of our employees to assist the Commission in developing and evaluating possible alternative industry structures. We believe the above approach follows useful precedent in the lower-48, particularly with regard to the formation of workgroups. Such workgroups would address and seek consensus on as many issues as possible, thereby minimizing both the burden on staff and the Commission and the amount of time required to reach decisions on essential points for restructuring.

- c. **The Commission should coordinate related proceedings.** The APUC has current, and will likely have additional future proceedings which involve issues related to or impacted by the process here. ML&P recommends that such proceedings be coordinated with this one, in order to

Minimize the burden on Commission and staff resources;
Minimize duplication and waste of participant time and resources;
Minimize public confusion concerning the nature and focus of Commission activity on this subject.

This would be particularly appropriate with respect to the proceedings concerning the prospects for a railbelt power pool (Docket U-97-140), since that matter is implicated in review of competitive issues set out in 1, above. Other pending matters likewise should be coordinated with this process to ensure congruity of the ultimate findings in each.



3. Deciding on a market structure, including draft regulations.

- a. **Regulations:** This step logically flows from the preceding actions. Based on public input, the industry workgroups, and the formal record developed at hearing, the Commission would be positioned to determine basic public interest issues. These could be reflected in draft changes, if any, to current regulations. The drafting burden could be shared through the solicitation of the participants in the proceeding for drafts of proposed regulations.
- b. **Legislation:** As a collateral matter, ML&P would also recommend that the Commission consider the possibility that its process may also lead it to conclude that additional or changed statutory authority is required. In that case, the record developed through the process will permit the Commission to make an intelligent, documented presentation to the legislature on any such needed legislation. ML&P believes that such consideration and documentation is necessary to secure the public interest in any proposal for legislative consideration.
- c. **Substantive issues:** Electric industry restructuring is not a one-dimensional proposition. The multiplicity and overlay of potential issues creates a complex fabric from which the Commission must create a functioning, beneficial market structure. A very basic, initial outline of substantive matters implicated in any market restructuring is attached hereto for Commission consideration as Attachment A. ML&P respectfully directs the Commission's attention to this list during its consideration of the likely scope of activity required by this proceeding.

4. Developing a transition plan, including draft regulations.

As noted in its basic principles, above, ML&P believes a transition plan will prove essential to ensure that all classes of consumers will benefit equitably from any changes proposed in the electric energy marketplace. Equally, such a plan will provide a level playing field for all competitive entities. As with matters addressing basic market structure, such a transition plan should be set out in proposed regulations, with the drafting burden eased through solicitation of draft regulations, as above. Specific issues for transition appear in Attachment A.

5. Issue draft regulations (market structure and transition plan) for review, comment and adoption under normal rulemaking procedures.

This step also proceeds logically from the course pursued above. That process will have focused Commission attention on the main public interest issues involved; will have isolated those not amenable to resolution on a consensus basis; and will have provided part of the record upon which final Commission action can be taken. These factors should ensure a rulemaking that is comprehensive in scope; comprehensible by the public; based upon a sound record; and efficient in terms of utilization of Commission resources. Further, the rights of the public and the interested parties are protected from a due process perspective, making subsequent legal challenge to the regulations less likely.

6. Adopt and implement regulations as finally approved.

ML&P supports the above sequential process as the best way to fully develop and address the issues relevant to any proposed electric market restructuring. In tandem with the four basic principles set out above, this process should ensure an articulation of all public interest issues and result in a reasonable and effective balance of public and private interest. It represents the appropriate way to address a matter of such vital importance to consumers and to the economy of the State, as a whole.



ATTACHMENT A

Outline of Substantive Issues Implicated by Electric Industry Restructuring

- 1. Vertical Integration and Anti-Competitive Concerns**
 - a. Basic economic considerations
 - Scope
 - Scale
 - Market characteristics
 - b. Essential facilities issues
 - c. Product tying and rate unbundling
 - d. Imputation and "comparability"
 - e. Degrees of separation
 - Divestiture issues
 - Fully separated affiliates
 - Accounting safeguards
 - Integrated system operation (negotiated pools, ISO, etc.)
 - f. Integrated system operators (contract-based, ISO, etc.)
 - g. Open market sales (spot market, power exchange, etc.)
- 2. Transmission Restructuring**
 - a. Open access requirements
 - b. Monopoly regulation
 - c. Open access tariffs
 - d. Operating information systems
 - e. Costing and pricing
 - f. Control area functionalities
- 3. Distribution Restructuring**
 - a. Identification/demarcation of facilities
 - b. Operating issues
 - Open access tariffs
 - Costing and pricing
 - System reliability and safety
 - Spinning reserve
- 4. Generation Issues**
 - a. Cost classifications
 - Fixed v. variable
 - Sunk v. marginal
 - Demand v. energy
 - Book v. economic
 - Pricing issues



- b. Stranded cost theories
 - Social compact
 - Confiscation
 - Basic business risk
 - Adverse competitive impacts
 - Public policy
 - Sharing principles
 - Forced costs
- c. Stranded cost characteristics
 - Prudently incurred
 - Legitimate
 - Verifiable
 - Accurately calculated
 - Sunk in prior period
 - Stranded by transition to competition
 - Not marginal in nature
- d. Stranded cost types
 - Utility-owned generation
 - Purchase power contracts
 - Regulatory assets
 - Deferred taxes
 - Post-retirement employee benefits
 - Plant decommissioning
 - Demand-side management
- e. Stranded cost measurement
 - Revenues lost
 - Market valuation
 - Cost of service valuation
 - Auction bid price
- f. Stranded cost mitigation
 - Future efficiencies
 - Buydowns of existing obligations
 - Mitigation sales
 - Stranded "benefits"
 - True-up
 - Recovery period
- g. Stranded cost recovery mechanisms
 - Exit fees
 - Non-bypassable surcharges
 - Accelerated depreciation
 - Price cap/incentive regulation



5. Other Issues

- a. Defining the "public" in public interest
- b. Rate structure issues
 - Customer classifications
 - Rate classifications
 - Cost classifications (methodologies, assumptions)
 - Implicit subsidies
- c. Competitive neutrality and asymmetrical regulation

6. Universal Service

- a. Provider of last resort
- b. Current subsidy mechanisms
- c. Basic services package
- d. Cost support mechanisms
- e. Competitive neutrality

7. Financial Market Issues

- a. Municipal bond issues
- b. Uncompensated takings
- c. Impairment of contracts
- d. Transitional uncertainty and foreseeability
- e. Securitization and monetization

8. Consumer Protection and Education

- a. Misperceptions arising from prior market condition
- b. Identification of issues, impacted parties
- c. Scope of protection and educational programs
- d. Monitoring and enforcement mechanisms

9. Relevant Law

- a. Current State statutes
- b. Current APUC rules
- c. Current state case law
- d. Current federal statutes
- e. Current FERC rules
- f. Current federal case law
- g. Proposed legislation
 - State
 - Federal
- h. Subject matter areas
 - Electric energy
 - Antitrust
 - Environmental (water, emissions, species)
 - Consumer rights (capital recovery sharing)



**Before the
JOINT COMMITTEE ON ELECTRIC RESTRUCTURING
ALASKA STATE LEGISLATURE
(HCR No. 34)**

**Remarks of
Donn T. Wonnell
Counsel for Municipal Light & Power
Municipality of Anchorage**

August 6, 1998

**Remarks of Donn T. Wonnell
Counsel for Municipal Light & Power
Municipality of Anchorage**

**Before the
Joint Committee on Electric Utility Restructuring
Alaska State Legislature
(HCR No. 34)**

August 6, 1998

Introduction

- As ML&P has elsewhere noted, the scope of electric restructuring issues is extremely broad, as demonstrated by the issues which have arisen in other state and federal proceedings to date in the lower-48.
- The Legislature obviously recognizes the magnitude of the Committee's task and the import of its review. In establishing the Committee, the Legislature clearly and correctly set the tone for the legislative inquiry into this topic:
 - “...adequate, reliable, and reasonably priced electrical energy is essential to the daily functions, safety, and economic well-being of Alaskans...”
 - “...electric utility restructuring is a highly complex issue, carrying with it profound implications for all classes of electrical consumers...”
 - “...restructuring deserve[s] detailed, careful and informed decision making by the Alaska Legislature...”
- ML&P's presentation outlines some of the considerations contributing to that complexity. The presentation is organized into 5 topics to promote an appropriate focus on the more important issues, and consists of:
 1. **Basic Principles:** A statement of underlying requirements which any restructuring activity should take into account;
 2. **Industry Restructuring Outside:** An outline highlighting the most significant aspects and assumptions attending the evolution of electric industry restructuring in the lower-48;
 3. **Alaska is Different:** An analysis comparing certain conditions and factors in Alaska to those in the lower-48;
 4. **Additional Problems:** A discussion of three of the many additional matters implicated by electric restructuring; and
 5. **Recommendations:** A listing of specific issues and directions which the Committee and the Legislature may wish to consider.

1. Basic Principles

- **Competition:** Competitive principles should be developed and applied wherever sustainable and wherever the public interest is demonstrably and equitably served thereby.

Competition can promote positive consumer benefits when neutrally applied.

Competition, however, does not automatically provide particular benefits nor distribute such benefits equitably among all classes of consumers.

Competition and deregulation are interrelated, but not necessarily the same thing. No industry is wholly free from regulation.

Competition is a means, not an end. Public policy must distinguish between competition and individual competitors.

- **Change must be synonymous with improvement.**

Electricity affects health, education, and the economy 24 hours a day, 365 days a year.

Safety, reliability and availability are critical issues, easily impacted by the law of unintended consequences.

Alaskans currently enjoy safe, reliable, and available power and have not yet experienced the market-created shortages that have already begun to dot the lower-48 marketplace.

Change should only be undertaken where improvements benefiting the public will result without detriment to particular consumers groups or market segments.

- **Change must not result in discrimination.**

The introduction of change (particularly competition) should benefit consumers in a non-discriminatory fashion.

Changes should not disadvantage those in either remote, rural, or suburban areas, nor provide windfall benefits to specific classes of customers at the expense of other classes of customers.

Quality service, at affordable rates, should remain available or become available throughout all serving areas.

- **Alaskan issues require Alaskan solutions.**

On the one hand, "we don't care how they do it outside" ignores useful experiences and data from other states.

On the other hand, other states do not share Alaska's unique internalities and externalities. Therefore, the interpretation of and reliance upon lower-48 experience and precedent should be tempered.

The results elsewhere have been mixed, frequently falling short of expectations.

Alaska's ability to absorb the negative impacts of such public policy failures is limited.

2. Industry Restructuring Outside

- Electric industry restructuring in the lower-48 developed in a sequential, cause-and-effect way, from changes affecting electric generation (non-integrated sources), to those impacting transmission (wholesale competition), to those now being considered with respect to local distribution.

- **Generation:** Electric restructuring in the lower-48 arises from regulatory and technological changes affecting electric generation.

PURPA created new classes of generation sources, separate from the vertically integrated regulated utility structure. Technology made smaller units more economical, reducing the size/cost/time to construct, further accentuating power generation outside an integrated utility structure.

Multiple, active generators of electrical supply, offering energy under different price schedules, formed the basis of competitive provisioning. Multiplicity in generation sources was further encouraged by the Energy Policy Act of 1992 (exempt wholesale generators).

Currently, many policy makers are concerned that joint ownership of generation facilities and bottleneck transmission facilities (below) presents anti-competitive opportunities which must be addressed through some form of separation, such as code of conduct requirements or asset divestiture. Conversely, divestiture or lesser forms of safeguards (e.g., structural or accounting) may result in loss of economies and efficiencies or in the imposition of unnecessary costs adversely affecting consumer prices.

Another current issue arises from the concern that insufficient competition may exist now or in the future in generation, whereby certain generators may be able to exercise "market power" in a monopolistic or oligopolistic fashion.

- **Transmission:** For consumers to benefit from price differences in generation nationwide, electrical power must be moved from the source to a consumer/buyer located beyond traditional utility boundaries. This implicates facilities and regulatory issues.

Facilities issues: In the lower-48, the transmission of electrical energy across large geographic distances between states is physically possible. The interstate power grid is structured and intertied physically in a pyramid fashion into 5 interconnected areas encompassing 20 power pools and 137 control areas. This arrangement generally permits consumers in one state to access power produced in a different state.

Regulatory issues: Transmission facilities are asserted to be "bottleneck" facilities, in that they cannot be economically replicated or effectively substituted for by competitors. Vertically integrated utilities could arguably use control of the bottleneck transmission facilities (for which there is no competitive market) to favor sales of their own electrical generation (for which there is a competitive market).

Congress in the 1992 Energy Policy Act encouraged Federal Energy Regulatory Commission (FERC) efforts to open up the nationwide electric transmission system to wholesale suppliers. Order No. 888 established open access tariff requirements that provide non-utility wholesalers with access to the grid "comparable" to that afforded by the utility to itself and its affiliates. Order No. 889 provided for the establishment of real-time information systems and a code of conduct to ensure that all parties received non-discriminatory dispatch of their power.

Alternatively, potential discrimination in transmission can be addressed by requiring operation of the transmission network by an independent, non-utility entity, often called an

"independent system operator" or "ISO." The creation, costs, and operations of an ISO are matters still to be tested in the lower-48.

- **Local distribution:** Historically, the typical local electric utility offered electric energy as part of a "bundled" service offering which included (i) the electric energy itself, (ii) delivery of that energy to the customer's premises, (iii) meter reading, (iv) billing, (v) customer services, and other matters.

Under local distribution competition, described as "retail wheeling" or "direct access," electric energy is sold to end users separately from other services ("unbundled").

From the utility perspective, retail wheeling raises many issues. Utility costs and rate processes are not geared to reflect unbundling and pricing of discreet services. Multi-party access to the local distribution system requires extensive operational, financial, and ratemaking adjustments. The local distribution system itself (like the transmission system) is a bottleneck facility, and thus issues concerning equal access, ownership, and operation also arise at this level.

From a consumer perspective, retail wheeling raises consumer information, universal service, and consumer protection issues. Rates for energy may increase as unbundling occurs, since under competition rates are driven towards cost (cost causation, supply and demand). High cost low volume customers may prove unattractive and therefore may be unserved or served at higher prices in a competitive market. Large volume customers (industrial and commercial) may receive more (or all) of the benefits of competition. The appearance of unregulated, non-utility sellers of energy can obscure accountability for service provisioning, create consumer confusion, and result in abuse of consumer interests through improper business practices. Most important, the duty to provide electricity to any customer desiring same must be clearly addressed ("default provider: or "provider of last resort" issues).

- Competition in the local distribution market, where it has been attempted, has been based upon the developments arising in connection with generation and transmission, as described above. Pilot projects are one way among several of transitioning a regulated local market to a competitive one. Incentive regulation, regulatory forbearance, and selected market experiments represent others, but all of these rely on antecedent developments in generation and transmission.

3. Alaska is Different

- Conditions and antecedents in Alaska are significantly different from those in the lower-48. These differences diminish the precedential value of lower-48 competitive efforts and increase the risk of competitive experimentation.

- The total energy market in Alaska is extremely small compared to outside.

In 1996, electric consumption was:

	(Consumers - All Sectors)	(Thousand kWh)
U.S. Total (50 states)	120,002,093	3,097,809,945
California	12,671,531	218,112,485
Idaho	568,180	21,119,253
Alaska	256,103	4,779,562

(Source: "Electric Sales and Revenue 1996," Energy Information Administration, DOE/EIA-0540(96))

The railbelt marketplace, which looks large here, is extremely small comparatively. Competitive factors which work in the lower-48 may not work in a materially smaller, wholly isolated Alaskan market. It may well prove too small to induce enough competing generation to sustain competition, particularly since the lack of a lower-48 intertie (below) prevents the sale of any excess power elsewhere.

- Alaska's system is completely isolated from the lower-48 grid.

Alaska cannot physically participate in the lower-48 marketplace and thus cannot obtain benefits from competitive pricing in such markets.

If competitive policies here should produce declines in the quantity or quality of electric energy, Alaska cannot look to the lower-48 for compensating or emergency sources of power.

- Alaska's system in general, and the railbelt's in particular, is not a true power grid in the sense of the lower-48 interconnected areas.

Within each interconnected lower-48 system, individual utility systems are connected by AC transmission with the same frequency of current at all points within the connected area. Significant constrictions are minimized.

Even with the Northern Intertie, the railbelt system has significant points of constriction and lacks redundancy/alternate dispatch routing in the event of system failures.

Power cannot move in an unrestricted fashion as competitive markets require.

- Alaska has no significant non-utility generation base from which competition in generation could emerge.

In the railbelt, most significant generation is utility-owned and operated.

While the opportunity for increased efficiency exists, imposition of retail wheeling is neither the only nor the best way of going about achieving those efficiencies.

The absence of competitive generators limits the sources of power for market middlemen (marketers, brokers, arbitrageurs, etc.)

- There is no competitive Alaskan wholesale electric market structure comparable to that in the lower-48.

FERC Order No. 888 does not legally apply to Alaska. No federally-mandated, supervised structure for equal access, comparability, and real time information – the underpinnings of a competitive wholesale market – exists here.

The APUC could create one, in theory, but would have to do so from whole cloth.

- Thus, none of the key building blocks upon which competition at the local distribution level is being considered elsewhere exists in Alaska. These differences make a significant difference in charting a course toward restructuring in this State.

4. Additional Problems

- In addition to the absence of a proper foundation, the matter of electric industry restructuring in Alaska raises many other important issues. Three such issues are addressed below, but many more would require the attention and effort of public policy makers.

- **Stranded investment**

Investment becomes “stranded” when the transition to competition reduces the price for which electricity can be sold. At a lower price, only a portion of previously invested capital can earn a fair rate of return. The rest of the invested capital earns nothing and is therefore stranded.

Preliminary consultant estimates place the potential amount of stranded railbelt investment at \$30 – 40 million a year.

If not recovered, serious issues arise, including those legal (confiscation of property; bonding and financing restrictions) and public policy (deterrence to future investment).

Recovery poses significant issues in terms of who pays for the stranded costs (exiting customers, all customers, all market participants, the State?) and how the costs are to be identified and monitored.

- **Public ownership**

Unlike the lower-48, there is no significant investor-owned utility in the railbelt. All electric utilities are owned directly or indirectly by their customers.

MI & P is a division of the Municipality of Anchorage. It is capitalized in part through revenue bonds issued by the Municipality, which bonds contain multiple restrictions on the ownership and use of the assets securing those bonds.

The implementation of competition will generate complex issues concerning the nature of utility ownership in the State. For example, divestiture of generating capacity (being

discussed in the lower-48, as described above) in Alaska would raise serious issues since, in ML&P's case, privatization would first be required.

It is unclear that the State has the power to force such privatization. If it does not, issues concerning bottleneck facilities, open access, and comparability would have to be addressed in some other way.

Further, structural changes in facility ownership, facility operation, the creation of stranded investment, and so on, could implicate existing bond restrictions and requirements. This in turn could impact the credit worthiness of the Municipality, a matter of continuing focus for the Mayor and the Assembly of Anchorage.

- **Rate impacts**

Competition does not necessarily lower rates. Rather, competition tends to drive price towards cost. Where prices are above cost because of inefficiency or lack of competition, then the introduction of competition may lower those prices.

On the other hand, where prices are above cost because of public policy (e.g., implicit subsidies of one group of ratepayers by another group), the introduction of competition may destroy the basis for such subsidies. Some rates may go down, but others will go up.

Further, the benefits of price declines may not be equitably distributed. High volume/low cost consumers (e.g., businesses) may be able to bargain for advantages where high cost/low volume users (e.g., non-urban consumers) lack such bargaining power and could suffer higher prices.

Equally important, universal service policies could be impaired, in at least two ways. Increases in the price of electric energy may come to exceed the ability of individual consumers to pay. In the alternative, for some market segments (e.g., small communities located away from major transmission lines or poorer segments of urban areas) market forces may cause no competitive carrier to offer any electricity for sale. Some provisions for a "default carrier" or "provider-of-last-resort" would be required.

5. Recommendations

In light of these considerations, ML&P recommends that the Committee proceed in the "detailed, careful and informed" manner set forth in the Resolution. This would include:

- **Take steps in an orderly sequence**

The available experience of other states indicates that electric industry restructuring can and should be undertaken in a sequence of steps. At each stage, goals can be set, progress measured, and results assayed. The next step could then be pursued or forestalled as the empirical evidence gathered from the preceding step justifies. In this manner, the Committee maximizes the opportunity for achieving public benefits at each stage while minimizing the potential for serious error and harm to the public which overreaching could entail.

The logical and practical approach to restructuring in Alaska would entail the following three stages of activity -

Stage 1 - Power Pooling The power pooling concept, already under examination by the APUC (Docket U-97-140), focuses upon the improved coordination of utility generating resources and dispatch as a way to lower the effective cost of electric energy to Alaskan consumers.

Potential benefits include economy in dispatching power; attenuation and economies in future investment cycles; reduction of operating and generating risk; reduction in financial risk (through reduced costs of capital); and more equitable distribution of economic benefits among customer classes.

Successful pooling will also provide the regulatory and operational experience upon which the next stage of restructuring could be considered.

Stage 2 - Wholesale competition Building upon the pooling experience, wholesale competition may (or may not) prove feasible and a desirable means for securing additional consumer benefits. Like pooling, wholesale competition offers the prospect of more equitable distribution of consumer benefits. Unlike pooling, however, wholesale competition may raise issues (system operation, generation ownership, stranded investment, etc.) which cannot be solved at present on the basis of available experience, and may prove intractable in this market.

Stage 3 - Retail competition ML&P believes that for retail competition to be practicable, it must be grounded upon the restructuring included in the previous two stages. As with the prior stages, retail competition should be considered only when it can be established that the public interest benefits to be derived outweigh the costs and risks associated with the restructuring.

- **Utilize agency expertise.**

The Legislature should remain focused upon the overall role and effects of electric industry restructuring on the State as a whole. For example, as other states have done, the Legislature should consider commissioning a study of key variables in restructuring and the impacts of these on the State's economy and specific segments thereof.

The mechanics of restructuring could effectively be referred to the Alaska Public Utilities Commission. The Commission has already begun an inquiry into power pooling and has opened a general docket on restructuring issues. Further, the APUC has already demonstrated in a series of orders over the past 18 months its ability to address changing industry patterns in telecommunications. The Commission and its Staff have the resources and expertise to explore electric restructuring issues in more depth and breadth than the Legislature or this Committee reasonably can be expected to acquire or devote. Coordination between the Commission and the Legislature can be effected as the Legislature desires, including recommendations for changes in the APUC's powers.

- **Focus on Consumers**

The Committee and the Legislature will hear much from existing and would-be industry participants. While their input is essential, their interests are diverse. Their views should be balanced against the larger public interest benefits (if any) which must result from a particular proposed course of restructuring.

Retail competition is elsewhere being built on wholesale competition, which in turn was built on competitive generation. Retail wheeling is the tail, not the dog of electric restructuring.

Alaska's railbelt electric utilities are consumer owned, directly or indirectly. Financial impacts from changes can be far-reaching and severe in their consequences. The potential for \$50-60 million per year in stranded cost recovery requirements is a clear example and warning.

Competition does not produce lower rates for everyone, and may produce higher rates for some.

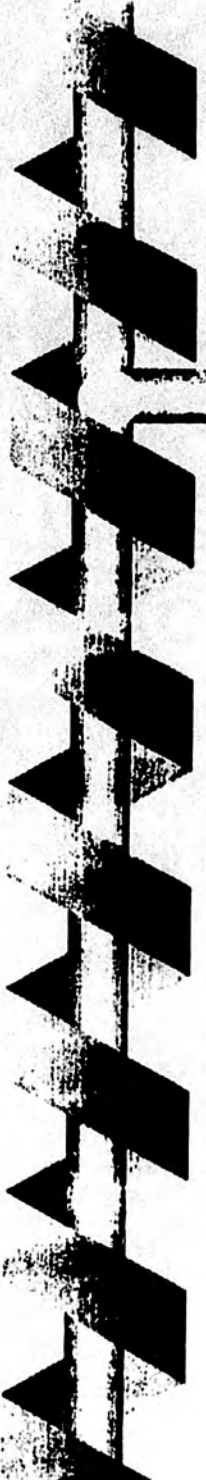
Although it seems large in relative terms, the Alaska railbelt energy market is quite small. It is also quite isolated. Mistakes in policy cannot be easily absorbed, and cannot be spread at all.



Aurora Power Presentation

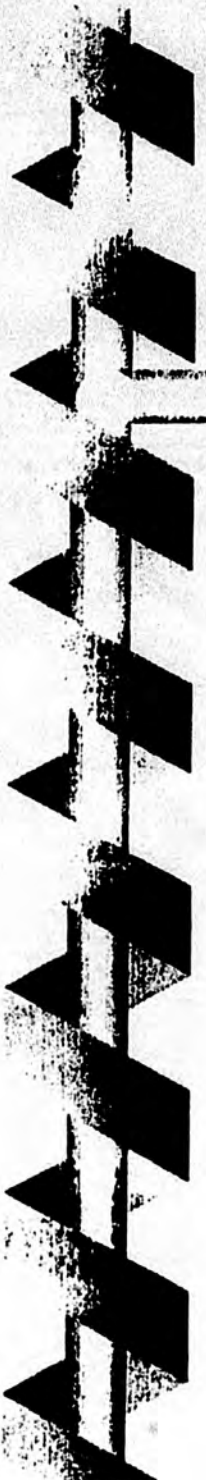
**“Joint Committee on Electric Utility
Restructuring “
August 6, 1998**

Legislative Presentation



Agenda

- ⊗ **Aurora Power**
- ⊗ **The Time is NOW**
- ⊗ **Benefits of introducing competitive forces**
- ⊗ **Various approaches**
 - **Study**
 - **Pilot Program**
 - **Full Retail Wheeling**
- ⊗ **Pilot Program**
- ⊗ **Legislative Considerations**



Description of Aurora Power

- **Established in 1994 as an Alaskan Company**
- **Largest independent Natural Gas Marketer in Alaska**
- **Sells natural gas to over 700 large commercial users**
- **Provides an avenue for competitive pricing of natural gas in the marketplace, resulting in substantial savings to end-users.**
- **Introduce restructuring in the electric industry**



The Time is Now

- ⊗ **Competition in Electricity**
- ⊗ **PILOT PROGRAM to accompany STUDY**
- ⊗ **Market vs. Regulation to determine the Price**
 - **“cost- based tariffs”**
 - **market model based on price**
- ⊗ **Economic Dispatch**



Benefits of Competition

- **Lower price**
- **Stimulates innovation / technological improvements**
- **Provides an avenue for “Customer Choice”**



Necessary Components of Competition in Electricity

- ⦿ **Willing Buyers and Sellers of Electricity, at rates and structures different than available today**
- ⦿ **Unbundling of Generation, Transmission, Distribution and Services components**
- ⦿ **Resolve Billing and Metering issues prior to FULL Competition**



Various approaches to introduce competitive market forces

- **Study**
- **Pilot Program**
- **Full Retail Wheeling**



Electric Industry Restructuring - Box Score and Existing Pilots

⦿ Retail Wheeling Pilots - the first 6

- Central Illinois Light Company (CILCO)**
- Illinois Power Company (IP)**
- Massachusetts Electric Company (MECO)**
- New Hampshire utilities**
- Orange & Rockland Utilities, (O&R)**
- Washington Water Power Company (WWP)**

Findings of Pilots

- **Pilots are valuable**
- **Technical implementation issues are important**
- **Receptivity to pilots differs by customer class and size**
- **Participating customers are content with Pilots**
- **Need for customer education**
- **Aggregation worked**
- **Accurate load profiles are needed**
- **Below-Cost offers existed**
- **Design of Pilots has been evolutionary**
- **Price is dominant**



Objectives and Goals of the Pilot Program

- **Reduce electric rates to consumers**
- **Allow competitive choice for consumers**
- **Educate and prepare consumers for a competitive retail marketplace for electric generation and capacity**
- **Test on a limited basis the effectiveness and readiness of the generation, transmission and distribution systems for a competitive marketplace**
- **Preserve and promote reliability, safety, and consumer protection**



Aurora Power - Pilot Program

- ⦿ **Limited Scope - 35MW**
- ⦿ **Limited Time - 2 years**
- ⦿ **Power Supplier- Wholesale Power Tariff**
- ⦿ **CEA/ML&P - Unbundled Transmission and Distribution**
- ⦿ **Qualified Power Marketer**
- ⦿ **Consumers in the Anchorage Service area can participate through any Qualified Power Marketer**
- ⦿ **Consumer Protection**
- ⦿ **Informational Reports furnished to the APUC on results of the pilot program**



Legislative Considerations

- **Pilot Program to accompany any study**
- **Test on a limited basis the readiness of the generation, transmission and distribution system to react to a competitive environment**
- **Separate Rural and Railbelt Issues**
- **Realize that Businesses, Organizations and Consumers want Competitive Choice Now**
- **Act in a timely manner**

STATE OF ALASKA
THE ALASKA PUBLIC UTILITIES COMMISSION

COPY

Before Commissioners:

Sam Cotton, Chairman
Alyce A. Hanley
Dwight D. Ornquist
Tim Cook
James M. Posey

In the Matter of the Application by Aurora)
Power Resources, Inc. to Establish a Pilot Program)
to Allow the Limited Competitive Sale of)
Electric Power in the Chugach)
Electric Association, Inc. and Municipal Light &)
Power Service Areas)
)
)
)

U-98- _____

**AURORA POWER RESOURCES, INC.'S APPLICATION TO ESTABLISH A PILOT
PROGRAM TO ALLOW THE LIMITED COMPETITIVE SALE OF ELECTRIC
POWER IN THE CHUGACH ELECTRIC ASSOCIATION, INC. AND MUNICIPAL
LIGHT & POWER SERVICE AREAS**

I. INTRODUCTION

Pursuant to 3 AAC 48.600-.660, Aurora Power Resources, Inc. ("Aurora") respectfully requests the Alaska Public Utilities Commission ("Commission") approve a limited pilot program ("Pilot Program") to permit the limited competitive sale of electric power to consumers in the Chugach Electric Association, Inc. ("CEA") and Anchorage Municipal Light & Power ("ML&P") service areas ("Application"). The Pilot Program will provide consumers the benefits of competitive choice and reduced electric costs. The Pilot Program will also provide an opportunity for the Commission and its Staff to introduce competitive choice on a limited basis and thereby gain the knowledge necessary to consider the public interest in allowing full electric retail competition in Alaska.

The Pilot Program is consistent with the federal and state trend of allowing competition, direct access, and consumer choice within regulated industries. Throughout the nation, both federal and state regulators are allowing competitive forces to shape the marketplace of virtually every regulated industry including the natural gas industry, the telecommunications industry, the crude oil transportation industry, and both the wholesale and retail electrical power industry. In the wholesale and retail electrical power industry, this national trend has resulted in radical and long-lasting changes in the way consumers purchase their power.

Consistent with this national trend, the Commission has allowed or is considering retail competition within every industry it regulates. The Commission has allowed retail competition to varying degrees for natural gas transportation, telecommunications, crude oil transportation, and refuse. The Commission has approved several special contracts for the wholesale competitive sale of electric power throughout the Railbelt in Alaska. The Commission has also established a general regulatory docket for the purpose of considering the retail competitive sale of electric power within Alaska.

II. THE APPLICANT

Aurora is the largest, independent natural gas marketer in the Anchorage marketplace and has developed a great deal of direct experience in bringing the benefits of competitive choice to Alaskan consumers.¹ Aurora has already brought the benefits of competitive choice and reduced natural gas costs to a great many consumers including several agencies of the State of Alaska,

¹ Aurora does not own or operate any physical plant, pipeline, or system and is, therefore, not a public utility as defined in AS 42.05.990(4) and is not required to obtain a certificate of public convenience and necessity under AS 42.05.221(a).

municipalities, school districts, a university, major hospitals, and other governmental, nonprofit, and for-profit consumers. Aurora would be a qualified power marketer under the Pilot Program. Aurora has aggregated electric consumers representing approximately 25 MWs of electric power. In its capacity as a qualified power marketer, Aurora will purchase electric power under the terms of the Pilot Program for sale to its customers.

III. THE PILOT PROGRAM

A. Objectives of the Pilot Program

The Pilot Program is designed to achieve the following specific objectives:

- * Reduce electric rates to consumers;
- * Allow competitive choice for consumers;
- * Educate and prepare consumers for a competitive retail marketplace for electric generation and capacity;
- * Encourage development of a competitive retail marketplace for electric generation and capacity;
- * Test on a limited basis the effectiveness and readiness of the generation, transmission, and distribution systems for a competitive marketplace; and
- * Preserve and promote reliability, safety, and consumer protection.

In accomplishing these specific objectives, the Pilot Program will provide the Commission and other interested parties with the information and experience necessary to reshape the electric marketplace in Alaska from a marketplace based solely on monopoly regulation to a marketplace based, to the degree practical, on competitive choice.

Pilot programs have been used successfully in several other areas. Attached for the Commission's benefit as Exhibit A to this Application are the relevant portions of a survey

prepared by the Edison Electric Institute on the status of the various pilot programs throughout the nation. Aurora will supplement these portions with a complete copy of the survey as soon as it becomes available. In summarizing its observations on the benefits of a pilot program, Edison Electric Institute observed:

Pilots are Valuable. The fundamental finding from our review is that all the pilot utilities felt that the programs were worthwhile. . . . At least one utility representative said conducting retail programs was essential before the advent of full competition. Learning how to prepare for full competition is less disruptive when retail access is offered to only 3% of customers. Another utility said that, "every utility should do a pilot to learn."

Technical Implementation Issues are Important. Some of the interviewed utilities have indicated that the true value of pilots is the ability of the utility to understand, learn and develop procedures to accommodate customer choice, schedule customer meter readings, and process load profile estimates.

Participating Customers are Content With Pilots. Although there have been cases of customer confusion and dissatisfaction with levels of savings, customers are generally content with their decision to participate in the pilot. In most cases, their expectations have been met. One of the few pilot program surveys on customer choice and participation was conducted in New Hampshire, and it indicates strong customer satisfaction.

Aggregation Has Worked. Attempts to aggregate customer load were tried in most of the pilots. It was found to be successful and valuable especially when the pilots were focused on specific geographic areas.

Exhibit A at 16-17.

B. Description of the Pilot Program

1. Overview

The Pilot Program is designed to provide consumers with competitive choice. The Pilot Program will allow consumers located in the CEA and ML&P service areas to participate through any qualified power marketer. To qualify as a power marketer in the Pilot Program, a power marketer will have to (1) notify the Commission of its intention to participate at least 60 days prior to hearing, (2) demonstrate through prefiled testimony it has accumulated and subscribed an electric load of no less than 5 MWs nor more than 25 MWs from the CEA and ML&P service areas, and (3) fulfill any registration or bonding requirements which may be imposed by the Commission prior to participating in the Pilot Program. The Pilot Program will be limited to a maximum load of 35 MWs. The term of the Pilot Program will be two years. At no time during the Pilot Program will a consumer be charged (on average) more for electric power than that consumer would have otherwise paid under existing tariff rates. During the term of the Pilot Program, any qualified power marketer will be required to regularly provide the Commission with informational reports. These informational reports will be in whatever form and contain whatever information the Commission may deem most helpful.

2. Competitive Model Proposed Through the Pilot Program

The competitive model proposed through the Pilot Program may only be understood by considering the separate elements associated with providing electric service to the consumer. Essentially, electric service is comprised of five basic elements: (1) power generation; (2) power transmission; (3) power distribution; (4) consumer services; and (5) energy sales and marketing.

For any competitive model to work, CEA's and ML&P's electric services must be unbundled into separate service elements. Following is a brief description of each of these elements as well as a description of the impact of the Pilot Program on each element.

a. **Power Generation:** Power generation is the process and related services associated with producing electrical power. Under the Pilot Program, qualified power marketers would be allowed to collectively purchase up to 35 MWs--roughly 10 percent of the 350 MWs of total retail electric load in the CEA and ML&P service areas. These purchases would be on a competitive basis from any power supplier. Essentially, the Pilot Program allows competition among power suppliers for approximately 10 percent of the total electric load in the CEA and ML&P service areas.

b. **Power Transmission:** Power transmission is the process and related services associated with moving large amounts of electricity from the generator site to the general location where it will be consumed. Under the Pilot Program, there will be limited transmission of bulk electric energy between the CEA and ML&P service areas. This transmission will be on the existing facilities owned by CEA and ML&P. The qualified power marketer will be responsible for arranging this limited transmission of bulk electric energy. The Commission will need to continue to regulate rates to be charged by the electric utility for transmission.

c. **Power Distribution:** Power distribution is the process and related services associated with moving electric power from the bulk transmission lines to the consumers' location. Under the Pilot Program, power will be delivered to selected points of delivery on the

transmission/distribution facilities of either CEA or ML&P. The qualified power marketer will be responsible for arranging the distribution of electric power with the electric utility, either CEA or ML&P, which owns the distribution system used by the participating consumer. The Commission will need to continue to regulate rates to be charged by the electric utility for distribution.

d. **Customer Services:** Customer services are the services associated with the activities that are needed by customers in order to receive electric power. These services include adding and terminating service, meter reading, billing, collection, and emergency service restoration. Under the Pilot Program, CEA or ML&P will continue to be responsible for the emergency service restoration in their own service areas and the qualified power marketer will be responsible for arranging or providing all other customer services. The rates for all customer services except for emergency service restoration (the costs of emergency service restoration are included within the cost of transmission or distribution) will be fully competitive.

e. **Energy Sales and Marketing:** Energy sales and marketing are the services associated with marketing electric power to the participating consumer. These services include marketing, sales, and education directed at the participating consumer. Under the Pilot Program, energy sales and marketing will be performed by the qualified power marketer. The rates for these services will be fully competitive.

3. Subscription in Pilot Program

To allow power marketers an opportunity to qualify for participation in the Pilot Program, each power marketer will have until the date set by the Commission for prefiled testimony in which to aggregate and subscribe retail electric consumers for the Pilot Program. In the event the Pilot Program is oversubscribed, each qualified power marketer will be allowed to sell a prorated share of the 35 MWs of total retail electric load available to the Pilot Program. The prorated share will be based on each qualified power marketer's subscribed retail electric load, which may be no less than 5 MWs nor more than 25 MWs.

4. Rates for Electric Power

As noted above, under the Pilot Program, any power supplier may provide electric power to qualified power marketers. To compliment these power sales, the Commission should require power suppliers to file a wholesale bulk power tariff under which any qualified power marketer may purchase electric power and related services at wholesale bulk power rates. The Commission should also allow power suppliers and qualified power marketers to enter into special contracts under which power suppliers may sell qualified power marketers electric power and ancillary services at wholesale bulk power rates.

5. Rates for Transmission and Distribution

As noted above, under the Pilot Program, CEA's and ML&P's services will need to be unbundled to allow a competitive marketplace to develop. Thus, the Commission will have to continue to establish rates for those unbundled services for which there continues to be a natural

monopoly while at the same time allowing the marketplace to establish rates for those unbundled services for which there is no natural monopoly.

For the purposes of the Pilot Program, rates for power generation, customer support services, and energy sales and marketing will be competitively determined. Competition between CEA, ML&P, and other power suppliers may be trusted to establish more competitive rates for power generation. Likewise, competition may be trusted to establish competitive rates for support services and energy sales and marketing services.

Competition, however, may not be trusted to establish competitive rates for transmission and distribution. These services require the use of the existing transmission and distribution systems for CEA and ML&P. Just and reasonable rates for transmission and distribution services have already been determined in operating agreements, participants' agreements, and cost-of-service studies. For the purposes of the Pilot Program, the Commission should set unbundled rates for transmission and distribution based on these existing agreements and cost-of-service studies.

IV. CONSUMER IMPACTS

A. Consumer Benefits

The Pilot Program will result in both immediate benefits to participating consumers and long-term benefits to all consumers. Participating consumers should realize cost savings of approximately 10 percent as compared to what they would have paid absent the Pilot Program. In addition, the introduction of competitive forces into the electric marketplace may be expected to result in the more efficient utilization of power generation and lower costs for all consumers

over time. These benefits may be expected to be shared by a broad range of consumers. Currently, Aurora has residential, small commercial, and large commercial consumers under contract who are willing to participate in the Pilot Program.

B. Consumer Protection

The Pilot Program will allow any participating consumer to terminate participation on 30-days' notice. If a participating consumer elects to terminate participation or if the qualified power marketer fails to arrange or provide service for the consumer, the consumer will simply return to his original electric provider. The Pilot Program will also provide that a participating consumer may not be charged any more than he would otherwise have been obligated to pay absent participation in the Pilot Program. Finally, the Commission may also require registration and consumer bonding from qualified power marketers who wish to participate in the Pilot Program.

V. UTILITY IMPACTS

The Pilot Program is geographically restricted to the CEA and ML&P service areas and quantitatively restricted to 35 MWs or 10 percent of the total electric retail market of approximately 350 MWs. As the result, the Pilot Program will not impact utilities nearly as much as allowing full retail competition. The Pilot Program will, however, do a good job of foretelling and defining the issues both CEA and ML&P will have to confront if the Commission determines that full retail competition is in the public interest.

CEA and ML&P will be impacted in a similar manner relative to the services they provide. For both, the primary risk is that their customers will have a choice which may be

exercised to the customers' own economic benefit and to the utilities' economic disadvantage. This risk may be expected to result in greater efficiency for CEA and ML&P and lower costs for their consumers.

VI. QUALIFIED POWER MARKETERS

To qualify as a power marketer under the Pilot Program, a power marketer will have to

- (1) notify the Commission of its intention to participate at least 60 days prior to hearing,
- (2) demonstrate through prefiled testimony it has accumulated and subscribed an electric load of no less than 5 MWs nor more than 25 MWs from the CEA and ML&P service areas, and
- (3) fulfill any registration or bonding requirements which may be imposed by the Commission prior to participating in the Pilot Program.

Establishing a minimum electric load for qualification as a power marketer under the Pilot Program is also an important requirement for the Pilot Program to be successful. A 5 MW minimum load will avoid the regulatory burden associated with monitoring an unlimited number of power marketers with no substantial load in so limited a Pilot Program.

In addition, the Commission may see fit to require qualified power marketers to register with the Commission and provide consumer bonding to ensure the public's trust and confidence in the Pilot Program.

VII. AFFILIATE RULES

Existing power suppliers who provide electric power and services to affiliated, qualified power marketers should be allowed to do so under a set of affiliate rules which prevent existing power suppliers from taking unfair advantage of their position as a power generator to gain or maintain market share as a qualified power marketer. The affiliate rules should ensure a level playing field between affiliated, qualified power marketers and independent, qualified power marketers. Among other broad-based affiliate rules, the Commission should provide that any affiliated, qualified power marketer must purchase electric power and services from its affiliated power supplier under the same wholesale bulk power tariff which is available to independent, qualified power marketers.

VIII. IMPLEMENTATION OF THE PILOT PROGRAM

A. Commission Authority

The Commission has full regulatory authority to approve and implement the Pilot Program. AS 42.05.141(a), (a)(1), (a)(2), and (a)(3) grant the Commission full regulatory authority to regulate every public utility to the extent not preempted by federal law. Moreover, AS 42.05.151(a) grants the Commission the authority to adopt regulations which are not inconsistent with the law. AS 42.05.221(d) contains the only restriction to the Commission's authority to allow competition and provides that the Commission may act to disallow competition only when that competition is found to be not in the public interest. Clearly, the Commission may act to approve and implement a limited pilot program to allow participating consumers, representing only 10 percent of the total electric market, a choice.

B. Request for Expedited Consideration

Aurora respectfully requests the Commission to expedite its consideration of the Pilot Program and not to allow the broader issues associated with the complete restructuring of the electric industry to allow full retail wheeling in Alaska to bog down its consideration of the Pilot Program. By its nature, the Pilot Program is designed to provide an efficient opportunity from which to further consider full retail wheeling in Alaska. If the Commission allows the broader issues associated with full retail wheeling to be considered at the same time, the efficiencies of the Pilot Program will be diminished. For its part, Aurora believes the limited approach advanced in the Pilot Program has merit and will more efficiently focus the Commission's future consideration of full retail wheeling.

C. Commission Action Necessary to Implement Pilot Program

To approve and implement the Pilot Program, the Commission should (1) open a "U" docket to consider this Application, (2) establish an expedited procedural schedule, (3) require and approve wholesale bulk power tariffs, (4) set unbundled rates for the transmission and distribution of electric power within the CEA and ML&P service areas based on their existing cost studies and contracts, and (5) approve the terms and conditions of the Pilot Program.

IX. CONCLUSION

The Pilot Program is a reasoned and measured approach to the introduction of competitive forces into the electric marketplace in Alaska. The Pilot Program will provide participating consumers the benefits of competitive choice and reduced electric costs and will provide the Commission and the stakeholders in the existing electric market place with the

knowledge and experience necessary to fully consider the public's interest in full electric retail competition in Alaska.

Dated: _____

BRENA, BELL & CLARKSON
Attorneys for Aurora Power Resources, Inc.

By _____
Robin O. Brena
Kevin G. Clarkson
310 K Street, Suite 601
Anchorage, Alaska 99501
(907) 258-2000

VERIFICATION

I, Robin Brena, being first duly sworn upon my oath, state as follows:

I am an attorney for Aurora Power Resources, Inc. in the above-referenced matter. I have read the foregoing document and know the contents thereof to be true and accurate to the best of my knowledge and belief.

DATED this _____ day of June, 1998.

Robin O. Brena

SUBSCRIBED AND SWORN TO OR AFFIRMED before me this _____ day of June, 1998.

Notary Public in and for Alaska
My Commission Expires: _____

+ .
Testimony of Robert A. Wilkinson
Before the Joint Legislative Committee on
Electric Utility Industry Restructuring
August 6, 1998

My name is Robert A. Wilkinson, and I am the General Manager of Copper Valley Electric Association, Inc.

Thank you Senator Sharp, Representative Rokeberg, and members of the Committee for allowing me the opportunity to testify before you today.

I am here today as a representative of the Purchasing Utilities of the Four Dam Pool. Prior to making specific remarks pertaining to Four Dam Pool concerns about restructuring, I would offer some brief general comments on behalf of the Four Dam Pool utilities.

Restructuring of the electric utility industry in Alaska is an enormous undertaking with far reaching and potentially serious consequences. While this industry sees possible benefits from competition, and in fact, many Alaska utilities are already delivering economic and improved service benefits to customers in preparation for industry change we also see many unanswered questions. We believe the following basic principles should be kept firmly in mind as you weigh the benefits and impacts of restructuring.

- ◆ All customers should be treated equitably.
 - ◆ All potential power suppliers should be held to the same standard of reliability and safety, as are utilities.
 - ◆ Suppliers of last resort, in the event of shortages, should be clearly determined.
- And finally,
- ◆ Stranded costs must be fairly addressed.

The information accumulated on this subject is voluminous. The U.S. Congress, and virtually every state, either through the legislative process or through their public utility commission, is dealing with this issue. The one thing we know for certain is that the more we as utilities learn about electric industry restructuring, the more questions we have. Four Dam Pool utilities say, what's the rush? Numerous studies and pilot programs are under way nationwide. We urge this Committee to conduct deliberate, scientific, and thorough study prior to coming to any conclusions, and we suggest the appropriate strategy is to watch what others are doing so that we may learn from their experiences.

You have no doubt heard countless times that Alaska is unique, which brings me to a subject, which is truly a one of a kind - The Four Dam Pool. The Four Dam Pool is comprised of four state-owned hydroelectric projects operated by five utilities that serve Petersburg, Wrangell, Ketchikan, Kodiak Island, Valdez, and the Copper River Basin. These utilities, together with the Alaska Energy Authority, entered into a 45-year Power Sales Agreement in 1985. Effectively, the utilities pool the costs to operate the four projects and then sell energy at a postage stamp rate back to the individual utilities.

Ratemaking in the electric utility industry, in its most simplistic terms, involves dividing the operation, maintenance, and debt-service costs by energy sales to produce a retail rate.

This is a very capital-intensive business, and the fixed costs of operations generally represent a very large percentage of any utility's operating costs.

We are all familiar with the term "stranded investment." While each Four Dam Pool utility is concerned with their own stranded cost in a competitive environment, we are collectively concerned that the Long Term Power Sales Agreement represents additional stranded investment to the utilities and the State as well. Under the energy program for Alaska, the State invested many hundreds of millions of dollars in the Four Dam Pool, in part, in exchange for the Long Term Power Sales Agreement, which provides a revenue stream of 4¢ kwh on sales from the four hydro projects. In the face of retail competition, utilities could lose energy sales to competing providers, which could reduce sales from the Four Dam Pool projects. Should this occur, not only will the State lose the 4-cents-debt-service revenue, but with a declining denominator in the rate equation, the cost of Four Dam Pool power to the utilities will rise as well, and ultimately, so will the rates of those utilities who under the Long Term Power Sales Agreement are required to purchase all output these projects can generate.

Finally, I mentioned earlier many utilities are looking inwardly for ways to improve service and reduce the price of electricity in anticipation of the new competitive environment, and I want to share some of those activities with you by Four Dam Pool members.

Ketchikan is trying to put together the Southeast Intertie project which will electrically connect the Tyee and Swan Lake hydro projects allowing the Four Dam Pool utilities, as well as the State, to benefit from the underutilized Tyee project.

Kodiak is currently developing a steam-turbine-cogeneration project with the United States Coast Guard aimed at saving the government and Kodiak customers' money.

Copper Valley is developing a combustion-turbine-cogeneration project with a Valdez refinery aimed at reducing the cost of power for all 3,300 CVEA customers.

The Four Dam Pool is currently conducting a study for more efficient economic dispatch of the two Southeast hydros.

The point I would like to drive home here is that utilities are proactively working on developing competitive solutions to the problem of high-cost energy in coastal Alaska.

In closing, Alaska cooperatives and municipal utilities have done business as regulated monopolies for over 50 years. Transition to a competitive environment may or may not be good for Alaskan ratepayers. We urge this Committee to carefully and deliberately evaluate this extraordinarily complex issue. The Four Dam Pool utilities stand ready to participate in this process, and we pledge our assistance to the effort. Thank you for the opportunity to speak to you today on this very important issue.

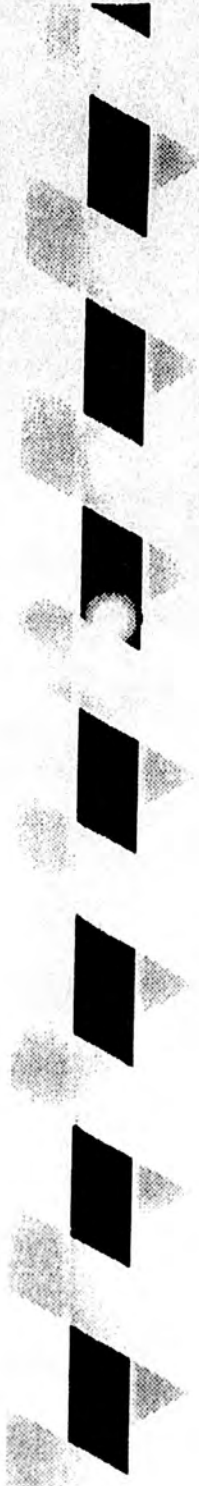


Electric Industry Restructuring

ARECA REPORT, August 6, 1998

ARECA Topic

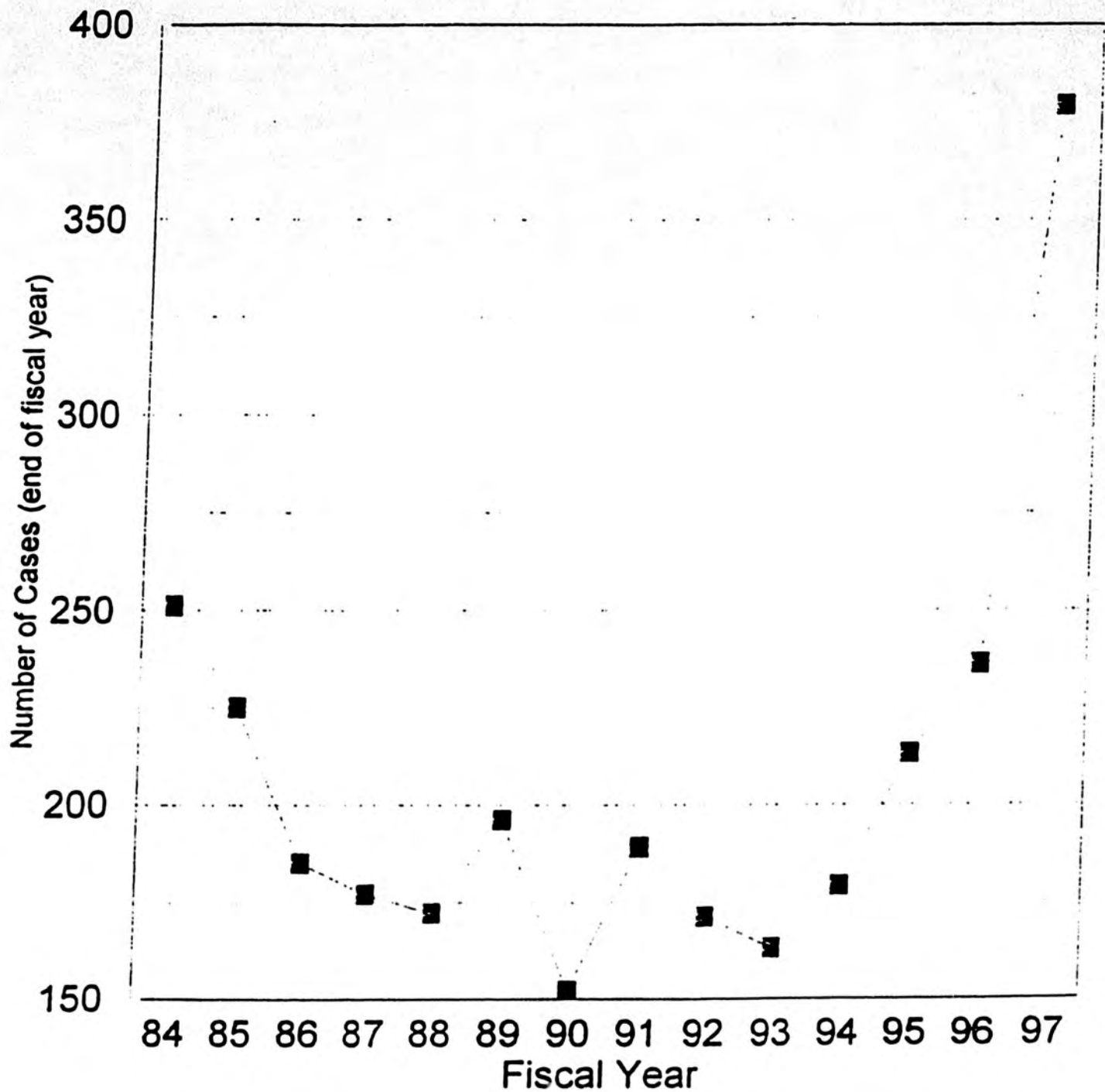
- State and Federal Activity on Utility Deregulation
- The Electric Utility industry in the State of Alaska
- Important Issues for the State of Alaska
- Standards for the State of Alaska
- Summary



Electric Utility Deregulation

- **Deregulation**
 - **Reregulation**
 - **Retail Wheeling**
 - **Restructuring**
 - **Customer Choice**
 - **Retail Competition**
 - **Unbundling**
- 

APUC Formal Caseload



Deregulation

National

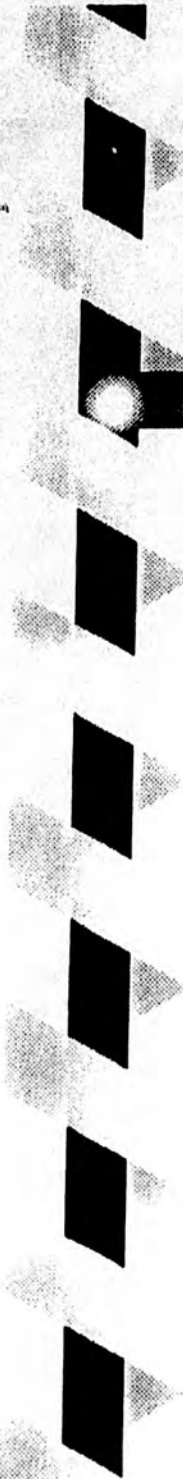
- **Gas pipelines**
- **Communications**
 - **Airlines**
- **Electric Utilities (???)**

State



Federal Legislation Pending

- **HR 1119 & S 936**
 - **HR 655 Dan Schaefer**
 - **S 237 Dale Bumpers**
 - **S 1401 Slade Gorton**
 - **S 487 Frank Murkowski**
 - **S 687 Jim Jeffords**
 - **S 1276 Jeff Bingaman**
 - **S 1230 Tom DeLay**
 - **HR 1359 Peter DeFazio**
 - **S 722 Craig Thomas**
 - **HR 1960 Edward Markey**
 - **Murkowski Hearings**
- 



State Activity – Retail Wheeling

- **14 States enacted restructuring legislation**
- **6 State PUC's issued orders**
- **26 States studying**
- **5 States – No Action**

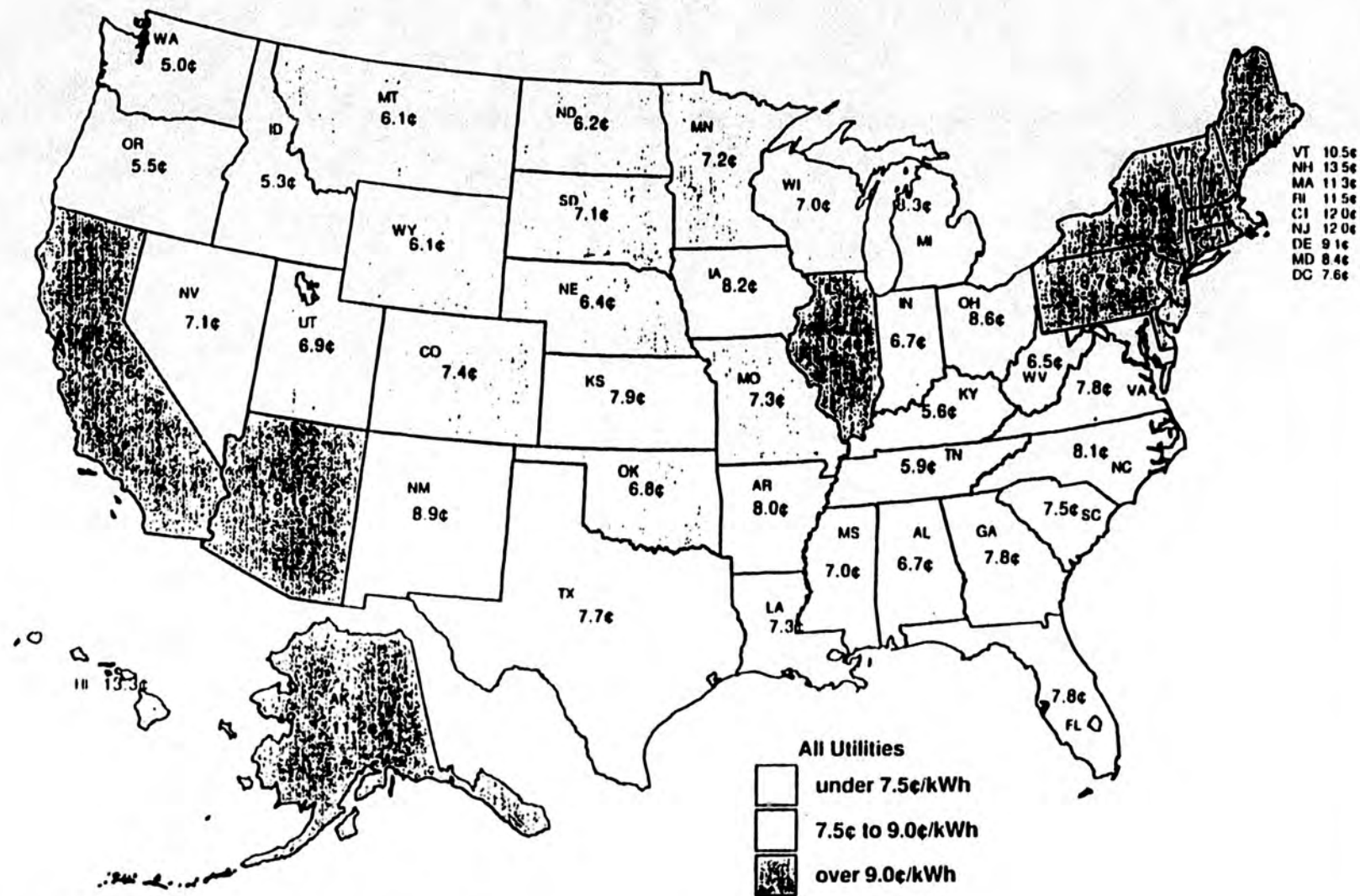


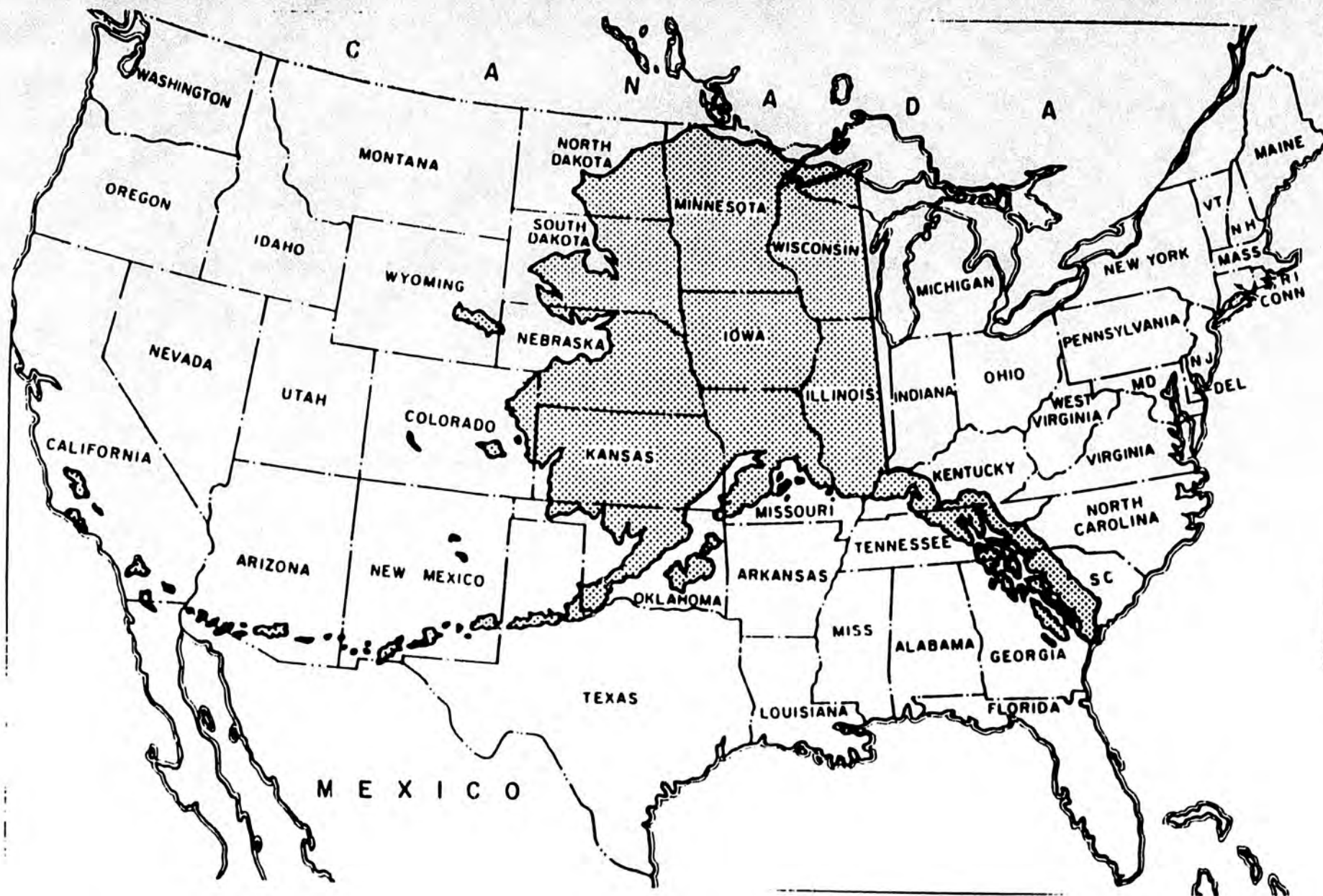
State of Alaska Efforts to Restructure

- **SB 54 Service Area Protection**
- **HB 235 Cautious Deregulation**
- **HB 287 Anchorage Area Deregulation**
- **HCR 34 Legislative Subcommittee**
- **SB 355 Anchorage Area Deregulation**
- **Regulatory-APUC Docket R-97-10**
- **Regulatory- Various Open Dockets**



Residential Rates cents per kWh

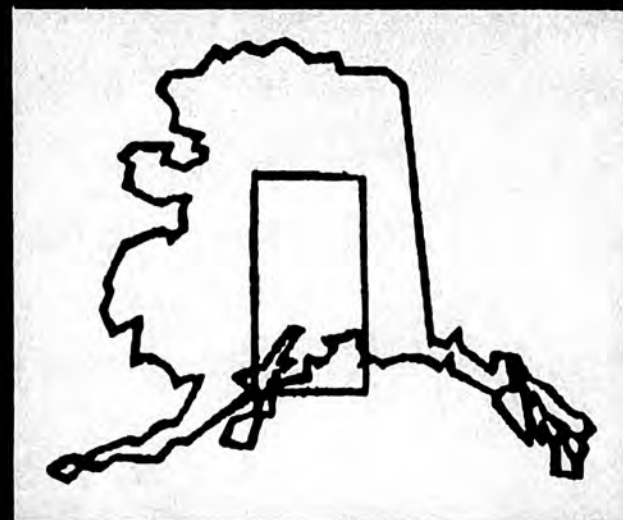
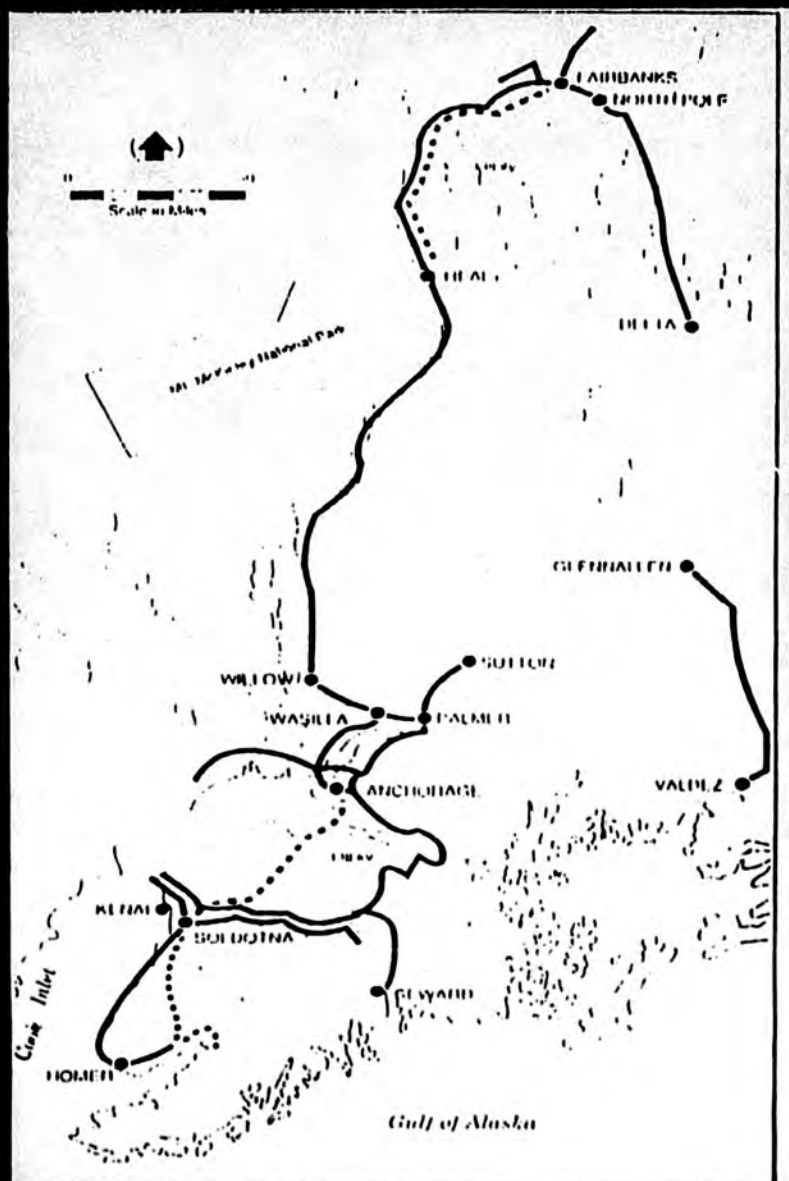




Electric Utility Rates

	<u>Residential</u> ¢ /KWH	<u>All Class</u> ¢ /KWH
<u>U.S. Average</u>	8.4	7.6
<u>Alaska</u>	11.2	10.1
CEA	9.5	8.4
ML&P	9.8	8.3
GVEA	9.8	8.8
Rural	>40.0	

Minimal Transmission Grid



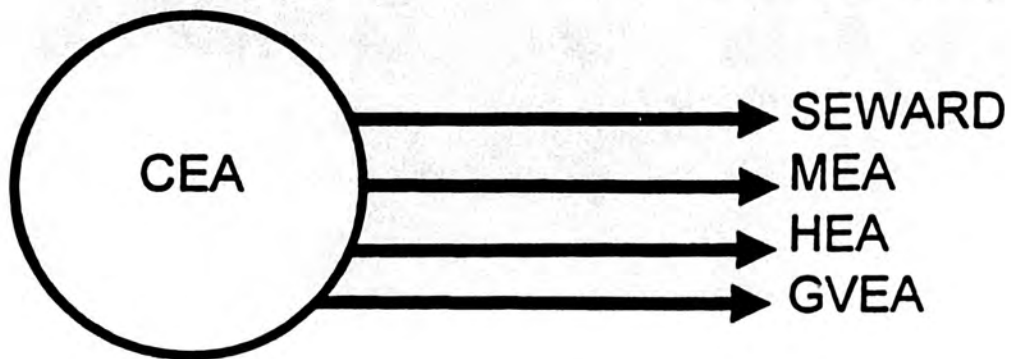
Railbelt Area

- Existing Transmission Lines
- Bradley Lake Transmission Lines
- - - Proposed Northern and Southern Transmission Lines

RAILBELT GENERATION

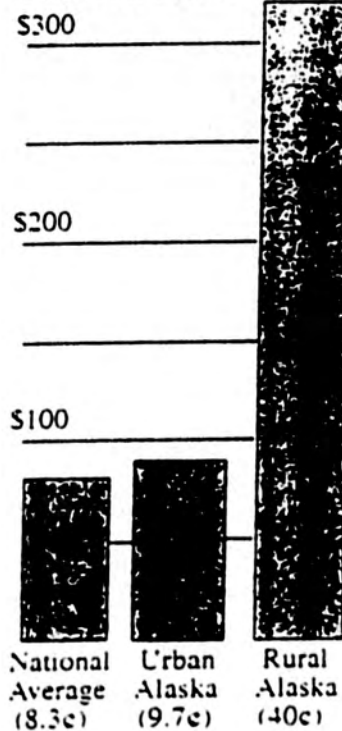
Self
Generation

Wholesale
Generation



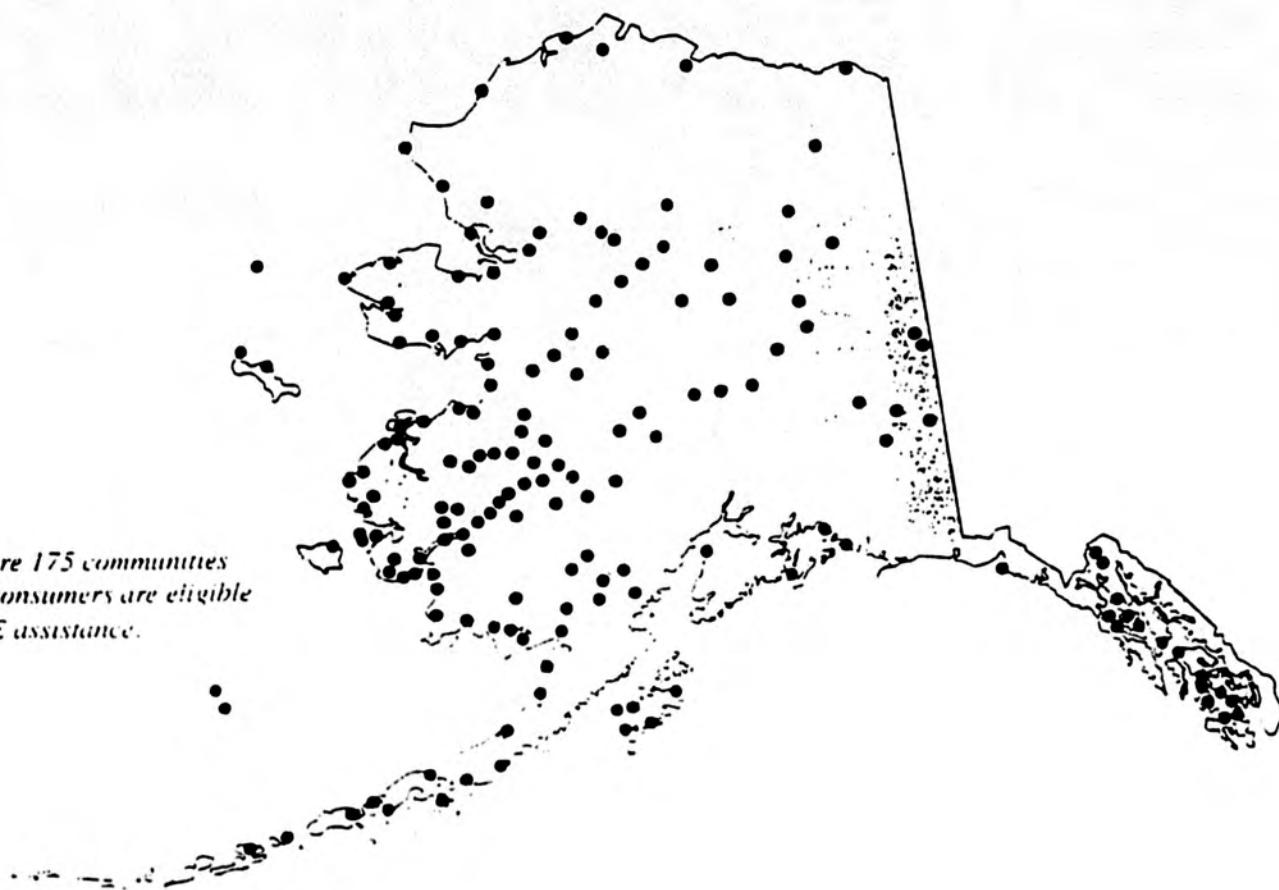
Electricity Costs

Dollars Per Month

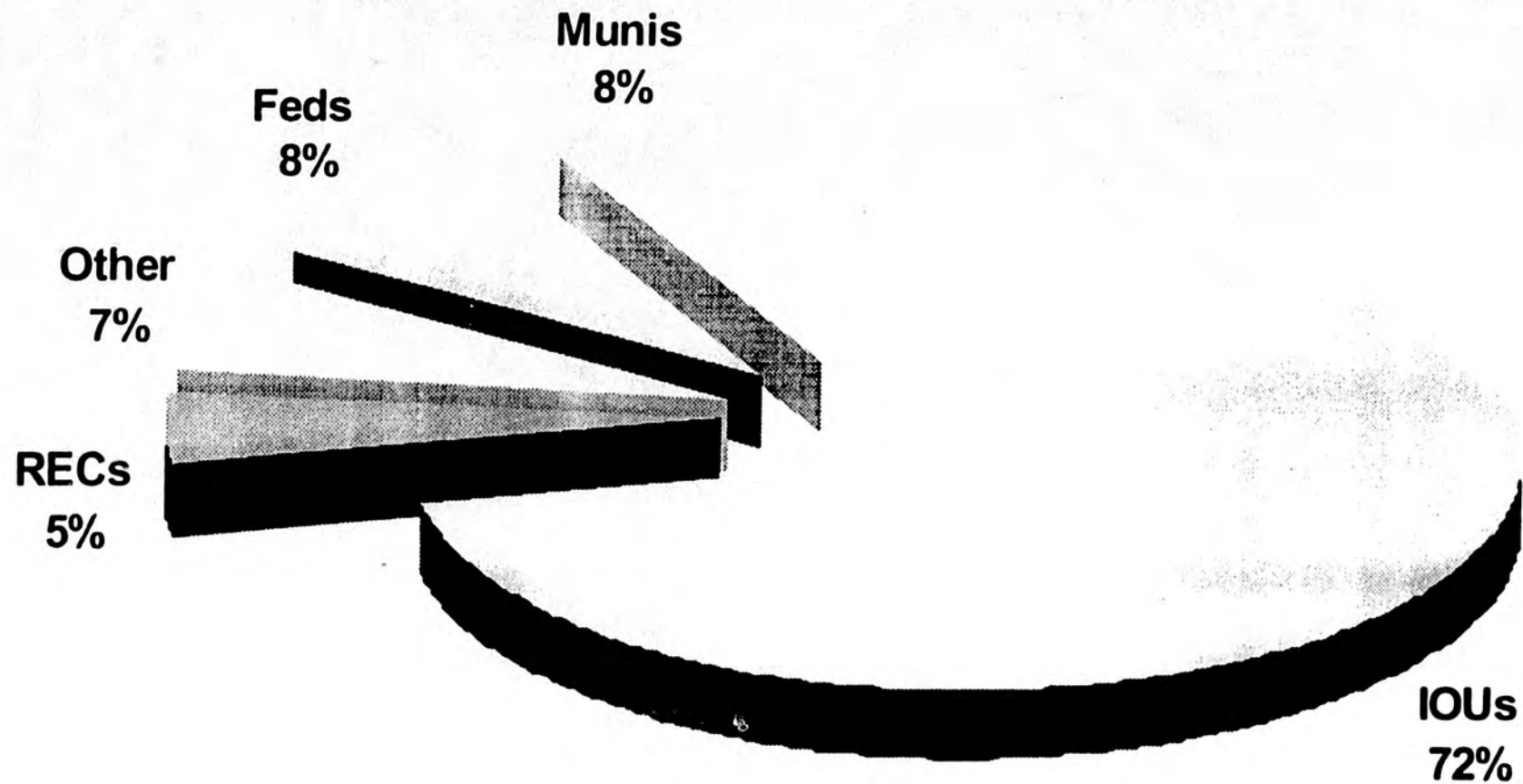


1995 Cost per Kilowatt-Hour
Based on National Average
822 Kilowatt-Hours Per Month

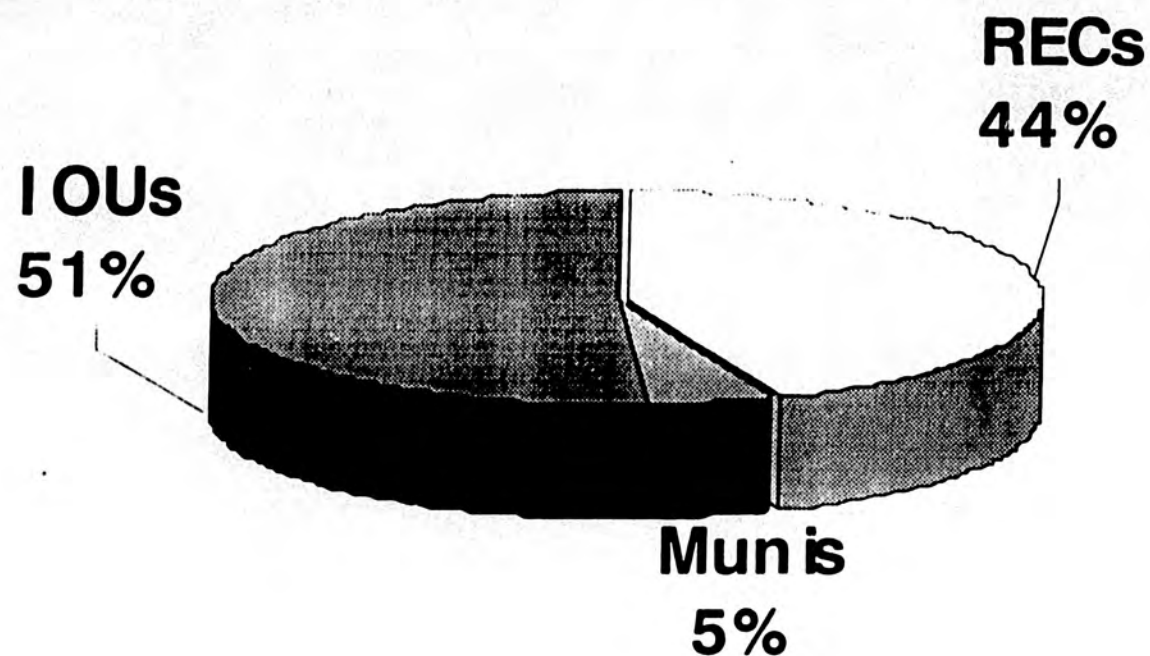
*There are 175 communities
where consumers are eligible
for PCE assistance.*



U.S. Generation



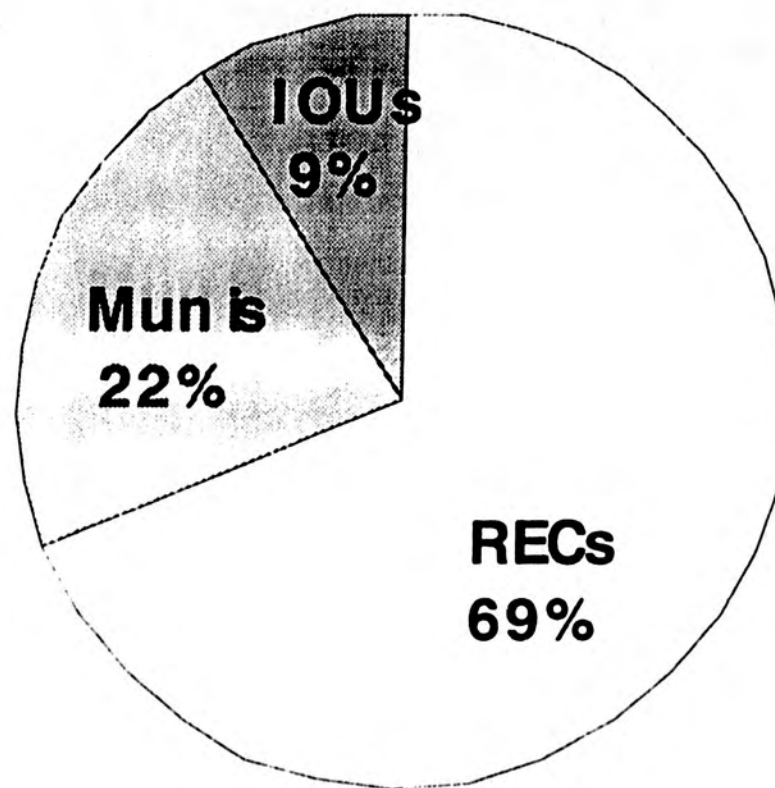
U.S. Distribution Line Miles



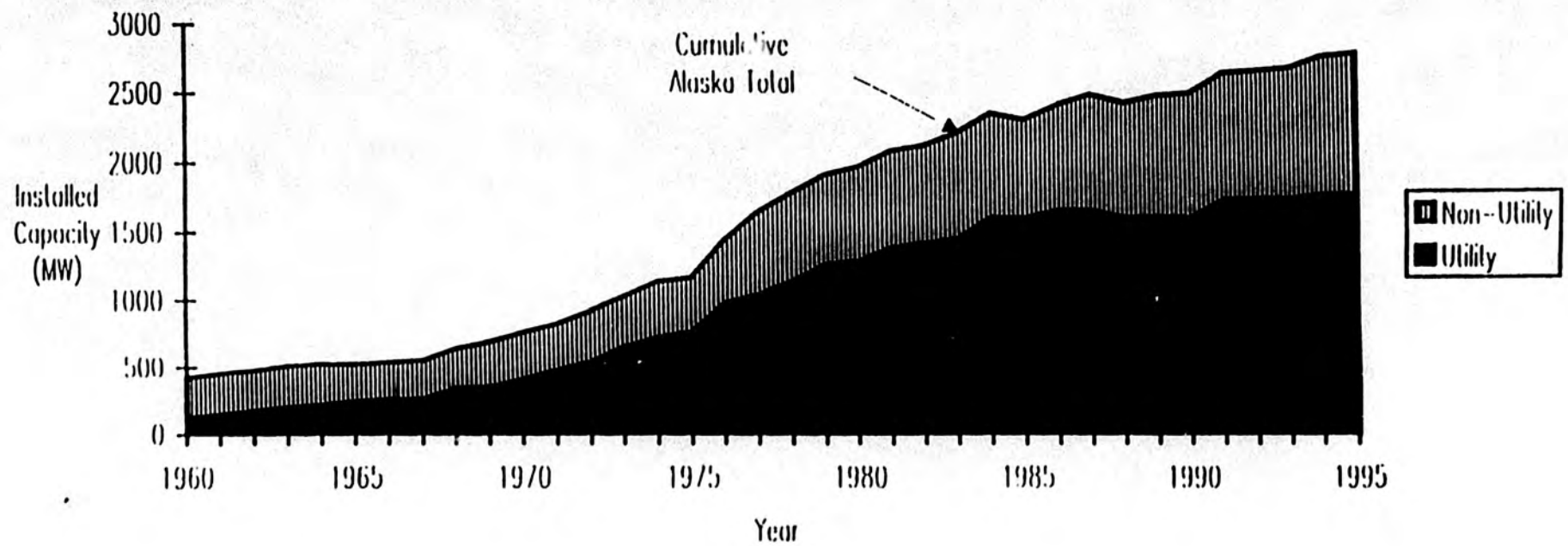
U.S. Total 4.7 Million Miles

Alaska Electric Utilities

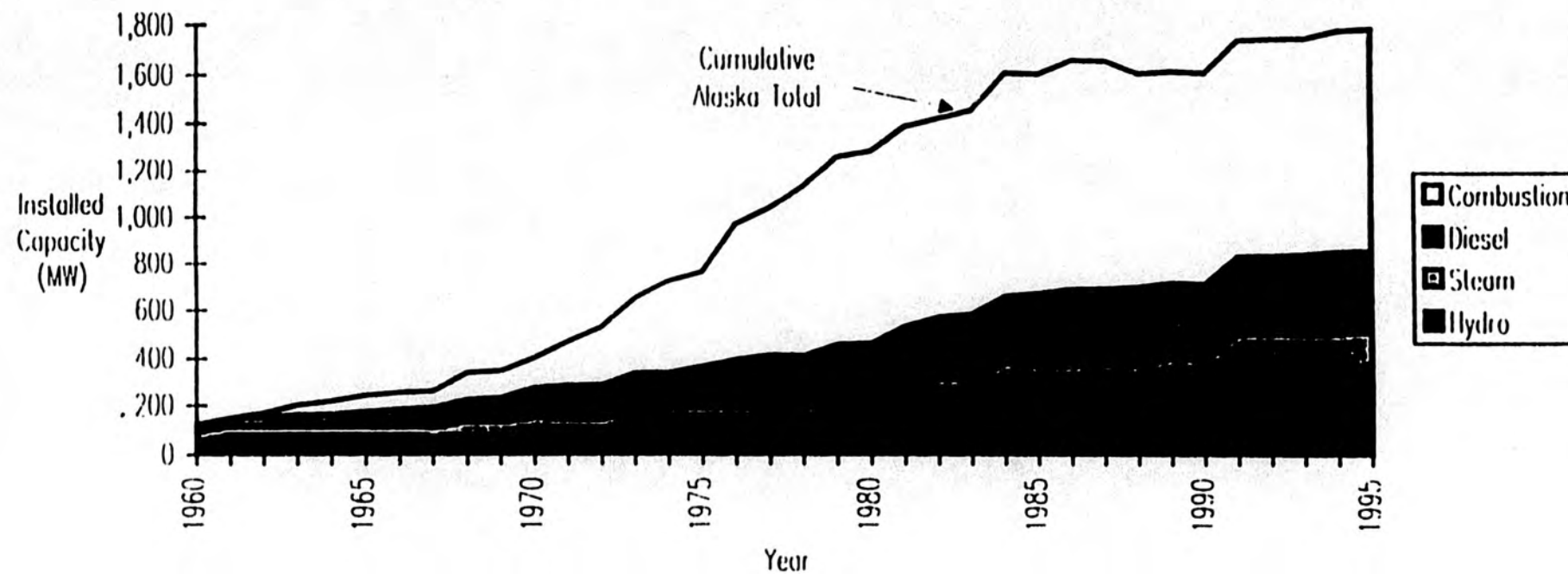
Residential Customers Served



Alaska Installed Capacity
Historical Summary
Utility and Non-Utility
(1960 - 1995)

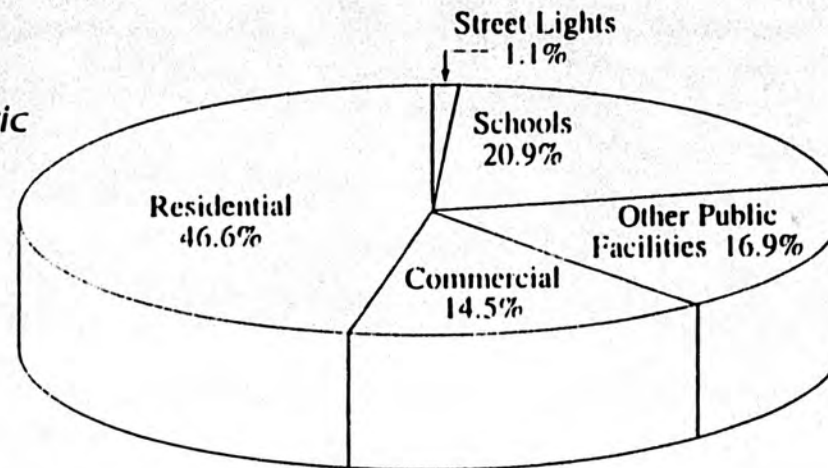


Alaska Utility Installed Capacity
by Prime Mover
(1960 1995)

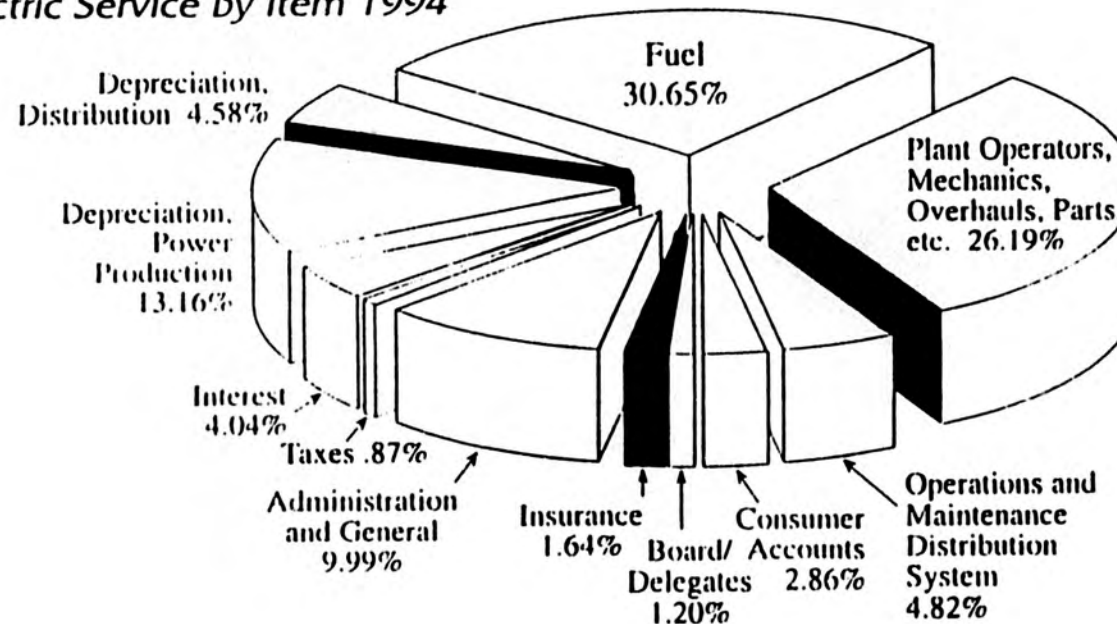


The Cost of Power

**Alaska Village Electric
Cooperative (AVEC)
Source of Electric
Revenue 1994**



**AVEC Total Cost of
Electric Service by Item 1994**

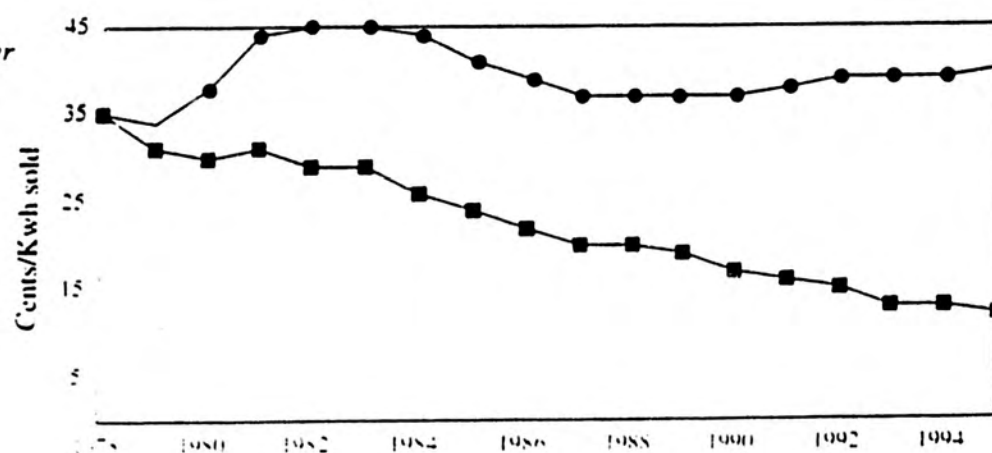


In 1978, the Alaska Village Electric Cooperative sold electricity for about 35¢ per kwh. The rate was 40¢ per kwh in 1995 — but only 12¢ per kwh in 1978 dollars.

- Actual cost
- Costs adjusted for inflation using the Consumer Price Index

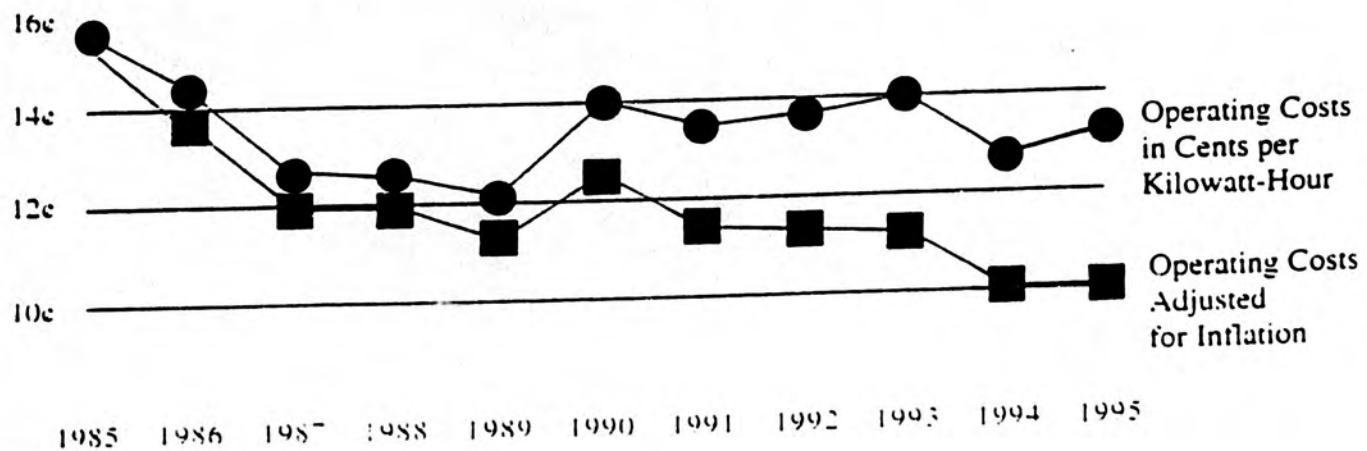
AVEC Average Revenue Per Kwh Sold

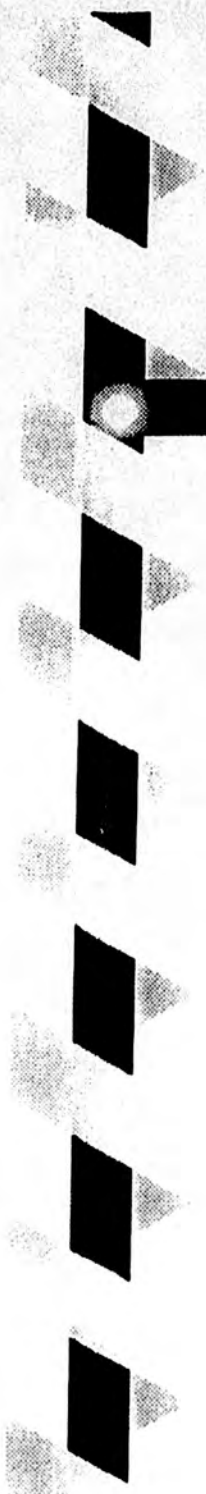
AVEC has reduced the real cost of power to consumers.



Operating Costs for Utilities Receiving PCE, 1985 to 1995 (does not include fuel costs)

Rural utilities are winning the battle against inflation. Through efficiency improvements and other means, PCE utilities have reduced operating costs by about one-third since 1985.





Deregulation Issues

- **Monopolization (Market Presence)**
- **Cherry Picking**
- **Stranded Cost**
- **Obligation to Serve**
- **Universal Service (PCE)**
- **Reliability**
- **Tax-exempt status**

Principals adopted by
National Association of Regulatory Commissioners

1. Assign states the responsibility for determining "the extent of and pace for expanding choice for customers under their regulatory oversight."
2. Maintain universal service at reasonable rates, as well as the safety, reliability, quality and sustainability of electric service.
3. Protect customers from anti-competitive behavior and other malfeasance.
4. Preserve or improve the quality of the environment.
5. Stranded investment that result from existing regulatory and legal requirements should be addressed in a fair and reasonable manner by the states.

Power and Generation Committee (G)

ELECTRIC INDUSTRY RESTRUCTURING — The National Rural Electric Cooperative Association should protect the interests of consumer-owners and their cooperatives by participating in congressional legislative actions to ensure inclusion of essential provisions. These provisions would protect and advance the interests of the consumers, while doing no harm to cooperatives or other rural electric systems in any state.

- All consumers must be treated equitably.
- If stranded costs are to be recovered, they should be recovered in a competitively neutral manner, without placing an undue burden on residential and small business customers.
- All energy providers – not just utilities – must be subject to the same standards as utilities.
- All consumers must have universal access to affordable electric service.
- Reliability and safety must not be jeopardized.
- Exclusive distribution service areas must be maintained to avoid duplication of electrical facilities.
- There must be a transition and educational period before full consumer choice is implemented.

As consumer-owned utilities, we are concerned by efforts on both the state and national levels to restructure the electric utility industry without providing appropriate safeguards for all consumers. Without such safeguards, these efforts may result in degradation of system reliability, negatively affect long-range planning and the ability to provide reliable service to remaining ratepayers at reasonable cost. Such efforts, whether on a state or national level, threaten to damage both consumers and their cooperatives. (98-G-1)

Restructuring
Concepts and Principals for Alaska

- Recognize Unique features of Alaska's system
- Vast sections of the State are not interconnected
- Uniform standards for all energy providers
- Maintain Exclusive distribution service areas
- Universal access to affordable electric service
- Role of "supplier of last resort" must be clearly defined
- Stranded costs must be addressed
- The issue of wholesale contracts must be addressed
- Any proposed pilot program must be carefully planned

Conclusions

- Adopt uniform standards
- Protect all consumers
- Consider no restructuring for Rural Utilities
- Conduct a third party economic assessment aimed at creating a template for restructuring the industry
- Be objective enough to conclude that restructuring may not be appropriate for Alaska yet

Elizabeth A. Moler, Chair

Federal Energy Regulatory Commission

March 20, 1997 before Senate Energy Committee

Moler said Congress should promote choice at the retail level. "Direct the states to establish consumer choice programs, but with the opportunity to opt out if a state determines that retail competition is contrary to its own needs and interests."

Doug Lattner, Utility Consultant with Deloitte & Touche

Dow Jones article on deregulation of electric utilities.

March 25, 1997

“I foresee a market containing only about 10 major power generators in 10 years’ time – much like the six or seven major airlines that exist now.”

August 6, 1998

**Testimony to the Joint Committee on Electric Utility Restructuring
from Bruce D. Scott, CREC, Director of Member and Public Relations
Matanuska Electric Association, Inc.**

Senators, Representatives, and members of the audience, I thank you for this opportunity to offer a few comments on the subject of utility restructuring to the Joint Committee on Electric Utility Restructuring. My name is Bruce D. Scott and I'm the director of member and public relations for Matanuska Electric Association, Inc., called MEA by its members.

Incorporated in 1941, MEA is a nonprofit electric cooperative that serves more than 29,000 members in Southcentral Alaska. Our service area is 3,360 square miles, nearly the same size as the 2.2-million-acre Yellowstone National Park, twice the size of Delaware and three-fifths the size of Connecticut.

We have nearly 35,000 active accounts and more than 2,966 miles of line. Last year, we built 56 miles of new line and 1,248 new services, or hookups, and look forward to continued growth this year and for the foreseeable future.

Matanuska Electric Association has not yet taken a position on whether retail competition is good, bad or indifferent to the interests of our consumer-members. Our major reason for such a stance is that we think one needs to build the cart, and make sure the wheels work, before hooking up the horse. In this instance, the "cart," if you will, is competition on the wholesale side of the electric utility market. I'll come back to this point in a few minutes.

The argument for deregulation of the electric utility industry could be stated as follows: The consumer should have the right to choose from whom he buys the product we sell, electricity.

By virtue of having that choice, the argument goes, consumers will pay less for the product. The argument, simply stated, is that where two merchants are offering the same item for sale, the two will compete to have the lowest cost item for sale. This is why the Sam's Clubs and Costcos and Wal-Marts of the nation thrive, the argument goes.

Now, I realize I'm simplifying here – there are time constraints to my testimony – but these stores owe much of their power to compete to the trucks, barges and airplanes that bring them their products – along highways, oceans and the atmosphere – from the Lower 48 and other countries, where several companies manufacture each of the products they sell in their warehouse stores.

Testimony by Bruce D. Scott, CREC
for Matanuska Electric Association, Inc.
Page 2
August 6, 1998

In the electrical utility industry, our product is transported via electrical interconnections. In the Lower 48, these interconnections span the nation, creating electrical highways from state to state. Unfortunately, the interconnections in Alaska – unlike in the Lower 48 or the aforementioned highways, oceans and atmosphere – cannot link up across interstate or international lines.

Wal-Mart may be able to buy the T-shirts it sells you from New York, Los Angeles, or Hong Kong. Their computer paper could come from Canada or an East Coast paper mill.

Electric utilities in the Lower 48 may be able to buy the electricity they sell you from Florida, Georgia or New Jersey on the East Coast, or from California, Nevada or New Mexico on the West Coast. Theoretically, at least, they could buy electrical energy from New York and sell it to you in San Diego, California.

In Alaska, the electricity our industry buys comes from Alaska, Alaska ... or Alaska. As Alaskans, our power suppliers are both insulated and isolated from the rest of the electric utility world: Insulated in that there are no electrical interconnections with the outside world; isolated in that Alaska's power suppliers have historically planned their respective power supply and transmission systems independently.

In the Lower 48, the choices are first and foremost choices between wholesale power suppliers. Where retail competition is being attempted, it is only after the retail supplier has the option to choose its own wholesale supplier, or a mix of wholesale suppliers.

And this right of "retail choice," if you will, is not being extended unilaterally. California is a state with 30 million people and is frequently considered to be "on the cutting edge" of electric utility deregulation. In California, electric cooperatives are exempted from the California Public Utility Commission regulations that mandate head-to-head competition among utilities, as directed by A.B. 1890, the California restructuring legislation.

There are no investor-owned utilities in the Railbelt, where the overwhelming majority of the state's electricity consumers reside. Statewide, most residents receive their electricity from cooperatives, with municipal utilities ranking second and IOUs a very distant third.

As I have stated in past testimony to other bodies – none as august as this one, of course – we are a "captive" market for one of our most likely competitors, should retail competition be allowed. All of MEA's electricity is purchased under contract from Chugach Electric Association. This contract, and others similar to it, was negotiated and signed in a day when electric utilities were guaranteed an exclusive service territory. Since these contracts account for more than 50 percent of our costs, we have a hard time envisioning any sort of level playing field for competition if those contracts are allowed to stand.

To refer back to my Wal-Mart example, this is as if Wal-Mart was the only T-shirt manufacturer in business, and manufactured the T-shirts it sold to both Wal-Mart and Costco, its competitor. Guess which T-shirt would cost less? And although the shirt on your back may be important, electricity is more of a necessity.

If one is to have competition, it must first come at the wholesale level. One should set up the mechanism to allow for competitively priced wholesale electricity, then see that competition works at that level, before going on to retail competition. First the cart, then the horse. It is for this very reason that the APUC is currently in the final stages of a comprehensive study examining the issue of pooling generation resources in the Railbelt. That study, by the national consulting firm of Black & Veatch, is due out later this year.

We understand this committee is charged with two tasks: First, determining whether competition is good for electric utility consumers in Alaska; and second, if it is, how to implement electric utility restructuring.

As you wrestle with these issues, we would like to consider the seven points made by the Power and Generation Committee of the National Rural Electric Cooperative Association. NRECA is a national association representing MEA and approximately 1,000 other electric cooperatives.

1. All consumers must be treated equitably.
2. If stranded costs are to be recovered, they should be recovered in a competitively neutral manner, without placing an undue burden on residential and small business customers.
3. All energy providers – not just utilities – must be subject to the same standards as utilities.
4. All consumers must have access to affordable electric service.
5. Reliability and safety must not be jeopardized.
6. Exclusive distribution service areas must be maintained to avoid duplication of electrical facilities.
7. There must be a transitional and educational period before full consumer choice is implemented.

With these points in mind, I wish to emphasize my earlier statement that MEA has not yet taken a position on whether retail competition is good, bad or indifferent to the interests of our consumer-members. However, we do hold one position firmly: that our membership should be protected against unfair, unscrupulous actions masquerading as "competition."

In the Lower 48, large commercial power users – customers – are the driving force for competition in the electric industry. In Alaska, the prime forces clamoring for competition are not customers, but a large electric utility that wishes to take customers

Testimony by Bruce D. Scott, CREC
for Matanuska Electric Association, Inc.
Page 4
August 6, 1998

and revenues from other, smaller utilities, and power brokers who want to take revenues from everybody.

Like its sister cooperatives, MEA is obligated to provide service to anyone in our service territory that requests it. If these boundaries were to be opened to competitors, in all likelihood they would attempt to serve our high-margin, low-cost customers, the larger businesses, the urban population centers. They would not battle us for the low-margin, high-cost customers, the ones who pose a credit risk or those who are just plain inconvenient to serve for factors of density and distance.

Because we are a member-owned cooperative, our rates are designed so that each customer pays his or her "fair share" of our total costs -- no more, no less. If we lose a customer to the sort of predatory "cherry-picking" described above, we can expect two things to happen.

First, although we no longer will have to purchase wholesale power for that customer, the price we pay for the wholesale power we sell to our remaining customers will go up. This is because we pay our supplier their overall average cost, and less sales do not translate into corresponding cost reductions at the power plants.

Second, MEA's direct costs -- such as O&M, general and administrative and depreciation -- stay the same. This means that these remaining costs must now be recovered through fewer units of sales, fewer kilowatt-hours, which also translates into higher rates for our remaining customers.

Losing high-margin, low-cost customers will have the effect of driving up MEA's costs to serve low-margin, high-cost customers.

There is, of course, the possibility that MEA could acquire additional revenue by serving other utilities' high-margin, low-cost customers. But, to refer back to the T-shirt analogy, as a captive customer at the wholesale level, how could we possibly compete under the existing contractual framework?

In conclusion, if it is determined that electric utility restructuring is good for Alaska, then we believe this committee should analyze the benefits, risks and the impact on the organizations and the ratepayers of any proposed restructuring. If at the end of the day, there are sufficient benefits to justify the risks, then you will see MEA standing up to go forward.

Matanuska Electric Association, Inc.
163 E. Industrial Way
Palmer, Alaska 99645
(907) 745-3231

Competitive "We Believes" for GVEA -July, 1998
Mike Kelly, President and CEO

We believe that competition in the electric industry in Alaska will generally provide lower cost and better service to the consumer in the long-term.

We believe that GVEA maintains very competitive rates and service when compared to any electric utility in the state. We believe that we must become globally competitive and that doing so will involve exciting challenges and painful change.

We believe that when a consumer announces that he or she can get lower cost service from another source, we should be interested enough to roll up our sleeves and see if we can help.

We believe that any adjustment to the competitive and regulatory environment in Alaska should be approached with the consumers' long range preferences in mind. It will be a challenge to faithfully represent the consumer in this matter - particularly when the preference of one consumer class may cause a negative impact on another and when a particular benefit for the consumer may appear to have negative consequences for the utility or its directors and employees.

We believe that Alaska is comprised of several economic sectors containing markets that range from relatively mature to very immature. A single competitive solution may not work for all.

We believe we can learn to thrive across the complete spectrum, from total service area protection to total deregulation (including no APUC), using only our elected co-op Board for regulation.

We believe that new business ventures are critical to GVEA's becoming the energy and services provider of choice for our present

and future consumers. Regulation may be a clumsy surrogate for competition in these ventures.

We believe there are benefits to be gained from Alaska watching and learning from electric utility deregulation successes and failures as they unfold in the lower 48. We believe GVEA's member-owners will be advantaged by a slow and careful approach to deregulation.

We believe that if electric service territory protection is to be abandoned in Alaska, that the order of preference is as follows:

- 1. Southcentral**
- 2. Railbelt**
- 3. Bush**

We believe our members are very satisfied with the status quo. Our acquisition of FMUS and our service and rate competitiveness have generally stopped the clamor for service territory elimination in our area. However, we believe our member-owners will not be so satisfied five years from now if we do not change our utility significantly. We are excited and confident concerning our future.

0 11/1/98
Bjornstad
CEA

The Legislature Sets Policy

I would like to begin by reading a quote by a Railbelt Electric Utility Manager on October 21, 1996, "One thing is certain and that is that the customer can't lose as a result of competition." This was not Chugach speaking although we believe it to be true.

Another quote is equally enlightening "The transition to competition holds an enormous challenge and opportunity for electric utilities. Like any new development change can be profitable if you're positioned to take advantage of it. ML&P is!" (1996 Annual Report - Published 1997)

You are here to investigate and make written recommendation on two burning questions.

1. Whether to implement electric utility restructuring in Alaska.
2. How to implement electric utility restructuring in Alaska

Chugach believes the answer to the first question is intuitively obvious. Restructuring implies allowing competition. Competition is a cornerstone of American business. Competition makes for new ideas, better customer service, innovation, efficiency, reduction in costly regulatory oversight, and added value to customers and shareholders.

The consequence of elimination or restriction of competition is an important issue of public policy.

We all know that one of the most important functions of the legislature is to set the **broad policy** of the state. It takes nothing away from the important work of regulators and technicians to say that their job is to implement the broad policy decisions of the legislature.

We will be suggesting that today's discussion will be most productive if it is kept at a high level of broad policy. The issue for you should not be how to implement competition or restructuring. The legislature sets policy, the APUC implements it.

The question is very timely because we have a recent order from our regulators, the APUC, which interprets the policy you, the legislature, has set for them to follow.

In your notebook under the tab entitled "APUC Authority" you can see the comparison of Legislation Policy Guidance and the PUC interpretation of its authority. It is apparent that the PUC understands that the legislature intended to displace competition and delegated to the PUC the policy making of when to eliminate or implement competition.

Legislative Policy Guidance

The only statutory reference to competition is in A.S. 42.05.221 (d) which says:

"In an area where the commission determines that two or more public utilities are competing to furnish identical utility service and that this competition is not in the public interest, the commission shall take appropriate action to eliminate the competition and any undesirable duplication of facilities."

The statute goes on to describe some of the measures the APUC can employ, including creating service area boundaries and eliminating duplication of plant.

PUC Interpretation of its Authority

In the recent APUC proceeding Chugach asked the APUC to conclude that service territories are not exclusive except when the APUC acts to limit competition pursuant to A.S. 42.05.221(d). The APUC liberally construed its authority stating:

"There is no Alaska statute that specifically addresses the issue of retail competition . . . The Commission's authority to decide these matters derives from its general power to regulate utilities . . . require certificates . . . and to eliminate competition that it finds is not in the public interest."

...

The Commission concludes that the Alaska Legislature has evidenced its intent to displace competition in the utility industry by creating a comprehensive regulatory structure, which the Commission administers, and furthermore delegating to the Commission the power to determine when to eliminate or implement competition in the public interest pursuant to A.S. 42.05.221(d)."

I want to be very clear. We are not here to reargue the issue with the APUC or to take them to task. We appreciate that we have a legitimate disagreement with them and we recognize that they are performing their jobs in the true spirit of public service. We also appreciate that they made their decision in advance of this hearing so that we know where they stand on this issue.

Nevertheless, in light of the APUC's view that the legislature intended to preclude competition except in unusual circumstances, the issue is ripe for a public policy decision first by this joint committee and next winter by the legislature.

Here is the circumstance we are in right now. The current **status quo is that restructuring and/or competition is not allowed**. Unless policy makers' step up to the issue, customers cannot choose from now until that status quo is changed, customers cannot receive the benefits of choice.

It's Simple

I. **First**, I want to impress upon you that **your work here can be simple**. What the customers need is primarily a broad policy statement that competition is allowed as the general rule. The message needs to be clear: suppliers don't have to get special permission unless if they want to be exempted from competition. We think that's what the law already says but we believe that the legislature needs to clarify it. If you do that -- if you are willing to step that far, you will have satisfied the charge of HCR 34.

II. **Second**, even though you do not need to get into the detail of implementation, the **actual implementation of customer choice in Anchorage could be pretty simple**.

Here's how it could work:

A **customer** in Chugach's or ML&P's distribution service territory **asks for service** from another supplier. The supplier pays a **fair rate set by the PUC** for access over the other system.

If it's a **large customer**, equipment is installed, which communicates with the suppliers' computers and generators to follow this load. If it's a **small customer** the supplier uses load research data, determines an estimate of the customer's usage and operate its generators to match that expected load. At the end of the month, the differences if any are **trued up**. This is what we've been doing for over a decade since the ML&P and Chugach systems were interconnected. It is that simple.

III. **Third**, choice by consumers for goods and services from suppliers happens every minute of the day it is not complex. You know it, your constituents know it and all of the utilities represented in the room today know it. But you will hear that allowing competition in the electric utility industry is going to be very difficult and complex. I daresay you will hear words to that effect again today.

Confusion and complexity = delay. And, delay is the prime objective.

The strategy of the opponents of competition is achieving delay. Delay is fully as effective at preventing customer choice as a policy statement by the legislature to prevent competition. Those who proclaim that the sky will fall in if the customers are allowed to chose will raise many questions and make it seem as complex as possible. By the end of the day you can expect to see a long list of questions and concerns.

Is competition really a good idea in Alaska?

The starting point for this discussion must be with basic human behavior. The argument over whether the competitive or the collectivist model is the better way of organizing productive enterprises must be classed as one of the great debates of our century. History shows the outcome: Western competitive capitalism: One, Soviet collectivism: ZERO.

Competition works because it is more in synch with the way humans behave. Competition encourages efficient behavior in business enterprises.

So the burden of proof on this one ought to be on those who want to prevent competition to prove why it cannot work here and why the forces of the state government ought to continue to be used to prevent it.

We think the opponents of competition have a tough row to hoe because competition is already working here.

Lets talk about competition, here are some examples:

- 1994 ML&P offers lower rates to MEA,
- 1994 ML&P offers economy energy to Fairbanks,
- 1995 ML&P attempts to get CVEA in a joint venture,
- 1996 ML&P attempts to get Seward as a customer,
- 1997 ML&P signs contract to sell energy to GVEA.

A review of competition for sales to Fairbanks will show benefits enjoyed by the customers in Fairbanks as well as the millions of dollars of rate reductions that have been passed on to Southcentral customers resulting from the additional revenues from sales to Fairbanks. Now the opponents of competition will tell you with great confidence (maybe even today) that you can't have competition that works where there is only one buyer and 2 sellers. But, that situation (two sellers and one buyer) is exactly the situation, which has brought millions of dollars in savings to the railbelt for over a decade. It reminds me of the joke about the economist who would not pick up the \$5 bill he saw lying on the side walk offering the explanation (with great confidence I might add) that if the \$5 bill were real someone would already have picked it up.

Second, look at all the efforts that just the fear of competition has brought. MEA again recently cut prices to its customers. The MEA bill for this month proudly announces that small commercial rates are lower than Chugach's. ML&P in 1997 proudly announced that their rates are lower than Chugach's. GVEA's message to its customers at their annual meeting is "Our rates are competitive." Chugach in 1997 did not pass on to its customers both wholesale and retail \$3.5 million in fuel costs. Copper Valley Electric proudly announces a joint project with one of its major customers to jointly develop a cogeneration project. Ask yourselves did these events just happen? HEA, and ML&P are attempting to sign up existing customers with special contract considerations. Aurora Power is signing five-year contracts promising to represent an electrical customer as a Power Pool Administrator and charge 20% of the customer's monthly savings as a fee. These are just a few examples of what happens when businesses try to satisfy their customers.

So the question is not really properly stated as: "Will it work?" because it 's already working. There is every reason to believe that it will work even better when policy makers actually allow it.

Customer choice is the key to competition.

Customer choice is the key to why competition works. It is not just "what happens" when there is competition. It's the key to why it works. It works because the customer chooses. Not the legislature, not the regulators, not the Municipal assembly, and not the utility managers or their boards of directors. Competition works because you let the customer choose. You let the customer make all the choices they are used to making when they decide to buy something. They get to decide when, from whom, how much they buy and how much they will pay. The blessings of competition flow from the system of incentives and how they operate to get people to do what you want: provide good value to the customers.

It is because you let them choose that it works. It's the reason it works not just a pleasant consequence.

It follows then - the flip side of this is - the more you or the regulators make choices for the customer, the less choice you leave them - and the less they will benefit. This certainly is what the Brookings Institution study says. This is why it is so important to just let the customers choose and not get carried away trying to create elaborate perfect structures where all the various "stakeholders" get something. And it is why we wince when people - even the well meaning people - talk about "leveling the playing field." What criterion does one use to "level the playing field?" Because one person's leveling is another person's unfair tilting. Leveling the playing field can move dangerously toward picking winners and losers. Leave that to the customers and we will all be better off.

This is why less is more.

When you set up a system where the parties compete to please the customers, customers win because the customer gets to choose. The winner is the one the customer decides to buy from.

If you keep more of the decision-making with the regulators or the legislators, then the utilities will be directed at winning your approval. The customer's interests will take a back seat to winning regulatory or legislative approval for each entities favorite scheme. It will work better if you leave more choice with the customer. The more you try to build the perfect system of checks in the marketplace to protect this or that interest group, the less customers will benefit.

Policy Maker's guide to Listening
Toward Simplicity

To help you listen through the noise, we offer the following suggested questions to apply to what you hear.

- Is this really a high level policy issue or is it something best left to regulators and technical people once the legislature has clearly articulated a policy favoring competition in retail electric sales?
- If people with the right expertise had a genuine desire to solve the problem and got together to solve it would it really be a problem?
- Is there a solution to this problem/question that does not require a long delay?
- Keep a tally of the number of times opponents of customer choice use words like "complex."

Are there any places in the United States where two electric utilities serve one service territory? How about Cleveland, Ohio, Columbus Ohio, Lubbock Texas, Paris Kentucky, Bushnell, Illinois.

Conclusion

When I reflect on this situation, I think of the old joke that asks **how many therapists does it take to change a light bulb?** Answer: **Only 1, but the light bulb has to want to change.**

We have a whole industry that definitely does not want to change. And we have heard from them for years now and you will hear more in a minute -- all the different reasons why we have to go slow, why its scary and what won't work.

The problem is, we've got a lot of bright lights in these utilities but not a one of them wants to change. They are all using their considerable talents to prevent and slow competition.

Wouldn't it be great if they began to use those considerable talents to figure out ways to make it happen instead of ways to stop it or slow it down?

With the very simple broad policy announcement in favor of competition, you can change the focus of the industry in Anchorage from **why we can't do it** to **HOW WE CAN DO IT**. **All these smart hard working people can redirect their considerable talents from slowing it down to making it happen.**

We think Anchorage customers should be able to choose their electric service providers. More importantly, they don't think they need the government to choose for them.

I urge you to clearly re-establish that it is the policy of this state that competition is the rule and only authorizations to monopolize require specific authorization of the APUC.

By the way MEA's General Manager made the quote "One thing is certain and that is that the customer can't lose as a result of competition" in an interview with the Alaska Star newspaper.

I'd like to end with one last quote. "ML&P is not opposed to competition, but if it is to come, it must be carefully orchestrated by regulators and the legislature and must be crafted so no electric customers are harmed in the process."

Chugach believes that unless the regulators and legislators have the genius of Mozart in orchestrating a sheet of music for a perfect symphony, it is better to start practicing competition now.

Thank you for the opportunity to present our views.

CONCERN NO. 1

Stranded Investment

POINT ONE

There may or may not be stranded investments. We won't know until we examine it. Chugach might even have some.

POINT TWO

Let the Commission sort it out. The Commission has indicated it does not need any additional authority. If a competitor has a problem, they can bring it to the PUC for resolution. FERC in Order 888 outlined a method of recovering stranded costs.

POINT THREE

We are very lucky in Alaska. Not only is our system simple but:

- No nukes

- No huge over built coal plants

- No hyper expensive regulatory mandated contracts

- In Anchorage we have no regulatory mandated systems for subsidies

We simply don't have the problems of a state like California.

POINT FOUR

Types of stranded investments include generating plants, long-term fuel or purchased power contracts and "Regulatory Assets."

POINT FIVE

Chugach has carefully protected itself from some of its stranded investment exposure through contracts with its largest customers. We hear ML&P has been doing this as well. It is a smart move. Chugach entered into agreements in which we promised to make the investment in the system to meet their electric power needs. In return our WC promised to get specified amounts of power from us. They promised to be there and not strand our investments. Unless we negotiate a different contract (which we have repeatedly suggested we are willing to discuss) we expect them to live up to their promise just as we have lived up to ours.

Many of us have heard the stories of business people returning from China, Russia or Eastern Europe — especially a few years back. They shake their heads about how they don't understand the importance of contracts. In the bad old days, contracts did not mean much because the government might simply change the rules. Fortunately, here in the U.S. and Alaska, we have constitutions, which protect contracts property rights, which cannot be taken without due process, and this is the key underpinning of our commercial success.

CONCERN NO. 2

Reliability

This is a red herring. The bottom line is that nothing will change which has any real potential to affect reliability. It is a measure of the desperation or opponents of competition that they raise this issue as if it were serious.

For the foreseeable future, the same generators run by the same people will produce the power.

For the foreseeable future, the same people will operate the transmission and distribution systems and will have every incentive they currently have to operate and maintain the system in good repair.

The competition between ML&P and Chugach for sales to Fairbanks has not affected reliability. The GVEA annual reports state the service is there 99.999% of the time.

CONCERN NO. 3

Universal Service

We think the supplier of last resort obligation should reside with the Distribution Service Provider. We have said so. We have never heard anyone object to that. It is not a problem as far as we are aware.

CONCERN NO. 4

Level Playing Field

- Perhaps the most important point to make is that we believe that as a matter of law there are no restrictions on retail competition unless after competition has begun, the Commission holds a hearing and decides it must be restricted. This means that ML&P is free to compete anywhere it wants. Now the Commission has said that the legislature has put it in charge of establishing policy in this area and that no competition is allowed unless they decide it's o.k. The point is that in our view (with which the Commission disagrees) there already is a very level playing field on which anyone can play.
- Contracts with wholesale customers were arrived at in a competitive environment. No one made them buy power from us. They did have the realistic option and the actual ability to build their own supply sources. The governing bodies, the APUC and REA approved the contracts. You repeatedly hear the desire that the AEG&T/MEA/Chugach contract should be set aside because MEA has no option to its power supply. On the contrary, the contract clearly allows MEA to change to net requirements or partial requirements. There are notice provisions and financial settlements, which apparently MEA wants the APUC to change.
- Contracts protect Chugach from stranded investment – each in its own way.
- We will not consent to setting them aside but we have repeatedly advised our wholesale customers that we are willing to negotiate changes or early termination. There is no free lunch. They promised to pay costs on the system we built to serve them and we expect them to honor that promise.
- It would not do any good to void those contracts. For one thing, it would not withstand legal challenge. But more importantly, it would simply mean that Chugach would be entitled to stranded investment payments. It would solve nothing.
- If our wholesale customers want competition in their service territories, it is not for us to force that on them. They can speak for themselves. If they want it, they can so indicate and we are willing to work with them toward a mutually beneficial transition – with or without contract changes.
- Aurora presents an interesting question. They are not regulated but they propose to compete with regulated utilities. We are not convinced the retail business will need to be regulated in the future so we are reticent to suggest that power marketers need to become regulated. We have reservations about Aurora's pilot program on this basis. It's too small. It's too restrictive and, of course, Aurora need not follow it if it does not choose to because it is not regulated. We think a better pilot would be to simply allow anyone to compete in the Chugach and ML&P distribution service territories.

CONCERN NO. 5

Cherry picking will occur and rates will go up for the little guy.

Think about it. If a utility loses some large customers are they really going to think?

I don't need to cut costs.

I don't need to reduce margins.

I don't need to learn to operate more efficiently.

I'll just raise my prices for all my other customers.

I think you should be suspicious of people who come to you and tell you that is their marketing strategy. That is not believable.

If they really did decide that raising prices is the best way to defend market share then they need to go out of business - the sooner the better.

We feel it is far more likely that it will happen as is described in the Brookings Institution study. Customers will benefit - not just large customers. **The KEY is, all customers must be free to choose.**

CONCERN NO. 6

ENRON pulled out of California

There are several interesting things to note:

Competition for retail customers are lukewarm because of the elaborate mandated 10% discount and stranded investment recovery mechanism that the legislature set up. The result is that if someone comes in with a lower price, that price gets boosted up to the cap so that it is no different than the incumbent utility price. It's great for the incumbent utility and o.k. for the residential customer in the short run but it clearly stunts competition of the residential customers.

We've spoken with one of the competitors there, which is holding back and waiting for the legislature's transition period to pass so they can compete.

Note the last observation in the Brookings Study executive summary: Legislators should resist the temptation to elaborately plan and structure competition. To the extent we want to learn from past experience, the simpler, the better.

There is no need to make it complicated and in fact there are very good reasons to keep it simple.

>
>>From WASHINGTON POST Tuesday July 28 Business Section
>
>
>Interesting story on electric power situation on July 25-26
>

>
>Dave
>
>
>David McColloch
>Office of Emergency Management
>US Department of Energy
>202-586-4560
>mccolloc@cem.doe.gov
>
>
>

>UTILITIES LICK WOUNDS AFTER ENCOUNTER WITH SHARP-TOOTHED POWER TRADERS
>

>By Allan Sloan
>WASHINGTON POST
>Tuesday, July 28, 1998; Page E03
>

>Watching electric companies deal with one another used to be about as
>exciting as watching cows graze. The herd members were ultra-polite. They
>traded power back and forth, but no one gouged, because the guy you gouged
>today might be in a position to gouge you tomorrow. But since deregulation
>began in the electric biz a few years ago, a whole
>new bestiary has emerged. Bye, bye, cows. Hello, independent electricity
>traders: sharp-toothed velociraptors willing to bite, slash and maim
>to make a buck. Scattered among them are utilities trying to cash in by
>playing the same game: bovines acting like beasts of prey.
>

>All this jostling and churning helps explain what happened in the Midwest
>recently when the wholesale price of power—the prices that companies
>and traders charge one another—surged a thousand-fold during a
>shortage. Utilities serving Ohio and Illinois lost millions by paying \$5
>for power they were selling to residential customers for a dime or so.
>Then, on July 9, the California Independent System Operator, which
>provides electricity to most Californians as part of the state's
>deregulation program, got bagged. It had to pay \$9 million for a day's
>backup power, about 300 times the normal cost.
>

>"This is exactly the kind of gouging we will see in the future if we go
>to fully deregulated utilities," argues John Cameron of Citizen Action,
>a public interest organization. Counters Mark Palmer of Enron Capital;
>Trade Resources, the nation's biggest electricity trader: "What happened
>in the Midwest was a stinging indictment of the monopoly system. It
>shows a need for further competition all the way down to the end users."
>

>Who's right? As usual, life comes in shades of gray. Both the regulated
>utilities and the free market messed up big time in the Midwest on June
>24, 25 and 26, when the crisis—and the prices—both peaked. Utilities
>first. Commonwealth Edison of Chicago, Illinova of Decatur, Ill., and
>FirstEnergy of Akron, Ohio, all paid obscene prices for power to keep
>from having to pull the plug on their service areas. The utilities argue
>that they were unfairly gouged because they have to pay unregulated
>prices for power, but regulators won't let them charge customers for
>those costs and force them to keep power flowing regardless of how
>much it costs.
>

>That's true. But there's something people don't know but that the
>utilities all readily admitted when Newsweek asked them. To wit: that
>part of their problem is that earlier this year, when supplies seemed
>ample, they sold power to outsiders to make a few extra bucks. Were it
>not for those outside commitments, ComEd, Illinova and FirstEnergy might
>have been able to escape uncouged.

>
>But the free market wins no prize, either. Under the Wild West rules
>that prevail, almost anyone can become an electricity marketer, without

>assets, a reputation or a credit check. And unlike organized exchanges,
>in this market no one guarantees delivery if a player defaults. If you
>fail to deliver, whatever the reason, you have to pay the difference
>between what you promised to sell the power for and what the other guy
>had to pay for it.

>
>One of the dirty little secrets of electricity trading is that the same
>50,000 kilowatts can change hands a dozen times at the same price, as
>traders build up volume to look respectable. This daisy chain caused
>trouble when things got tight in the Midwest.

>
>As power prices started spiking in the Midwest, a company called Federal
>Energy Sales said it would default on its obligation to provide promised
>power to the municipal utility of Springfield, Ill., and to Power
>Company of America of Greenwich, Conn., a trader. That led to defaults
>by Springfield and Power Company, both of which had resold the power.
>Suddenly, a zillion people up and down the line were scrambling for the
>same megawatts.

>Supplies were tight to start with because of a heat wave, and grew
>tighter when storms knocked out transmission lines. Lightning strikes
>knocked two plants off line and a tornado struck near a big nuclear
>plant, knocking down the lines that tied it to the power grid. All
>that was missing were locusts.

>
>Desperate utilities and traders offered to pay anything for power-
>and happy sellers obliged them. "It was a classic squeeze," says John
>O'Brien, president of Wheeled Power Electric Co. of Uniondale, N.Y.
>"The utilities didn't know how to trade, and they got clobbered."

>
>Is this the precursor of more turmoil? Who knows? Wholesale prices in
>the Midwest are back down to normal levels, at least for now. The
>city of Springfield, which made \$61,000 trading Federal Energy power
>but is being sued for millions, has vowed to stop speculating. You can
>bet the utilities will be a lot more careful. The moral: Cows aren't
>exciting or efficient. But unlike velociraptors, they won't scare
>you to death.

>
>Sloan is Newsweek's Wall Street editor.
>His e-mail address is sloan@panix.com.

>

*Draft of July 16, 1998
For Discussion, Only*

*FROM ERIC YOUNG
6 AUG 1998*

ALASKA LEGISLATURE

**SOLICITATION AND REQUEST FOR PROPOSALS
RFP 98-1**

**FOR THE PROVISION OF PROFESSIONAL CONSULTING SERVICES REGARDING
ELECTRIC INDUSTRY RESTRUCTURING ISSUES**

**[Address]
[Phone Numbers]**

SYNOPSIS

THE ALASKA LEGISLATURE represents all classes of electric consumers in the State of Alaska. Alaska consumer-owned electric utilities provide electric service to most of the state's nearly 600,000 residents. Although the electric system in Alaska is physically isolated from those of the lower-48 states, the social, economic, and political considerations underlying electric industry restructuring initiatives in other states have begun to manifest themselves in Alaska, as well. The primary state regulatory agency, the Alaska Public Utilities Commission (APUC) and the State Legislature have undertaken initiatives to examine the present condition of and possible future alternatives for the electric industry in this state. In particular, APUC proceedings in Docket U-97-140 have lead to the production of a preliminary study by the consulting firm of Black & Veatch International (the B&V Study) directed to power pooling and central dispatch planning for the integrated portion of Alaska's electric network (the "railbelt" area).

THE ALASKA LEGISLATURE seeks to retain the services of a qualified professional consultant or consulting firm to assist it in evaluating the risks, potential benefits, and impacts associated with restructuring the electric utility industry in Alaska, and more broadly, to analyze and evaluate options for responding to the initiatives of the APUC and the State Legislature. Familiarity with current industry structures, practices, and technology and with ongoing developments in electric restructuring at the state and federal level is essential. Deliverables include written analyses, publishable reports, and ancillary materials. Because of the rigid timeframe established by the Legislature, time is of the essence with respect to milestones and deliverables.

CONTENTS

- I Background
- II Objectives
- III Scope of Services
- IV Consultant Capabilities
- V Selection Process
- VI Other Matters

1. Background

The electric utility industry is undergoing significant, evolutionary changes in the lower-48 states. Spurred on, in part, by the Energy Policy Act of 1992 and Order No. 888 of the Federal Energy Regulatory Commission (FERC) in derivative proceedings, the industry has begun to move away from a vertically integrated monopoly regulated paradigm. At the federal level, new requirements for "comparable" transmission access and non-discriminatory availability of real-time network information are promoting competition in generation. Concomitantly, approximately half of the states have adopted or are considering changes in the way consumers receive electric service, including the introduction or examination of retail competition and consumer choice.

Whether such restructuring efforts will produce sustained, sustainable consumer benefits is an unresolved issue. The form, scope, and substance of the individual state programs varies widely from state to state, as does the relative degree of enthusiasm for large scale reformation of the industry. To the extent states have adopted programs, those programs are for the most part in an inception stage. Inadequate time has elapsed to provide an empirically sound basis for assessing the long run public interest benefits available from any particular program. Moreover, in some cases, the programs themselves are limited to trials or demonstration projects, underscoring the uncertainties facing policy makers and industry participants.

Against this backdrop, issues concerning competition and deregulation have come to Alaska. Though not physically interconnected to the lower-48 grid, Alaska is not insulated from the social and political forces driving review and revision elsewhere in the country. These forces have begun to move policy makers in the State to at least review and consider the present condition of the electric industry in Alaska, the possibilities of change in the industry structure here, and the likelihood of public interest benefits flowing from whatever course might be chosen. This movement is reflected primarily in the current activities of the Alaska Public Utilities Commission and the State Legislature. However, in making an informed decision on restructuring, it is imperative that the Alaska utility structure is properly evaluated in comparison to the more cohesive infrastructure, technology options, and generation providers available to the lower-48. In short, if beneficial to Alaska in all or in part, it is important to establish a restructuring template for Alaska that will insure economic benefits to its citizens while insuring against harm to consumers that don't have the market strength to protect their financial interests.

The Alaska Public Utilities Commission (APUC) which has formal jurisdictional oversight over all electric utilities and utility services in the state¹, has been engaged for several years in various adjudications which, to some degree, have implicated electric industry and market restructuring issues². More recently and specifically, the APUC inaugurated dockets focused upon (a) power pooling and dispatch planning among the railbelt electric utilities (Docket U-97-140), and (b) a more general rulemaking inquiry into electric restructuring issues (Docket R-97-

¹ See AS 42.05. Significant jurisdictional issues may arise in connection with any future modifications to the industry structure (e.g., oversight of power marketers or brokers who may not technically fall under existing statutory definitions.)

² E.G., *In the Matter of the Formal Complaint Filed by the MUNICIPALITY OF ANCHORAGE d/b/a MUNICIPAL LIGHT & POWER Against CHUGACH ELECTRIC ASSOCIATION, INC.*, APUC Docket U-97-201.

10). Both dockets raise a wide range of issues with broad potential impacts upon the public as well as industry participants. APUC activity is now paralleled by legislative action. Pursuant to House Concurrent Resolution 34, The Alaska Legislature has impaneled a "blue ribbon" Legislative committee to examine various restructuring and competitive issues. This task force intends to complete its review and to submit a report (and possible recommendations) to the Legislature for consideration during the 1999 session.

In order to establish a utility position on restructuring, the Board of Directors of THE ALASKA LEGISLATURE established a General Managers Subcommittee on Restructuring (GMSR). The Subcommittee is composed of the General Managers of the Railbelt utilities, and General Managers from four rural utilities: Kotzebue, AVEC, Kodiak, and Copper Valley. The GMSR through the umbrella of THE ALASKA LEGISLATURE is seeking an objective assessment of the potential risks, benefits, and impacts from restructuring in Alaska. The GMSR will serve to guide THE ALASKA LEGISLATURE in its negotiations and input to the Legislature and to the APUC docket on restructuring.

II. Objectives

The level and import of this governmental activity requires a concomitant increase in the efforts of the state's electric utilities, who will be directly involved in and impacted by the results of APUC and legislative activities. Hence, the involvement of THE ALASKA LEGISLATURE.

THE ALASKA LEGISLATURE – the Alaska Rural Electric Cooperative Association Inc. is a non-profit, non-governmental entity which provides to its members representation, insurance, safety and training, information, and education services. THE ALASKA LEGISLATURE is a statewide trade association representing electric cooperative corporations, municipally-owned electric utilities, and regional electric authorities. Its constituency enables THE ALASKA LEGISLATURE to aggregate resources and provide beneficial input to the above-described agency and legislative processes.

To maximize the efficacy of its contribution, THE ALASKA LEGISLATURE has determined to seek the aid of an outside consultant or consulting firm (Consultant). The role of the Consultant would be to conduct an economic assessment of the risks, benefits and impacts of utility restructuring in Alaska and to formulate positions on issues relevant to electric industry matters in Alaska. The initial role of the Consultant would be upon contrasting the differences between Alaska and the lower-48 states from an electric utility perspective and then evaluating which benefits and risks that might accrue should various restructuring scenarios evolve from either the Legislative or Regulatory efforts. The initial focus of the Consultant's effort would be upon information transpiring from the APUC Docket L-97-140, and specifically the "Power Pooling/Central Dispatch Planning Study" being developed in that docket by the firm of Black & Veatch International (the B&V Study). The use or enhancement of materials developed in this docket by the Consultant in other proceedings or processes may be considered and authorized by THE ALASKA LEGISLATURE as subsequent events warrant. In addition, it is imperative that the Consultant become familiar with the sensitive economic balance that prevails in each of the isolated satellite utility systems throughout rural Alaska. In addition to the almost third tier

template that would be needed for rural Alaska, the Consultant must assess the impact and benefits that may accrue as a result of the elimination, or diminution of the State subsidy manifested under the Power Cost Equalization program. Finally, the Consultant must be prepared to assess the State's exposure on the four-dam pool, and other power generation and transmission line, and the contractual obligation that the State has to preserve the present economic setting under which these projects operate.

The Alaska Legislature's primary objectives with respect to participation in these processes (occasioning the need for a Consultant) would include the following:

- A. **Obtain a third party perspective:** THE ALASKA LEGISLATURE wants the skills and input of an informed, experienced, but unbiased Consultant to ensure that the positions ultimately taken in any proceedings reflect consideration of the interests of all potential stakeholders,
- B. **Identify options:** The positions considered and adopted by THE ALASKA LEGISLATURE should result from a broad ranging review and analysis, conducted for the express purpose of identifying all plausible, relevant issues, as well as options for addressing those issues,
- C. **Produce a risk/reward analysis:** Working with the specific options identified, THE ALASKA LEGISLATURE seeks to evaluate the risks and benefits of each approach in terms of consumer interest, current and potential industry participants, and overall economic, environmental, and social effects on the state.
- D. **Quantify impacts:** To the extent practicable, THE ALASKA LEGISLATURE seeks quantification of the economic costs and benefits of each identified approach, to the end that a common basis for evaluation of each option can be established.
- E. **Rank alternatives:** As a result of the foregoing analysis and evaluation, THE ALASKA LEGISLATURE desires a comparative evaluation of the options, resulting in an ordering of those options (potentially under more than one set of criteria).
- F. **Select and pursue an optimal course:** If found to have merit for Alaska, THE ALASKA LEGISLATURE anticipates adopting suitable approaches to the issues and incorporating them into a comprehensive regulatory and legislative program on electric restructuring.

The methodologies employed by and the deliverables obtained from the selected Consultant must reflect and/or prove consistent with these objectives.

III. Scope of Services

The Contractor will perform all work necessary to:

- A. Familiarize himself or herself with the engineering, operational, financial and regulatory conditions attending the current electric industry structure in Alaska;
- B. Critically and comprehensively analyze the B&V Study above-referenced, including subsequent iterations thereof and render a written analysis thereon;
- C. Independently examine relevant conditions, issues, and factors impacting current and potential electric industry structures in Alaska;

- D. Identify and analyze alternatives for addressing the conditions, issues, and factors examined above, from multiple perspectives including but not limited to current and anticipated industry engineering and operational parameters, first and continuing/operating costs, consumer welfare and impact, public interest benefits, public "goods," potential regulatory issues (state and federal; electric and other), and other matters relating to electric industry restructuring. In accomplishing the foregoing, Consultant will be expected to draw upon the restructuring experiences of other, non-Alaskan jurisdictions and integrate such experiences on a comparative basis for further reference and evaluation;
- E. Engage in economic and other relevant quantification of the identified alternatives, including the production of statistical analysis sufficient to support such quantification. All methodologies employed in such quantification will be described and justified;
- F. Propose a preliminary ranking of the alternatives as quantified, inducing therein a written discussion of the basis and support for such ranking;
- G. As directed by THE ALASKA LEGISLATURE, produce a final and comprehensive written report reflecting the processes of items A through F.
- H. Following completion of the written report in item G, above, prepare and sponsor, as required, summaries or descriptions of the written report, position or "white" papers testimony, and other documentation in support of the written report together with representation at and participation in private and public meetings concerning the written report and THE ALASKA LEGISLATURE's positions on industry matters,
- I. [Other?]

In carrying out the foregoing, the Consultant will be expected to make available resources sufficient (as measured in terms of quantity, quality, and timeliness) to effectively address the scope of work identified above.

IV, Consultant Capabilities

In evaluating responses to its solicitation, THE ALASKA LEGISLATURE will consider demonstrated capabilities and skills in the following areas, among other matters:

- A. **Analysis:** The Consultant must have sufficient resources (personnel, software, and hardware) to effectively process, analyze, and evaluate significant amounts of raw data. Multiple sources of data may be offered and disparate forms, protocols, etc., can be anticipated. Some data may be proprietary, confidential or otherwise privileged in source or character, requiring the ability to handle such data in a conforming manner and to effectively control and limit the exposure or dissemination of such data.
- B. **Experience:** THE ALASKA LEGISLATURE seeks a Consultant with experience in electric industry matters, generally, and with respect to the current condition of restructuring

elsewhere in the country. Prior experience in Alaska is helpful but not mandatory. The Consultant must be familiar with all aspects of policy formulation, from data gathering, to data analysis, to evaluation, to policy development and exposition.

- C. **Presentation/Support:** A written, publishable report will be a required deliverable product of the engagement, in sufficient quantities and forms necessary to achieve the objectives. Additionally, support of the published report in terms of public or private presentation, explanation, or testimony before the GMSR and THE ALASKA LEGISLATURE Subcommittee on Electric Utility Restructuring will also be required.
- D. **Availability:** The Consultant must be readily available to THE ALASKA LEGISLATURE during the course of the project for discussion and advice. This will include informal as well as formal meetings and may involve consultation with the GMSR or other executive group as THE ALASKA LEGISLATURE may constitute from time to time. The Consultant may be required to interact with individual THE ALASKA LEGISLATURE members, but will under no circumstances be required to engage in individual members projects or other matters outside the scope of this engagement. The Consultant must be free on conflicts of interest at inception of work on this project and must remain so at all times until after termination of the project.
- E. **Timeliness:** The anticipated magnitude of the work effort and the limited, defined time period available to respond to the identified agency and legislative initiatives places a premium on responsiveness to schedule. Time is of the essence. The Consultant will be expected to meet all deadlines and milestones established without sacrificing the accuracy, completeness, and quality of the work product.
- F. **Subject Matter Expertise:** The Consultant must be familiar, generally, with the technical aspects of the engineering, operational, and financial aspects of the electric utility industry, including without limitation generation, transmission, distribution, and energy/ancillary services. Additionally, familiarity with emerging technical, operational, and financial issues (e.g., ISO functionality, securitization, power marketing, etc.) will be required.
- G. **[Other?]**

VI. Other Matters

Responses to this request for proposals should be made in writing and directed to the following:

(INSERT)

Responses may be made at any time, as there is no formal deadline for such. Consistent with the matters discussed above, however, THE ALASKA LEGISLATURE intends to move rapidly in evaluating alternative providers of consulting services. Accordingly, early and complete submissions of interest would be appropriate. Such responses should address the matters set out above, and particularly those items detailed in Sections II, III, and IV, Five (5) copies of the response to this request for proposals should be submitted to the above THE ALASKA LEGISLATURE designee, for review and evaluation. Any response, to be considered, must be signed by a duly authorized representative of the Consultant and must be valid for a period of thirty (30) days following transmission to THE ALASKA LEGISLATURE. Responses received from parties not ultimately selected will be destroyed.

Interviews or negotiations, if any, will only be conducted with a potential Consultant or Consultant representative legally authorized to represent and to bind the Consultant.

[Other matters, as desired]



Money

FRIDAY, JULY 10, 1998

Business Travel Today

By David Field

Sale: Southwest offers fares of \$99 or less each way between any of its 52 cities. Buy by July 23; fly Aug. 18-Dec. 6. Sample: Phoenix to Las Vegas, \$39 each way.

React: America West began a sale with the same deadlines and \$99 one-way limit as Southwest's. Sample: Phoenix to Seattle, \$99 each way.

Open Jameson Inns opened



a hotel in Eden, N.C., its 71st.

Class: Denver-based Frontier Airlines will stay all-coach

instead of adding a premium class, which it had studied.

Still time: Northwest again extended the deadline for its fare sale. Buy before July 24 for travel Aug. 19-Dec. 6.

Adding: Delta Express starts daily nonstop round-trip flights Oct. 1 between Orlando, Fla., and four New York cities: Albany, Buffalo, Rochester and Syracuse. It will then have 22 routes from Orlando.

Got a travel tip?
E-mail money@usatoday.com

Deregulation puts electricity reliability in question

By Beth Bellon
USA TODAY

Deregulation could make the threat of random emergency electricity cutoffs increasingly common, experts warn.

Federal and state regulators have been asked to investigate a harrowing situation late last month in the Midwest.

Rolling blackouts were barely avoided after four days of blistering heat that surprised electricity providers early in the summer.

The crisis, made worse by understorms and tornadoes

that knocked out power generators from Minnesota to Ohio, was averted only after utilities jumped into the wholesale market and bought electricity for \$7,000 a megawatt. Normal price: \$30 to \$50 a megawatt.

No one is predicting widespread outages in the world's most reliable electricity system. But uncertainty about how a deregulated industry can maintain reliability is creating widespread anxiety.

"It's like running the rapids every day," says Don Kirchhoffner, a spokesman at Commonwealth Edison, an investor-owned Chicago utility.

CommonEd's losses — more than \$30 million — won't be passed on to consumers. But its shareholders and other investors in utility stocks will feel a bite out of quarterly earnings.

A dozen utilities have asked the Federal Energy Regulatory Commission to look into what happened.

But allowing competition among utilities, which previously enjoyed monopolies, will benefit consumers, experts say. Competition will translate into lower rates. But in the short term, the threat of rolling

blackouts could disrupt businesses and consumers.

The process will last two to three years, says Peter Christensen at Services Resources in Atlanta. Fewer than 10 states have launched deregulation and all but two have deregulation legislation pending.

"It's a classic case of growing pains," Christensen says.

Meanwhile, excess generating capacity is shrinking in some regions. Existing utilities are reluctant to build plants because they can no longer pay for new plants by increasing customer rates.

New companies in the market are lagging on plans to invest in plants until the pricing landscape of a deregulated industry becomes clearer.

Regional reliability councils rather than government regulators monitor the situation and make crucial decisions about when and where power should be transmitted.

But "there are no mandatory rules of the road for reliability," says Dan Adamson, a Department of Energy official. President Clinton has proposed mandatory rules. The legislation is pending in Congress.

A mountain of moguls | Caution flag

x



Municipality of Anchorage Municipal Light & Power

"Basic Perspectives on the Electric Power Industry"

August 7, 1998

Presented by:

Marilynn Semro, Senior Project Manager

EES Consulting, Inc.

**A registered professional engineering corporation with
offices in the Seattle and Portland metropolitan areas and
an affiliate office in Calgary**

Telephone (425) 452-9200 Facsimile (425) 452-9299



Agenda

- Overview of Seminar
- Basic Electric Utility Operations
- Origins of Industry Restructuring
- ML&P Position on Restructuring
- Questions and Answers





Overview of Seminar

- Introductions
- Definitions and Terminology
 - Control Area. Part of a power system, or a combination of systems to which a common generation control scheme is applied
 - Kilowatt (kW). Power (work done per unit of time); when referring to generating plants power is called capacity or capability; when referring to customer usage power is called demand
 - Kilowatt-hour (kWh). Energy (force times the distance through which it acts); 1000 watt hours equals 1 kilowatt-hour; unit of measure in a customer's bill
 - Megawatt-hour (MWh). 1,000,000 watt hours; unit of measure for generation system
 - Watt. Basic unit of capacity; a 100 watt bulb burning constantly for one hour uses 100 watt-hours of electricity



Basic Electric Utility Operations

■ Electric Industry Characteristics

● Power Supply

✓ Generation

- Coal
- Oil
- Natural Gas
- Hydroelectric
- Geothermal
- Wood Waste
- Wind

✓ Power Purchases

- Bilateral Contracts
- Spot Market

Basic Electric Utility Operations

■ Electric Industry Characteristics (cont'd)

- Transmission. Transportation of power from the point of origin (generating plant or delivery point from other utility) to load center; facilities consist of substations and high voltage power lines

- ✓ 500 kV (none in Alaska)

- ✓ 230 kV

- ✓ 138 kV

- ✓ 115 kV

- ✓ 34.5

- Distribution. Connects the customer to the transmission grid; facilities include substations, primary (4 kV and up) and secondary conductors (< 4 kV), poles and line transformers, services, meters and installations

- ✓ 115 kV

- ✓ 34 kV

- ✓ 12 kV

- ✓ 4 kV



Basic Electric Utility Operations (cont'd)

■ Customer Classes

- Residential
- Commercial
- Industrial
- Wholesale

■ Customer Service and Facilities Function

- Meter and Service Drop
- Meter Reading, Billing and Collection
- Customer Information and Services
- Public Purposes (Demand Side Management, Low Income, Renewable Resources)



Basic Electric Utility Operations (cont'd)

■ Customer Service and Load Characteristics

- Size of Load
- Shape of Load
 - ✓ Annual
 - ✓ Seasonal
 - ✓ Daily
 - ✓ Hourly
- Voltage Level
 - ✓ High Voltage
 - ✓ Primary Voltage
 - ✓ Secondary Voltage



Basic Electric Utility Operations (cont'd)

■ System Operations

● Instantaneous Load Following/Regulation (AGC)

- ✓ Instantaneous (second-by-second) regulation of the power supply to maintain a continuous balance between loads and generation
- ✓ Automatic generation control (AGC) - the regulation of the power output of electric generators within a control area in response to changes in system frequency, time error, and tie-line loading, so as to maintain the scheduled system frequency and the established interchanges with other areas

● Load Shaping/Balancing

- ✓ The arrangement and operation of generating resources to meet a given load, or
- ✓ The arrangement of load to meet a given resource over specified periods of time.
- ✓ Load shaping on a hydro system usually involves the adjustment of storage releases so that generation and load are continuously in balance

Basic Electric Utility Operations (cont'd)

■ **System Operations (cont'd)**

● **Scheduling, System Control and Dispatch**

- ✓ **Scheduling.** The planned dispatch of resources to meet forecast loads on an hourly basis and notification.
- ✓ **System Control.** Monitoring, control and operation of the power system
- ✓ **Dispatch.** Operation of the AGC equipment to regulate the loading of the generators to help maintain scheduled system frequency and scheduled power interchange with other utilities

● **Reserves/Standby**

- ✓ **Generation reserves:**
 - Extra generating capacity available to meet unanticipated demands for power or
 - To generate power in the event of loss of generation resulting from scheduled or unscheduled outages of regularly used generating capacity.
- ✓ **Spinning reserve.** A reserve generating capacity connected to an output bus and ready to take immediate load.



Basic Electric Utility Operations (cont'd)

■ System Operations (cont'd)

● Reactive Power/Voltage Control

- ✓ The out of phase component of the total volt-amperes in an electric circuit.
- ✓ Reactive power has two components:
 - Reactive demand (expressed in kilovars or kVAr)
 - Reactive energy (expressed in kilovarhours or kVArh)
- ✓ Voltage control. Equipment that controls the output of reactive power resources based on local system voltage or loads



Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications

● Cost Recovery

- ✓ Revenue Requirement
- ✓ Cost of Service Analysis
- ✓ Rate Design

● Revenue Requirement

- ✓ Power Supply
- ✓ Transmission
- ✓ Distribution
- ✓ Customer
- ✓ Administrative and General
- ✓ Taxes
- ✓ Depreciation
- ✓ Return on Investment

Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications (cont'd)

● Cost of Service

✓ What is cost of service?

- A study that allocates costs (including joint costs) to those who cause the cost to be incurred
- Based on generally accepted rate setting techniques

✓ Why do a cost of service study?

- To design rates
 - Generally accepted as fair and equitable
 - Avoids interclass subsidies
 - Revenues track costs
 - Provides accurate price signal



Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications (cont'd)

✓ How is a cost of service study done?

- Functionalization. Revenue requirement is functionalized to power supply, transmission, distribution and customer functions
- Classification. Functionalized costs are classified to demand, energy and customer components
- Allocation. Functionalized and classified costs are allocated to customer classes based on their demand and energy usage characteristics



Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications (cont'd)

● Rate Design

✓ Principles of Rate Design

- Recover utility costs
- Cost-based
- Fair and equitable
- Easy to understand and administer
- Conform to generally accepted rate setting techniques
- Provide revenue stability to the utility and rate stability to the customer



Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications (cont'd)

● Rate Design (cont'd)

✓ Traditional

- Flat
- Block
 - Declining
 - Inverted
- Time of Use
 - Time of Day
 - Seasonal
 - Real-time
- Index
- Marginal
- Non-firm or interruptible
- Economic development



Basic Electric Utility Operations (cont'd)

■ Cost and Pricing Implications (cont'd)

● Rate Design (cont'd)

✓ Unbundled

- Power supply
- Ancillary services
- Wires
- Meters
- Meter reading and billing
- Customer service
- Taxes
- Universal systems benefits

Basic Electric Utility Operations (cont'd)

■ Specific Alaska Railbelt Issues

● Existing System Attributes

- ✓ 3 utilities that own generation
- ✓ 3 utilities that have essentially no generation and purchase from generating utilities
- ✓ 3 load control areas
- ✓ limited transmission between load control areas
- ✓ about 700 MW of load (WSCC about 110,000 MW load)
- ✓ about 1200 MW of generation (WSCC about 150,000 MW of generation)
- ✓ insignificant non-utility generation
- ✓ no competitive wholesale market

WSCC = Western Systems Coordinating Council

Origins of Industry Restructuring

- Historical Utility Structure
 - Vertically Integrated
 - Cost-Based, Regulated Pricing
 - Internal Planning Process



Origins of Industry Restructuring (cont'd)

■ Changing Utility Environment

● Wholesale Competition

- ✓ EPACT 1992, FERC Orders 888 and 889 (FERC Orders 888 and 889 do not apply in Alaska)
- ✓ Wholesale markets growing and changing in lower 48
- ✓ Marketers/brokers propagating (and throwing in the towel)
- ✓ East and west coast "juice" market well developed
- ✓ Financial information systems working well (DJ cash prices, COB, Four C's, Mid C, Palo Verdes, NYMEX, etc.)
- ✓ Transmission information systems (OASIS) need work
- ✓ Wholesale competition fierce
- ✓ Growing pains (market volatility)

EPACT = Energy Policy Act of 1992

PURPA = Public Utilities Regulatory Policy Act of 1978 (federal driving force)

Origins of Industry Restructuring (cont'd)

■ Changing Utility Environment

● Retail Access

✓ California started April 1, 1998

- Penetration rate for access
- Customer savings
- Customer reaction
- Marketers
- Cost

✓ Montana started on July 1, 1998

✓ Washington, 1999(??)

✓ Oregon 2000(??)

✓ Alberta

✓ Ontario

✓ Federal legislation in 2000



Origins of Industry Restructuring (cont'd)

■ Changing Utility Environment (cont'd)

- Significant Issues to be Resolved Under Restructuring
 - ✓ Market power
 - ✓ Stranded costs
 - ✓ ISO control and pricing
 - ✓ Control of metering/billing
 - ✓ Technical power supply accounting/settlement problems
 - ✓ Customer churn
 - ✓ Price volatility



Origins of Industry Restructuring (cont'd)

■ Changing Utility Environment (cont'd)

● Trends

- ✓ Market power deadly
- ✓ Independence imperative
- ✓ Prices unpredictable
- ✓ Technical issues significant
- ✓ Customer confused or oblivious



ML&P Position on Restructuring

- April Strategic Planning Process
- Competition/Customer Choice Good Concepts That Have Been Cornerstone of Public Power for Decades
- Any Change Must Make Customer Better Off
- Guiding Principles
 - No loser
 - ✓ Customer bills
 - ✓ System reliability
 - ✓ ML&P financial integrity
 - ✓ Environment
 - Level playing field
 - Must be Alaska-specific
 - ✓ Size/market power
 - ✓ Geography
 - ✓ Isolated vis-à-vis lower 48



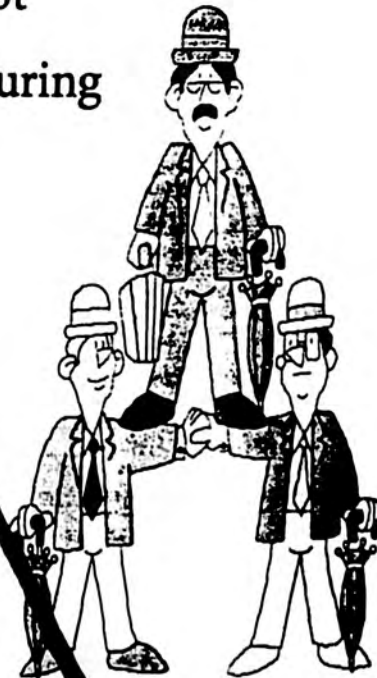
ML&P Position on Restructuring (cont'd)

■ Sequential Based on Cost-Effectiveness

- Pool
- Wholesale
- Retail

■ Recent Developments Locally

- PUC docket on wholesale Railbelt pool
- Legislative task force
- Aurora petition for retail pilot
- PUC rulemaking on restructuring
- 1999 legislative session



Questions and Answers



<http://www.new-pi.com>

Millennium

A.P.U.C.
RECEIVED

98 MAR 25 AM 9:54

"Constructive Notice"

(ex facie) Scientific and legal fact

Geocentric construction and mathematical logic equation with
multiple applications through applied science, including the
manufacture of digital software

M.O.A.

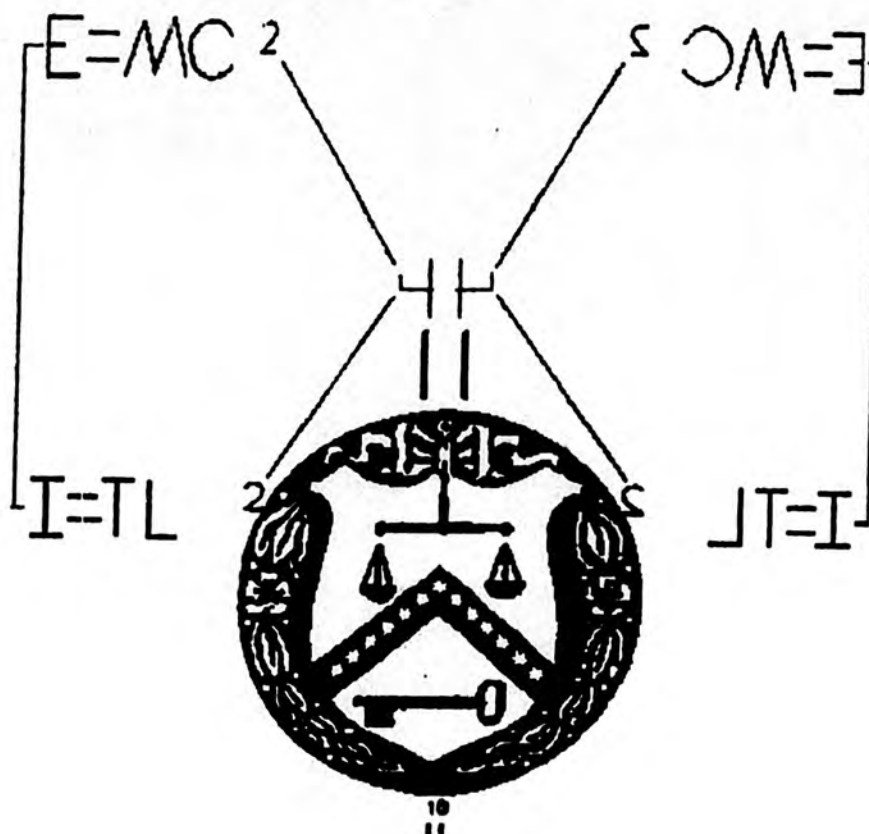
1000 1000 1000
1000 1000 1000

I=Inspired

T=Thought

L=Light

©1992



Title of Origin

Charles Edison McKee

PO Box 243053

Anchorage, AK 99524

e-mail mckee@new-pi.com

