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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner-Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. U-0000-94-165

NOTICE OF FILING

Pursuant to the Commission's Procedural Orders dated December 1 and 11, 1997, Arizonans for Electric Choice and Competition, Cyprus Climax Metals and ASARCO hereby file the Direct Testimonies and Summaries for Kevin C. Higgins, J. Robert Malko, and Alan E. Rosenberg and the Rebuttal Testimony of Kevin C. Higgins, which witnesses are being sponsored jointly with Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company, in the above-captioned matter.

Respectfully submitted this 21st day of January, 1998.

Arizona Corporation Commission
DOCKETED

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DIRECT TESTIMONY

OF

KEVIN C. HIGGINS

ON BEHALF OF
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,
BHP COPPER, CYPRUS CLIMAX METALS, ASARCO,
PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND
MORENCI WATER & ELECTRIC COMPANY

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF
ELECTRIC SERVICE THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. U-0000-94-165

January 21, 1998

Direct Testimony of Kevin C. Higgins

Summary of Conclusions and Recommendations

The public interest dictates that the Commission strike an appropriate balance between customer and utility interests in implementing a stranded cost recovery program. It is also critical to design stranded cost recovery in a way which maximizes utilities' incentives to undertake successful mitigation activities.

These objectives can be accomplished by adopting the following proposed calculation, recovery, and mitigation approach in its entirety:

(1) A limited transition period of three to five years for calculation and recovery of strandable cost is designated.

(2) Strandable cost is calculated using a hybrid of the replacement cost valuation and net revenues lost approaches, in which:

(a) The net revenues lost approach is used to estimate strandable cost on a *year-to year* basis.

(b) *Total* strandable cost is calculated using the replacement cost valuation method. This calculation is designated to be the maximum allowable strandable cost over the transition period, providing an upper bound on the sum of year-to-year strandable costs.

(3) Customers pay for a portion of strandable cost through a transition charge levied on distribution service. During any given year, the transition charge applies only toward strandable cost associated with that same year.

(4) The portion of strandable cost recovered through the transition charge declines each year, such that the overall percentage falls within the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent.

(5) Utilities are deemed to be at-risk for recovery of the remainder of their strandable cost (associated only with the competitive market). They are free to implement whatever mitigation actions they believe to be most effective, and retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

(6) Any "true-ups" are limited to adjustments for deviations from the market price of power.

(7) At the end of the designated transition period, strandable cost is no longer estimated and the transition charge ceases.

This approach automatically builds in a price cap, ensuring that the final delivered price to consumers under competition is no greater than under regulation. A price cap is an essential objective in designing a strandable cost recovery mechanism.

In allocating the transition costs among customer classes, the Commission should follow the consensus recommendation of the Stranded Cost Working Group, which states that strandable cost should be allocated among customer classes "in a manner consistent with the specific company's current rate treatment of the stranded asset, in order to effect a recovery of stranded costs that is in substantially the same proportion as the recovery of similar costs from customers or customer classes under current rates." This provision is critical for preventing cost-shifting among customers in the recovery of strandable costs.

The Commission should also retain the important language in the Rule which states that any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than retail access shall not be used to calculate or recover any Stranded Cost from a consumer. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. In addition, strandable cost charges should not be assigned to service that had been interruptible under the customer's previous arrangement with the Affected Utility, because generation capacity is not constructed to provide interruptible service.

Retail competition will present opportunities and risks for both customers and utilities, while the burden of strandable cost represents a hindrance to both groups. Equity and efficiency require that a reasonable sharing of this burden be devised. This testimony proposes an approach in which a reasonable sharing is achieved and the incentive for mitigation is maximized. It combines calculation methods supported by both utilities and customers and presents a strategy for genuine transition to a competitive marketplace for consumers and utilities alike.

CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q. What are your qualifications to testify in this proceeding?

A. My academic background is in economics, and I have completed all course work and examinations toward the Ph.D. in Economics at the University of Utah, and have served on the adjunct faculties of both the University of Utah and Westminster College. Prior to joining ESI, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I testified regularly before the Utah Public Service Commission on matters involving structural change in the provision of energy services, including introduction of retail

[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

competition in the natural gas industry, implementation of rules governing small power production and cogeneration, joint ownership of electric transmission facilities, and the merger between major electric utilities. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, one of the larger municipal governments in the western U.S., where I was responsible for development and implementation of a broad spectrum of public policy. In 1995, I joined ESI, where I assist private and public-sector clients in the area of energy-related economic and policy analysis.

For much of 1996, I was involved in the workshop process conducted by the Arizona Corporation Commission to develop rules governing the implementation of retail access. In 1997, I participated in the Working Group process established by the Commission, serving as one of five voting consumer representatives on the Stranded Cost Working Group; as part of that effort, I participated in each of the Working Group's three subcommittees.

Also during 1997, I provided expert testimony on stranded cost recovery in the Con Edison restructuring hearing conducted by the New York Public Service Commission. In that case, I recommended against adoption of the stranded cost recovery charge that had been incorporated into a settlement between Staff and the utility on the grounds that the resulting cost to customers would be excessive and thwart competition. The Commission agreed with this position and ordered that the stranded cost charge in the settlement be modified to reduce the cost to customers.

A more detailed description of my qualifications is contained in Exhibit KCH-1, attached to this testimony.

Q. What general areas will your testimony address?

A. My testimony addresses the nine stranded-cost-related questions posed in the Commission's Procedural Order of December 1, 1997, as amended December 11, 1997, and includes specific recommendations for supplementing the Commission's Electric Competition Rule ("Rule"). These recommendations are included in Exhibit KCH-2. Also included in my testimony are general policy recommendations, as well as a specific proposal for calculation, recovery, and mitigation of stranded cost using a hybrid of the replacement cost valuation and net revenues lost approaches. I recommend these policies be adopted by the Commission in its implementation of the Rule. These policy recommendations are presented in Exhibit KCH-3.

Two other witnesses are providing testimony in conjunction with mine. Dr. J. Robert Malko provides additional testimony pertaining to questions 3, 6, and 9. Dr. Malko's testimony focuses on the issue of risk sharing between customers and investors in the determination of a stranded cost recovery mechanism, and provides an evaluation of the risk-sharing proposal contained in my testimony.

Dr. Alan Rosenberg offers testimony pertaining to questions 3, 4, and 5. His testimony presents an assessment of stranded-cost calculation methodologies and recovery mechanisms, providing a helpful framework for selecting an appropriate approach in Arizona.

Q. **<u>Should the Electric Competition Rules be modified regarding stranded costs? If so, how? (Question 1)</u>**

A. If by "modifying the Rules" we mean changing fundamental features of the Rule, the answer is no: the Electric Competition Rules do not need to be modified regarding stranded cost. The Rules provide a workable definition of stranded cost and anticipate that utility-specific stranded cost determination will be resolved in evidentiary hearings. In addition, the Rules provide guidance by identifying the factors to be considered in designing a stranded cost recovery program.

However, if by "modifying the Rules" we mean adding supplemental and clarifying provisions to the existing Rules, the answer is yes. In responding to the questions posed in the Procedural Order, I will be making specific recommendations concerning utility filing deadlines, allocation of strandable cost among customers, and reinforcement of the Commission's intention to balance utility and customer interests. These recommendations can be adopted as supplements to the existing Rules, and as indicated previously, are presented in Exhibit KCH-2.

Q. <u>When should Affected Utilities be required to make a "stranded cost" filing pursuant to A.A.C. R14-2-1607? (Question 2)</u>

A. As a general proposition, Affected Utilities are *not* required to make a stranded cost filing -- nor should they be. Such a filing is only necessary if an Affected Utility wishes to recover potentially strandable cost from customers through a Commission-assessed charge. If a utility wishes to effect such a recovery, the burden should be on that utility to file far enough in advance of the date it wishes to initiate recovery to allow for evidentiary hearings on the request. I recommend that such a period be no less than eight months.

Q. If an Affected Utility's stranded cost situation is unresolved before January 1, 1999, should implementation of retail competition be delayed?

A. Absolutely not. Affected Utilities have been on notice since 1996 that retail access would begin January 1, 1999. It is also clear that the burden of making a request for stranded cost recovery rests with the Affected Utility. If an Affected Utility does not take sufficient steps to address its stranded cost concerns in time to effect recovery starting January 1, 1999, then retail competition should begin as planned, with stranded cost recovery implemented at the time it is finally resolved.

Q. <u>What costs should be included as part of "stranded costs" and how should those costs be calculated? (Question 3)</u>

A. "Stranded cost" is a term used to refer to that portion of a utility's regulator-approved, generation-related fixed costs and regulatory assets which the utility does not recover due to the introduction of a competitive generation market and the resultant lower electricity prices. The Electric Competition Rule defines stranded cost in an equivalent manner: it is the net difference between the value of a utility's generation-related assets and obligations under traditional regulation and the market value of those assets and obligations directly attributable to the introduction of competition. As such, stranded cost is not an enumeration of costs per se, but the *difference* between these two valuations.

Stranded cost does not include any operating costs. If a facility's operating costs can not be recovered in a competitive market, economic rationality dictates that the facility be shut down. The exception to the shut-down rule would occur only in the case of a facility required to operate for reliability-related reasons. Such facilities require special pricing and operating treatment under retail competition.

It follows, then, that the only costs which should be included as part of stranded cost is some portion of Commission-approved, generation-related fixed costs and regulatory assets.

Q. The Rule indicates that retail access is to be phased in over a four-year period. What are the stranded cost implications of such a phase-in?

The only portion of an Affected Utility's fixed cost that has the potential to be "stranded" is the portion exposed to competition. Consequently, under the Rule, only 20 percent of a utility's retail generation business has any strandable cost exposure for the first two years of retail access. In subsequent years, the exposure will be proportionate to the share of the retail market which is open to competition under the Rule's phase-in provisions.

Q. Before proceeding to a more detailed discussion on calculation methods, are there any important overview considerations you wish to address?

A. Yes. It is particularly important to discuss: (1) the speculative nature of stranded cost, (2) the interrelationship between the magnitude of stranded cost and the design of the recovery program, and (3) equity considerations. It is important to address these matters at the outset, so that the discussion of calculation methods is placed in a proper framework.

Q. What do you mean by the "speculative nature" of stranded cost?

A. When we speak today of "stranded cost," we are really speaking of costs which are *at risk* of being "stranded" some time in the *future* – after the introduction of competition. This distinction is sometimes overlooked, because in common usage, the word *stranded* suggests an action which has *already* occurred, as in someone or something being left stranded in the desert. However, such is not the case with stranded cost. Prior to the introduction of competition, there is no stranded cost. To estimate, in the present, what stranded cost will turn out to be requires speculation about the future.

In order to emphasize the speculative or at-risk nature of "stranded" cost, some jurisdictions prefer the term *strandable* cost. It is a term I too will use in this testimony when referring to future or potential stranded cost.

Q. **Why is it important to emphasize the speculative nature of stranded cost?**

A. Emphasizing its speculative nature is important because too often stranded cost is discussed as if it can be known with great specificity in advance, whereas, in fact, for any utility there is a *range* of potential stranded costs, corresponding to a variety of possible future outcomes. Complicating matters further, part of this uncertainty involves the future performance of the utility itself -- e.g., whether it will be successful in reducing future operating costs, finding new markets for its products, and so on.

Q. **How does a utility's future performance impact stranded cost?**

A. Utilities which are successful in cutting costs or increasing market share will lower their stranded cost from what it would have been otherwise because they will be able to recover a greater portion of their fixed generation costs and regulatory assets from the marketplace. Thus, when we address the question, "What will be the magnitude of stranded cost and how do we estimate it?" we are simultaneously faced with the question, "How successful will the utility's mitigation efforts be?" Yet it follows that the success of a utility's mitigation efforts will depend, in large part, on the *design* of the stranded cost recovery program and the *incentives* to mitigate stranded cost which are incorporated into that program.

Significantly, then, the magnitude of stranded cost is dependent on the success of utility mitigation which, in turn, is dependent on the design of the recovery program.

Therefore, it is critical to design stranded cost recovery in a way which maximizes utilities' incentives to undertake successful mitigation activities.

Q. What type of mitigation incentives do you recommend?

A. The best mitigation incentive is for the utility to be at risk for recovery of a substantial portion of its potentially stranded cost, and to be financially rewarded when its mitigation efforts are successful. This type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies and represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved. Note that during the phase-in period, the utility's exposure to strandable cost risk is limited to the portion of its historical customer base that participates in the competitive market.

Q. What approaches to recovery of strandable cost should be avoided?

A. We should avoid any recovery program in which all (or most) of the stranded cost risk is placed on customers (as was proposed, for example, by the former staff director in the Report of the Stranded Cost Working Group). Using such an approach, customers are required to guarantee recovery of a utility's potentially stranded cost under what are, in effect, worst-case conditions; then, if mitigation occurs, stranded cost charges are subject to a later reduction by means of a "true-up." From the perspective of both equity and efficiency, this type of approach represents the worst of both worlds: the burden of guaranteeing recovery of uneconomic costs is disproportionately borne by customers (inequitable), while the incentive mechanism for utilities to lower future stranded cost through mitigation is minimized (inefficient). In essence, such an approach presumes a worst-case scenario at the outset; then, by means of the recovery program design, the presumption of a worst-case scenario becomes a self-fulfilling prophesy.

Q. **What equity issues should the Commission consider?**

A. We must first recognize that the assignment of responsibility to customers for recovery of any potentially stranded cost is an extraordinary proposition. Regulatory change is a business risk inherent in all industries, and generally, it is expected that this risk is borne by company shareholders. But because the electric utility industry has been heavily regulated, utility advocates maintain that strandable cost recovery is the sole responsibility of customers under the terms of an implicit compact. Their argument presumes that deregulation of generation service is a one-way street: good for consumers, bad for investors. It ignores the fact that deregulation of generation prices will mean that investors will have the opportunity over the long-run to earn above a regulated return – using the very assets that will be the subject of stranded cost claims. Certainly, investors in electric utilities have been on notice for a number of years that restructuring and regulatory changes were coming which would introduce greater competition. These changes will provide long-term opportunities for some companies, but might also place full recovery of fixed costs at risk, at least in the short run. Because competition will provide opportunities for both customers and investors, it is inappropriate to conclude that changing the regulatory paradigm requires customers alone to shoulder the risk of strandable cost.

We should also bear in mind that the introduction of competition *by itself* does not cause stranded cost – nor is stranded cost caused by customers choosing new suppliers. Stranded cost can only occur if a monopoly generation provider is unable to recover all of its fixed costs plus regulatory assets in the new competitive market. This circumstance can only occur if competitive sellers are willing and *able* to sell generation at prices below what the former monopoly requires for recovery of fixed costs plus regulatory assets. *The ability of competitive suppliers to undercut incumbent utility prices is a situation which is not caused by customers*; nonetheless, the very concept of stranded cost recovery presumes that customers will be responsible for funding a program to subsidize some portion of above-market costs after the introduction of competition.

Given that the Rule contemplates that some customer charge for recovery of strandable cost will be levied, the public interest dictates that the Commission strike an appropriate balance between customer and utility interests in designing the recovery mechanism. The Commission recognizes this obligation in the Electric Competition Rules by enumerating eleven factors it will consider in determining stranded cost recovery. Included in these factors are: the impact of stranded cost recovery on prices paid by consumers in the competitive market, the impact on customers who do not participate in the competitive market, and the impact of stranded cost recovery on the effectiveness of competition itself. It is clear from these factors that the Commission seeks to balance customer and utility interests in approving a stranded cost recovery mechanism. To emphasize this intention, I recommend an addition to Section 1607(I) of the Rule which explicitly references this balancing, as indicated in Exhibit KCH-2. In addition, Section 1607(B) should be clarified by referencing the governing principles of 1607(I).

Q. How can the Commission best achieve a balance between customer and utility interests in approving a stranded cost recovery mechanism?

A. The recovery mechanism can be designed to ensure recovery of some reasonable portion of strandable costs via a transition charge paid by customers, while giving the utility the opportunity for recovery of the remainder through its mitigation efforts. The portion to be recovered through mitigation should be deemed to be "at-risk" for the utility from the outset; it should not be assigned at any time to the customers' transition charge.

Q. What portion of potentially stranded cost should be ensured via a transition charge on customers?

A. The answer to this question depends on the calculation method/recovery mechanism package which is adopted. For example, if the approach used to estimate strandable cost is relatively generous to the utility, then the portion of strandable cost recovered from customers through a transition charge should be lower. As a general proposition, the portion of strandable cost that is recovered through the transition charge should be in the range of 25 to 50 percent.

Q. Please clarify what you mean when you refer to a calculation approach which is "relatively generous to the utility."

A. As I have indicated previously in this testimony, when we speak today of stranded cost, we are really speaking of costs which are *at risk* of being "stranded" some time in the future; thus, for any utility there is a *range* of potential stranded costs, corresponding to a variety of possible future outcomes – some of which even depend on the utility's own future performance. Because there is a range of possible outcomes, the estimation of potential stranded cost will be very assumption-sensitive. The estimation will also be sensitive to the inclusion of certain variables in the calculation. How these variables and assumptions are treated will impact the magnitude of the estimate; certain treatments will result in strandable cost estimates which are higher, or more generous, than others. In general, the more an estimation approach builds into the strandable cost calculation the expectation that the utility's future *non-fixed* costs will continue to be equal to or above the levels experienced under regulation, the more generous the calculation is to the utility.

Q. **Can you give an example of the point you are making?**

A. Yes. At the risk of getting ahead of the discussion on calculation methods, I will note that certain methods – notably the utility-preferred net lost revenues approach – produce results in which the estimate of strandable cost is driven by assumptions concerning future operating costs and administrative and general (A&G) costs, such that for every dollar increase in the present-value forecast of these *non-fixed* costs there is a one dollar increase in the calculation of *strandable* (fixed) cost. Using such an estimation approach, every dollar of A&G cost which is assigned to generation results in a dollar of strandable cost. It is easy to see, then, that if we use such a method, and assume that a utility plans not to reduce – but to increase – its A&G costs in a competitive market, the entire increase shows up in the strandable cost estimate, a result which is very generous to the utility indeed. Strandable cost estimated in a manner this favorable to the utility should be balanced by recovering a lower portion of strandable cost via the transition charge and by considering a commensurately greater portion of strandable cost to be at-risk.

A. A price cap should be part of the development of a stranded cost recovery program. In addition, rate ceilings on traditional, bundled service, which are already in effect for certain utilities, should be continued for Standard Offer service.

Q. Please describe what you mean by the term "price cap."

A. In general, the term "price cap" simply refers to a ceiling on prices. However, in the context of strandable cost recovery in Arizona, particularly in the discussions of the Stranded Cost Working Group, "price cap" has been used in a very specific way. In this context, incorporating a price cap into the design of the strandable cost recovery program means that, for any customer, the sum of the transition charge plus delivery charges (i.e., transmission, distribution, ancillary services, system benefits charge) plus the market price of generation (used in calculating strandable cost) does not exceed current rates for that customer. The purpose of a price cap in this context is to design the strandable cost recovery program in a way to ensure that the final delivered price to consumers under competition is no greater than under regulation.

Q. Can you provide a simple example to illustrate this application of a price cap?

A. Yes. Suppose a particular customer (or customer class) pays 9 cents per kWh for electric service under current regulated rates. Further suppose that the unbundled charge for delivery services is 3.5 cents per kWh and that, for a given year, the forecasted market price of generation used to calculate strandable cost is 3.25 cents per kWh. Then if a price cap were required in the recovery program design, the transition charge for this customer could not exceed 9 cents minus 3.5 cents minus 3.25 cents, or 2.25 cents per kWh. Note that the price cap is accomplished not by regulating the price of generation – which, of course, under competition is set by the market; instead, the price cap results from the design of the transition charge, which is constrained to be no greater than the contribution to strandable cost that a customer makes under regulated rates. As I stated previously, this design feature can be met by calculating strandable cost on a year-to-year basis, and by having customers pay only for strandable cost associated with that year.

Q. What is the proper interpretation of the transition charge that is calculated under the price cap principle?

A. It is important to keep in mind that a price cap simply provides an *upper limit* on the transition charge. It identifies the *maximum* transition charge that could be levied on a customer; it is by no means the *target* level. Mathematically, a transition charge which is calculated/recovered on a year-to-year basis *and* which is designed to be less than 100 percent of strandable cost would meet the objectives of the price cap with room to spare.

This assurance notwithstanding, a price cap should still be part of the recovery mechanism design, at least as a backstop, because other parties' proposals for strandable cost recovery might very well caused delivered prices to be above what would be permitted under a price cap. For example, the former staff director advocated the use of the net revenues lost approach to *calculate* strandable cost over the remaining life of generation assets – 25 to 30 years; at the same time, he advocated *recovery* in ten years – but opposed making a price cap part of the recovery design. Under such a proposal, the introduction of competition could be accompanied by a price increase to customers that was directly attributable to the design of the strandable cost recovery program. If indeed, strandable cost recovery were designed in a manner that violated the price cap principle, the results would be nothing less than a regulatory fiasco.

Q. What factors should be considered for "mitigation" of stranded costs? (Question 9)

A. The Rule makes it clear that any activity undertaken by an Affected Utility that lowers cost or increases net revenue is considered to be mitigation of strandable cost. The question that faces us here is how to design strandable cost recovery such that cost-effective mitigation is given maximum encouragement.

By their nature, mitigation actions are an integral part of corporate strategy that should be governed by the principles of risk and reward, rather than regulatory prescription or second-guessing. Previously in this testimony, I recommended that the best mitigation incentive is for the utility to be at risk for a substantial portion of its strandable cost, and to be financially rewarded when its mitigation efforts are successful. This is accomplished by designing the transition charge to cover no more than 50 percent of strandable cost in a given year. Then, we can leave it to the utilities to implement whatever mitigation actions they believe to be most effective. As I testified, this type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

KEVIN C. HIGGINS
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Vitae

PROFESSIONAL EXPERIENCE

Senior Associate, Energy Strategies, Inc., Salt Lake City, Utah, February 1995 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," Utah Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Prefiled testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs); cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," Utah Public Service Commission, Case No. 84-999-20. Prefiled direct testimony submitted June 17, 1985. Prefiled rebuttal testimony submitted July 29, 1985; Cross-examined August 19, 1985.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," Utah Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986; cross-examined July 17, 1986.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," Utah Public Service Commission, Case No. 86-035-13; prefiled direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"Cogeneration: Small Power Production," Federal Energy Regulatory Commission, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," Utah Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," Utah Public Service Commission, Case No. 86-057-07. Prefiled direct testimony submitted January 15, 1988; cross-examined March 30, 1988.

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," Utah Public Service Commission, Case No. 87-035-27; prefiled direct testimony submitted April 11, 1988; cross-examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," Utah Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989; cross-examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," Utah Public Service Commission, Case No. 89-057-15. Pre-filed direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," Utah Public Service Commission, Case No. 95-057-02. Prefiled direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 1995.

"Questar Pipeline Company," Federal Energy Regulatory Commission, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," Wyoming Public Service Commission, Docket No. 2000-ER-95-99. Prefiled direct testimony submitted April 8, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," Arizona Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," Utah Public Service Commission, Docket No. 96-2018-01. Prefiled direct testimony submitted July 8, 1996.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," New York Public Service Commission, Case 96-E-0897. Testimony filed April 9, 1997. Cross examined May 5, 1997.

OTHER RELATED ACTIVITY

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present.

Member, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to present.

Member, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to present.

Member, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to present.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to present.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Consultant to business customers, "In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Preparation of comments and participation in staff workshops. Rule on retail electric competition adopted December 23, 1996.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Recommended additions to the Competition Rule

1. R14-2-1607.(B)

The Commission shall allow recovery of unmitigated Stranded Cost by Affected Utilities IN ACCORDANCE WITH THE PROVISIONS OF R14-2-1607(I).

2. R14-2-1607.(G)

~~The~~ AN Affected Utilit~~ies~~Y shall file estimates of unmitigated stranded cost AT LEAST EIGHT MONTHS PRIOR TO THE DATE IT REQUESTS STRANDED COST RECOVERY CHARGES TO BEGIN. Such estimates shall be fully supported by analyses and by records of market transactions undertaken by willing buyers and sellers.

3. R14-2-1607.(I)

The Commission shall, after hearing and consideration of analyses and recommendations presented by the Affected Utilities, Staff, and intervenors, determine for each Affected Utility the magnitude of Stranded Cost, and appropriate Stranded Cost recovery mechanisms and charges. In making its determination of mechanisms and charges, the Commission shall BALANCE UTILITY AND CUSTOMER INTERESTS BY considerING at least the following factors:

1. The impact of Stranded Cost recovery on the effectiveness of competition;
2. The impact of Stranded Cost recovery on customers of the Affected Utility who do not participate in the competitive market;
3. The impact, if any, on the Affected Utility's ability to meet debt obligations;
4. The impact of Stranded Cost recovery on prices paid by consumers who participate in the competitive market;
5. The degree to which the Affected Utility has mitigated, or ~~offset~~ SHOULD BE AT RISK FOR MITIGATING, Stranded Cost;
6. The degree to which some assets have values in excess of their book values;

7. Appropriate treatment of negative Stranded Cost;

8. The time period over which such Stranded Cost charges may be recovered. The Commission shall limit the application of such charges to a specified time period;

9. The ease of determining the amount of Stranded Cost;

10. The applicability of Stranded Cost to interruptible customers;

11. The amount of electricity generated by renewable generating resources owned by the Affected Utility.

4. R14-2-1607.(M)

STRANDED COST SHALL BE ALLOCATED AMONG CUSTOMER CLASSES IN A MANNER CONSISTENT WITH THE SPECIFIC COMPANY'S CURRENT RATE TREATMENT OF THE STRANDED ASSET, IN ORDER TO EFFECT A RECOVERY OF STRANDED COSTS THAT IS IN SUBSTANTIALLY THE SAME PROPORTION AS THE RECOVERY OF SIMILAR COSTS FROM CUSTOMERS OR CUSTOMER CLASSES UNDER CURRENT RATES.

Recommended Policies for Implementing the Competition Rule

1. The Commission should strike an appropriate balance between customer and utility interests in implementing a stranded cost recovery program. In addition, the program should be designed in a manner which maximizes utilities' incentives to undertake successful mitigation activities.

2. The portion of strandable cost recovered from customers through a transition charge should be in the range of 25 to 50 percent, depending on the specific calculation/recovery program that is adopted.

3. Utilities should be deemed to be at-risk for recovery of the remainder of their strandable cost (associated with the competitive market). They should be free to implement whatever mitigation actions they believe to be most effective, and should retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

4. The strandable cost recovery mechanism should be designed to incorporate a price cap, ensuring that the final delivered price to consumers under competition is no greater than under regulation. Incorporating a price cap into the design of the strandable cost recovery program means that, for any customer, the sum of the transition charge plus delivery charges (i.e., transmission, distribution, ancillary services, system benefits charge) plus the market price of generation (used in calculating strandable cost) does not exceed current rates for that customer.

5. The Commission should retain the important language in the Rule which states that any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than retail access shall not be used to calculate or recover any Stranded Cost from a consumer.

6. Strandable cost charges should not be assigned to service that had been interruptible under the customer's previous arrangement with the Affected Utility, because generation capacity is not constructed to provide interruptible service.

Specific Proposal for Calculation, Recovery, and Mitigation of Strandable Cost

1. A limited transition period of three to five years for calculation and recovery of strandable cost is designated.

2. Strandable cost is calculated using a hybrid of the replacement cost valuation and net revenues lost approaches, in which:

   (a) The net revenues lost approach is used to estimate strandable cost on a *year-to year* basis.

   (b) *Total* strandable cost is calculated using the replacement cost valuation method. This calculation is designated to be the maximum allowable strandable cost over the transition period, providing an upper bound on the sum of year-to-year strandable costs.

3. Customers pay for a portion of strandable cost through a transition charge levied on distribution service. During any given year, the transition charge applies only toward strandable cost associated with that same year.

4. The portion of strandable cost recovered through the transition charge declines each year, such that the overall percentage falls within the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent.

5. Utilities are deemed to be at-risk for recovery of the remainder of their strandable cost (associated only with the competitive market). They are free to implement whatever mitigation actions they believe to be most effective, and retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

6. Any "true-ups" are limited to adjustments for deviations from the market price of power.

7. At the end of the designated transition period, strandable cost is no longer estimated and the transition charge ceases.

DIRECT TESTIMONY

OF

J. ROBERT MALKO

ON BEHALF OF
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,
BHP COPPER, CYPRUS CLIMAX METALS, ASARCO, PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND MORENCI WATER & ELECTRIC COMPANY

IN THE MATTER OF THE COMPETITION
IN THE PROVISION OF ELECTRIC SERVICE
THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. U-0000-94-165

January 21, 1998

SUMMARY OF DIRECT TESTIMONY OF J. ROBERT MALKO

Q. PLEASE SUMMARIZE THE PRIMARY CONCLUSIONS OF YOUR DIRECT TESTIMONY.

A. The primary conclusions of my direct testimony are:

(1) A general framework for assessing stranded costs in the context of corporate restructurings in the electric utility industry from a public policy perspective has been proposed.

(2) Fairness and efficiency considerations need to be addressed and balanced when developing a risk sharing proposal concerning the calculations and collection (allocation) of electricity generation stranded costs between customers and investors.

(3) Mr. Kevin Higgins' proposal shares risks between customers and investors concerning the treatment of stranded costs by reasonably addressing fairness and efficiency considerations.

CONTENTS

DIRECT TESTIMONY OF J. ROBERT MALKO

I. INTRODUCTION AND WITNESS QUALIFICATION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is J. Robert Malko. I am a Professor of Finance for the College of Business at Utah State University located in Logan, Utah. My business consulting address is 245 North Alta Street, Salt Lake City, Utah 84103.

Q. WOULD YOU PLEASE DESCRIBE YOUR QUALIFICATIONS?

A. Yes. I received my Bachelor's degree, cum laude, in economics and mathematics from Loyola College in Baltimore, Maryland. I received my Master's and Doctorate degrees in economics from the Krannert Graduate School of Management at Purdue University in Lafayette, Indiana. I have taken graduate courses in business finance at the University of Wisconsin at Madison and accounting courses at Illinois State University in Normal, Illinois. I was also a Visiting Scholar in industrial engineering at Stanford University in Palo Alto, California.

At Utah State University, I teach the following undergraduate level and graduate level courses: Principles of Corporate Finance, Investments, Case Studies in Finance, and Managerial Economics. Besides my current position with Utah

State University, I have been on the faculties at Illinois Wesleyan University and Illinois State University. I have also presented guest lectures concerning energy utility issues at the University of Wisconsin at Madison, Stanford University, Michigan State University, University of California-Berkeley, and University of Utah.

I served during the period, 1975-1977, as the Chief Economist for the Public Service Commission of Wisconsin (PSCW). During this time, I also served as Chair and Vice Chair of the National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Economics. From 1977 to 1981, I was Project Manager and then Program Manager for the Electric Utility Rate Design Study. This study was prepared for NARUC and housed at the Electric Power Research Institute (EPRI) in Palo Alto, California. From 1981 to 1986, I returned to the position of Chief Economist with the PSCW. In 1981-1982, I was the Senior Staff Advisor to the NARUC Ad Hoc Committee on Utility Diversification. I assisted the committee in the preparation and publication of its "Final Report" in 1982. I also served as the Vice Chair of the NARUC Staff Subcommittee on Economics and Finance during this time period.

I have written or co-authored approximately 125 articles on energy utility economic and finance issues. During 1994 and 1995, I co-edited two books entitled Electric Utilities Moving Into the 21st Century and Reinventing Electric Utility Regulation published by Public Utilities Reports, Inc. I have also addressed several national conferences. I am a member of the American Finance Association, the American Economic Association, the Financial Management Association, and the Council on Economic Regulation. I am a past President of the Society of Utility and Regulatory Financial Analysts (SURFA), and I have served on its Advisory Council. I am a past Chair of the Transportation and Public Utilities Group of the American Economic Association, and I have served on its Executive Committee. I am a member of the Advisory Council of the Center for Public Utilities at New Mexico State University, and I serve on the Board of Directors at the National Regulatory Research Institute (NRRI).

I have testified on behalf of state regulatory commissions, state offices of consumer counsel, energy utilities, and customer groups before the following regulatory agencies: the Arizona Corporation Commission, the Connecticut Public Utilities Control Authority, the Federal Energy Regulatory Commission, the Hawaii Public Utilities Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Nevada Public Service Commission, the New Hampshire Public Utilities Commission, the New York Public Service Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of the District of Columbia, the Public Service Commission of Wisconsin, the Utah Public Service Commission, and the Virginia State Corporation Commission.

Exhibit JRM-1 provides additional information concerning my educational and professional background.

Q. BY WHOM ARE YOU EMPLOYED TO PRESENT THIS TESTIMONY?

A. I am employed as a Senior Consultant, on a part-time basis, by Energy Strategies, Inc. (ESI) of Salt Lake City, Utah. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, Morenci Water & Electric Company, and BHP Copper.

Q. WHAT ARE THE PRIMARY PURPOSES OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. The primary purposes of my direct testimony are to:

(1) Propose a framework to assess the treatment of stranded costs in the content of corporate restructurings in the electric utility industry from a public policy perspective;

(2) Examine the concept of risk sharing or risk allocation between electric utility investors and electric utility customers concerning the recovery of stranded costs in a restructuring environment; and

[1] AECC is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

(3) Critique and evaluate the proposals included in direct testimony presented by Mr. Kevin C. Higgins concerning the calculation of stranded costs and the collection of stranded costs.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR PREPARED UNDER YOUR DIRECTION?

A. Yes.

Q. HOW DOES YOUR DIRECT TESTIMONY RELATE TO THE 9 QUESTIONS SPECIFIED IN THE PROCEDURAL ORDER DATED DECEMBER 1, 1997?

A. My direct testimony primarily addresses issues related to Questions 3, 6, and 9 in the Procedural Order.

II. FRAMEWORK FOR ASSESSING STRANDED COSTS IN THE CONTEXT OF CORPORATE RESTRUCTURINGS

Q. PLEASE PROPOSE A FRAMEWORK FOR ASSESSING STRANDED COSTS IN THE CONTEXT OF CORPORATE RESTRUCTURINGS IN THE ELECTRIC UTILITY INDUSTRY FROM A PUBLIC POLICY PERSPECTIVE.

A. A proposed framework is presented and discussed in the following paper (Exhibit JRM-2): J. Robert Malko, "Assessing Corporate Restructurings in the Electric

Utility Industry: A Framework," appears in NRRI Quarterly Bulletin, Volume 17, Number 4, December 1996.

This proposed framework consists of a hierarchy of common and significant issues and addresses electric utility corporate restructurings from a public policy perspective. Regulatory issues are at the top in this framework of common issues. These issues involve matters that are of important concern to regulatory commissions regarding electric utility corporate restructurings and related impacts on the public interest. There are subsidiary or technical categories of issues in this framework.

Q. HOW DOES THE CONCEPT OF STRANDED COSTS RELATE TO THE PROPOSED FRAMEWORK?

A. The treatment of **stranded costs** in a restructuring environment has implications relating to regulatory issues and subsidiary (technical) categories of issues in the proposed framework.

Specifically, the treatment of stranded costs of an electric utility clearly has implications concerning risks to customers and associated customer choice, as well as, risks to investors and the financial health of the utility. Unreasonable allocations of stranded investment to customers will be harmful to customer choice and will create market barrier problems. Unreasonable allocations of stranded investment to investors will be harmful to the financial health of the utility.

III. RISK SHARING AND STRANDED COSTS

Q. WHY IS RISK SHARING OR RISK ALLOCATION BETWEEN CUSTOMERS AND INVESTORS IMPORTANT IN A RESTRUCTURING ENVIRONMENT FACING ELECTRIC UTILITIES?

A. There are changing risks facing customers and investors in this current environment. A regulatory commission should reasonably and prudently attempt to share or allocate risks to customers and investors in this transition process in order to address the important objectives of fairness and efficiency.

Q. WHAT IS ONE PRINCIPLE OR CONCEPT OF RISK SHARING THAT SHOULD BE CONSIDERED WITH RESPECT TO THE TREATMENT OF STRANDED COSTS?

A. **One principle** of risk sharing that should be considered with respect to stranded costs is the following: **If stranded costs in the aggregate have negative (positive) value, then the gain (loss) goes to investors.** This principle is based on the theory of estimated risk and expected return facing investors. On the other hand, customers forego the opportunity for potential gains, but they are not exposed to the potential losses of stranded costs.

Q. SHOULD THIS PROPOSED PRINCIPLE OF RISK SHARING WITH RESPECT TO THE TREATMENT OF STRANDED COSTS BE TEMPERED BY OTHER CONSIDERATIONS?

A. Yes. This proposed principle of risk sharing with respect to stranded costs should be tempered by other considerations, including economic and financial factors, in order to balance the objectives of (1) fairness between customers and investors, and (2) efficiency concerns relating to market and company operations, customer choice, transition to competition, and incentives.

Q. PLEASE DISCUSS THE ISSUE OF FAIRNESS BETWEEN CUSTOMERS AND INVESTORS RELATING TO STRANDED COSTS.

A. A critical issue is the "fair" and reasonable allocation of stranded costs between customers and investors. By balancing the interests of customers and investors, regulators attempt to arrive at a fair and reasonable allocation of stranded costs. The following considerations or factors should be recognized in this balancing process. First, restructuring activities in the electric utility industry are causing changes in activities and expectations associated with utility managers, investors, customers, and regulators including an increasing interest in using incentive and performance based tools. These restructuring activities are changing perceptions and expectations by various groups concerning fairness and efficiency issues in the electric power industry. Second, investors face various changing investment risks, including business and financial risks, when purchasing electric utility securities. Third, embedded generation capacity has been constructed to meet the forecasted needs of customers under the traditional regulatory framework of rate base regulation of an energy monopoly. However, technological and economic factors are now affecting customer choice.

Q. PLEASE DISCUSS THE ISSUE OF EFFICIENCY RELATING TO STRANDED COSTS.

A. Efficiency relates to the allocation of limited resources in the production of products and services in order to meet the needs of consumers. The baseline or target model for economic efficiency is the competitive market structure and associated marginal cost pricing. Therefore, a movement from a monopoly model to a workably competitive model is viewed as improving allocative efficiencies and pricing of products. A critical issue is how the treatment of stranded cost will affect or impact the obtaining of various efficiencies including customer choice, innovative pricing structures, and incentives for energy suppliers.

Q. PLEASE SUMMARIZE YOUR POSITION CONCERNING RISK SHARING AND STRANDED COSTS.

A. Fairness and efficiency considerations need to be recognized and balanced in the development of a risk sharing proposal concerning the calculation and collection (allocation) of electricity generation stranded costs between customers and investors.

IV. EVALUATION OF MR. HIGGINS' PROPOSAL CONCERNING STRANDED COSTS

Q. HOW DOES MR. HIGGINS' PROPOSAL CONCERNING THE CALCULATION AND COLLECTION OF STRANDED COSTS ALLOCATE RISK?

A. Mr. Higgins' proposal concerning stranded costs includes the following primary components.

(1) The proposal integrates the calculation method and the recovery mechanism into one framework or package.

(2) Stranded cost is estimated on an asset-by-asset basis by subtracting or taking the difference between: (i) the net book value of a utility's generation assets plus regulatory assets (regulatory value) **and** (ii) the current replacement cost of those assets (market value), using the most cost-effective available technology. One adjustment for any capitalized energy value implicit in utility facilities that have variable energy costs lower than the replacement technology would be made in the estimation of replacement costs.

This estimated stranded cost calculation using the replacement cost valuation approach represents an upper-bound estimation of stranded cost over the transition period. For each year during the transition period, a net revenues lost approach would be used to estimate stranded cost by estimating the difference between generation related revenues that the electric utility might have been expected to collect under continued traditional regulation and the generation related revenue forecasted under competitive market pricing. On a present value basis, total stranded cost using the replacement cost valuation approach would serve as an upper-bound constraint on the sum of the year-to-year stranded cost estimates based on a net revenues lost approach for the transition period of three to five years.

(3) The transition period for stranded cost recovery would be kept within a limited time period of three to five years. The portion of stranded costs assigned to customers would be kept within the 25% to 50% range of total stranded costs based on a net revenues lost approach for each year. As a feature of the transition design, the percentage of stranded cost recovered from customers via the transition charge would decline each year during the three to five year period, but the effective average (overall) percentage would be within the 50% to 25% range.

(4) The transition range would be levied as a "wires" charge on distribution service.

Q. HOW DOES MR. HIGGINS' PROPOSAL CONCERNING THE CALCULATION AND COLLECTION OF STRANDED COSTS ADDRESS FAIRNESS AND EFFICIENCY CONSIDERATIONS?

A. Concerning the issue of fairness, a range of 25% to 50% allocation of stranded costs of generation to customers reflects a reasonable balance between the interests of customers and investors during a changing and transition period of restructuring in the electric utility industry. This range is a balance of interests between the historic world of traditional regulation of electricity generation and the emerging world of deregulated electricity generation markets.

Concerning the issue of efficiency, the transition period of three to five years in the collection mechanism provides movement and direction to deregulated generation markets and effective customer choice. The collection mechanism provides some financial incentive for utility managers in the recovery of stranded costs.

Mr. Higgins' proposal addresses both fairness and efficiency considerations in the calculation method and recovery mechanism of stranded costs in order to share risks between customers and investors.

V. CONCLUSIONS

Q. WHAT ARE THE PRIMARY CONCLUSIONS OF YOUR DIRECT TESTIMONY?

A. The primary conclusions of my direct testimony are:

(1) A general framework for assessing stranded costs in the context of corporate restructurings in the electric utility industry from a public policy perspective has been proposed.

(2) Fairness and efficiency considerations need to be addressed and balanced when developing a risk sharing proposal concerning the calculations and

collection (allocation) of electricity generation stranded costs between customers and investors.

(3) Mr. Kevin Higgins' proposal shares risks between customers and investors concerning the treatment of stranded costs by reasonably addressing fairness and efficiency considerations.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION:

Doctor of Philosophy degree in economics from the Krannert Graduate School of Management at Purdue University (Lafayette, Indiana), 1972.

Master of Science degree in economics from the Krannert Graduate School of Management at Purdue University (Lafayette, Indiana), 1968.

Bachelor of Science degree, cum laude, in mathematics and economics (majors) and political science (minor) from Loyola College (Baltimore, Maryland), 1966.

Business finance courses at Graduate School of Business, University of Wisconsin (Madison), 1982-1986.

Visiting Scholar in industrial engineering and public utility economics, Stanford University (Palo Alto, California), 1980.

Accounting courses at Illinois State University (Normal, Illinois), 1971-1973 and public utility courses at the University of Wisconsin (Madison), 1976-1977.

GOVERNMENT AND BUSINESS:

Chief Economist, Public Service Commission of Wisconsin, Madison, Wisconsin, January 1981 to December 1986.

Economist, Program Manager, The Electric Utility Rate Design Study at the Electric Power Research Institute at Palo Alto, California; this is a study for the National Association of Regulatory Utility Commissioners; Program Manager, December 1979 to January 1981; Project Manager, December 1977 to December 1979.

Chief Economist, Public Service Commission of Wisconsin, Madison, Wisconsin, June 1975 to December 1977.

Economist, Utility Rates Division, Public Service Commission of Wisconsin, Madison, Wisconsin, December 1974 to June 1975.

Energy Utility Consultant (Spring 1996-present), Energy Strategies, Inc., Salt Lake City, Utah.

Energy Utility Consultant (Winter 1997), Retail Merchants Association, Concord, New Hampshire.

Energy Utility Consultant (Summer 1995-Spring 1996), Southern Company Services, Inc., Atlanta Georgia.

Energy Utility Consultant (Spring 1995), PECO Energy Company, Philadelphia, Pennsylvania.

GOVERNMENT AND BUSINESS: (Cont.)

Energy Utility Consultant (Fall 1994-Spring 1995), Virginia State Corporation Commission Staff, Richmond, Virginia.

Energy Utility Consultant (Fall 1994), Mountain Fuel Supply Company, Salt Lake City, Utah.

Energy Utility Consultant (Summer 1994-Fall 1994), Brooklyn Union Gas Company and the E Cubed Company, Brooklyn, New York.

Senior Consultant (Winter 1993-Winter 1997), Utility Services Group - AUS Consultants, Moorestown, New Jersey.

Energy Utility Consultant (Spring-Fall 1992), Wisconsin Energy Conservation Corporation, Madison, Wisconsin

Energy Utility Consultant (Fall 1990-Fall 1991) Associated Electric Cooperative, Inc., Springfield, Missouri.

Energy Utility Consultant (Fall 1990), Arizona Electric Power Cooperative, Inc., Benson, Arizona.

Energy Utility Consultant (Fall 1989 to present), The Management Exchange, New York City, New York.

Energy Utility Consultant (Summer 1989-Fall 1991, Spring 1993, and Spring 1997), Washington Gas Light Company, Washington, D.C.

Energy Utility Consultant (Spring 1989), LMSL, Inc. and the Arizona Corporation Commission, State of Arizona.

Energy Utility Consultant (Summer 1986-Spring 1988), Illinois Office of Public Counsel, State of Illinois.

Energy Utility Consultant (Fall 1985), Virginia State Corporation Commission, State of Virginia.

Energy Utility Consultant (Summer-Fall 1982, Spring 1984, Spring 1985, Spring-Summer 1990, Fall 1991-Spring 1992, Winter 1994), Hawaii Consumer Advocacy Division, State of Hawaii, Honolulu, Hawaii.

Energy Utility Consultant (Spring-Summer 1982, Summer-Fall 1983), Alaska Public Utilities Commission, State of Alaska.

Energy Utility Consultant (Winter 1982), Nevada Public Service Commission, State of Nevada.

Energy Utility Consultant (Fall 1981), Kentucky Public Service Commission, State of Kentucky.

Energy Utility Consultant (Spring 1981), Hawaii Public Utilities Division, State of Hawaii.

Energy Utility Consultant (Fall 1977), Electric Power Research Institute, Palo Alto, California.

Energy Utility Consultant (Spring-Summer 1977), Illinois Commerce Commission, State of Illinois.

Energy Utility Consultant (Spring-Summer 1977), Office of the Consumer Advocate, State of Pennsylvania.

Energy Utility Consultant (Winter 1976), Public Utilities Commission of Ohio, State of Ohio.

Energy Utility Consultant (Spring 1976, Spring 1977), Office of Consumer Counsel, State of Connecticut.

Economist, U.S. Department of Commerce, Bureau of Economic Analysis, Government Division, Washington, D.C., June 1974 to December 1974.

Program Performance Budget Consultant (Spring-Summer 1973), City of Bloomington, Bloomington, Illinois.

Tax Consultant (Summer-Fall 1972), City of Bloomington, Bloomington, Illinois.

GOVERNMENT AND BUSINESS: (Cont.)

Administrative Analyst (Summer 1969), Department of Fiscal Services, Division of Fiscal Research, State of Maryland, Annapolis, Maryland.

Worked on research projects in the Business Methods Department (Summer 1964) and the Business Computer Department (Summer 1965) of Western Electric Company, Baltimore, Maryland.

RESEARCH:

At Utah State University, I am continuing to focus my research on various financial and pricing issues, such as corporate restructuring, nuclear decommissioning, cost of capital analysis, and time-of-use pricing, concerning energy utilities.

At the Public Service Commission of Wisconsin between 1981 and 1986, I focused my research on various financial issues, such as diversification and rate of return analysis, concerning energy utilities and telephone utilities. In addition, I analyzed issues relating to rate design and cost-of-service studies for electricity, natural gas, and telephone. I developed and presented expert testimony in rate and rule making proceedings that pertain to economic and financial issues relating to public utilities.

At the Electric Power Research Institute between 1978 and 1980, I focused my research on the desirability and technical feasibility of time-of-use pricing and direct load controls for electricity usage.

At the Public Service Commission of Wisconsin between 1975 and 1977, I focused my research on various problems faced by electric utilities and gas utilities. I have analyzed problems related to rate design, cost of service studies, load management, consumer and environmental impact analysis, public utility productivity and demand forecasting. I have developed and presented expert testimony in rate and rule making proceedings that pertain to economic issues relating to public utilities.

At the U.S. Department of Commerce during 1974, I focused my research on estimating the interest subsidy associated with programs of the Federal Government and its agencies incorporated in the Federal Government sector of the national income accounts.

At Illinois Wesleyan University and Illinois State University between 1971 and 1974, I focused my research work on analyzing relationships between microeconomic theory and financial cost accounting theory.

For my doctoral research, I analyzed various aspects of benefits received by business firms and households from municipal fire protection services, and I proposed policy implication concerning taxes needed to finance these services. In this analysis, fire insurance rates were used in order to quantify benefits received by economic units. Dissertation has been used by Insurance Services Office, Midwestern Regional Office (Chicago). Dissertation Director, Keith Brown.

TEACHING:

Professor of Finance, College of Business, Utah State University (Logan, Utah), January 1987 to present; granted tenure in June 1988 and promoted to Full Professor in June 1989; I teach the following courses: Principles of Corporate Finance, Advanced Finance Problems (Case Studies), Finance Issues and Public Utilities, Managerial Economics, and Investments; won Outstanding MBA Professor of the Year Award, 1989-90 and 1990-91.

Visiting Guest Lecturer, College of Law, University of Utah (Salt Lake City, Utah), 1993.

Guest Lecturer, School of Business, University of Wisconsin at Madison, Spring 1976 to December 1986; I have taught and presented guest lectures in regulation of public utility courses and have presented guest lectures in business finance courses on a part-time basis.

Guest Lecturer, Department of Industrial Engineering and School of Business, Stanford University, Summer 1978 to Summer 1980; School of Business, University of California at Berkeley, Spring 1979; Department of Economics, Michigan State University, Spring 1978; I have presented guest lecturers in regulation of public utilities and applied microeconomics courses at these universities.

TEACHING: (Cont.)

Assistant Professor of Economics, Illinois Wesleyan University (Bloomington, Illinois), September 1970 to May 1974. At Illinois Wesleyan, I taught the following courses: Principles of Economics, Principles of Accounting, Intermediate Microeconomic Theory, Business Statistics, Money and Banking, Public Finance, Economic Growth and Development, and Mathematical Economics.

Assistant Professor of Business Administration, Illinois State University (Normal, Illinois), Spring 1973 to Spring 1974 on a part-time basis. Course taught: Managerial Economics.

Teaching Assistant (Graduate Instructor) at Purdue University from September 1966 to June 1970; won outstanding teaching award in 1970. At Purdue University, I taught the following courses: Principles of Economics, Economic History, Intermediate Microeconomic Theory and Intermediate Macroeconomic Theory.

PAPERS AND PUBLICATIONS:

This section of the resume lists papers and publications and is organized in the following manner: (1) academic and policy journals, (2) books, (3) chapters in books, (4) academic and policy conferences with published proceedings, (5) academic and policy conferences and (6) technical reports.

I. Academic and Policy Journals

J. Robert Malko, "Assessing Corporate Restructurings In The Electric Utility Industry: A Framework," appears in NRRI Quarterly Bulletin, Vol. 17, No. 4, Winter 1996-97 issue.

Joseph F. Brennan and J. Robert Malko, "Rate Unbundling: Are We There Yet? A Reality Check," in Public Utilities Fortnightly, June 1996 issue.

David A. Foltz, J. Robert Malko, Gregory J. Pumilia, and Thomas J. Purvenas, "Purchased Power Is Not A Riskless Strategy," appears in The Electricity Journal, Vol. 7, No. 10, December 1994.

J. Robert Malko, "Comments On The Paper by Rodney Stevenson and Dennis Ray," appears in Utilities Policy, Vol. 3, No. 4, October 1993.

Caryn L. Beck-Dudley and J. Robert Malko, "Dotting the Horizon: Will The United States Be Able To Decommission Its Nuclear Power Plants?" appears in Journal of Energy Law and Policy, Vol. 10, No. 2, 1990.

Donna L. Tanner, Richard J. Williams, and J. Robert Malko, "Utility Diversification: Issues and Activities in Virginia," appears in Electric Potential, February 1989 issue. This paper was also presented at The Sixth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute at The Ohio State University, Columbus, September 1988; this paper also appears in Conference Proceedings.

J. Robert Malko and Philip R. Swensen, "Corporate Restructurings In The Electric Utility Industry: Some Common Issues," appears in Business Insights, Spring 1989 Issue, Vol. 8., No. 2; an earlier version of this paper was presented at the Tenth Annual Public Utilities Conference, sponsored by New Mexico State University, held in Albuquerque, New Mexico, October 1987.

Ahmad Faruqui and J. Robert Malko, "Pakistan's Economic Development in a Global Perspective," appears in Asian Profile, Vol. 16, No. 6, December 1988 issue; an earlier version of this paper was presented at the Second Biennial Conference Of The Pakistan Engineers and Scientists Association, held at Stanford University, Palo Alto, California, September 1987; also appears in the Conference Proceedings.

J. Robert Malko and George R. Edgar, "Energy Utility Diversification and Small Business: A Wisconsin Perspective," appears in The Journal of Energy and Development, Vol., 13, No. 1 (issued July 1988); an earlier version of this paper was prepared for presentation to the Midwest Economics Association Annual Meeting, Chicago, Illinois, April 1988.

J. Robert Malko, "Alternative Approaches For Funding Nuclear Power Plant Decommissioning Expenses: Some Financial Issues and Considerations," appears in Forum For Applied Research And Public Policy, Vol. 2, No. 4, Winter 1987 issue.

PAPERS AND PUBLICATIONS: (Cont.)

I. Academic and Policy Journals

J. Robert Malko, Caryn L. Beck-Dudley, and Philip R. Swensen, "Corporate Restructuring and Transferring Regulation of Electricity Generation: Some Issues, Considerations and Activities," appears in Electric Potential, November-December 1987 issue; an earlier version of this paper was presented at the Nineteenth Financial Forum, sponsored by the National Society of Rate of Return Analysts, Washington, D.C., May 1987.

J. Robert Malko and George R. Edgar, "Diversification in the Gas Industry: Some Comments," (short comments) appears in Public Utilities Fortnightly, October 1987 issue.

J. Robert Malko, Richard Williams, and George Hermina, "Electric Utility Diversification: Activities In Some Eastern States," appears in The Kentucky Journal of Economics and Business, Vol. 7, September 1987 issue; an earlier version of this paper was presented at the Eastern Finance Association 1987 Annual Meetings, Baltimore, Maryland, April 1987; an abstract of this paper appears in the 1987 Proceedings Issue of the Financial Review; this paper was also presented at the National Association of Regulatory Utility Commissioners (NARUC) Annual Summer Committee Meetings San Francisco, California, July 1987; this paper also appears in The 1987 Report of the NARUC Committee on Utility Diversification, National Association of Regulatory Utility Commissioners, Washington, D.C., March 1988.

George R. Edgar and J. Robert Malko, "Electric Utilities as Part of Diversified Business: Some Considerations and Thoughts," appears in Electric Potential, July-August 1987 issue; this paper was presented at the Thirteenth Annual Rate Symposium, sponsored by the Institute for the Study of Regulation and the University of Missouri-Columbia, held in St. Louis, Missouri, February 1987; also appears in the Symposium Proceedings; this paper also appears in The 1987 Report of the NARUC Committee on Utility Diversification, National Association of Regulatory Utility Commissioners, Washington, D.C., March 1988.

J. Robert Malko, "Diversification and Strategic Planning in the Electric Power Industry," (short comments) appears in Forum For Applied Research And Public Policy, Vol. 2, No. 2, Summer 1987 issue.

J. Robert Malko and George R. Edgar, "Energy Utility Diversification: Its Status in Wisconsin," Public Utilities Fortnightly, August 1986 issue.

Steven G. Kihm, Clarence E. Mougin, and J. Robert Malko, "An External Fund Approach for Nuclear Power Plant Decommissioning Expenses: Wisconsin Activities," appears in Electric Potential, March-April 1986 issue.

J. Robert Malko, "Applying Regulatory Strategic Planning to Electric Utilities," appears in Electric Potential, January-February 1986 issue.

J. Robert Malko and Gregory B. Enholm, "Applying CAPM In a Utility Rate Case: Current Issues and Future Directions," appears in Electric Potential, September-October 1985 issue.

Ahmad Faruqui and J. Robert Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Evidence from Twelve Experiments with Peak-Load Pricing," appears in Energy: The International Journal, October 1983 issue.

J. Robert Malko, "Comments: Jury Still Out On The Arbitrage Pricing Theory," (short comments) appears in Public Utilities Fortnightly, June 1983 issue.

J. Robert Malko and Terrace B. Nicolai, "Implementing Residential Time-of-Day Pricing of Electricity in Wisconsin: Some Current Activities and Issues," presented at Ninth Annual Symposium on Problems of Regulated Industries, sponsored by the Institute for Study of Regulation and the University of Missouri-Columbia, held at Kansas City, Missouri, February 1983; appears in Proceedings of this conference; also appears in Electric Ratemaking, February/March 1983 issue.

Stanley York and J. Robert Malko, "Utility Diversification: A Regulatory Perspective," Public Utilities Fortnightly, January 1983 issue.

PAPERS AND PUBLICATIONS: (Cont.)

I. Academic and Policy Journals

Gregory B. Enholm, Theodore M. Jaditz, and J. Robert Malko, "Electric Utility Diversification In The 1980s: A Challenge For Applied Regulatory Economics," presented at the Midwest Economics Association Forty-Sixth Annual Meeting, Chicago, Illinois, April 1982; appears in The Journal of Energy and Development, Autumn 1982 issue.

J. Robert Malko and Gregory B. Enholm, "Electric Utility Diversification: Some Regulatory Concerns and Issues," appears in Electric Ratemaking, Vol. 1, No. 2, April 1982.

J. Robert Malko, Dennis J. Ray and Nancy L. Hassig, "Time-of-Day Pricing of Electricity Activities in Some Midwestern States," presented at the Midwest Economics Association Annual Meeting, Chicago, Illinois, April 1979; appears in Journal of Business Administration, Volume 12, Spring 1981.

Teri L. Vierima and J. Robert Malko, "Natural Gas Rate Design: Innovative Activities in Wisconsin," Public Utilities Fortnightly, October 1981 issue.

J. Robert Malko and Robert G. Uhler, "Helping Regulators Evaluate Load Management: An Update of The Rate Design Study," Public Utilities Fortnightly, October 1979 issue.

Carol T. Everett and J. Robert Malko, "Measuring the Impact of Residential Gas and Electric Rates," Public Utilities Fortnightly, December 1977 issue.

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J. Robert Malko and David Stipanuk, "Electric Peak-Load Pricing: A Wisconsin Framework," Public Utilities Fortnightly, July 1976 issue.

Richard D. Cudahy and J. Robert Malko, "Electric Peak-Load Pricing: Madison Gas and Beyond," Wisconsin Law Review, Volume 1976, Number 1, Spring 1976.

J. Robert Malko and Ernst Harwig, "Municipal Electric Utility Pricing," Governmental Finance, February 1976.

II. Books

Gregory B. Enholm and J. Robert Malko, editors, Reinventing Electric Utility Regulation, published by Public Utilities Reports, Inc., Vienna, Virginia, 1995.

Gregory B. Enholm and J. Robert Malko, editors, Electric Utilities Moving Into The 21st Century, published by Public Utilities Reports, Inc., Arlington, Virginia, 1994.

James M. Fischer, J. Robert Malko, and Richard L. Wallace, editors, Pricing Electric, Gas, and Telecommunication Services: Rate Symposium Proceedings, published by University of Missouri-Columbia, 1989.

III. Chapters in Books

J. Robert Malko and Richard J. Williams, "Traditional and New Regulatory Tools," appears in Reinventing Electric Utility Regulation, edited by Gregory B. Enholm and J. Robert Malko, Public Utilities Reports, Inc., 1995.

Gregory B. Enholm and J. Robert Malko, "Assessing the Future of Electric Utility Regulation," appears in Reinventing Electric Utility Regulation, edited by Gregory B. Enholm and J. Robert Malko, Public Utilities Reports, Inc., 1995.

PAPERS AND PUBLICATIONS: (Cont.)

III. Chapters in Books

Gregory B. Enholm and J. Robert Malko, "Meshing New Regulation with New Utilities," appears in Reinventing Electric Utility Regulation, edited by Gregory B. Enholm and J. Robert Malko, Public Utilities Reports, Inc., 1995.

Gregory B. Enholm and J. Robert Malko, "Assessing the Electric Utility Industry's Future," appears in Electric Utilities Moving Into the 21st Century: 18 Views of the Elephant, edited by Gregory B. Enholm and J. Robert Malko, Public Utilities Reports, Inc., 1994.

Gregory B. Enholm and J. Robert Malko, "Electric Utilities in the 21st Century," appears in Electric Utilities Moving Into the 21st Century: 18 Views of the Elephant, edited by Gregory B. Enholm and J. Robert Malko, Public Utilities Reports, Inc., 1994.

J. Robert Malko and Philip R. Swensen, "Pricing And The Electric Utility Industry," appears in Public Utility Regulation: The Social Control Of Industry, edited by Kenneth Nowotny, David B. Smith, and Harry M. Trebing, Kluwer Academic Publishers, 1989.

Gregory B. Enholm and J. Robert Malko, "Financing The New Midwest Bell Holding Company - AMERITECH," presented at Midwest Finance Association Annual Meeting, held at Chicago, Illinois, April 1984; appears in: Albert L. Danielsen and David R. Kamerschen, editors, Telecommunications In The Post Divestiture Era, D.C. Heath and Company, 1986.

Gregory B. Enholm and J. Robert Malko, "State Regulatory Treatment of Electric Utility Diversification," presented at the Fifth Annual Public Utilities Conference, sponsored by New Mexico State University, held at Albuquerque, New Mexico, October 1982; appears in Terry A. Ferrar, James L. Plummer, and William Hughes, editors, Electric Power Strategic Issues: Deregulation and Diversification, Public Utilities Reports, Inc., 1983.

J. Robert Malko and Gregory B. Enholm, "Challenges For Electric Utilities and Regulatory Commissions in the Decade of the 1980s," appears in Albert L. Danielsen and David R. Kamerschen, editors, Current Issues in Public Utility Economics: Essays in Honor of James C. Bonbright, published by D.C. Heath and Company, 1983.

J. Robert Malko, Dennis J. Ray, and Nancy L. Hassig, "Time-Of-Day Pricing of Electricity Activities in Some Midwestern States," appears in Energy Crisis: Policy Response, edited by Peter Nemetz, The Institute for Research of Public Policy, Montreal, Canada, 1981.

Robert G. Uhler and J. Robert Malko, "Electricity Pricing for Conservation and Solar Energy Systems," appears as a chapter in Economics of Energy Conservation and Use of Solar Energy, edited by F. Keith and R. West, CRC Press, Volume I, 1980.

J. Robert Malko and Ahmad Faruqui, "Implementing Time-Of-Day Pricing of Electricity: Some Current Challenges and Activities," presented at Public Utility Conference, Graduate School of Business Administration, Rutgers University, Newark, New Jersey, October 1979; appears in, Issues In Public Utility Pricing and Regulation, edited by M. Crew, Lexington Books, 1980.

IV. Academic and Policy Conferences with Published Proceedings

J. Robert Malko and Philip R. Swensen, "Assessing Corporate Restructurings And The Electricity Markets: Some Issues And Framework," presented at 10th Annual Conference on Electricity Law and Regulation, sponsored by ABA Section of Natural Resource, Energy and Environmental Law, Denver, Colorado, February 1997; this paper appears in Conference Proceedings.

Gregory B. Enholm and J. Robert Malko, "Changing The Rules: The Pros and Cons of Incentive and Performance Based Regulation," presented at 106th Annual Convention and Regulatory Symposium, National Association of Regulatory Utility Commissioners, Reno, Nevada, November 1994; this paper appears in Symposium Proceedings.

J. Robert Malko and Philip R. Swensen, "Corporate Restructuring In The Electric Utility Industry: Some Thoughts," presented at Twenty-Third Annual Conference, sponsored by the Institute of Public Utilities at Michigan State University, Williamsburg, Virginia, December 1991, appears in Regulatory Responses to Continuously Changing Industry Structures, Michigan State University Public Utilities Papers, 1993.

PAPERS AND PUBLICATIONS: (Cont.)

IV. Academic and Policy Conferences with Published Proceedings

Dennis Ray, Gary Mathis, and J. Robert Malko, "Electric Rate-Making Innovations In Wisconsin During the 1980s," presented at the Fifteenth Annual Rate Symposium, sponsored by the Missouri Public Services Commission, The University of Missouri-Columbia, and Utah State University, held in St. Louis, Missouri, February 1989; this paper appears in Conference Proceedings.

J. Robert Malko, "Utility Financial Planning In The Wake of Seabrook and Shoreham," presented at the One-Hundredth Annual Convention and Regulatory Symposium, National Association of Regulatory Utility Commissioners, San Francisco, California, November 1988, and appears in Proceedings, of this symposium.

Caryn L. Beck-Dudley and J. Robert Malko, "Nuclear Power Plant Decommissioning: Unanswered Questions Still Loam," presented at the American Business Law Association Annual Meeting, New Orleans, Louisiana, August 1988; this paper appears in the refereed Conference Proceedings, Fall 1988.

J. Robert Malko, Caryn L. Beck-Dudley, and Philip R. Swensen, "Corporate Restructurings In The Electric Utility Industry: Some Issues and Activities," presented at The Utility Industries In Transition Conference, sponsored by New Mexico State University, held in Albuquerque, New Mexico, April 1988; this paper appears in Conference Proceedings, 1988.

Ahmad Faruqui, J. Robert Malko, and Philip R. Swensen, "Competitive Electricity Pricing Strategies: A California Perspective," presented at the Fourteenth Annual Rate Symposium, sponsored by the Missouri Public Service Commission, the University of Missouri-Columbia and Utah Sate University, held in Kansas City, Missouri, February 1988; this paper appears in Conference Proceedings.

Rodney E. Stevenson, George R. Edgar, and J. Robert Malko, "An Assessment of Reforms and Deregulation in the Context of Societal Values and Equity," Nineteenth Annual Conference, sponsored by the Institute of Public Utilities at Michigan State University, Williamsburg, Virginia, December 1987; appears in Alternatives to Traditional Regulation: Options for Reform (Conference Proceedings), edited by Patrick C. Mann and Harry M. Trebing, Michigan State University Public Utilities Papers, 1988.

Caryn L. Beck-Dudley and J. Robert Malko, "Diversified Regulatory Approaches To Electric Utility Diversification," presented at the American Business Law Association Annual Meeting, Philadelphia, Pennsylvania, August 1987; appears in the Conference Proceedings.

George R. Edgar and J. Robert Malko, "Electric Utility Diversification And The Role of The Regulator: A Wisconsin Perspective," presented at the Current Issues Challenging The

Regulatory Process Conference, sponsored by New Mexico State University, held at Albuquerque, New Mexico, April 1987; appears in Conference Proceedings.

J. Robert Malko, Clarence E. Mougin and Steven G. Kihm, "Funding For Nuclear Power Plant Decommissioning Expenses: Considerations of Financial Assurance And Federal Tax Regulations," presented at The Eighteenth Annual Williamsburg Conference, Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986; appears in New Regulatory And Management Strategies In A Changing Market Environment, edited by Patrick C. Mann and Harry M. Trebing, Michigan State University Public Utilities Papers, 1987.

J. Robert Malko and Steven G. Kihm, "Internal vs. External Fund Approaches for Nuclear Power Plant Decommissioning Expenses: Current Issues and Activities," presented at The Fifth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute, The Ohio State University, Columbus, September 1986 and appears in Proceedings of this conference.

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VI. Technical Reports

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An Analysis of Revenue Sources For The City of Bloomington, prepared by J. Robert Malko, prepared for the Municipal Government of Bloomington, Illinois, September 1972.

PRESENTATIONS:

Electric Utility Rate Design Study Activities (1979-80)
Utah Public Service Commission Staff, Salt Lake City, Utah, July 1980
NARUC Committee on Electricity, San Francisco, California, July 1980
Northwest Public Power Association Rates Symposium, Vancouver, B.C., Canada, July 1980
Quebec Hydro Staff, Montreal, Quebec, Canada, July 1980
Illinois Commerce Commission Staff, Springfield, Illinois, June 1980
Western Conference of Public Service Commission, Anchorage, Alaska, June 1980
Alaska Public Utilities Commission, Anchorage, Alaska, June 1980
APPA Load Management Conference, Kansas City, Missouri, June 1980
Commonwealth Edison Company Staff, Chicago, Illinois, March 1980
Electricite de France Staff, Paris, France, February 1980
ANIE/INTEL Conference, Milan, Italy, February 1980
The Electricity Council Staff, London, England, February 1980
Tennessee Valley Authority Staff, Knoxville, Tennessee, December 1979
APPA Rates Workshop, San Francisco, California, November 1979
Commonwealth Club, San Francisco, California, November 1979
APPA Rates and PURPA Conference, Denver, Colorado, November 1979
Colorado Public Utilities Commission Staff, Denver, Colorado, November 1979
Bonneville Power Administration Staff, Portland, Oregon, October 1979
Iowa State Legislature, Public Utility Joint Subcommittee, Des Moines, Iowa, October 1979
Iowa State Commerce Commission Staff, Des Moines, Iowa, October 1979
Edison Electric Institute Rate Research Committee, Delavan, Wisconsin, September 1979
Tennessee Valley Authority Staff, Chattanooga, Tennessee, September 1979
NARUC Staff and District of Columbia Public Service Commission Staff, Washington, D.C., September 1979
Edison Electric Institute Staff, Washington, D.C., September 1979
U.S. Department of Energy, Economic Regulatory Administration, Office of Utility Systems Staff, Washington, D.C.. September 1979
National Rural Electric Cooperative Association Staff, Washington, D.C., September 1979
Connecticut Public Utilities Control Authority Staff, Hartford, September 1979
New Hampshire Public Utilities Commission, Concord, September 1979
Ontario Hydro Staff, Toronto, Ontario, Canada, August 1979

NARUC Committee on Electricity, San Francisco, California, August 1979
1979 NARUC Annual Regulatory Studies Programs, Michigan State University, August 1979
Michigan Public Service Commission, Lansing, August 1979
California Public Utilities Commission, San Francisco, California, July 1979
Minnesota Public Service Commission, St. Paul, July 1979
Virginia State Corporation Commission, Richmond, July 1979
North Carolina Utilities Commission, Raleigh, July 1979
Research Triangle Institute, Economics Section, Raleigh, July 1979
Wisconsin Public Service Commission, Madison, July 1979
University of Wisconsin, Utility Rates Conference, Madison, July 1979
American Public Power Association Conference, Seattle, June 1979
Washington Utility and Transportation Commission, Olympia, June 1979
Stanford University, Public Utilities Conference, Palo Alto, June 1979
Massachusetts Department of Public Utilities, Boston, May 1979
University of California, Graduate School of Business, Berkeley, May 1979
Federal Energy Regulatory Commission, Washington, D.C., April 1979
University of Wisconsin, Utility Load Management Conference, Madison, April 1979
Electric Power Research Institute, Energy Analysis Department Symposium, Palo Alto, March 1979
U.S. Department of Energy, Economic Regulatory Administration, Washington, D.C., February 1979
Edison Electric Institute Rate Research Committee Conference, New Orleans, January 1979

TESTIFYING EXPERIENCE:

Presented testimony before the Arizona Corporation Commission (1989), the Connecticut Public Utilities Control Authority (1976-77), District of Columbia Public Service Commission (1990), the Federal Energy Regulatory Commission (1986), the Hawaii Public Utilities Commission, (1981, 1984-85, 1990, 1992, 1994), the Illinois Commerce Commission (1987-88), Maryland Public Service Commission (1990-1991), the New Hampshire Public Utilities Commission (1997), the Nevada Public Service Commission (1982), the New York Public Service Commission (1994), the Pennsylvania Public Utility Commission (1977), the Public Service Commission of Wisconsin (1975-77, 1981-86), the Utah Public Service Commission (1994), and the Virginia State Corporation Commission (1985, 1993).

ORGANIZATIONS AND COMMITTEES:

American Finance Association

American Economics Association; Transportation and Public Utility Group, Vice-Chair, 1992, Chair, 1993, and Executive Committee, 1994-1996.

American Law and Economics Association

Financial Management Association

Midwest Finance Association

Midwest Economics Association

Eastern Finance Association

The National Society of Rate of Return Analysts Advisory Council, 1996-2000, Board of Directors, 1984-86, 1990-1996; Vice President, 1986-1988 and President 1988-90

Rate and Regulatory Symposium, University of Missouri, Advisory Council, 1987-97

Council on Economic Regulation Fellow, 1986-96

ORGANIZATIONS AND COMMITTEES: (Cont.)

National Association of Regulatory Commissioners - Staff Subcommittee on Economics and Finance (Chairman, 1976-77 and Vice Chairman, 1981-86)

Who's Who in California Business and Finance, 1980

University of Wisconsin-Madison, Wisconsin Public Utility Institute, Executive Board (Chairman 1981-82), 1981-1985.

New Mexico State University, Public Utility Conference Advisory Committee, 1981-97.

Electric Power Research Institute, Demand and Conservation Program, Project Review Committee, 1982-83.

Alpha Sigma Nu, the National Jesuit Honor Society

Beta Gamma Sigma, National Honor Society for Business Schools.

Electric Ratemaking Journal, Board of Advisors, 1982-83.

Electric Potential Journal, Honorary Board of Editors, 1987-88.

Forum For Applied Research and Public Policy, Editorial Board, 1987-91.

The Kentucky Journal of Economics and Business, Board of Editors 1987-97.

The Electricity Journal, Board of Editors 1988-97.

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- *B.S. Mathematics and Economics with honors, Loyola College*
- *M.S. and Ph.D. Economics, Krannnert Graduate School of Management at Purdue University*
- *Visiting Scholar in Industrial Engineering, Stanford University*
- *Graduate Courses in Business Finance and Investment Theory, University of Wisconsin at Madison*
- *Accounting Courses, Illinois State University*
- *Member of Beta Gamma Sigma*

Expertise

- *Energy Utility Financial Issues*
- *Energy Utility Costing/Pricing Issues*

Recent Selected Projects

- *Southern Company Services Consultant (Summer 1995-Spring 1996)*
- *Virginia State Corporation Commission Consultant (Spring 1995)*
- *Brooklyn Union Gas Company Consultant (Fall 1994)*

Dr. Malko is a Professor of Finance in the College of Business at Utah State University in Logan, Utah. He serves as an Advisory Council Member of the Society of Utility and Regulatory Financial Analysts and served as President of this organization between 1988 and 1990. He serves on the Executive Committee of the Transportation and Public Utilities Group of the American Economic Association. He also serves on the Advisory Council of the Public Utilities Center at New Mexico State University.

Earlier (1975-77 and 1981-86), J. Robert Malko served as Chief Economist at the Public Service Commission of Wisconsin. He also served as Chairman and Vice-Chairman of the Staff Subcommittee on Economics and Finance of the National Association of Regulatory Utility Commissioners. In 1978-80, he served as Program Manager of the Electric Utility Rate Design Study at the Electric Power Research Institute in Palo Alto, California. During 1974, Dr. Malko was employed as an Economist at the U.S. Department of Commerce in Washington, D.C.

Dr. Malko has presented guest lectures on public utility and regulatory issues at several universities. He has carried out consulting assignments for state governments and energy utilities. Dr. Malko has appeared as an expert witness on energy utility finance and pricing issues before several regulatory commissions. He has written approximately 125 articles on public utility economics and finance that have been published in books and journals including, <u>Forum for Applied Research and Public Policy</u>; <u>Energy: The International Journal</u>; and <u>Wisconsin Law Review</u>. Dr. Malko is co-editor of <u>Electric Utilities Moving Into The 21st Century</u>, published by PUR in 1994 and <u>Reinventing Electric Utility Regulation</u>, published by PUR in 1995.

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Assessing Corporate Restructurings In the Electric Utility Industry: A Framework

By
J. Robert Malko, Ph.D.

Introduction

Corporate restructurings of electric utilities in the United States have become an important and controversial issue during the 1980s and 1990s.[1] Regulators and electric utility executives have different perspectives concerning corporate restructurings associated with diversification, mergers, and functional separation of generation, transmission, and distribution.[2]

Regulators attempt to regulate electric utilities effectively in order to assure that adequate electricity services are provided at reasonable cost and to protect the public interest which includes considering choices and risks to customers. Regulators are considering and developing new regulatory approaches in order to address corporate restructurings and balance regulation and competitive pressures.

Corporate restructurings of electric utilities in the United States have become an important and controversial issue during the 1980s and 1990s. Regulators and electric utility executives have different perspectives concerning corporate restructurings associated with diversification, mergers, and functional separation of generation, transmission, and distribution.

Electric utility executives typically view corporate restructurings as a potential partial solution to financial challenges and problems and are analyzing corporate restructuring activities within the framework of the corporate strategic planning process. Executives attempt to find new sources of economic value and consider risks and potential returns to investors in an increasingly competitive environment. The parent holding company is generally used as the basic corporate form for restructuring activities in the electric utility industry. However, the wholly-owned utility subsidiary structure remains in use for some

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[1]For a discussion of corporate restructuring issues and activities in the electric utility industry, see the following:

> Gregory B. Enholm and J. Robert Malko, editors, *Reinventing Electric Utility Regulation* (Public Utilities Reports, Inc.: Vienna, Virginia, 1995); Gregory B. Enholm and J. Robert Malko, editors, *Electric Utilities Moving Into The 21st Century* (Public Utilities Reports, Inc.: Arlington, Virginia, 1994); Scott A. Fenn, *Mergers and Financial Restructuring In The Electric Power Industry: A New Investment Opportunity?* (Investor Responsibility Research Center: Washington, D.C., 1988); J. Robert Malko and Philip R. Swensen, "Corporate Restructuring In The Electric Utility Industry: Some Thoughts," presented at the *Twenty-Third Annual Conference*, sponsored by the Institute of Public Utilities at Michigan State University, Williamsburg, Virginia, December 1991, and appears in *Regulatory Responses to Continuously Changing Industry Structures* (Michigan State University Public Utilities Papers: East Lansing, MI, 1993); Curtis Moulton, "Analyzing Electric Utility Mergers and International Expansion," presented at the *Twenty-Eighth Financial Forum: The National Society Of Rate Of Return Analysts*, Richmond, Virginia, May 1996.

[2]For somewhat different perspectives and views concerning electric utility corporate restructurings, see the following:

> J. Robert Malko and Philip R. Swensen, "Corporate Restructurings In The Electric Utility Industry: Some Common Issues" *Business Insights* 8, no. 2 (1989); an earlier version of this paper was presented at the *Tenth Annual Public Utilities Conference*, sponsored by New Mexico State University, held in Albuquerque, New Mexico, October 1987; Philip R. O'Connor and Wayne P. Olson, "PUHCA Reform : Maintaining State Prerogatives," in *Regulatory Responses to Continuously Changing Industry Structures* (Michigan State University Public Utilities Papers: East Lansing, MI, 1993); James Plummer, Terry Ferrar, and William Hughes, editors, *Electric Power Strategic Issues* (Public Utilities Reports, Inc.: Arlington, Virginia, 1983); Harry M. Trebing, editor, *Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries* (Michigan State Public Utilities Papers: East Lansing, MI, 1983).

restructurings.[3]

The primary purpose of this paper is to propose a framework to assess corporate restructurings in the electric utility industry from a public policy perspective. This paper is organized in the following manner. First, different types of corporate restructurings in the electric utility industry are examined. Second, reasons for corporate restructuring activities are presented. Third, a framework for assessing corporate restructuring activities is proposed. Fourth, the application of the framework is discussed.

The primary purpose of this paper is to propose a framework to assess corporate restructurings in the electric utility industry from a public policy perspective.

Types Of Restructurings

Three general types of corporate restructuring activities concerning electric utilities include: (1) mergers, (2) diversification, and (3) functional separation of generation, transmission, and distribution. Chart 1 presents alternative corporate structures and compares the traditional integrated utility system to the emerging power industry.

The most common rationale for mergers is the existence of synergy.[4] The value of the combined enterprise is greater than the sum of the values of the separate firms when synergy exists. Synergism can arise from the following sources: operating economies, financial economies, managerial efficiency, and increased market power. Electric utilities have recently demonstrated an increased interest in horizontal mergers or combining in the same line of business.[5] Table 1 presents selective pending merger activities of electric utilities as of May 1996.

Electric utility diversification became an important and a controversial issue during the decade of the 1980s and continues to receive significant attention during the decade of the 1990s.[6] Electric utilities diversified into energy-related activities and nonenergy related activities. Electric utilities are typically using either the parent holding company structure or the wholly-owned utility subsidiary structure as the basic corporate form to pursue diversification activities. Examples of electric utilities that have pursued diversification activities include: Dominion Resources, Inc., FPL Group, Inc., Hawaiian Electric Industries, Inc., Pinnacle West Capital Corporation, PacifiCorp, Potomac Electric Power Company, and WPL Holdings, Inc.

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[3] J. Robert Malko, Richard Williams, and George Hermina, "Electric Utility Diversification: Activities In Some Eastern States," appears in *The Kentucky Journal of Economics and Business* 7, no. 9 (1987); an earlier version of this paper was presented at the *Eastern Finance Association 1987 Annual Meetings*, Baltimore, Maryland, April 1987.

[4] Eugene F. Brigham, *Fundamental of Financial Management* (The Dryden Press: Fort Worth, Texas, 1995), Chapter 21.

[5] Curtis Moulton, "Analyzing Electric Utility Mergers and International Expansion," presented at the *Twenty-Eighth Financial Forum: The National Society Of Rate Of Return Analysts*, Richmond, Virginia, May 1996.

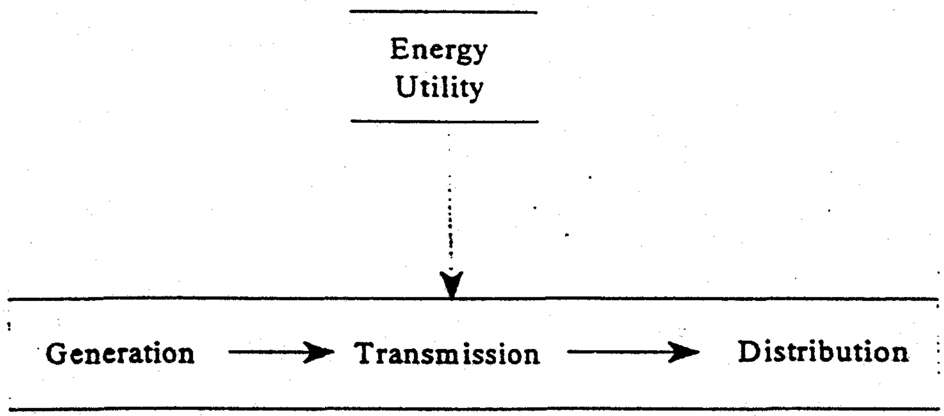
[6] For somewhat different perspectives and views concerning electric utility diversification and related corporate restructurings, see the following:

> George R. Edgar and J. Robert Malko, "Electric Utility Diversification and the Role of The Regulator" *Proceedings of The Current Issues Challenging The Regulatory Process Conference* (New Mexico State University: Albuquerque, New Mexico, April 1987); Edison Electric Institute (EEI), Economics Division, *Investor-Owned Electric Utility New Business Ventures: A Survey of Utility Diversification Activities* (EEI: Washington, D.C., October 1981, and [updated version] December 1984); Mark D. Luftig, Gregor B. Enholm, and Douglas W. Preiser, *Electric Utility Diversification* (Solomon Brothers: New York City, New York, October 1988); and Robert W. Shaw, Jr., "Diversification: Risks and Rewards" *Diversification, Deregulation, and Increased Uncertainty in the Public Utili Industries*, edited by Harry M. Trebing (Michigan State University Public Utilities Papers: East Lansing, MI, 1983)

CHART 1

ALTERNATIVE CORPORATE STRUCTURES FOR ELECTRIC UTILITIES: TRADITIONAL AND EMERGING

Integrated Utility System—The Traditional Power Industry



New/Emerging Power Industry

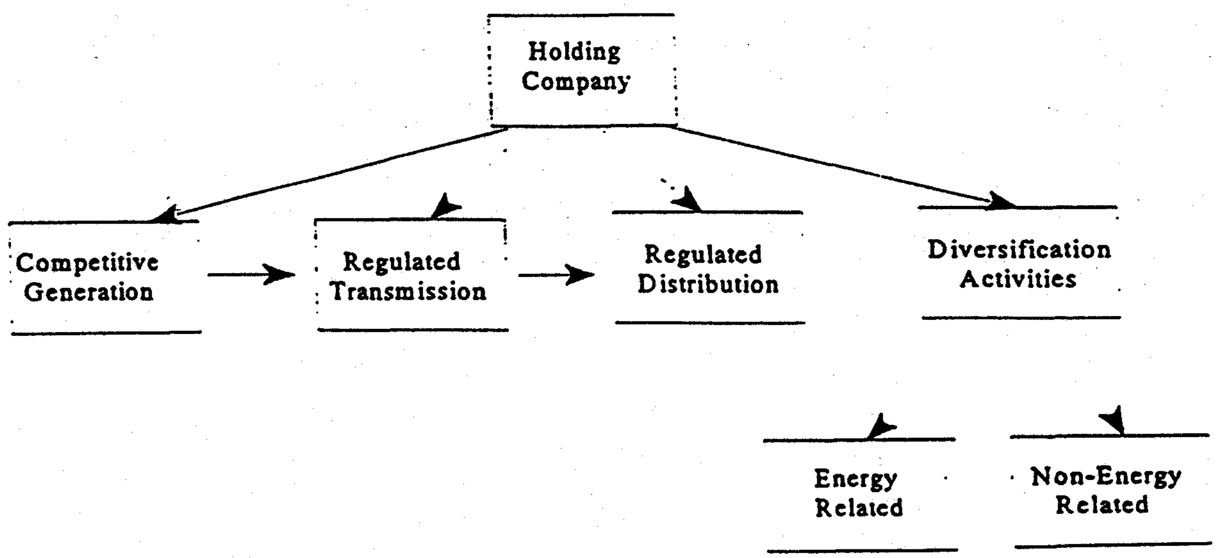


TABLE 1

PENDING UTILITY MERGERS—MAY 1996
(Mil $)

Company A	Total Assets	Sr. Debt Rating	Company B	Total Assets	Sr. Debt Rating	Projected Gross Savings (10 Yrs)	Likely Merged Rating
KLT	$ 2,867	A	UCU	$3,484	BBB	$ 636	A- or BBB+
UEP	$ 6,854	AA-	CIPS	$1,704	AA+	$ 590	AA or AA- (Ameren Corp.)
BG&E	$ 8,124	A+	PEPCO	$1,650	A+	$1,550	A+ (Constellation Energy)
NSP	$ 6, 073	AA-	WEC	$3,870	AA+	$2,000	AA or AA- (Primergy)
PSCo	$ 4,267	BBB+	SPS	$1,909	AA	$ 770	A+ or A (New Century Energies)
WPL	$ 1,593	AA	IES IPW	$1,667 $ 683	A A+	$ 834	A+ (Interstate Energy)
WWP	$ 2,001	A-	SRP	$1,652	A-	$ 450 (net)	A- (ALTUS Corp.)
PSD	$ 3,227	A-	WEG1	$8,901*	BBB	$ 370 (net)	BBB+ (Puget Sound Energy)
TU	$19,034	BBB+	ENS	$3,262*	BBB	Not Public	TU BBB+ ENS BBB

* gas

Source: Standard & Poor's Corp. and Edison Electric Institute

In response to increasing competitive pressures, electric utilities are seriously considering or have already implemented functional separation of generation activities, transmission activities, and distribution activities.[7] These restructuring activities typically take the form of separate functional organizations (i.e., divisions or wholly-owned subsidiaries) of the parent corporation and are compatible with the increasing emphasis on customer choice and market forces. Specifically, Edison International set-up an organizational structure that effectively functionally separates generation, transmission, and distribution.

In response to increasing competitive pressures, electric utilities are seriously considering or have already implemented functional separation of generation activities, transmission activities, and distribution activities.

Reasons For Restructurings

Important reasons driving corporate restructurings in the electric utility industry include: (1) financial considerations, (2) economic factors, (3) technological developments, and (4) government policies.[8] These forces are combining to cause the implementation of corporate restructuring activities of electric utilities at different speeds and phases in the various regions of the United States.[9]

Financial considerations that drive corporate restructurings center around adding economic value, increasing shareholder wealth, and managing business risk. Electric utility executives view corporate restructurings as a partial solution to financial constraints and problems and are analyzing corporate restructuring activities within the framework of the corporate strategic planning process. Management is attempting to find new sources of revenue, to reduce costs of operations, and to consider the risks to investors versus potential returns in an increasingly competitive environment.

Economic factors that drive corporate restructurings focus on customer choice relating to price and type of service. Electric utility restructuring activities reflect the global economic trend toward the increased emphasis on market forces and reduced regulatory involvement.

Financial considerations that drive corporate restructurings center around adding economic value, increasing shareholder wealth, and managing business risk. Electric utility executives view corporate restructurings as a partial solution to financial constraints and problems and are analyzing corporate restructuring activities within the framework of the corporate strategic planning process.

Technological developments have played a critical role in driving corporate restructurings i the electric utility industry. Specifically, advances in gas turbine efficiency and

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[7] John D. Edwards and Rachel A. Wardrop, *The Redwood 40: Company Summaries* (Redwood Securities Group, Inc.: San Francisco, California, 1996). Also see "Upcoming Electric Utility Events," *Electric Utility Research, Inc.*, January 11, 1996 and February 8, 1996.

[8] Donald F. Santa, Jr., "Electric Restructuring's Implications for Electric Power Research and Development Policy," *NRRI Quarterly Bulletin* 17, no. 3 (1996): 327-336.

[9] John C. Hoag, "Summary of State Electric Industry Restructuri Activities," *NRRI Quarterly Bulletin* 17, no. 3 (1996): 361-365.

technological developments associated with the production of natural gas have enabled co-generators and small power producers to challenge the monopoly generation position of electric utilities.

Government policies during the 1990s encouraged customer choice and emphasized market forces in the electric utility industry. Specifically, sections of the Energy Policy Act of 1992 reduced barriers to participating in the generation of sale of electricity, and the Federal Energy Regulatory Commission's (FERC's) Order No. 888 promotes the open access of the transmission system. In addition, several state legislatures and state regulatory agencies have developed and implemented policies that promote customer choice and competitive options. Government policies clearly have played a role in driving electric utility corporate restructuring activities.

These (and other) reasons are driving corporate restructuring activities in the electric utility industry. In order to assist regulators in their efforts to address and resolve issues and problems relating to corporate restructurings, a framework is proposed and discussed in the next section of the paper.

A Framework For Assessing Restructurings

There is a framework that consists of a hierarchy of common and significant issues and addresses electric utility corporate restructurings from a public policy perspective.[10] Regulatory issues are at the apex in this framework of common issues. These issues involve matters that are of important concern to regulatory commissions regarding electric utility corporate restructurings and related impacts on the public interest.

In this framework, there are four subsidiary (technical) categories of issues: legal, accounting, economic, and financial. Legal issues address matters which pertain to regulatory authority and jurisdiction over electric utility corporate restructuring activities. Accounting issues concern affiliate interest issues, such as transfer pricing and cost allocations. Economic issues concern motivations and incentives for management in the operation of the electric utility and market power and structure issues. Financial issues address factors that affect not only electric power company assets and earnings, but also how corporate restructuring activities, such as diversification, will be financed. Regulatory staff will clearly have significant responsibilities for providing technical analysis concerning these subsidiary issues for consideration by policy-makers.

In this framework, there are four subsidiary (technical) categories of issues: legal, accounting, economic, and financial.

Chart 2 presents a categorization and specification of this hierarchy of common and important issues in electric utility corporate restructurings. Corporate restructuring issues are presented in the form of questions in this paper. The level of importance of specific issues in this proposed framework will vary based on the type of proposed restructuring

[10] This proposed framework of issues is an extension of a hierarchy of issues developed during the early 1980s in order to analyze electric utility diversification activities from a regulatory perspective. See the following:

Gregory B. Enholm and J. Robert Malko, "Utility Diversification: Options For State Regulators," *Proceedings of The Third NARUC Biennial Regulatory Information Conference* (The NRRI: Columbus, Ohio, September 1982): 175-191; Stanley York and J. Robert Malko, "Utility Diversification: A Regulatory Perspective," *Public Utilities Fortnightly*, January 6, 1983; and J. Robert Malko and George R. Edgar, "Energy Utility Diversification: Its Stat[us in] Wisconsin," *Public Utilities Fortnightly*, August 7, 1986.

activity. For example, market power and market structure issues are clearly significant relating to merger activities of energy power companies. On the other hand, transfer pricing issues are important with respect to diversification activities and functional separation activities.

As specified by Chart 2, the regulatory category has a set of significant policy issues that regulators clearly need to consider when assessing electric utility restructurings. These issues focus on addressing and examining the impacts of corporate restructurings on providing adequate electricity services at reasonable prices to customers.

The following important questions facing regulators are presented:

- Does corporate restructuring by an electric utility present any increased or changing risks to ratepayers/customers?
- Do the state regulatory commissions have adequate authority and resources to regulate and review effectively the activities of a corporate restructured utility?
- What are the roles of and relations between federal regulatory agencies and state regulatory agencies concerning electric utility corporate restructurings? Are there conflicts in these roles and relations?
- What are the potential financial agency problems among economic units, such as bondholders, stockholders, and managers, associated with electric utility corporate restructurings?

Legal issues associated with electric utility corporate restructurings pertain to regulatory authority and jurisdiction over the utility and its corporate restructuring activities. Two important themes concerning legal issues emerge: (1) the effects of corporate structure selection, such as a parent holding company or a wholly-owned utility subsidiary, on the interests of utility management, shareholders, bondholders, customers, and regulators; and (2) the potential implications for regulatory authority of complex corporate restructuring activities.

The following important legal questions are presented:

- When an electric utility implements a corporate restructuring, what legal authority is needed to assure access to appropriate books, records, and officers?
- Will the specific organizational structure selected by the electric utility to pursue corporate restructuring affect regulatory authority?
- What is the legal significance of a corporate restructuring and related economic activities by an electric utility into different geographical areas?
- Does the regulatory agency have the legal authority to divest the core utility portion of the restructured energy pow company?

CHART 2

FRAMEWORK
CATEGORIZATION AND SPECIFICATION OF ELECTRIC UTILITY CORPORATE RESTRUCTURING ISSUES

Regulatory Issues in Utility Corporate Restructuring Activities

Definition: Assessing the impact of utility restructuring on adequate utility service at reasonable rates. The significant concern is for protecting the public interest as utilities pursue restructurings.

- Risk to ratepayers
- Federal vs state issues
- Adequate regulatory authority and approaches
- Financial agency problems

Subsidiary (Technical) Categories

Legal Issues	Accounting Issues	Economic Issues	Financial Issues
• Access to books, records and officers	• Auditing procedures	• Pricing policies	• Use of utility funds and credit
• Organizational structure	• Allocating common cost	• Market power and structure	• Variability of earnings (business risk)
• Geographic location of restructurings	• Transfer pricing	• Management incentives	• Effect on cost of capital and financial health
• Divestiture of utility	• Affiliate issues	• Customer choice	• Investor reaction

Accounting issues primarily relate to affiliate interest issues. Two important types of issues emerge: (1) allocating common costs and (2) transfer pricing.

The following important accounting issues facing regulatory staff are presented:

- How will common costs be allocated among divisions/business organizations in the event of a corporate restructure?
- What will be the impact of a corporate restructuring on the system of transfer pricing within an electric utility?
- Has the regulatory agency recently reviewed and updated its affiliate interest rules/statutes in order to address corporate restructuring activities?
- Does the regulatory agency have adequate and reasonable auditing procedures in order to address corporate restructuring activities?

Economic issues primarily relate to the allocation of limited resources in the providing of electricity services to customers in an atmosphere of corporate restructurings. Three important types of issues emerge: (1) market power and structure, (2) pricing policies and related customer choices, and (3) incentives for utility managers.

The following significant economic issues are presented.

- What will be the effect of a corporate restructuring on the pricing policies and practices of an electric utility?
- What will be the impact of electric utility corporate restructuring activities on customer choices?
- What will be the impact of a corporate restructuring on market power and structure?
- What will be the effect of a corporate restructuring on the system of utility management incentives?

Financial issues primarily relate to the implications of a corporate restructuring on valuation and financing. Important types of issues that emerge are: (1) changing risks, (2) financial health of the restructured business, and (3) reactions of investors.

The following significant financial issues are presented:

- How will utility funds and credit, including credit support agreements, be used in restructuring activities?
- What effect will a corporate restructuring have on the variability of electric utility earnings?
- What impact will a corporate restructuring have on the electric utility's financial health including its cost of capital and capital structure?
- What will be the reactions of the investments community, including equity analysts and debt analysts, to corporate restructuring activities of electric power companies?

In the next section of the paper, some insights concerning the application of the proposed framework are presented.

Applying The Framework

The following insights and suggestions concerning the application of the proposed framework consisting of a hierarchy of common issues for assessing electric utility corporate restructuring activities are presented.

First, regulatory issues consistently remain significant for the three primary types of corporate restructurings. Potential changing risks to different types of customers/ratepayers and potential financial agency problems facing different types of investors (bondholders vs. stockholders) exist in the current atmosphere of increasing corporate restructurings.

Second, the relative significance of specific subsidiary or technical issues will vary based on the type of corporate restructuring and related circumstances or conditions. For example, market power issues are assigned a high level of importance concerning merger activities as compared to diversification activities. On the other hand, transfer pricing issues are assigned a high level of importance concerning diversification activities and functional separation activities as compared to merger activities.

Third, as new regulatory frameworks, such as performance-based regulation, are implemented and replace the traditional regulatory framework of rate base regulation, regulatory commissions need to carefully address how technical issues, such as accounting and financial issues, will be analyzed in the atmosphere of increasing corporate restructurings. Specifically, methods for incorporating common cost allocations and estimating the cost of capital will clearly need to be incorporated in new regulatory frameworks in order for regulatory commissions to assess adequately impacts of corporate restructurings on the public interest.[11]

Fourth, potential conditions and restrictions, such as a dividend payout limitation, imposed by the regulatory commission on the regulated business entity will need to be carefully evaluated as multiple corporate restructurings are proposed and implemented. Regulatory commissions need to carefully analyze and determine if a specific financial or economic condition imposed to address a problem associated with one type of restructuring activity is counter-productive for another type of restructuring activity.

Fifth, current affiliate interest statutes and rules need to be reviewed and potentially updated by a regulatory agency. Transfer pricing issues and common cost-allocation issues will become technically challenging in the current environment of increasing corporate restructurings.

Sixth, the organization and training of regulatory staff needs to be addressed when applying the proposed framework and monitoring related restructuring activities. Regulators need to consider the comparative advantages and disadvantages of organizing staff along industry lines versus functional lines.

[11] For a discussion of the complexities associated with estimating the cost of capital for functionally separated activities, see Joseph F. Brennan and J. Robert Malko, "Rate Unbundling: Are We There Yet? A Reality Check," *Public Utilities Fortnightly*, June 1, 1996.

Summary

Corporate restructurings of electric utilities in the United States have become an important and controversial issue during the 1980s and 1990s and will most likely continue during the first decade of the twenty-first century. This paper presented a framework consisting of a hierarchy of common and significant issues, including regulatory, legal, accounting, economic, and financial issues, concerning electric utility corporate restructurings. The level of and importance of specific issues in this proposed framework will vary based on the type of proposed restructuring activity.

It is hoped that the proposed framework of common issues will be useful to regulators and their staffs in their efforts to protect the public interest in an atmosphere of increasing electric utility corporate restructuring activities including mergers, diversification, and functional separation of generation, transmission, and distribution. Innovative regulatory approaches and effective regulatory tools will be needed in the increasingly complex and increasingly competitive electric power industry.

Dr. J. Robert Malko is a Professor of Corporate Finance in the College of Business at Utah State University, and he previously served as Chief Economist at the Public Service Commission of Wisconsin.

Before the

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	))))	Docket No. U-0000-94-165

Prefiled Direct Testimony and Exhibit of

Dr. Alan E. Rosenberg

On Behalf of

Arizonans for Electric Choice and Competition, BHP Copper, Cyprus Climax Metals, ASARCO, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company

January 1998
Project 6855

Brubaker & Associates, Inc.
St. Louis, MO 63141-2000

Before the

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA

Docket No. U-0000-94-165

SUMMARY OF THE PREFILED DIRECT TESTIMONY OF ALAN E. ROSENBERG

The first section of my testimony provides a brief background on the definition and causes of strandable costs. The main points are that:

- Strandable costs are not caused by competition, but are only revealed by competition.
- Strandable cost recovery is generally not necessary for either equity reasons or on the grounds of economic efficiency.
- Strandable cost recovery can confer or exacerbate horizontal market power.
- If the goal of regulation is to emulate competition, stranded cost recovery would not be permitted.

As a corollary to the above, any strandable cost recovery mechanism, or transition charge as it is usually termed, should be kept as small as possible, and for as short a duration as possible. The primary considerations should be to allow customers unfettered access to the competitive market as soon as possible.

The next section of my testimony describes the goal of any administrative method of calculating stranded costs. The two main schools of thought on this avenue to strandable cost recovery are the lost revenues approach and the surrogate market value approach. I explain why the latter method is superior to the former. I also address the two main sources of uncertainty in any administrative approach – future operating costs and future market values, and what considerations should be given to each.

In the ensuing section, I give a non exhaustive list of more market based methods of estimating stranded costs, including:

- Asset sales to third parties through an auction or a negotiated sale;
- A spin-off, or a spin-down, of generation assets into a separately traded entity;
- An independent appraisal of the market value of generation assets;
- A reverse power solicitation;
- A utility determination of a market price concomitant with universal choice and an equitable sharing of stranded costs

I explain the major advantages and drawbacks of each method and how some of the problems may be redressed. I conclude that the optimal method is divestiture.

The next section of my testimony explores some of the pragmatic problems of actually constructing a stranded cost charge so as not to squelch a competitive market for electricity. My principal recommendations here are to caution against too low a contestable price for electricity – the price which the current captive consumer seeks to best by seeking an alternative supplier – and to deny a full return to the utility on the uncollected strandable amount.

At the end of my testimony I summarize my recommendations as follows:

First, market based approaches for determining strandable cost are superior to administrative ones, with divestiture being the optimal method. Under certain conditions and safeguards, and if divestiture is not an option, I find the utility market choice method to be most advantageous.

Second, if an administrative approach is used, it is advisable to use more than one method to provide a reasonableness check of any one method or determination or to narrow an otherwise wide range of estimates.

Third, the lost revenues approach is the least satisfactory of any determination method.

Fourth, strandable costs must be net of any stranded benefits, and only mitigated costs should be eligible for recovery. This means that not only should the utility have demonstrated past efforts for mitigation, but that a reasonable amount of future mitigation should be implicit in the calculations.

Fifth, strandable cost recovery should be viewed as extraordinary relief to utilities. Because transition charges are barriers to competition, they should be minimized – in both size and duration – to the greatest extent possible.

Sixth, the surest mechanism to encourage mitigation and to limit anti-competitive effects is to ordain an a priori sharing of stranded costs between shareholders and consumers.

Before the

ARIZONA CORPORATION COMMISSION

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Before the

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Prefiled Direct Testimony of Alan E. Rosenberg

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A My name is Alan Rosenberg and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This is summarized in Appendix A to this testimony.

Q **ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?**

A I am testifying on behalf of Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, ASARCO, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q WHICH OF THE NINE QUESTIONS SPECIFIED IN THE PROCEDURAL ORDER DATED DECEMBER 1, 1997 WILL YOU BE ADDRESSING IN YOUR TESTIMONY?

A My direct testimony will primarily address Questions 3, 6 and 9.

Q WHAT ISSUES WILL YOU ADDRESS?

A I have been asked to address the policy issues of the identification, calculation and recovery of any net uneconomic embedded generation costs–the so-called "strandable" cost dilemma–and the design of a recovery mechanism (which I term a Competitive Transition Charge or CTC) to recoup the portion of strandable costs that are allowable to be recovered from consumers.[2]

Q WHAT DOCUMENTS HAVE YOU REVIEWED THAT ARE SPECIFIC TO THIS PARTICULAR ASSIGNMENT?

A I have reviewed Decision No. 59943 which contained new rules (Rules) regarding competitive electric services. I also reviewed the September 30, 1997 Report to the

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1 Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

2 Competitive Transition Charge seems to be the phraseology of choice for the "wires" charge intended to recover the allowable portion of stranded costs. It conveys the message that this charge is intended to be a crutch for the utility until it is sufficiently fit to compete with non-regulated suppliers.

Arizona Corporation submitted by the Stranded Cost Working Group, as well as Dissenting Comments to that Report prepared on behalf of Asarco, BHP Copper, Cyprus Climax Metals, Phelps Dodge, and the Public Interest Coalition on Energy.

Q WHAT IS THE STATUS OF THE MOVE TO MORE COMPETITIVE MARKETS?

A Only a short time ago, the debate in Arizona, as well as the rest of the country, focused on whether there should be a competitive retail market for electricity. Today, the focus of the debate has changed. No longer is the discussion whether there should be a competitive retail market, but rather on when and how best to promote competition. Throughout the country, public utility commissions and legislatures in at least thirteen states have either issued orders moving to more competitive markets or are in the process of doing so. Besides Arizona, the Commissions and/or Legislatures of California, Illinois, Maine, Massachusetts, Michigan, Montana, Nevada, New Jersey, New York, Oklahoma, Pennsylvania, and Rhode Island have issued restructuring orders.

It is important for Arizona's consumers, and ultimately all parties, that Arizona get competition off on the "right foot," as it will be in the vanguard of those states. Moreover, it is my assessment that the stranded cost problem is not only the most critical, but also the most contentious hurdle to overcome as customers, utilities, and regulators enter the new paradigm of "Customer Choice."

Q YOU CITED A PARTIAL LISTING OF THE STATES THAT HAVE DEVELOPED REGULATORY OR STATUTORY PROVISIONS FOR THE IMPLEMENTATION OF RETAIL COMPETITION. DOES THIS MEAN THAT THERE ARE MANY CONSUMERS WHO ARE NOW TAKING ADVANTAGE OF COMPETITION TO

REDUCE THEIR RATES?

A Unfortunately, no–at least not yet. In fact, in a recent (January 12, 1998) article in Business Week the authors note that the results so far have been disappointing. Moreover, they attribute the gap between expectations and results, directly and primarily to the stranded cost recovery mechanisms that have been made the quid pro quo for "competition". I agree with that assessment. A high stranded cost charge is most damaging to the goals of retail access.

STRANDABLE COSTS

Q WHAT ARE STRANDABLE COSTS?

A I will confine my answer to generation assets, i.e., the utility's hydro and thermal resources.[3] Under traditional regulation, a utility recovers its investments through a depreciation charge. Thus, its investors not only earn a return on their money, but they recover their investment through the depreciation component of rates. At any point in time, the investment that remains unrecovered is the book value of the plant. If customers are free to choose suppliers, then the price received for the output would be set by the market, i.e., by supply and demand. If the utility's investment is uneconomic compared to its competitors, there is no guarantee that the full remaining book value could be recovered, either by sale to a third party or through

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[3] Regulatory assets, i.e., costs for which regulators have given the utility permission to defer for subsequent recovery, may also qualify for strandable cost treatment. However, the quantification and recovery of strandable regulatory assets appears to be far less controversial than that of generating assets and purchased power agreements. (It is implicit in this discussion that the regulatory assets are production related as this is the *primary* function that will be opened to competition.) The one caveat I would offer in this regard is that care be taken that regulatory assets be netted against regulatory credits, i.e., costs which have already been recovered in rates but which the utility may recoup from other parties or which liabilities which will not actually be paid. Yet another category of stranded costs may relate to above market purchased power contracts with qualifying facilities under PURPA.

depreciation in its rates. The portion of book value that could not be recovered is referred to by the euphemism, **"strandable costs.**"[4] A more descriptive term is the uneconomic portion of the utility's embedded cost.

Of course, in the event that a plant could be sold in a competitive environment for *more than its book value*, that plant gives rise to the inverse of a stranded cost (i.e., a *negative* stranded cost) or what could be termed a "stranded benefit."

Q WHY HAVE YOU ADOPTED AN "ASSET" BASED DEFINITION OF STRANDABLE COSTS?

A A proper definition of strandable costs should be based on the valuation the market would give to utility assets whose worth might be altered due to the transition to retail customer choice. This asset based approach recognizes that it is the value of an asset in competitive markets that is the ultimate determinant of utility strandable costs, not the amount of utility revenue lost due to a customer's choice to switch generation suppliers.

An asset based approach is also attractive in that it can provide a means of quantifying strandable costs without necessarily relying directly on estimates of competitive power prices. For example, an asset based approach can be undertaken by auctioning individual utility generation assets. While bidders for generation assets make their own assumptions regarding future competitive power prices in determining their bids, these market price assumptions are not made public and are not explicitly used to quantify strandable costs. Therefore, the asset based approach, especially when applied asset-by-asset, can quantify strandable costs

[4] Some observers refer to these as "stranded" costs. However, whether these costs are ultimately stranded or not will depend upon the universality of competitive access and the actions of the utility. Consequently I prefer the term strandable. The New York PSC, in its landmark Opinion No. 96-12 Opinion and Order Regarding Competitive Opportunities for Electric Service, also uses the term "strandable".

without explicitly relying on competitive power price estimates.

Q WHAT IS THE CAUSE OF STRANDABLE COSTS?

A Retail strandable costs are caused by cost increases which, over time, have driven up prices; coupled with engineering innovations and capacity additions which have kept marginal costs flat or declining. Strandable cost could also be caused by management decisions or estimates that simply did not pan out. It should be noted that the cause of strandable costs is **not** consumer behavior, but rather managerial decisions and engineering innovations. In other words, customer choice does not create strandable costs any more than the sun going down at night creates the stars. Customer choice only **reveals** strandable costs.

Q IS THERE ANY COMPELLING ECONOMIC ARGUMENT FOR THE IMPOSITION OF A CHARGE TO RECOVER STRANDABLE COSTS?

A No. Under a free market (i.e., competitive model) when a consumer stops buying from a former supplier–for whatever reason–the supplier is not entitled to any future payments from its former customer. Since regulation is intended to emulate competition, from a *purely theoretical perspective*, it is clear that the strandable cost charge should be **zero**.

Q IS A STRANDABLE COST CHARGE NECESSARY FOR SHAREHOLDER EQUITY?

A No. First, it must be recognized that shareholders are free to sell their shares at any time. Since shareholders have been fully apprised of the impending industry restructuring, shareholders are obviously convinced that the rewards of competition for this Company outweigh the risks.

Second, one of the risks of investment in a regulated industry is that regulation would change. In few industries has the risk of a change in regulation or the coming of deregulation been more publicized than in the electric utility industry, given the enactment of the Public Utility Regulatory Policies Act nineteen years ago or the 1992 Energy Policy Act. Utility managements–as well as investors–have known for some time that competition has been increasing in the electric utility industry.

Q IS THE RECOVERY OF STRANDABLE COSTS NECESSARY FOR ECONOMIC EFFICIENCY?

A No. The recovery of strandable costs is not only unnecessary for the sake of efficiency, it actually impedes economic efficiency by interfering with the working of a competitive market. Strandable cost recovery allows a supplier with above-market costs to compete unfairly with potential or actual competitors because some of its costs are subsidized by strandable cost recovery. Strandable cost recovery erects a price barrier between current captive customers and potential competitors for these customers. This thwarts competition and impedes the efficiencies that result from the discipline of market forces. In fact, if a monopoly supplier could anticipate that it would receive full strandable cost recovery, it could effectively block competition by increasing its fixed costs and lowering its variable costs.

Q CAN STRANDABLE COST RECOVERY CONFER OR EXACERBATE HORIZONTAL MARKET POWER ON THE PART OF THE RECIPIENT?

A Definitely. The higher the transition charge the more difficult it is for other suppliers to compete with the recipient.

Q CAN YOU ILLUSTRATE THAT FOR US?

A Yes. Suppose that the Company's charge for generation is 4.0¢ per kilowatthour. For the purposes of illustration, let us also assume that any alternative supplier needs to incur a transaction fee of 0.5¢ per kWh to deliver the power into the region and also requires a markup of 0.5¢ per kWh over variable generation costs to be profitable.[5] In that case, a potential competitor to the Company will be any supplier with variable generation costs of 3.0¢ per kWh or less.[6]

But, if the Company's 4.0¢ charge for generation is converted into a 2.0¢ per kWh charge for generation, plus a non-bypassable strandable cost charge of 2.0¢ per kWh, the universe of potential suppliers is now limited to those with variable generation costs of only 1.0¢ per kWh or less. That is because a variable generation cost in <u>excess</u> of 1.0¢ would result in a customer paying a total bill greater than the Company's 4.0¢ kWh charge (e.g., 1.5¢ variable generation cost + 0.5¢ delivery charge+ 0.5¢ minimum profit + 2.0¢ strandable cost = 4.5¢). Obviously there are far fewer suppliers with marginal cost of 1.0¢ per kWh than with a marginal cost of 3.0¢ per kWh. Thus, the transition charge narrows the universe of potential competitors and so increases market power of the incumbent utility.

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[5]Profit can also be thought of as a contribution to fixed costs.

[6]It must sell its output at under 4¢ delivered or it could not win the sale. However, after deducting 1/2¢ for delivery and 1/2¢ for a minimum contribution for profit, there is only 3¢ left to cover its variable (or marginal) cost of production.

Q WHY ARE YOUR OBSERVATIONS REGARDING THE RAMIFICATIONS OF STRANDABLE COST RECOVERY RELEVANT TO THIS PROCEEDING?

A As will become evident, absent full divestiture, no precise measurement of strandable costs is possible–the best that can be done is to provide a range of reasonable estimates. Therefore, I think it is important for the Commission to bear in mind the ramifications for genuine competition of choosing too high an estimate for those costs.

Q WHAT PREREQUISITES SHOULD BE IN PLACE FOR ANY STRANDABLE COSTS TO BE ELIGIBLE FOR RECOVERY?

A First, strandable cost must be net strandable costs–i.e., strandable costs must be netted against strandable benefits. This consideration was alluded to, for example, in Rule R14-2-1607 where it mandated that the degree to which some assets have values in excess of their book costs must be considered. (An analogous netting factor in relation to PPAs would be any short term purchases at less than market rates may offset above market contracts.) Second, the strandable costs must be demonstrably identifiable and quantifiable. This is only common sense.

Third, they must be mitigated to every reasonable extent. This consideration also was alluded to, for example, in Rule R14-2-1607 where it mandated that the degree to which the utility has mitigated or offset these costs must be considered. To that I would add that not only should the costs be mitigated, but that the mitigation must benefit the formerly captive ratepayers. Fourth, the recovery of strandable costs should not raise rates over what they would be under traditional regulation. The motivation for retail access has been to lower rates for consumers. It would be ironic and unfortunate if the move to restructuring had an effect contrary to the primary objective of this entire exercise. Fifth, extreme care must be taken so as to prevent a strandable cost recovery determination from resulting in windfall profits for the utility.

Q IS IT A SIMPLE PROBLEM TO CALCULATE AN APPROPRIATE STRANDABLE COST RECOVERY MECHANISM?

A No, it is not. Designing a stranded cost recovery mechanism that will be fair to the utility and to the consumer, that will encourage competition, that will motivate utilities to mitigate stranded costs and convey that mitigation to consumers, and that will be easy to administer, is probably one of the most complex problems facing regulators today.

Q WHY CANNOT THE STRANDABLE COST CHARGE SIMPLY BE SET AS THE DIFFERENCE, ON A REAL TIME BASIS, BETWEEN THE CURRENT REGULATED RATE AND SOME MEASURE OF THE MARKET RATE?

A The first problem is determining an appropriate measure of market prices. The second problem is calculating how long this recovery mechanism should be allowed to continue. However, even assuming that these two crucial issues could be satisfactorily resolved, let us examine the consequences of such a mechanism. Consider a hypothetical island with one grocery store (Monopolyshop) which has a monopoly on the sale of cola. Assume the Chief Arbiter of prices on our imaginary island has determined that a "fair and reasonable" price for a bottle of cola is $10 per liter. Now suppose that, unbeknownst to the Chief Arbiter, a flourishing and very efficient market for cola has sprung up on the mainland and the market price for cola there is $2 per liter. Now the inhabitants of this island, upon discovering the existence of the mainland and its relatively low priced cola demand the right to go shopping on the mainland. The Chief Arbiter, having concluded that competition is better than regulation, decides to let the inhabitants shop on the mainland. There is only one problem–the owner of the grocery store also has the only rowboat that can be used for shopping. Now the Chief Arbiter is convinced that the correct "cola backout credit" is the efficient $2 per liter. It thus declares that the nonbypassable charge for using the boat to go shopping is equal to the Monopolyshop price for the cola, $10, less the efficient price of $2.

Consider the consequences of this "backout". Could the inhabitants of our hypothetical island get any benefits from this brand of competition? The answer is–only if they knew in advance what the market price on the mainland was prior to making their supply arrangements, and then only if they could find a supplier that would be willing to sell consistently below the market. Since market prices must include a sufficient return on capital to remain in business, it is clear that only in the most unusual of circumstances could such conditions prevail for any length of time. Under the "backout credit" proposal, the consumers on our island are condemned (for as long as stranded cost recovery is allowed to persist) to keep on paying the uneconomic rates of Monopolyshop.

ADMINISTRATIVE METHODS OF CALCULATING STRANDED COSTS

Q PLEASE DESCRIBE THE TWO MAIN SCHOOLS OF ADMINISTRATIVE APPROACHES TO CALCULATING STRANDED COSTS.

A Administrative methods of quantifying stranded costs rely on the results of a contested case proceeding before a regulatory commission to establish stranded costs. There are two main schools of thought on this. One is a revenues lost method. The other approach is intended to derive a proxy or surrogate value of the asset if it were sold on a competitive market.

Q OF THOSE TWO, WHICH METHOD DO YOU PREFER?

A Of those two, the "surrogate market value" approach is certainly superior to the lost revenue approach.

Q WHAT PROBLEMS ARE THERE WITH THE "LOST REVENUE" APPROACH TO RECOVERING STRANDED COSTS?

A Implicit in the "lost revenue" approach is the assumption that, under continued regulation of generation, the utility should be guaranteed a fixed revenue stream. Even under regulation this may not be the case, however, as customers may leave the system or command discounts because of alternatives other than retail competition, e.g., transferring production or implementing cogeneration, and the utility may not be able to recoup the lost revenue from the remaining load.

Moreover, the lost revenue approach implies that the utility's costs of operating its plants are <u>per</u> <u>se</u> reasonable. However, it is plausible to expect that excess costs can and should be mitigated. Suppose that regulators grant a utility a 13% rate of return but that under competition it could only earn a 10% rate of return. Does that mean that the difference in earnings between the 13% and the 10% represents "stranded costs"? I would submit that the answer is no. Recall that regulation is intended to be a proxy for competition. If the utility can only earn 10% under competition, then the regulators, by definition, erred in granting 13% and that difference should not be considered a true stranded cost. Yet another example would be overhead costs. Most observers expect that, under the discipline of competition, owners will be able to operate their plants with much less overhead than in the past. Even incorporating just historic levels of overhead will essentially preclude consumers from seeing the benefits of the expected improvements in efficiency.

Yet another conceptual problem with the "lost revenue" approach is that it makes no reference to the book value of the underlying asset. Suppose, for example, that the book value of an asset is zero, i.e., investors have completely recovered the costs of this unit, but that the unit is still operating. If the market cannot sustain its stand-alone running costs, then this plant should shut down. Going forward costs should never be stranded because the operator always has the option of not running the plant and instead purchasing on the open market. Yet under a "lost revenue" approach this plant would appear to be contributing toward a stranded cost burden. Now, suppose that the market price is above its incremental costs but below its fully allocated fixed and variable costs. In that case it makes economic sense to run the plant because the net revenue is producing a profit for the operator. Yet under a lost revenue method this plant would appear to be "losing" money and be deserving of a stranded cost subsidy.

Still another problem with the lost revenue approach is that it thwarts competition. If the transition charge is designed to "sop up" the difference between current regulated rates and market rates, then the only way for customers to see any benefit from competition is to beat the market. Clearly, almost by definition, this will be extremely difficult to do.

Q HOW CAN ONE ESTIMATE THE MARKET VALUE OF A PLANT WITHOUT OBSERVING THE PRICE IT WOULD COMMAND IN AN ARMS-LENGTH SALE BY

A WILLING SELLER TO A WILLING BUYER?

A By considering and reflecting in the valuation methodology, the factors that would be considered by a willing buyer in determining the price it would be willing to pay for an asset. Prospective buyers would likely evaluate a production asset as the stream of future cash flows that the asset can be expected to generate for the new owner, expressed as a net present value, discounted at the buyer's opportunity cost of money. In implementing this conceptual approach, some buyers may value a plant on the basis of its replacement value using the latest technology. (Of course, adjustments would have to be made to account for differences in operating costs and expected useful life of the proxy replacement plant and the plant being valued.)

Q HOW DO THESE METHODS DIFFER FROM A NET LOST REVENUES APPROACH?

A The differences are important, if subtle. A lost revenues approach examines the plant from the perspective of the total revenues that would be expected under continued regulation. A proper economic valuation considers only cash items,[7] takes full advantage of tax laws, and considers other options such as repowering and the most economic manner of operating the plant. Moreover, a lost revenues approach loses sight of the fundamental definition of the problem–namely, that it is only the difference between the book value and market value of an <u>asset</u> that is potentially strandable.

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[7] For example, depreciation would be excluded because it is not a cash item, but capital improvements would be accounted for in the year they were made.

Q WHAT FACTORS MUST BE ESTABLISHED PRIOR TO AN ADMINISTRATIVE DETERMINATION OF THE COMPETITIVE OR MARKET VALUE OF A PLANT?

A In the free cash flow method (as well as with the "lost revenues" approach), the quantification of stranded costs necessarily depends on a long-term forecast of the year-by-year values for market price of capacity and energy, as well as the future operating costs include fuel expense, operation and maintenance expense, property and other taxes related to the operation of the unit, expected capital additions, and any other expected cash expenditures. It is also necessary to forecast capacity factors of existing generation assets. Small changes in the forecasted levels of these parameters can produce significant changes in the expected magnitude of a utility's stranded cost exposure.

Q SHOULD THESE CALCULATIONS BE PERFORMED ON A PLANT BY PLANT BASIS?

A Yes. When this approach is applied, it is necessary to look at the generation resources on a unit by unit basis in order to screen out the effects of any units where the going forward costs exceed the value of the sale of energy in the market. That is, if the going forward cost of the unit exceeds market price, costs can be minimized by shutting down the unit and not operating it, rather than by operating the unit and incurring net out-of-pocket expenditures.

Another advantage of a plant by plant estimation is that it facilitates a true up if a plant is sold at some time after the administrative determination is made.

Q IN ESTIMATING FUTURE OPERATING EXPENSES, IS IT REASONABLE TO TAKE PAST EXPENSES AND EXTRAPOLATE AT SOME FIXED ESCALATION

RATE?

A Absolutely not. Utilities have already begun to reign in their operating costs in reaction to wholesale competition and the portent of retail competition. This process can only intensify in the future. This trend is typified, for example, by PacifiCorp, a large western utility which notes, in its 1996 Annual Report,

> Many of the Company's *efforts to control operating costs* proved effective in 1996, keeping growth in fuel, operations and maintenance and other *costs well below the growth in revenues*. (Page 25, emphasis added)

Q DO THE RULES MANDATE THAT ANY PRODUCTIVITY GAINS BE PASSED ALONG TO CUSTOMERS?

A Unquestionably. Productivity gains are simply one way to mitigate stranded costs and Rule R14-2-1607 specifically calls for consideration of the degree to which these costs have been mitigated.

Q YOU STATED THAT THE OTHER UNKNOWN IN AN ADMINISTRATIVE DETERMINATION OF STRANDED COSTS IS THE MARKET PRICE. WHY IS THIS PROBLEMATIC?

A Current market price indices are generally based on spot wholesale energy prices. Therefore, they do not appropriately reflect the market price of the various types and qualities of power that are likely to be sold in competitive retail markets. Because spot energy prices are typically lower than the prices of other competitive power contracts, the exclusive use of spot energy to measure market prices is likely to increase the magnitude of stranded costs.

A spot market wholesale price is not indicative of the price that customers realistically will be able to obtain if they desire intermediate to long-term retail firm service. First, wholesale prices will be less than retail prices due to a host of factors such as economies of scale, diversity, higher load factor, lower transaction costs, lower losses, and others. Second, the existing indices are not for power with a degree of firmness comparable to what most retail customers purchase today.

Q CAN YOU GIVE AN ILLUSTRATION WHY IT WOULD BE INAPPROPRIATE TO USE A WHOLESALE MARKET PRICE IN THE CONTEXT OF AN ADMINISTRATIVE APPROACH TO DEVELOPING A STRANDED COST ?

A Yes. There are two compelling reasons why the use of wholesale market price is not suitable for this purpose. The first is that utilities are not likely to sell the entire output of their generation into the wholesale market. Second, if customers are only given credit, so to speak, for a wholesale price, but must replace that energy at a retail price, it is difficult to see how they can achieve any savings from competition.

Q ARE THE CURRENT RELATIVELY LOW PRICES OF MARKET INDICES REPRESENTATIVE OF MARKET PRICE LEVELS THAT YOU WOULD EXPECT TO PREVAIL OVER THE LONG RUN?

A No. Ultimately, the market price must reflect the long run (i.e., the operating costs and the capital cost of new capacity) costs of future resources. This is an inescapable law of economics. Current low rates are sustainable because utilities are essentially assured recovery of their fixed costs through bundled rates to their captive customers. In fact, this highlights a chicken and egg problem with the administrative determinations of stranded costs–the lower the market price used, the higher the stranded cost determination, which in turn allows the utilities to endure low selling prices for its marketing efforts, which leads to even higher stranded costs and so on and so on.

Q CAN THE INHERENT UNCERTAINTY IN THE FORECAST OF MARKET PRICES BE ALLEVIATED BY FUTURE TRUE UPS OR SANITY CHECKS?

A Yes. This approach would apply a "new look" from the point of examination to the end of the expected life of the asset being evaluated. Updated values for market price would be determined based on more current information, and experience with respect to cost reductions and improvements in efficiencies by the utility operating the asset would also be incorporated. To the extent that the Commission had specified cost reduction targets for the utility, they would be incorporated into the valuation equation. While this approach helps overcome some of the more fundamental data problems inherent with an administrative evaluation, it must be recognized that at any point in time when a true-up is performed, there still must be a forecast of all relevant parameters over the remaining life of the asset. A failure to forecast to the end of the life of the asset would ignore the long-term measure of asset value, to the detriment of current consumers.

MARKET-BASED METHODS OF CALCULATING STRANDED COSTS

Q CAN STRANDED COSTS BE CALCULATED VIA A MARKET BASED METHOD AS OPPOSED TO AN ADMINISTRATIVE METHOD?

A Yes. Stranded costs can also be quantified using market valuations of generation assets or competitive power prices. Market mechanisms provide an objective and definitive measure of the market value of assets. Thus, the use of such mechanisms can avert the need for prolonged legal proceedings to establish speculative, administratively determined market price levels to quantify stranded costs. Market mechanisms are attractive because the result of the market process *defines* the market value of the assets. This, in turn, reduces much of the controversy surrounding the quantification of stranded costs.

Q DOES A MARKET BASED METHOD FOR QUANTIFICATION ENTAIL TAKING A SNAPSHOT AT SOME POINT IN TIME?

A Yes. Consequently, there could be differences of opinion as to when that snapshot should be taken. Some may wish to take this snapshot at the beginning of the transition period when strandable costs appear the highest. My opinion is that a snapshot taken at the end of the transition period, when competition is more developed, will produce a more realistic picture.

Q WHAT MARKET BASED METHODS EXIST FOR QUANTIFICATION OF STRANDED COSTS?

A A non-exhaustive list of market based methods include:

- Asset sales to third parties through an auction or a negotiated sale;
- A spin-off, or a spin-down, of generation assets into a separately traded entity;
- An independent appraisal of the market value of generation assets;
- Reverse power solicitation;
- A utility determination of a market price concomitant with universal choice and an equitable sharing of stranded costs

Each of these market mechanisms has its advantages and drawbacks. In fact, strictly speaking only the first two methods can be said to be purely and totally market driven. The remaining three methods all entail, to some extent, judgment by third parties.

ASSET SALE

Q PLEASE DESCRIBE THE ASSET SALE METHOD.

A The most direct market mechanism for quantifying stranded costs is through arms-length, competitive asset sales to third parties. Under this approach, the stranded costs associated with the sold assets would be determined by offsetting the sale price of the assets against their net book value. These assets sales could be accomplished either through private negotiations with potential purchasers or through an open auction process. This market mechanism is attractive in that it establishes a market price for individual utility generation assets. An added advantage is that, if the sale is made to a wide array of purchasers, it could help mitigate market power.

One potential downside of an asset sale is that it may produce "fire sale" prices that could exacerbate the stranded cost problem. However, if stranded costs are shared, the utility has an incentive to obtain the highest possible price, since shareholders would have to absorb part of the shortfall from book value. On the other hand, it is possible that market mechanisms applied to today's market conditions could produce a price premium for generation assets. For example, generation asset sales that occur prior to the availability of retail competition in a particular market could garner high prices because they provide competitors with an attractive means of entry into emerging power markets.

Recognizing that market values may change over time for a variety of reasons, some of which are related to the advent of retail competition, it is possible to defer the market valuation in order to allow part of this phenomena to be reflected in the market. For example, if retail access is to begin January 1, 1999, it might make more sense to perform the market valuation in 2000 than to do it in 1998. Doing it after retail competition is available would certainly allow for prospective purchasers to have the benefit of the experience of operating in a competitive retail market; while an early evaluation date would not. Of course, this deferral should not be used as an excuse to delay the advent of retail choice.

Q IN AN ASSET SALE, WHICH METHOD DO YOU PREFER, AN AUCTION OR A NEGOTIATED SALE?

A An auction of generation assets is the most frequently applied market mechanism for quantifying stranded costs that has been proposed to date in the U.S. This method is being implemented by Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) in California, the New England Electric System (NEES), COM/Electric, Eastern Utilities Associates, and Boston Edison Company in Massachusetts, and by Central Maine Power Company and Maine Public Service Company in Maine, among others. In New York, under agreements with the Public Service Commission, New York utilities are divesting at least 22,800 MW of their total 36,615 MW of generation. In California, San Diego Gas & Electric Company recently decided to auction its power plants. In New Jersey/Pennsylvania, GPU stated that it will conduct an auction to sell all of its 34 generating stations.

An auction process is generally more desirable from the customer perspective than a privately negotiated asset sale because the auction process attempts to increase the amount of competition to purchase an asset, thereby maximizing the asset's price.

Q WHAT IS THE ROLE OF THE SELLING UTILITY IN AN AUCTION PROCESS?

A Perhaps the most critical factor in the auction process is the role of the selling utility. If the utility directly designs and administers the process, there is a concern that the utility will have an interest in designing the auction in a manner that reduces the resulting asset prices, simply because lower sales prices will translate into higher aggregate levels of stranded cost recovery. However, this concern is mitigated if the utility is put on notice that shareholders would be at risk for, let us say, 50% of the difference between book value and sale value, or were allowed to retain a modest share of a sale price sufficiently in excess of book value. Moreover, a properly designed and supervised auction, such as an auction that uses sealed bidding, can greatly reduce the potential for utility misconduct that might corrupt the auction results. Use of an independent party can help. For example, an agreement reached between Central Hudson Gas & Electric and the New York Staff specifies that an independent auctioneer will be utilized.

Q SHOULD THE SELLING UTILITY, OR AN UNREGULATED AFFILIATE, BE ALLOWED TO PARTICIPATE IN THE AUCTION?

A The answer depends on the relative concern about market power and whether such a condition is necessary to obtain the cooperation of the utility. Because many utilities in the U.S. are reluctant to contemplate generation asset divestiture, jurisdictions such as California and Texas have considered the possibility of conducting asset auctions in which the selling utility would be allowed to participate in the auction, either directly or through an affiliate, and retain a right of first refusal to match the bids of other parties, thereby giving the utility the opportunity to retain ownership of its generation assets while accomplishing a market-based quantification of the its stranded costs.

Such right of first refusal auctions could depress asset prices by reducing participation in the auction and causing participants to discount their bids for assets. This would occur primarily because potential buyers would recognize that an information asymmetry exists between the utility and other bidders regarding the operating performance and cost parameters of the utility's assets. Potential buyers would be reluctant to aggressively participate in the auction if they believed that the selling utility would use its information advantage to retain ownership of its most profitable generation units, while allowing the less attractive units to be sold to its competitors.

One possible solution to this problem is to require the utility to pay a fee in exchange for exercising a right of first refusal in its own asset auction. This fee would be added to the proceeds of the asset sales when the market value of the utility's assets was determined for the purpose of quantifying the utility's stranded costs. Other possible remedies would be to use any rejected bid as the floor on a stranded cost determination and/or to moot any incentive payments if the utility simply sells the plant to itself.

Q WHAT HAVE BEEN THE RESULTS TO DATE OF THE AUCTION PROCESS?

A Admittedly, there is not a large database to assess. Nevertheless, from what I have been able to observe in the literature, sellers are realizing prices that are, in general, considerably above book value and unexpectedly high.

Spin-Off or Spin-Down of Generation Assets

Q HOW COULD A SPIN-OFF OR SPIN-DOWN BE USED TO ESTABLISH STRANDABLE COST EXPOSURE OF A UTILITY?

A Under this method, stranded costs are quantified through a stock valuation when the utility spins-off its generation assets into a separate, publicly traded, non-affiliated corporation. The market price of the assets would be determined by using the average daily closing price of the stand-alone generation company's common stock over a specified period of time. Alternatively, the market price of the spun-off assets could be determined based on changes in the stock price of the original company which spun off the assets. In either case, the utility's stranded costs would then be determined by offsetting the stock price against the NBV of the utility's generation assets.

A spin-down mechanism involves essentially the same procedure described above. However, in a spin-down, the utility separates its generation assets into an unregulated affiliate, and distributes new shares of stock in the unregulated affiliate to its existing shareholders. The new affiliate's stock is then independently traded. Thus, a spin-down can accomplish a market-valuation of stranded costs without requiring complete generation asset divestiture.

Q HAS A SPIN OFF BEEN USED TO ESTABLISH STRANDABLE COSTS IN THE ELECTRIC INDUSTRY?

A Not that I am aware of.

Q WHAT ARE POTENTIAL DRAWBACKS OF THE SPIN-OFF OR SPIN-DOWN APPROACH?

A First, an auction could produce higher asset prices than a spin-off because buyers might be willing to pay a "control premium" for the direct purchase of individual assets. A spin-off would result in the creation of a publicly traded company owned by numerous shareholders. Therefore, one entity would be unable to exclusively control the operation of an asset.

Second, a spin-off can complicate the valuation of assets by introducing factors that do not pertain directly to the intrinsic value of the generation assets being sold. For example, investor perceptions regarding the quality of a newly created generation company's management could influence the new company's stock price. Investors might also attribute more risk to a newly created, stand-alone company simply because it has no operating history. Such perceptions could lead investors to discount the value of the new company's assets. A market valuation based on a spin-off can be further complicated if the spun-off company holds assets other than generation assets. In such a case, the market's valuation of the non-generation assets is likely to be factored into the new company's stock price. It can be argued that the consideration of such factors is not directly related to the inherent market value of the generation assets themselves. As a result, the value of utility assets could be captured more directly through an open auction.

Another complication with the use of a spin-off to quantify stranded costs is that the spun-off company's stock price is likely to fluctuate over time. Therefore, a "snap-shot" assessment of the newly created company's initial stock valuation might not accurately reflect the true market value of the underlying generation assets. This problem is exacerbated in the case of a spin-down because the initial stock valuation of the new affiliate would be determined by the holding company's management when it distributes the affiliate's stock among its shareholders. However, this problem can be remedied by using the average stock price of the spun-off company over a sufficiently long period of time as the market price of the underlying assets for stranded cost quantification purposes. This approach would be more likely to reveal the true market value of the utility's assets.

Asset Appraisal

Q HOW MIGHT THIS METHOD OPERATE TO ESTABLISH STRANDABLE COSTS?

A Industry stakeholders would submit an agreed-upon list of impartial and qualified asset appraisers, from which the Commission might select perhaps three, to value a utility's assets. The results of the consensus appraisal would then be used to quantify the utility's stranded cost exposure. If the utility rejected the appraisal, it would then be required to spin-off, or sell, the assets. In addition, the Commission should reserve the right to review and approve the appraisal to ensure that the utility did not improperly reject an appraisal and then receive a lower sale price, an eventuality that would increase the utility's total stranded costs.

Q WHAT ARE THE ADVANTAGES OF AN APPRAISAL METHOD?

A The major advantage of the appraisal approach is that it provides a means of arriving at a market valuation of a utility's assets without requiring asset divestiture. Thus, this option is likely to be more palatable to most utilities. An asset appraisal can also be considered superior to the pure administrative quantification in that the valuation relies on the opinions of independent industry experts, as opposed to the testimony of experts hired by the parties to a contested proceeding.

The use of independent experts to appraise the utility's assets could reduce litigation surrounding the quantification of utility stranded costs. However, this reduction in litigation might not materialize if the regulatory commission uses its approval process to second-guess the appraisal results. If this were to occur, then the appraisal would be effectively transformed into an administrative quantification of stranded costs.

Q WHAT ARE POSSIBLE WEAKNESSES TO AN APPRAISAL APPROACH TO THE STRANDABLE COST DILEMNA?

A The dearth of price comparables from other generation asset auctions would make it difficult to assess whether the appraisal resulted in a reasonable market value for an asset. To the best of my knowledge, with the exception of the NEES, California and others that I noted earlier, there are essentially no other completed generation asset auctions in the U.S. that an appraiser could use as a measure of a particular asset's market value. Also, the value depends upon the expected sales price of power, and even these completed auctions may not be applicable in other geographic areas since market prices will not be uniform from region to region. This absence of price comparables introduces a significant element of speculation into the appraisal process.

Finally, an asset appraisal is not truly market-based because it does not rely on the interaction of buyers and sellers in a competitive market to arrive at an asset's value. It is much easier for a regulatory commission to second-guess an appraisal that is conducted in the abstract than it is to nullify the results of a completed asset auction or spin-off. Therefore, the appraisal mechanism does not produce the definitive market valuation of utility assets that is the most desirable feature of truly market-based quantification mechanisms.

Power Solicitation or Reverse Solicitation

Q WHAT IS A POWER SOLICITATION?

A In a direct solicitation, the utility requests proposals for a given quantity of capacity and energy from competitive providers. In a reverse solicitation, the utility auctions a block of capacity and energy in the open market. In either case, the winning bid for the block(s) of power determines the market price for electricity. This market price is then used to calculate a utility's stranded costs.

Q WHAT ARE THE ADVANTAGES OF A SOLICITATION METHOD?

A The major advantages of the solicitation approach are that it is fairly easy to administer and it does not require asset divestiture or other restructuring of the utility's operations. These features make a solicitation desirable to many utilities, and perhaps to regulators who do not wish to address the issue of asset divestiture.

Q WHAT ARE THE DRAWBACKS TO A SOLICITATION METHOD FOR DETERMINING STRANDED COSTS?

A The principal weakness of the solicitation approach is that it produces a market price for *power*, not for utility *assets*. Therefore, critical assumptions still must be made to translate this power price into a stranded cost valuation. Needless to say, each of these assumptions has a significant impact on the amount of a utility's stranded costs.

Q WHAT KINDS OF ASSUMPTIONS MUST BE MADE?

A The first major assumption made in the solicitation approach is that the solicitation results provide a true indication of the regional market price for power. However, this is not necessarily true. Any solicitation will be designed to purchase or sell a certain quality of power (e.g., firm power, curtailable power, seasonal power, peaking power, etc.) for a designated period of time. This solicited power block represents only one type of power that is available in competitive power markets.

Another variable in the process is the length of the contractual obligation. The price that purchasers would be willing to pay for obligations of three years, five years, ten years, etc., will likely be different. It would seem appropriate that the contractual obligation commit the seller to sell, and the purchaser to purchase, the contractual quantity of power over a period somewhat representative of the life of the underlying assets that are being evaluated.

Moreover, the solicitation approach assumes that a power auction conducted in today's market environment will yield a market price that is representative of future prices in competitive retail markets. This is an unproven and debatable assumption. Prices in regional power markets are likely to increase as existing excess supply is absorbed by growing demand for electricity. In addition, it is possible that the advent of retail access will ultimately create upward pressure on power prices by introducing a large number of new buyers into power markets. Thus, there is a great deal of uncertainty regarding the future pattern of competitive power prices. Therefore, a solicitation conducted under today's market conditions might yield power prices that are significantly different from the regional market clearing prices that will prevail after the advent of retail access. If this proves to be the case, the solicitation mechanism will not accurately quantify a utility's stranded costs.

Q **ARE THERE ADDITIONAL ASSUMPTIONS THAT MUST BE MADE IN ORDER TO TRANSLATE THE POWER PRICES RESULTING FROM A SOLICITATION INTO A STRANDED COST VALUATION?**

A Yes. The solicitation approach is premised on the notion that a utility's assets should be valued based on the estimated profit margins that its power plants are likely to realize in competitive markets. While this presumption is basically accurate, the difficulty with the solicitation approach is that the key parameters which drive the expected profit calculation are based on administratively determined assumptions. In a truly market-based asset valuation, potential purchasers of the asset make their own independent judgements regarding projected power prices and plant operating characteristics. The bidders who see the most profit potential in the asset will bid the highest prices. By contrast, the solicitation approach requires regulators to specify the critical cost parameters that are used to value the utility's assets. For example, if the capacity blocks put out for bid do not comport with the actual capabilities of the plant, the potential profits will be understated.

A Utility Determination of a Market Price Concomitant with Universal Choice and an Equitable Sharing of Stranded Costs

Q **WHAT IS THE LAST MARKET BASED METHOD THAT YOU WILL DISCUSS?**

A Unlike the previous methods discussed, this method would not require the Commission to arrive at a specific calculation of the utility's strandable costs, i.e., it is a results driven method. The fundamental steps of this approach are as follows:

1. The utility chooses a level of production costs that it believes would be competitive in an open market.

2. Regulated but contestable rates for generation are designed to recover the

level of costs selected in Step 1.

3. A specified percentage, e.g., 50%, of the above market production costs, i.e., the production costs that are reflected in rates less the competitive level selected in Step 1, will be recovered from current customers via a transition charge.

4. As long as the utility continues to collect the transition charge, i.e., for the duration of the transition period, customers would have the choice of either continuing to buy generation from it at the regulated rate plus the transition charge, *or* of buying generation from any third party and paying the host utility only the transition charge. Of course, in either case the customer would pay the appropriate unbundled, cost-based delivery charge.

Q WHY DO YOU CHARACTERIZE THIS AS A MARKET DRIVEN APPROACH?

A This approach provides the utility with a strong incentive to choose the most realistic estimate of market prices that are sustainable over the long run, because the closer the forecast market prices are to the actual market prices, the greater will be the utility's revenue.[8] The algebraic proof of this is shown on Exhibit AER-1, Schedule 1. As an expedient, this proof uses a 50/50 sharing for clarity and simplification.

Q WHAT ARE THE OTHER ADVANTAGES TO THIS APPROACH?

A Other advantages of this approach are that it:

- avoids the controversy over choosing an appropriate market price,
- gives the utility an incentive to mitigate its stranded costs,
- avoids the problem of ex post reconciliation,
- allows customers of high cost utilities to experience immediate savings even if they remain customers of the utility, and

[8] Another element of this approach is that, as long as the utility continues to assess a non-bypassable stranded cost charge, its generation assets would remain under regulation. This is because while its generation is being subsidized by a regulatory artifact, it is only appropriate that it continues to be subject to regulatory oversight. This also provides the utility with an additional incentive to hasten the end of stranded cost recovery.

- it eliminates the step of translating a total strandable cost estimate into a CTC charge.

Q CAN YOU PROVIDE A SIMPLIFIED ILLUSTRATION OF HOW THIS METHOD WORKS AND WHY THE UTILITY MAXIMIZES ITS REVENUE BY CHOOSING AN ACCURATE MARKET PRICE?

A Certainly. I will only be discussing generation-related costs because those are the costs that are potentially stranded and for the sake of expediency, we will state all costs as 6¢ per kWh.[9] Also for the purpose of this illustration, I will assume that the sharing percentage is 50/50. Let us suppose that a utility's total embedded cost of generation is 6¢ per kWh, and hence that is the rate set under traditional regulation. Further suppose that the "actual" competitive or market rate is 3¢ per kWh. Consider the following three scenarios. In the first scenario (which I will refer to as the base case) the utility chooses 3¢ per kWh as its competitive rate. Under the Market Based Sharing Proposal (with a 50/50 sharing), the utility would be obligated to offer its customers a 3¢ rate for generation, and the Competitive Transition Charge (CTC)[10] would be half the difference between that rate and the fully regulated rate, or 1.5¢ per kWh. The utility thus gets a total of 4.5¢ for its output, 3¢ from the customer (or the market) and 1.5¢ as a CTC. Note too that all customers, even those who stay with

[9] In reality stranded costs will be fixed in nature, i.e., more related to peak demands than to energy produced, and hence stranded cost recovery mechanisms should be expressed in terms of dollars per kilowatt of demand rather than per kilowatthour of energy. Nevertheless, it is common parlance to express total production costs on the basis of energy alone. This is mainly for simplification of the illustration of concepts.

[10] It is important to note that when we speak of a 50/50 sharing, or any other a priori sharing arrangement, that is only on an a priori basis with no presupposition of mitigation. Under this method the utility would retain the proceeds from any and all mitigation measures subsequent to the start of the transition period as a quid pro quo for a meaningful a priori sharing.

the utility for any reason, enjoy a 1.5¢ savings vis-a-vis the fully embedded rate.

In the second scenario, the data is the same as the first, but the utility chooses an unrealistically low contestable charge, let us say 2¢ per kWh. Under all other stranded cost recovery methods, the utility would reap windfall benefits for such an underestimate of market costs. However, let us examine what happens under this method. The CTC is now set at 2¢ per kWh (or one half the difference between 6¢ and 2¢). Customers would now choose to buy their power from the utility for 2¢ per kWh (because it is less than the market price), for a total cost of 4¢ per kWh. Thus, the customers savings are 0.5¢ per kWh higher (and the utility's revenue is 0.5¢ lower) than in the base case. The utility, not the customer, has borne the risk of the erroneous estimate.

Q WHAT WOULD HAVE HAPPENED HAD THE UTILITY CHOSEN AN ARTIFICIALLY HIGH MARKET PRICE?

A Suppose the utility selects too high a level for its contestable production charge, let us say 5¢ per kWh. In this case the CTC will be calculated as 0.5¢ per kWh. However, customers will then abandon the utility in favor of buying from others at the market based rate of 3¢. The customers' new cost will be a total of 3.5¢, as will the utility's revenue as it too must turn to the market as an outlet for its production.

Note that in order for this mechanism to work, there must be three prerequisites. First, the utility <u>must</u> be obligated to sell to its present customers at the contestable rate it selected for the duration of the transition period. Second, all customers <u>must</u> have the ability to shop for and buy at a market based rate if that is less than the utility's contestable charge. Third, there <u>must</u> be a meaningful sharing of the uneconomic generation costs. These are the quid pro quo's for the utility being allowed to choose the contestable charge. **Absent these imperatives, the utility can game the system. Thus, regulators must still utilize a modicum of judgment and plain old common sense to insure that the final result is reasonable.**

Q WHAT PRAGMATIC CONSIDERATIONS ARE INVOLVED IN THIS METHOD?

A First, although utilities will maximize their revenues with an accurate choice of market price, the Commission must still be sensitive to the possibility that the utility will opt for an unrealistically low price. For instance, the utility may be motivated to sacrifice revenue during the transition period in order to freeze out competition. This type of pricing should be discouraged.

Second, to the extent that all customers may not have choice, the Commission should be alert to the possibility that the utility not choose too high a market price. If customers do not have choice, the utility knows it can extract an artificially high price from the captive customers. (This is the "flip side" of the first consideration discussed in the previous paragraph).

Third, the Commission will have to decide how often to allow the utilities to change the market price during the transition period. Most observers expect market prices to rise over the next decade. While it is not unreasonable to allow the utility to change its market price on a periodic basis, this change should be accompanied by an increased portion of the price difference (between current regulated rates and the market price) being absorbed by the utility (and conversely, of course, a smaller fraction being used for the transition charge).

Fourth, although it is not imperative that the sharing be precisely 50/50 in order for this method to work, the Commission should be aware that the greater the portion of price difference that is allowed for the transition charge, the greater is the utility bias toward choosing a spuriously low market price.

Q HAS THIS METHOD EVER BEEN USED TO RECOVER STRANDABLE COSTS?

A I do not believe so. However, I did propose this method in the context of a Central Hudson Gas & Electric restructuring case in which I represented an organization known as Multiple Intervenors (MI). In the Recommended Decision in Case 96-E-0909 Judge Rapheal Epstein found:

> MI's proposal purports to overcome these concerns by taking the estimation of strandable costs out of the realm of administrative fiat and, instead, assigning the Company the risks and benefits of analyzing what level of costs it can recover in the market. ..... The attraction of MI's approach is that it relies on a market based determination of strandable costs, instead of having the parties return in four years to negotiate or litigate an administratively determined value as a proxy for the market.

HOW TO CONVERT A STRANDABLE COST ESTIMATE INTO A COMPETITIVE TRANSITION CHARGE

Q ONCE AN ESTIMATE OR DETERMINATION OF A UTILITY'S TOTAL STRANDABLE COSTS IS MADE, AND THE AMOUNT ALLOWED TO BE RECOVERED FROM RETAIL CUSTOMERS IS RESOLVED, WHAT ARE THE STEPS NECESSARY TO DESIGN AN APPROPRIATE CTC?

A As I noted above, under the Market Based Sharing approach, the utility essentially is allowed to structure the CTC. Under all other methods there are essentially two schools of thought on this. Under what I will call the top down approach, an administratively determined market price for each rate class is determined or specified. This becomes the charge that the customer avoids by purchasing from an alternative supplier. The CTC is then the residual or difference between this "generation credit price" and the production charge that is embedded in current rates. The CTC continues to be in effect for as many years as it takes to completely recover the allowable stranded cost amount.

Q WHAT IS THE OTHER SCHOOL OF THOUGHT ON THE DESIGN OF THE CTC?

A The other approach is a bottom up approach. Under this process, the CTC is explicitly designed and it is the contestable portion of the production charge that becomes the residual. I use the term contestable (or avoidable) because it is this component of the rate that the consumer will shop for-if it finds a better rate, it buys from the alternate supplier (assuming that price is the sole criterion for choosing a supplier), if not, it stays with the local utility.

Q IF THE CONTESTABLE "PRODUCTION RELATED" COMPONENT OF THE RATE IS DERIVED ON A RESIDUAL BASIS, IS IT POSSIBLE THAT THIS RATE COULD BE GREATER THAN THAT WHICH COULD BE OBTAINED FROM A THIRD PARTY SUPPLIER?

A Certainly it is possible. In fact, if it were not possible to do so, competition would be pointless.

Q UNDER THE BOTTOM UP APPROACH TO DESIGNING A CTC, WHAT ARE THE NECESSARY STEPS?

A The first step is to decide over how many years the CTC will be collected. The shorter the collection period, the sooner consumers will be able to enjoy genuine competition without these artificial access rates. Unfortunately, the shorter the recovery period, the higher will be the CTC while it exists, all other things being equal. Consideration must be given to balancing those two countervailing objectives–a brief transition period and a low CTC.

The second step is to allocate the annual collectable amount for strandable costs among the rate classes. In order to minimize rate disruptions, this allocation should conform to the historic methods that the underlying strandable assets have been allocated among rate classes.

The third step is to design a rate, based on forecast billing units, that would be expected to recover the annual strandable cost amount.

Q IF THE TOTAL ALLOWABLE STRANDED COST AMOUNT IS COLLECTED OVER A PERIOD OF SEVERAL YEARS, SHOULD THE UTILITY BE ALLOWED TO COLLECT A RETURN ON THE UNCOLLECTED PORTION OF STRANDABLE COST?

A It is my recommendation that the utility be allowed to recover the cost of debt supporting these assets but that the utility not be allowed to earn a return on equity for that component of the financing. Strandable assets may be used, but they are not economically useful. Consequently, a full return is not warranted. As a general rule, Commissions have found that excessive costs, even if prudently incurred, may not be fully recoverable from customers. For example, in a Texas decision involving Central Light & Power Company rendered in March, 1997 the PUC of Texas found:

> CPL does not have generation assets sitting idle somewhere with "ECOM" written on them.[11] Instead ECOM exists in CPL's currently functioning generation

[11] ECOM is the acronym that the Texas Commission uses for strandable costs. It stands for Excess Cost over Market.

> units, that it uses to generate power it needs to serve customers, while maintaining an appropriate reserve. *To the extent that these units produce rates which exceed the revenue they would produce in a competitive environment, they are less "useful" to current customers.*
> (Docket 14965, Finding 364, emphasis added)

Q ARE THERE ANY ADVANTAGES TO DENYING A FULL RETURN ON THE UNAMORTIZED STRANDABLE COSTS?

A Yes. It will provide an incentive for the utility to sell the plants because they will not be earning a full return. Moreover, denying or reducing the return on the uncollected strandable costs will allow for a shorter recovery period, all other things being equal.

Q CAN YOU PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A Certainly. First, market based approaches for determining strandable cost are superior to administrative ones, with divestiture being the optimal method. Under certain conditions and safeguards, and if divestiture is not an option, I find the utility market choice method to be most advantageous.

Second, if an administrative approach is used, it is advisable to use more than one method to provide a reasonableness check of any one method or determination or to narrow an otherwise wide range of estimates.

Third, the lost revenues approach is the least satisfactory of any determination method.

Fourth, strandable costs must be net of any stranded benefits, and only mitigated costs should be eligible for recovery. This means that not only should the utility have demonstrated past efforts for mitigation, but that a reasonable amount of future mitigation should be implicit in the calculations.

Fifth, strandable cost recovery should be viewed as extraordinary relief to utilities. Because transition charges are barriers to competition, they should be minimized–in both size and duration–to the greatest extent possible.

Sixth, the surest mechanism to encourage mitigation and to limit anti-competitive effects is to ordain an a priori sharing of stranded costs between shareholders and consumers.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

Qualifications of Alan Rosenberg

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Alan Rosenberg. My business mailing address is P. O. Box 412000, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was awarded a Bachelor of Science Degree from the City College of New York in 1964 and a Doctorate of Philosophy in Mathematics from Brown University in 1969. Subsequently, I held an Assistant Professorship of Mathematics at Wesleyan University in Connecticut. In the summer of 1975, I was a Visiting Fellow at Yale University. From July, 1975 through January, 1981, I was Assistant Controller for a division of National Steel Products Company. My responsibilities there included supervision of management accounting, cost accounting and data processing functions. I was also responsible for internal control, working capital levels, budget preparation, cash flow forecasts and capital expenditure analysis. From February, 1981, through December, 1981, I was Project Manager of the Steel Fabricating and Products Group, National Steel Corporation, responsible for implementing an integrated general ledger system. I have published in major academic journals and am a member of the International Association for Energy Economics.

In January, 1982, I joined the firm of Drazen-Brubaker & Associates, Inc., the predecessor of Brubaker & Associates. Since that time, I have presented expert testimony on the subjects of industry restructuring, open access transmission, marginal and embedded class cost of service studies, electric and gas rate design, revenue requirements, natural gas transportation issues, demand-side management, and forecasting.

I have previously testified before the Federal Energy Regulatory Commission as well as the public service commissions of Connecticut, Delaware, Florida, Illinois, Iowa, Massachusetts, Michigan, Montana, New Mexico, New York, Ohio, Rhode Island, Vermont, Virginia and the Provinces of Alberta, British Columbia, Nova Scotia, and Saskatchewan in Canada. I was an invited speaker at the NARUC Introductory Regulatory Training Program and a panelist at a conference on LDC and Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have also spoken at several conferences on the topic of competitive sourcing of electricity for industrial users.

PROOF THAT UTILITY'S REVENUES ARE MAXIMIZED IF FORECAST OF MARKET PRICE EQUALS ACTUAL MARKET PRICE

Definitions

Current Supply Charge (CSC)	Supply Charge at status quo, i.e., current regulated charge for the supply function.
Estimated Market Price (EMP)	Forecast of market price which becomes regulated and contestable unbundled supply price.
Actual Market Price (AMP)	Prevailing price in a competitive market.
Transition Supply Surcharge (TSS)	Additional charge for supply, paid to former provider, that is independent of future source of supply.
Utility Revenue (UR)	The total revenue the utility receives for its generation, including transition charges

Assumptions

TSS equals 50% of difference between CSC and EMP, or

(1) TSS = .5 * (CSC - EMP)

Customer can purchase from utility at EMP or at market for AMP, hence

(2) UR = lesser of EMP or AMP, plus TSS

Proof

Case 1: EMP = AMP

In this case, UR = EMP + TSS

= EMP + .5 * (CSS - EMP)

= .5 * (EMP + CSS)

Since EMP = AMP, we have

(3) UR = .5 * (AMP + CSS)

Case 2: EMP < AMP

In this case,

$$EMP = AMP - D, \text{ where } D > 0$$

Since EMP < AMP, our second assumptions implies

$$UR = EMP + TSS$$
$$= EMP + .5 * (CSC - EMP)$$
$$= AMP - D + .5 * (CSS - AMP + D)$$
$$= AMP - .5\ AMP - D + .5\ D + .5\ CSS$$
$$= .5 * (AMP + CSS) - .5 * D$$

Since D > 0,

(4) $UR < .5 * (AMP + CSS)$

Comparing (3) and (4), we see that UR in Case 2 is less than it is under Case 1.

Case 3: AMP < EMP

In this case,

$$EMP = AMP + D, \text{ where } D > 0$$

Since AMP < EMP, our second assumption implies

$$UR = AMP + TSS$$
$$= AMP + .5 * (CSC - EMP)$$
$$= AMP + .5 * (CSS - AMP - D)$$
$$= AMP - .5\ AMP - .5\ D + .5\ CSS$$
$$= .5 * (AMP + CSS) - .5\ D$$

Since D > 0,

(5) $UR < .5 * (AMP + CSS)$

Comparing (3) and (5), we see that UR in Case 3 is less than it is under Case 1.

REBUTTAL TESTIMONY

OF

KEVIN C. HIGGINS

ON BEHALF OF

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,

BHP COPPER, CYPRUS CLIMAX METALS, ASARCO,

PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND

MORENCI WATER & ELECTRIC COMPANY

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF

ELECTRIC SERVICE THROUGHOUT THE STATE OF ARIZONA

DOCKET NO. U-0000-94-165

January 21, 1998

Rebuttal Testimony of Kevin C. Higgins

Summary

The following rebuttal testimony is offered:

Balancing of Customer and Utility Interests – Mr. Bayless' claim that customers must bear the costs of TEP generation for up to thirty years after the introduction of competition is unreasonable on efficiency and equity grounds. However, Dr. Fessler offers some useful examples from California of shareholder sacrifice that are relevant for Arizona – lower returns on equity and a price cap.

Calculation method – A number of utility witnesses express support for the net revenues lost approach. Carried to its logical end, this approach completely defeats the purpose of competition. Auction and divestiture and replacement cost valuation are both superior methods for calculating strandable cost. Any use of the net revenues lost approach must be accompanied by important safeguards, which are outlined in the Rebuttal testimony, and addressed in greater detail in Higgins Direct testimony.

Mitigation – A number of utility witnesses seek to have the Commission change the Rule's treatment of mitigation by excluding the net revenues earned by the utility or its affiliates in unrelated enterprises. As indicated in Higgins Direct testimony, accounting for mitigation activities is best resolved by deeming the utility to be at risk – up front – for recovery of a substantial portion of its potentially stranded cost, and to allow the utility to be financially rewarded when its mitigation efforts are successful. Under this approach, it is not necessary to distinguish between the mitigation efforts of related and "unrelated" enterprises.

Market price – Mr. Bayless proposes a market price index which is reflective of wholesale market prices. A similar concern exists for Mr. Davis' proposal. Appropriate adjustments to convert these indices to retail prices would have to be made.

Treatment of Self-generation and Demand-Side Management – Proposals to repeal the Rule's present treatment of these customer options should be rejected.

Changes in the Definition of Stranded Cost – Proposals to modify the definition of stranded cost should be rejected.

CONTENTS

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

I. INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q. Have you filed other testimony in this proceeding?

A. Yes. I have filed direct testimony.

Q. What is the purpose of this testimony?

A. In this testimony I offer rebuttal to the direct testimony of Tucson Electric Power (TEP) Witnesses Bayless, Gordon, and Fessler; Arizona Public Service Co. (APS) Witnesses Davis and Hieronymus; Arizona Electric Power Cooperative (AEPCO) Witness Minson, and Citizens Utilities Witness Breen.

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[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

Q. How is your rebuttal testimony organized?

A. The rebuttal testimony is arranged by topic.

II. BALANCING OF CUSTOMER AND UTILITY INTERESTS

Q. Does Mr. Bayless (TEP) propose a reasonable approach to balancing customer and utility interests in the recovery of strandable cost?

A. No, he does not. Mr. Bayless maintains that customers have the obligation to pay for all strandable costs over the remaining life expectancy of TEP's generation assets, a period in excess of thirty years. Mr. Bayless justifies this claim by referring to an implied regulatory compact that he believes binds customers for the coming decades to the cost incurred by TEP to build and operate its generation facilities.

Mr. Bayless' view is unreasonable. The regulatory environment in which TEP has heretofore operated does not convey a blanket responsibility upon customers to bear the costs of TEP generation for up to thirty years after the introduction of competition. His argument presumes that deregulation of generation service is a one-way street: good for consumers, bad for investors. It ignores the fact that deregulation of generation prices will mean that investors will have opportunities over the long-run to earn above a regulated return – using the very assets that will be the subject of stranded cost claims. As pointed out in my direct testimony and by others, investors in electric utilities have been on notice for a number of years that restructuring and regulatory changes were coming which would introduce greater competition. These changes will provide long-term opportunities for some companies, but might also place full recovery of fixed costs at risk, at least in the short run. Because competition will provide opportunities for both customers and investors, it is inappropriate to conclude that changing the regulatory paradigm requires customers alone to shoulder the risk of strandable cost.

Q. Are there other grounds for your objections to Mr. Bayless' position?

A. Yes, there are significant efficiency reasons for not assigning all potentially stranded costs to customers. First, strandable cost charges distort the price of electric power by making the effective price to consumers higher than the true long-run marginal cost. Today there are technologies and suppliers which can provide electric power at an overall lower cost than incumbents can using higher-cost technology. The economically efficient price for electric power is one which reflects this lower cost. In an efficient market, owners of production facilities with relatively high fixed costs would be forced to lower their prices to meet the new market standard. These production facilities would continue to be operated so long as the market price covered their variable cost.

In contrast, strandable cost charges keep prices artificially high. With strandable cost charges to pay, a business considering locating or expanding in Arizona would face electricity prices that are higher than true long-run marginal costs. This incorrect price signal would discourage business expansion or retention which would otherwise be efficient.

Second, assigning full responsibility for strandable cost to customers is inefficient because it weakens the utility's incentive to mitigate strandable cost.

As I stress in my direct testimony, the best mitigation incentive is for the utility to be at risk for recovery of a substantial portion of its potentially stranded cost, and to be financially rewarded when its mitigation efforts are successful. This type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies and represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved.

Q. **What is your analysis of Mr. Bayless' claim that assigning full responsibility for recovery of stranded cost to customers is good for the nation's economy?**

A. Assigning full responsibility for recovery of stranded cost to customers may be good for TEP's shareholders, but it is not good for TEP's customers or for the economy of Arizona. As I have just indicated, stranded cost charges will distort price signals to the detriment of the local economy. To the extent that a transition charge is levied on customers, it can only be argued in terms of equity considerations. There are no efficiency benefits.

This point is very well illustrated by Mr. Bayless' own example of OLDCO vs. NEWCO [Bayless Direct, pp. 8-9]. In Mr. Bayless' example, the incumbent, OLDCO, has sunk plant costs of 5 cents/kWh, and the new entrant, NEWCO, has new plant costs of 2 cents/kWh. Both companies have identical short-run marginal costs of 1 cent/kWh and mark-ups of 1 cent/kWh. Therefore, OLDCO sells power at 7 cents/kWh, while NEWCO is willing to sell it for 4 cents/kWh. In Mr. Bayless' view, society should discourage construction of NEWCO's plant, because OLDCO has plant available to do the job. Mr. Bayless believes that the proper vehicle to carry out this policy is a stranded cost charge, in which a customer purchasing from NEWCO would have to pay OLDCO 3 cents/kWh, removing NEWCO's price advantage and effectively discouraging construction of its plant.

What Mr. Bayless fails to present is the efficient market solution, in which OLDCO lowers its price to 4 cents/kWh to meet the new long-run marginal cost. It is true that, in doing so, OLDCO will not be able to cover all of its sunk costs. But after all, its technology is obsolete – or its original construction costs were just too high. It will have to write down the asset and/or restructure its financing or ownership, but it will remain in OLDCO's interest to keep operating, given its low marginal cost. On the whole, society benefits, because prices reflect true long-run marginal costs and customers can make efficient purchasing decisions.

To see this point another way, simply change Mr. Bayless' example from power plants to apartment houses. Both OLDCO and NEWCO offer identical apartments, but NEWCO's can be constructed at a lower cost. OLDCO's rent for $700/month; NEWCO's can rent for $400/month. Could it possibly be in society's interest to discourage construction of NEWCO's apartments by placing a rental surcharge on NEWCO's tenants of $300/month payable to OLDCO? On *efficiency* grounds? Can society possibly be better off if apartment prices were forced by the government to rent for $700/month when new properties could actually be built profitably at $400/month? Just so "unnecessary" apartments weren't built? Of course not.

Q. **Do other utility witnesses also argue for 100% customer responsibility for strandable cost?**

A. Yes. Dr. Gordon (TEP), Mr. Breen (Citizens), and Mr. Minson (AEPCO) also make this assertion. The rebuttal I offer to Mr. Bayless' position generally applies to their testimony on this issue as well.

Q. **Do any utility witnesses make a case for shareholder sacrifice?**

A. Yes. Dr. Fessler (TEP) describes the sacrifices imposed on investors in California [Fessler Direct, pp. 16-17]. Of particular interest for Arizona is California's mandated reduction on allowed equity return for assets receiving stranded cost support. This reduction in return on equity is to a level ten percent below that of long-term debt. I suggest that if the net revenues lost approach is used to calculate strandable cost in Arizona, a similar reduction in the return on equity should be applied to stranded assets to account for absorption of shareholder risk provided by the transition charge.

Q. **Does Dr. Fessler describe any other shareholder sacrifices of relevance to Arizona?**

A. Yes. Dr. Fessler notes that the California Commission adopted a price cap because it "recognized that a major goal of the restructuring effort was to lower the price consumers paid for electricity." [Fessler Direct, p.17] As obvious as that goal sounds, Arizona utilities continue to quibble about a price cap. For example, Mr. Bayless' endorsement of a price cap appears limited to conditions in which TEP shareholders face almost no risk [Bayless Direct, p. 17]. In contrast, the California price cap places shareholders significantly at risk for recovery of strandable cost, a policy Dr. Fessler supported with his vote as Commissioner. Yet when it comes to price cap for Arizona, Dr. Fessler seems to be lukewarm. Perhaps, he suggests, Arizona Commissioners should just place their faith in the market. My response is that it is not the market we are worried about – it's the stranded cost charges. It is essential that the design of the strandable cost recovery program incorporate a price cap. And a price cap does not mean regulating the price of generation; it means designing the transition charge appropriately.

III. CALCULATION METHOD

Q. Many utility witnesses advocate use of the net revenues lost approach to calculating strandable cost. What is your position to this recommendation?

A. The net revenues lost approach is advocated by Mr. Davis (APS), Dr. Hieronymus (APS), Mr. Minson (AEPCO), and Mr. Bayless (TEP). Somewhat qualified support is provided by Dr. Gordon (TEP) and Dr. Fessler (TEP). My direct testimony includes an extensive discussion on the net revenues lost approach. I point out that the salient feature of the net revenues lost approach is its presumption that stranded cost is whatever additional amount consumers would have had to pay for electric power if regulation continued and competition never occurred. I do not consider this to be an appropriate presumption for establishing fair and efficient transition charges to customers. Carried to its logical end, this approach completely defeats the purpose of moving to a competitive market – at least for the foreseeable future. In general, I am opposed to its use.

I rank auction and divestiture, as well as replacement cost valuation as superior approaches. However, in my testimony, I suggest that the net revenues lost approach could have limited application for calculating strandable cost on a year-to-year basis, if accompanied by each of the following important safeguards:

(1) the transition period for strandable cost eligibility is kept within a limited period of time, i.e., three to five years,

(2) the customer-paid transition charge is kept well within the 25 to 50 percent range, e.g., 35 percent,

(3) customers in a given year pay only for strandable cost associated with that year, and

(4) the magnitude of strandable cost is capped using replacement cost valuation.

Q. **Do you have any other observations on the testimony of utility witnesses regarding the net revenues lost approach?**

A. Yes, Dr. Gordon (TEP) implies that the net revenues lost approach necessarily incorporates an adjustment to the strandable cost charge in response to changes in actual market prices. I agree that such adjustments can be attempted, but the method, as it has been discussed in Arizona, does not necessarily include the feature described by Dr. Gordon. Instead, strandable cost is presumed to be calculated using market price estimates, followed by after-the-fact true-ups.

Q. Do you have any observations on Dr. Fessler's testimony concerning the net revenues lost approach?

A. Yes. I think Dr. Fessler's discussion on the subject is thought provoking. [Fessler Direct, Q.43] He draws an important distinction between California's treatment of strandable cost and the treatment recommended by the former Arizona staff director in the Report of the Stranded Cost Working Group. The California transition charge was designed to allow a return *of* investor capital, but not a return *on* that capital. In contrast, as Dr. Fessler points out, the net revenues lost approach espoused in Arizona "seeks to protect the expectations formed under the existing regulatory regime with respect to both the recovery of an investment *and the income stream on that investment.*" [Fessler Direct, p. 37, emphasis added] In my direct testimony I refer to calculation approaches that are "relatively generous to the utility." The net revenues lost approach described in the Working Group Report is an example of what I mean.

IV. MITIGATION

Q. Some utility witnesses recommend changes in the Rule's treatment of mitigation. What is your recommendation on this issue?

A. Mr. Davis (APS), Mr. Minson (AEPCO), Mr. Breen (Citizens), and Mr. Bayless (TEP) seek to have the Commission change the Rule's treatment of mitigation by excluding the net revenues earned by the utility or its affiliates in unrelated enterprises. As I indicate in my direct testimony, accounting for mitigation activities is best resolved by deeming the utility to be at risk – up front

-- for recovery of a substantial portion of its potentially stranded cost, and to allow the utility to be financially rewarded when its mitigation efforts are successful. Under this approach, it is not necessary to distinguish between the mitigation efforts of related and "unrelated" enterprises.

V. MARKET PRICE

Q. What is your assessment of the market price recommendations made by Mr. Davis (APS) and Mr. Bayless (TEP)?

A. Both Mr. Bayless and Mr. Davis recommend using the net revenues lost approach to calculating strandable cost. If that approach is used, it is necessary to calculate the value of the utility's generation in the competitive retail market. Mr. Bayless suggests using the DJ Palo Verde price index for the purpose; however, the DJ Palo Verde price index is an index of *wholesale* prices. It essential that appropriate adjustments be made to any wholesale prices index to reflect the average cost at the retail level. I suggest a number of such adjustments in my direct testimony on pages 22-23.

Mr. Davis proposes using the California Power Exchange as a basis of market price. While I believe the Power Exchange will serve a useful function for Arizona, the packaging of Power Exchange generation for sale in Arizona seems likely to develop into a wholesaler activity that will be accompanied by a retail mark-up. As I indicated in my response to Mr. Bayless' proposal, it is the retail price which matters here. If the California Power Exchange is used as the basis of market price for calculation of strandable cost, an appropriate adjustment to convert the California price into a meaningful Arizona retail price would have to occur.

VI. TREATMENT OF SELF-GENERATION AND DEMAND-SIDE MANAGEMENT

Q. Do you object to any of the positions taken by utility witnesses on the treatment of self-generation and demand-side management?

A. Yes. Mr. Minson (AEPCO) proposes deleting Section 1607(J) of the Rule. This section states:

> Stranded cost may only be recovered from customer purchases made in the competitive market using the provisions of this Article. Any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer.

As I stated in my direct testimony, the reasoning behind this provision is straightforward. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. Thus, in adopting the

Rule, the Commission found that "there is no compelling reason to impose Stranded Cost responsibility on self generators under these Rules, when none has been imposed in the past." [Opinion and Order, Appendix B, p. 49]

This important provision should remain in the Rule.

VII. CHANGES IN THE DEFINITION OF STRANDED COST

Q. Do any utility witnesses propose changes in the definition of stranded cost in the Rule?

A. Yes, Mr. Davis proposes to substitute the word "cost" for "value" in the Rule. This particular debate occurred during the rulemaking process, and the Commission concluded that this change was unnecessary. [Opinion and Order, pp. 42-43] Likewise, it was a consensus recommendation of the Stranded Cost Working Group not to change the definition in the Rule.

Of greater concern, Mr. Davis proposes to delete language that limits stranded cost recovery to assets or obligations acquired or incurred prior to adoption of the Rule. This deletion should not be made. Customers should not be placed at risk for recovery of utility generation assets or obligations yet to be acquired. A cut off point is necessary. If the cut off date is to be changed, there is as much (or more) reason to move it backward in time as there is to move it forward. I recommend that the definition of stranded cost remain unchanged.

Q. Does this conclude your rebuttal testimony?

A. Yes, although I may be filing additional rebuttal on February 2.