17235

Witness CCS-2
Exhibit CCS-2

RECEIVED
JUN 18 3 45 PM '99
SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	Docket No. 98-2035-04
In the Matter of the Application	)	
of PacifiCorp and ScottishPower plc	)	PRE-FILED DIRECT TESTIMONY OF
for an Order Approving the Issuance	)	BRUCE E. BIEWALD
of PacifiCorp Common Stock	)	FOR THE
	)	COMMITTEE OF CONSUMER SERVICES

June 18, 1999

Table of Contents

1. Qualifications

Q. State your name, occupation and business address.

A. My name is Bruce Edward Biewald. My address is Synapse Energy Economics, Inc., 22 Crescent Street, Cambridge, Massachusetts, 02138.

Q. Please describe your current employment.

A. I am President of Synapse Energy Economics, Inc., a consulting company specializing in economic and policy analysis of electricity restructuring, particularly issues of consumer protection, market power, stranded costs, renewable energy, efficiency, environmental quality, and nuclear power.

Q. What are your qualifications with regard to energy policy?

A. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for fifteen years at the Tellus Institute where, as Manager of the Electricity Program, I was responsible for studies on a broad range of electric system regulatory and policy issues. I have provided testimony on energy issues in more than 50 cases in 20 states, two Canadian provinces, and before the Federal Energy Regulatory Commission. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility

Commissioners. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. My resume is provided here as Exhibit CCS-2.1.

2. Summary and Recommendations

Q. What is the purpose of your testimony in this case?

A. I have been asked to assist the Committee of Consumer Services (Committee) by reviewing and commenting upon the benchmarking analysis and projected savings filed by ScottishPower in this case.

Q. How does your testimony relate to that of the other witnesses for the Committee of Consumer Services?

A. My testimony complements that of Mr. Neil Talbot and Mr. Paul Chernick. We all support the conclusions and recommendations of Mr. Dan Gimble of the Committee.

Q. Please provide an overview of your analysis and this testimony.

A. I begin with a discussion of ScottishPower's expectation of large cost savings potential at PacifiCorp and contrast this with the "commitment" to pass $10 million per year in corporate cost reductions on to PacifiCorp customers. I then address the two key areas of support that ScottishPower offers for its expectation of cost savings – its benchmarking analysis and its experience with Manweb in the United Kingdom.

The benchmarking analysis is a very abstract and limited exercise that deals with only a relatively small portion of PacifiCorp's costs in a rather superficial way. Thus, the analysis is not very useful. ScottishPower itself expresses a lack of faith in its benchmarking analysis and declines to make a specific projection of savings or to guarantee any such savings on the basis of this analysis.

Mr. Richardson points to the experience with Manweb as support for his confidence that ScottishPower "can achieve significant efficiencies in PacifiCorp's operations, and the resulting cost reductions will be captured through the ratemaking process to produce rates for customers that are lower than had the transaction not occurred" (Richardson Supplemental Testimony, pages 16 and 17). Specifically, Mr. Richardson points to reductions in bills for residential customers over a recent five-year period since ScottishPower acquired Manweb. ScottishPower did reduce costs at Manweb, but the situation faced in the UK by Manweb differs in important ways from that faced by PacifiCorp, most notably that Manweb was a government-owned and operated business in the process of being privatized. To the extent that Manweb may be relevant, it should be viewed in context. Based upon data from OFFER for bills to typical residential customers over the same five-year period used by Mr. Richardson, the reductions at Manweb (22%) are not exceptional, or even above average. Most of the Public Electricity Suppliers in Great Britain had even greater residential bill savings over this same five-year period, and the average for England and Wales as a whole was 23%.

Q. What do you recommend in this case with regard to ScottishPower's savings projections?

A. While $10 million per year of corporate cost savings is not insignificant, it should be viewed in the context of PacifiCorp as a $2 billion per year company, and in the context of the risks associated with the merger discussed in Mr. Talbot's testimony on behalf of the Committee. Moreover, before the $10 million amount represents any real benefit to PacifiCorp customers, there would have to be a rate case, and even then realization of the savings could be elusive, since additional costs could offset the savings.

As for any additional cost savings, ScottishPower makes positive but unsubstantiated and noncommittal claims. I recommend that the Utah Public Service Commission (Commission) take a skeptical view toward cost savings that are not backed up by enforceable guarantees and specific mechanisms. I recommend that the Commission recognize the potential for PacifiCorp to reduce costs as a stand-alone company without the merger with ScottishPower. I also recommend that the Commission not approve the merger on the basis of ScottishPower's unsubstantiated and noncommittal claims.

3. ScottishPower's Projection of Cost Savings

Q. What level of cost savings does ScottishPower expect to achieve in operating PacifiCorp?

A. ScottishPower's objective is that "PacifiCorp should be within the top ten major U.S. electric utilities with respect to non-generation operating costs as soon as possible" (MacRitchie Direct Testimony, page 4) and that the "current estimate is that it will take up to five years…" (MacRitchie Direct testimony, page 13). In round numbers, it would appear that this would require a reduction in PacifiCorp's non-production operating cost of about $100 per customer, yielding a total savings of $140 million per year (see ScottishPower's response to Utah CCS data request 9.19).

ScottishPower also expects to realize savings in production costs, but it has not estimated these or set specific goals. ScottishPower has indicated savings of $200 million. When asked about the basis for this figure, ScottishPower pointed to the $140 million in potential cost savings identified in the benchmarking analysis of one category of costs, and stated that "It is not therefore unreasonable for ScottishPower to speculate that if it was to look across the whole company, to also include all the previously excluded costs, then there could indeed be the potential to save up to $200 million." (Response to Utah CCS data request 9.19).

There is also an expectation of a net savings of $10 million in corporate costs.

Q. What amount of savings has ScottishPower offered as a benefit of

the merger?

A. ScottishPower has offered only the $10 million savings in corporate costs. The Company states that it "will commit to reflecting this reduction in PacifiCorp's results of operations filed with the Commission" (Richardson Supplemental, Ex. SP___(AVR-1), page 6) and that this amount "will be reflected in cost of service by the end of the third year after the transition closes" (Richardson Supplemental Testimony, page 2).

Q. How does the $10 million figure compare with the size of PacifiCorp?

A. The $10 million amount is very small in the context of a Company the size of PacifiCorp, with annual revenues of about $2 billion.

Q. Is it assured that the $10 million savings will be reflected in electricity prices?

A. No. The treatment of the $10 million savings that is committed is not clear. According to Mr. Richardson's Supplemental Testimony (April 16, 1999) ScottishPower has "committed to flow it through to customers through the ratemaking process" (page 1, line 13). This would require a rate case. It would also require that the net $10 million reduction in corporate costs be achieved without shifting, or increasing other categories of costs offsetting the $10 million reduction. ScottishPower has not offered to pass the $10 million savings to customers in a merger-related rate reduction. It merely offers to recognize such savings in a rate case filing, if such a filing occurs and is far enough into the future to include savings that are not expected until "the end of the third year following the closing of the transaction" (Mr. Green's Direct Testimony, page 9).

In Utah, this would require a test year no earlier than 2002 for a filing no sooner than 2003. Given a typical rate proceeding, Utah consumers might see their share of the $10 million from a 1999 transaction reflected in rates in 2004. However, given the relatively small and uncertain size of any Utah share of the proposed benefits, it is also possible that rates would increase if any of the risks described by Mr. Talbot come to pass or if PacifiCorp alleges underearnings.

Q. What evidence does ScottishPower offer in support of its expectation that it will be able to significantly cut costs in PacifiCorp's operation?

A. The two areas of support offered by ScottishPower are its benchmarking analysis and its experience with transforming Manweb. I will address each of these in turn.

4. ScottishPower's Benchmarking Analysis

Q. Please describe the benchmarking analysis offered by ScottishPower in this case.

A. Mr. MacRitchie has presented ScottishPower's "high-level preliminary estimates of the potential for operating cost savings" in PacifiCorp. The benchmarking analysis involved comparing 1996 cost data – excluding production, customer service and informational expenses and uncollectables – across roughly 144 U.S. companies. The comparison showed that "PacifiCorp's operating costs per customer were higher than those experienced by many other utilities both in the Pacific Northwest and across the rest of the U.S." and led ScottishPower to believe that "there is potential for reducing operating costs at PacifiCorp" (MacRitchie Direct Testimony, page 2).

Q. Is the ScottishPower benchmarking analysis a reasonable basis to predict savings in PacifiCorp's operations?

A. It may have some value, but only in a very limited sense. It is a very superficial comparison – presented in a simple two-page table sponsored by Mr. MacRitchie. It excludes production costs and several categories of non-production costs (customer service, informational, and uncollectables). This leaves only about $415 million to be included in the analysis, less than one fifth of PacifiCorp's annual retail operating revenues.

The benchmarking analysis involves almost no effort to account for differences in the conditions of the different companies. For example, companies of widely different sizes are compared, ranging from six thousand customers to 4.6 million customers. Companies in the benchmarking analysis also have very different amounts of distribution lines, one of the primary factors driving distribution system maintenance costs. The benchmarking analysis is done by expressing costs per customer – making no effort to account for the fact that industrial customers are larger and impose greater costs than residential customers. Companies in the benchmarking analysis have significantly different mixes of high and low usage customers.

Also, PacifiCorp has an extensive transmission system and mine-mouth coal generation, so one might reasonably expect its generation costs to be low and its transmission costs to be high, relative to a more typical company. Benchmarking comparisons, such as ScottishPower's, that focus exclusively upon non-production operating costs could thereby tend to overstate the potential for cost reduction in that area for PacifiCorp.

Q. **How do PacifiCorp's total residential prices compare with other companies in the U.S.?**

A. I have listed residential prices for 177 U.S. companies in Exhibit CCS-2.2, with PacifiCorp's state-specific prices indicated. The data source is the Edison Electric Institute's Typical Bills database for Winter 1998. PacifiCorp's prices are among the lowest, particularly for its sales in the Washington (#10), Wyoming (#14), and Oregon (#27) areas.

Q. **Does the price data presented in Exhibit CCS-2.2 have the same**

problem of comparing companies in different situations?

A. Yes. It is a simple comparison of simple revenue per unit of sales, and does not involve any adjustments to account for differing conditions in which various companies operate. I offer these price data in order to show how PacifiCorp compares with other U.S. companies when all of the cost categories are included. These residential price data suggest that PacifiCorp is among the lower cost companies overall. This is similar to the conclusion reached by Mr. MacRitchie in his examination of non-production costs – but indicates that perhaps there is somewhat less room for cost reduction in the production area, at least on a percentage basis.

Q. Are there other assessments that indicate that PacifiCorp is doing reasonably well on its own?

A. Yes. A recent article in Public Utilities Fortnightly analyzed data for one hundred U.S. utilities and identified PacifiCorp as one of nineteen "efficient" utilities ("The Fortnightly 100: Which Utility Ranks the Highest," by Forrester, Khawaja, Haeri, and Carter, September 1, 1998).

Q. Does the benchmarking analysis account for PacifiCorp's ability to realize cost savings on its own?

A. No. The benchmarking simply compares PacifiCorp with other companies and indicates that there may be some room for improvement in reducing costs per customer. It makes no attempt to account for savings that PacifiCorp could achieve without the merger. PacifiCorp has already made some substantial employment reductions over the past few years, and with its renewed focus upon its core electric utility business can be expected to make gradual efficiency improvements in the future. A true analysis of the "benefits of the merger" would compare scenarios with and without the proposed merger.

Q. Does ScottishPower disagree with your view of the adequacy of the benchmarking analysis?

A. I expect that ScottishPower would generally agree with my view that the benchmarking analysis is not adequate as a reliable estimate of future cost savings. ScottishPower has been careful to state that the benchmarking is "preliminary" and was used only to determine that "there is potential to reduce operating costs in PacifiCorp" (MacRitchie Direct Testimony, page 2). Mr. MacRitchie has stated that ScottishPower would conduct more detailed benchmarking as part of its overall process of "transforming the business" after the closing date of the merger (MacRitchie Rebuttal Testimony before the Public Utility Commission of Oregon, June 2, 1999, in UM 918).

Q. What is your conclusion regarding the benchmarking analysis?

A. I conclude that savings may be somewhat more difficult to achieve at PacifiCorp than would be suggested by ScottishPower's preliminary benchmarking analysis, and that there has been no analysis whatsoever of incremental savings attributable to the merger, other than the claimed net savings of $10 million in corporate costs discussed above.

5. ScottishPower's Experience With Cost Reduction in the UK

Q. What evidence from the UK does ScottishPower point to in support of its expectation that it can reduce costs in PacifiCorp's operations?

A. The primary example put forward by ScottishPower in support of its ability to transform a regulated electric utility business is Manweb, which ScottishPower acquired in 1995 (see MacRitchie direct testimony, page 6 and 8). Mr. Richardson provides a specific example of the average residential customer's bill in the Manweb service territory, which he points out declined by 25% in real terms between 1993/94 and 1998/99 (Richardson supplemental testimony, page 15).

Q. Please comment on the relevance of the Manweb experience to PacifiCorp.

A. The situation at Manweb in 1995 was quite different from that currently faced by PacifiCorp. The distribution companies in the UK had been government organizations with well-known inefficiencies, and were in the process of being privatized. In contrast, PacifiCorp has been a privately-owned company subject to state price regulation and some degree of competition – and has already made substantial employment reductions over the past few years. Also, the geographic differences between Manweb and PacifiCorp are considerable. Manweb serves a fairly small and densely populated area in England while PacifiCorp serves a sprawling area including portions of five Western states that in total is larger than the entire UK. While the experience with Manweb has some relevance to what ScottishPower may do with PacifiCorp, the applicability is limited.

Q. Is the 25% reduction in residential bills at Manweb an accurate figure?

A. I am not certain. It does not agree with data from OFFER which shows a reduction of only 22% for Manweb between 1993/94 and 1998/99. I have not been able to establish the reason for this difference.

Q. How does the amount of residential bill reduction for Manweb over this period compare with that experienced by customers of other electricity suppliers in the UK?

A. The data published by OFFER showing a bill reduction for Manweb customers of 22% has analogous data for the other systems in the UK. These prices are summarized in Exhibit CCS-2.3. They show that most of the Public Electricity Suppliers in Great Britain had even greater average residential bill savings over this same five-year period, and that the average for England and Wales as a whole was 23%.

The Manweb experience is not exceptional, at least insofar as savings to residential customers is concerned.

Q. Have you reviewed data on cost trends at Manweb and other systems in the UK?

A. As far as I am aware, cost data analogous to the data on bill trends discussed above is not available. However, as discussed in Mr. Talbot's testimony, the trend in Manweb's returns on capital employed has been similar to the trend for other Public Electricity Suppliers, supporting the idea that Manweb's costs have followed a trend similar to the other suppliers as well.

Q. What has the trend been in ScottishPower's own residential prices in recent years?

A. The data in Exhibit CCS-2.3 indicate that ScottishPower's current prices are among the highest in the UK, well above average – and that the bill reductions for residential customers have been lagging behind other companies. ScottishPower's typical residential bill decreased by only 18% over the recent five-year period during which the average decline for residential customers in Great Britain was 22%.

Similar data for the four-year period just prior to this (1989/90 to 1993/94) show that ScottishPower's average residential bill actually increased slightly in real terms (by 1%) while the general trend in Great Britain was downward (by 3%).

Q. What do you conclude about ScottishPower's UK performance and its ability to transfer that performance to PacifiCorp?

A. ScottishPower's performance, based upon the information described above, is adequate but not spectacular. Price reductions appear to be in line with what other UK providers have achieved. This does not indicate that the Commission and consumers in the U.S. should expect results that PacifiCorp could not achieve on its own.

Q. Does this conclude your testimony?

A. Yes.

NVhb8
17237

Committee of Consumer Services

Witness: Bruce E. Biewald

Docket No. 98-2035-04

CCS Exhibit 2.1 (BEB)

Exhibit CCS-2.1 (BEB)

Bruce Edward Biewald

Synapse Energy Economics, Inc.
22 Crescent Street, Cambridge, MA 02138
(617) 661-3248 • fax: 661-0599
www.synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA
President, 1996 to present:
Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric industry restructuring, electric power system planning, performance-based regulation, stranded costs, system benefits, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, environmental disclosure, nuclear plant decommissioning and radioactive waste issues, climate change policy, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, fuel prices, purchased power availability and cost, dispatch modeling, economic analysis of power plants and resource plans, and risk analysis.

Tellus Institute, Boston, MA
Senior Scientist and Manager of the Electricity Program, 1989 to 1996:
Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.
Research Associate, later Associate Scientist, 1980 to 1988.

EDUCATION

Massachusetts Institute of Technology
BS 1981, Architecture, Building Technology, Energy Use in Buildings.

Harvard University Extension School
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Expert testimony on energy, economic, and environmental issues in more than 50 regulatory proceedings in 2 Canadian provinces, 20 States, and before the Federal Energy Regulatory Commission.

Co-author of approximately 100 reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, and the National Association of Regulatory Utility Commissioners.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, and others.

TESTIMONY

Federal Energy Regulatory Commission (Docket Nos. EC98-40-00, et al.) – April 1999
Horizontal market power and barriers to entry in consideration of the proposed merger of American Electric Power Company and Central and South West Corporation.

Connecticut Department of Public Utility Control (Docket No. 99-03-04) – April 1999
Market power, market prices, and simulation modeling as related to the application of United Illuminating Company for recovery of stranded costs.

Connecticut Department of Public Utility Control (Docket No. 99-02-05) – April 1999
Market power, market prices, and simulation modeling as related to the application of Connecticut Light & Power Company for recovery of stranded costs.

Maryland Public Service Commission (Case No. 8797) – January 1999
Simulation analysis of the ECAR market and projected market prices for electricity for estimation of Potomac Electric Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Case No. 8795) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Delmarva Power and Light Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Cases Nos. 8794 and 8804) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Baltimore Gas and Electric Company's stranded generation costs and unbundled rates.

Vermont Public Service Board (Docket No. 6107) – September 1998
Excess capacity, used & useful, and the economics of Green Mountain Power's purchase from Hydro Quebec.

Mississippi Public Service Commission (Docket No. 96-UA-389) – September 1998
Analyses of market concentration and market power, behavior of affiliated companies, need for an independent system operator.

California Public Utilities Commission (Application No. 97-12-020) – July 1998
Nuclear power plant decommissioning and radioactive waste disposal. Also, rebuttal testimony in August.

Federal Energy Regulatory Commission (Docket No. EC97-46-000) – June 1998
Affidavit on market power implications of the proposed merger between Allegheny Power System and Duquesne Light Company.

New Jersey Board of Public Utilities (Docket Nos. EX4120585Y, EO97070460, and EO97070463) – March 1998
Economic and environmental benefits of energy efficiency, including estimation of marginal air emissions from the PJM System. (Joint testimony with Nathanael Greene, Edward Smeloff, and Thomas Bourgeois.)

Vermont Public Service Board (Docket No. 6018) – February 1998
Excess capacity and the economics of Central Vermont Public Service Company's purchase from Hydro Quebec.

Public Service Commission of Maryland (Case No. 8774) – February 1998
Market power implications of the APS-DQE merger.

Federal Energy Regulatory Commission (Docket Nos. OA97-237-000 and ER97-1079-000) – January 1998
Market power in New England electricity markets.

British Columbia Utilities Commission – November 1997
British Columbia Hydro and Power Authority Wholesale Transmission Services Application.

Pennsylvania Public Utility Commission (Docket R-00973981) – November 1997
West Penn Power Company Restructuring Plan. Environmental disclosure, consumer education, and allocation of default customers.

Pennsylvania Public Utility Commission (Docket R-00974104) – November 1997

Duquesne Light Company Restructuring Plan. Environmental disclosure, consumer education, nuclear decommissioning, and allocation of default customers. Also surrebuttal testimony in December 1997.

Mississippi Public Service Commission (Docket No. 97-UA-496) – November 1997
Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing Construction of a Generating Plant in Jackson County.

Pennsylvania Public Utility Commission (Docket Nos. R-00973953 and P-00971265) – November 1997
Application of PECO Energy Company for approval of its restructuring plan and petition on Enron Energy Services Power, Inc. for approval of an electric competition and customer choice plan. Allocation of default customers.

Vermont Public Service Board (Docket No. 5983) – October 1997
Excess capacity and the economics of Green Mountain Power Company's purchase from Hydro Quebec. Also rebuttal testimony in December 1997 and supplemental rebuttal testimony in January 1998.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – September 1997
Joint petition for partial settlement of PECO Energy Company's proposed restructuring plan and application for a qualified rate order. Environmental disclosure, nuclear decommissioning and spent fuel.

Pennsylvania Public Utility Commission (Docket No. R-00974009) – September 1997
Pennsylvania Electric Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Pennsylvania Public Utility Commission (Docket No. R-00974008) – September 1997
Metropolitan Edison Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Indiana Legislature, Regulatory Flexibility Committee -- September 23, 1997.
Testimony on "Electric Industry Restructuring To Benefit Consumers and the Environment: Stranded Costs, Nuclear Issues, and Air Emissions."

Pennsylvania Public Utility Commission (Docket No. R-00973954) – June 1997
Pennsylvania Power & Light Company's Restructuring Plan. Environmental disclosure, customer education, PJM market structure, nuclear decommissioning and spent fuel, rate design for stranded cost recovery. Also, surrebuttal testimony in August.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – June 1997
PECO Energy Company's Restructuring Plan. Environmental disclosure, PJM market structure, nuclear decommissioning and spent fuel.

New York Public Service Commission (Case 96-E-0897) -- April 1997
Consolidated Edison Company's Plans for Electric Rate Restructuring. Analysis of market power in the New York City load pocket.

Pennsylvania Public Utility Commission (Docket No. R-00973877) -- February 1997
Application of PECO Energy Company for Issuance of a Qualified Rate Order. Nuclear power plant decommissioning costs, stranded cost recovery, and securitization.

New Hampshire Public Utilities Commission (DR 96-150) -- November 1996
Electric industry restructuring, including stranded costs, industry structure, market power, and nuclear issues.

Massachusetts Department of Public Utilities (96-100) -- July 1996
Nuclear plant stranded costs and decommissioning.

Vermont Public Service Board (5854) – July 1996
Electric industry restructuring, including stranded costs, industry structure, and environmental protection.

Ontario Energy Board (H.R. 23) -- June 1995
Electricity rate options (joint evidence with John Stutz).

Pennsylvania Public Utility Commission (R-00943271) -- April 1995
Discount rates and system benefits charge.

Colorado Public Utilities Commission (94A-516A) – January 1995
Construction of new generating resources.

Public Service Commission of Nevada (94-9002) – November 1994
Environmental and health impacts of a proposed power plant.

Nuclear Decommissioning Finance Committee of New Hampshire (93-001) – September 1994
Seabrook decommissioning cost, spent fuel storage, and cost collection methodology (joint testimony with William Dougherty).

Public Service Commission of Wisconsin (6630-CE-197 and 6630-CE-209) – September 1994
Point Beach externalities, economics, spent fuel storage, and aging (joint testimony with William Dougherty).

British Columbia Utilities Commission – August 1994
Greenhouse gas emissions and environmental externalities policy

Public Service Commission of Wisconsin (05-EI-14) – February 1994
Cost of decommissioning Point Beach and Kewaunee nuclear power plants. Also, rebuttal and surrebuttal testimony in February.

Delaware Public Service Commission (91-39) – September 1992
Nuclear and fossil power plant performance targets.

Massachusetts Department of Public Utilities (91-131) – December 1991
Internalization of environmental externalities, greenhouse gas valuation and policy.

Massachusetts Department of Public Utilities (91-131) – October 1991
Environmental externalities valuation, emissions effects and global warming.

Massachusetts Department of Public Utilities ((89-141, 90-73, 90-141, 90-194 and 90-270) – December 1990
The incorporation of environmental externalities in specific utility RFPs.

Massachusetts Department of Public Utilities (90-55) – June 1990
Costs and benefits of high-efficiency gas heating equipment.

Massachusetts Department of Public Utilities (86-36-G and 89-239) – March 1990
Environmental externalities of electric resources.

Florida Public Service Commission (890973-E1) – January 1990
Integrated energy planning, power plant emissions, and nuclear plant performance.

Pennsylvania Public Utilities Commission (R-891364) – October 1989
Generating capacity requirements of the Philadelphia Electric Company and the Pennsylvania-New Jersey-Maryland Interconnection.

Maryland Public Service Commission (8199) – October 1989
Performance standards for coal, oil, and nuclear power plants.

Michigan Public Service Commission (U-9172) – April 1989
Economic analysis of the Palisades Power Purchase Agreement. Ratepayer impacts, incentives, and implications for plant operation and decommissioning.

Pennsylvania Public Utility Commission (P-870216, P-880283, P-880284, and P-880286) – March 1989
Allegheny Power System planning and avoided costs.

Michigan Public Service Commission (U-8880) – February 1988
Detroit Edison Company power supply costs, economics of Fermi "buy-back" purchase, nuclear fuel expense, oil costs, and power transactions.

Michigan Public Service Commission (U-8866) – December 1987
Consumers Power Company power supply costs, including projections of oil prices and purchased power costs.

Pennsylvania Public Utility Commission (R-850220) – September 1987
Economic analysis of West Penn Power Company's participation in the Bath County Pumped Storage Project, and Allegheny Power System capacity reserve requirements. Also, surrebuttal testimony in October.

Arizona Corporation Commission (U-1345-85-367) – February 1987
Palo Verde decommissioning cost.

Michigan Public Service Commission (U-8545) – December 1986
Consumers Power Company power costs, projected cost of oil and purchased power, economic evaluation of the Big Rock Point nuclear unit.

Public Service Commission of Indiana (38045) – November 1986
Northern Indiana Public Service Company system reliability and excess capacity.

California Public Utility Commission (84-06-014 and 85-08-025) – July 1986
Diablo Canyon decommissioning cost and collection issues.

Michigan Public Service Commission (U-8042R) – June 1986
Review of Consumers Power Company system operations during 1985 and economic evaluation of the Big Rock Point nuclear unit.

Michigan Public Service Commission (U-8291) – April 1986
Detroit Edison Company power supply costs, application of a multi-area dispatch model.

Michigan Public Service Commission (U-8286) – February 1986
Consumers Power Company power supply costs, application of a multi-area dispatch model.

Maine Public Service Commission (85-132) – January 1986
Standard and long term rates for cogeneration and small power production. Surrebuttal testimony in February.

Arkansas Public Service Commission (84-249-U) – June 1985
Impact of the Grand Gulf nuclear unit upon Arkansas Power and Light Company and Middle South Utilities electricity production costs.

Kentucky Public Service Commission (8666) – February 1984
Production costing modeling issues.

REPORTS

Stranded Nuclear Waste: Implications of Electric Industry Deregulation for Nuclear Plant Retirements and Funding for Decommissioning and Spent Fuel, by Bruce Biewald and David White, January 15, 1999.

New England Tracking System, a report to the New England Governors' Conference, Inc., funded by a grant from the U.S. Environmental Protection Agency, prepared with Environmental Futures, Inc. and Tellus Institute, October 1998.

The Role of Ozone Transport In Reaching Attainment in the Northeast: Opportunities, Equity and Economics, a Synapse Energy Economics report for the Northeast States for Coordinated Air Use Management, by Tim Woolf, David White, Bruce Biewald, and William Moomaw, July 1998.

Competition and Market Power in Northern Maine Electricity Market, a Synapse Energy Economics report for the Maine Public Utilities Commission, by Tim Woolf, Bruce Biewald, and Duncan Glover, November 24, 1998.

Grandfathering and Environmental Comparability: An Economic Analysis of Air Emission Regulations and Electricity Market Distortions, a Synapse Energy Economics report for the National Association of Regulatory Utility Commissioners, by Bruce Biewald, David White, Tim Woolf, Frank Ackerman, and William Moomaw, June 11, 1998.

Analysis of Market Power in the APS and Duquesne Service Territories, prepared for the Maryland Office of People's Counsel, by Bruce Biewald and David White, February 9, 1998.

Performance-Based Regulation in a Restructured Electric Industry, a Synapse Energy Economics report for the National Association of Regulatory Utility Commissioners, by Bruce Biewald, Tim Woolf, Peter Bradford, Paul Chernick, Susan Geller, and Jerrold Oppenheim, November 8, 1997.

Massachusetts Electric Utility Stranded Costs, a Synapse Energy Economics report for MASSPIRG, Union of Concerned Scientists, Clean Water Action, Massachusetts Citizens for Safe Energy, and Public Citizen, by Bruce Biewald, Tim Woolf, and Marc Breslow, November 4, 1997.

Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis, prepared for the New England Conference of Public Utility Commissioners, by Bruce Biewald, David E. White, and William Steinhurst, June 11, 1997 (a draft was published as Vermont DPS Technical Report No. 39 in March, 1997).

Zero Carbon Electricity: The Essential Role of Efficiency and Renewables in New England's Electricity Mix, a Tellus Institute report for the Boston Edison Company Settlement Board, by Bruce Biewald, Tim Woolf, Bill Dougherty, and Daljit Singh, April 30, 1997.

Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information, a Regulatory Assistance Project report funded by the Pew Charitable Trusts, the Joyce-Mertz Gilmore Foundation, the U.S. EPA, and the U.S. DOE, by David Moskovitz, Tom Austin, Cheryl Harrington, Bruce Biewald, David E. White, and Robert Bigelow, March 1997.

Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests, for the Maryland People's Counsel, by Paul Chernick, Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise, February 20, 1997.

Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring, a report to the New England Governors' Conference, by Bruce Biewald, Max Duckworth, Gretchen McClain, David Nichols, Richard Rosen, and Steven Ferrey, Tellus No. 95-310, January 1997.

Restructuring New Hampshire's Electric Power Industry: Stranded Costs and Market Power, a report for the New Hampshire Office of Consumer Advocate, by Bruce Biewald, Paul Chernick, Jonathan Wallach, and Peter Bradford, Synapse Report No. 96-05, November 1996

Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric Utility Industry, by Bruce Biewald, Paul Chernick, Jonathan Wallach, and Peter Bradford, Synapse Report No. 96-04, October 18, 1996.

Can We Get There From Here?: The Challenge of Restructuring the Electricity Industry so that We Can All Benefit, a White Paper for CalNeva, Consumer Action, Consumer Federation of California, Consumers First, Greenlining Coalition, Latino Issues Forum, Towards Utility Rate Normalization, and Utility Consumers' Action Network, by John Stutz, Bruce Biewald, Daljit Singh, Tim Woolf, George Edgar, and Wayne DeForrest, April 1996.

A Study of the Impacts of EPA Phase II SO_2 and NO_x Emissions Standards on Electrical Facilities in the ECAR Region, for the Advisory Committee on Competition in Ontario's Electricity System, Ministry of Environment and Energy, by Stephen Bernow, Bruce Biewald, William Dougherty, Maxim Duckworth, and Daljit Singh, Tellus No. 96-069, April 15 1996.

A Projection of Future Market-Based Prices for Air Emissions: Consequences for Renewable and Demand-Side Management Resources, for the Massachusetts Division of Energy Resources, by Maxim Duckworth and Bruce Biewald, Tellus Institute, March 29, 1996.

Promoting Environmental Quality in a Restructured Electric Industry, for the National Association of Regulatory Utility Commissioners, Tellus No. 95-056, December 1995.

Systems Benefits Funding Options, a report to Wisconsin Environmental Decade, Tellus No. 95-248, October 1995.

Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities, prepared for the U.S. EPA, Tellus No. 93-251, September 1995.

Electric Resource Planning for Sustainability, a report to the Texas Sustainable Energy Development Council, Tellus No. 94-114, February 1995.

New York State Environmental Externalities Cost Study Report; Report 3a: EXMOD User manual; Report 3b: EXMOD Reference manual; Report 4: Case Studies, prepared for the Empire State Electric Energy Research Corporation and New York State Energy Research and Development Authority. ESEERCO Project EP91-50, December 1994.

"Comments on the DOE's Proposed Rulemaking Regarding Energy Conservation Standards for Three types of Consumer Products: Including Fuel Cycle Environmental Impacts and Resource Depletion in a Societal Cost-Benefit Framework," December 1994.

Comments on the Northwest Power Planning Council's Issue Paper #94-50: "Accounting for Environmental Externalities in the Power Plan," Tellus No. 94-284, December 1994.

Comments on Incentive Regulation in Massachusetts, DPU 94-158, November 1994.

Valuation of Environmental and Human Health Risks Associated with Electric Power Generation: A Discussion of Methods and a Review of Greenhouse Gas Studies, a report prepared for the Izaak Walton League of America, Minnesotans for an Energy Efficient Economy, American Wind Energy Association, Clean Water Action, American Lung Association, Minnesota Center for Environmental Advocacy, and Institute for Local Self Reliance, Tellus No. 94-202, November 1994.

Resource and Compliance Planning: A Utility Case Study of Combined SO_2/CO_2 Reduction, Report Prepared in Cooperative Agreement with the U.S. EPA Acid Rain Division, Tellus No. 92-185, October 1994.

Modelling Renewable Electric Resources: A Case Study of Wind, a report to the U.S. Department of Energy, Tellus No. 91-187, October 1994.

A Review of Methods and Models for Estimating the System Risk Reduction Value of DSM, prepared for the Boston Edison Settlement Board, Tellus No. 93-174B, September 1994.

Life Extension and Repowering for Fossil Plants: Guidelines for Evaluating Projects, prepared for the Energy Foundation, Tellus No. 92-147A, August 1994.

License Renewal for Nuclear Power Plants: Guidelines for Evaluating Continued Operation, prepared for the Energy Foundation, Tellus No. 92-147B, August 1994.

Greenhouse Gas Emissions: Targets and Control Costs, for the British Columbia Energy Coalition, Tellus No. 94-195, August 1994.

Non-Price Benefits of BECo Demand-Side Management Programs, for the Boston Edison Settlement Board, Tellus No. 93-174A, July 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Air Pollutants, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/2, June 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Air Toxics - Heavy Metals, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/3, June 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Greenhouse Gases, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/4, June 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Land and Water Impacts, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/5, June 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Nuclear Fuel Cycle Externalities: Uranium Mining, Reactor Operations, Accidents, and Waste Disposal, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/6, June 1994.

Comments on the State of Wisconsin Draft Environmental Impact Statement - Point Beach Nuclear Power Plant Projects Proposed by Wisconsin Electric Power Company, for the Wisconsin Citizens' Utility Board, Tellus No. 92-058, April 1994.

Incorporating Environmental Externalities in Energy Decisions: A Guide for Energy Planners, a report to the Swedish International Development Agency, Tellus No. 91-157, February 1994.

Development of Externality Values for Energy Resource Planning in Ontario: Introductory Report, prepared for the Ontario Externalities Collaborative, Tellus No. 94-016/1, January 1994.

Cooling Towers for Hudson River Power Plants, Economic and Environmental Considerations, for Scenic Hudson, Inc., Tellus No. 92-022, July 1993.

Energy Efficiency for Massachusetts: A Strategy for Energy, Environment and the Economy, a report to the Massachusetts Division of Energy Resources, Tellus No. 92-236D, April 1993.

Renewable Energy for Massachusetts: A Strategy for Energy, Environment and the Economy, a report to the Massachusetts Division of Energy Resources, Tellus No. 92-236H, April 1993.

The Environmental Impacts of Demand-Side Management Measures, a report for the Electric Power Research Institute, EPRI No. TR-101573, Research Project 3121-05, Tellus No. 92-089, December 1992.

Incorporating Environmental Externalities in Electric System Planning, a report to the Colorado Office of Energy Conservation, Tellus No. 91-203/SB, April 1992.

Evaluation of the Application of Aquidneck Power Limited Partnership to Construct an Energy Facility in Portsmouth, Rhode Island, a report to the Rhode Island Division of Public Utilities and Carriers, The Governor's Office of Housing, Energy and Intergovernmental Relations, and The Department of Administration/Division of Planning, Tellus No. 91-255, April 1992.

Need for and Alternatives to Nuclear Plant License Renewal, a report sponsored by the Vermont Department of Public Service, Tellus No. 91-248, March 1992.

Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company, Ltd., prepared for Consumers Gas Company, Ltd., Tellus No. 91-001, January 1992.

America's Energy Choices: Investing in a Strong Economy and a Clean Environment, in collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy, Tellus No. 90-067, 1991.

Valuation of Environmental Externalities: Sulfur Dioxide and Greenhouse Gases, for the Massachusetts Division of Energy Resources, Tellus No. 91-085, December 1991.

CASM: Coordinated Abatement Strategy Model, Stockholm Environment Institute, Stockholm, Sweden, November 1991.

Valuation of Environmental Externalities for Electric Utility Resource Planning in Wisconsin, a report to Citizens for a Better Environment, Milwaukee, WI, Tellus No. 91-104, November 1991.

The Environmental Costs and Benefits of DSM: A Framework for Analysis, prepared for the Electric Power Research Institute, Tellus No. 90-177, January 1991.

The Potential Impact of Environmental Externalities on New Resource Selection and Electric Rates, for and with the Massachusetts Division of Energy Resources, Tellus No. 90-165, January 1991.

Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management, prepared for Long Island Power Authority, Tellus No. 90-028A, September 1990.

Review of Southern Connecticut Gas Company's Conservation Impact Model, prepared for the Conservation Collaborative Group (Southern Connecticut Gas Company, Connecticut Department of Public Utility Control (DPUC), Prosecutorial Division, DPUC, Office of Policy and Management/Energy Division, and Office of Consumer Counsel), Tellus No. 90-084, July 1990.

Disposal Costs at Existing and Proposed Low-Level Radioactive Waste Disposal Facilities and the Implications for Vermont, prepared for the Vermont Department of Public Service, Tellus No. 89-168, March 1990.

Affidavit on Seabrook Decommissioning, prepared for the Massachusetts Attorney General, ESRG Project No. 89-246, February 1990.

The Economics of the Palisades Nuclear Plant: An Analysis of the Proposed Sale and Power Purchase Agreement, a report to the Michigan Attorney General, ESRG No. 88-100C, April 1989.

An Analysis of Physical Excess and Uneconomic Capacity Resulting from the Addition of Beaver Valley 2 and Perry 1 to the Centerior Generating System, a report for the Ohio Office of Consumers' Counsel, ESRG No. 88-38B, October 1988.

The Economics of Diablo Canyon: Analyses of the Proposed Settlement Agreement and the Continued Operation of the Plant, a report for the Redwood Alliance, ESRG No. 88-050R, September 1988.

The Fort St. Vrain Nuclear Plant: Economics and Related Issues, a report to the Colorado Office of Consumer Council, ESRG No. 86-004, May 1987.

Towards an Energy Transition on Long Island: Issues and Directions for Planning, a report for Nassau and Suffolk Counties, New York, ESRG No. 87-05, April 1987.

The Economics of Completing and Operating the Vogtle Nuclear Generating Facility, prepared for the Georgia Office of Consumers' Utility Counsel, ESRG No. 85-098, April 1986.

Audit-Related Issues in the WHIP Program, a report to Technical Development Corporation, ESRG No. 85-41, January 1986.

Two Issues in Georgia Power Company's Planning: The Economics of the Vogtle Plant - The Company's Load Forecasting, ESRG No. 85-51A, December 1985.

Cost-Benefit Analysis of the Cancellation of Commonwealth Edison's Braidwood Nuclear Generating Station, ESRG No. 83-87, October 1984.

The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners, a report to the Maine Public Utilities Commission, ESRG No. 84-38, September 1984.

Evaluation of the Massachusetts Energy Conservation Service, ESRG No. 84-07, August 1984.

Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant, ESRG No. 83-81/1, May 1984.

Power Planning in Kentucky: Assessing Issues and Choices, Technical Report III: Conservation as a Planning Option, ESRG No. 83-51/TRIII, January 1984.

Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant, ESRG No. 83-10, January 1984.

Power Planning in Kentucky: Assessing Issues and Choices, Technical Report I: Long Range Forecasts of Electricity Requirements for Kentucky and its Six Major Utilities, ESRG No. 83-51/TRI, December 1983.

Power Planning in Kentucky: Assessing Issues and Choices, Project Summary to the Public Service Commission, ESRG No. 83-51, November 1983.

Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs, a report to the New Jersey Division of Rate Counsel, ESRG No. 82-43/2, October 1983.

Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences, ESRG No. 83-14/S, July 1983.

A Technical Report to the Staff of the District of Columbia Public Service Commission on the Benefits to Ratepayers of the Electric Power Research Institute and Gas Research Institute Programs, ESRG No. 83-11, February 1983.

Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options, ESRG No. 82-14, December 1982.

The Economics of Alternative Space and Water Heating Systems in New Construction in the New Jersey Power and Light Service Area, a report to the Public Advocate, ESRG No. 82-31, December 1982.

Report on Electricity Conservation in the State of Vermont: Assessing the Potential and Developing Program Strategies, a report to the Department of Public Service, ESRG No. 82-23, October 1982.

Long-Range Forecast of Electric Loads in the State of Vermont, ESRG No. 82-16, October 1982.

The Economics of Closing the Indian Point Nuclear Power Plants, ESRG No. 82-40, October 1982.

Priority Residential Customer Programs to Conserve Electricity and Gas in the Public Service Electric and Gas Company Area, a report to the Division of Rate Counsel for New Jersey Board of Public Utilities, ESRG No. 82-43, September 1982.

The Impacts of Early Retirement of Nuclear Power Plant: The Case of Maine Yankee, ESRG No. 82-91, August 1982.

Long Range Forecast of Atlantic City Electric Company Electric Energy and Peak Demand, a report to the New Jersey Board of Public Utilities, ESRG No. 82-17/1, July 1982.

A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company, a report to the Staff of the Maine Public Utilities Commission, April 1982.

Long Range Forecast of Detroit Edison Company Electric Energy Requirements and Peak Demands, a report to the Michigan Public Service Commission, ESRG No. 81-60/2, April 1982.

Long Range Forecast of Consumer's Power Company Electric Energy Requirements and Peak Demands, a report to the Michigan Public Service Commission, ESRG No. 81-60, March 1982.

A Conservation Case Forecast of Electric Energy Consumption and Peak Demand in the Sierra Power Company Service Area, ESRG No. 81-42/2, February 1982.

Maine Public Service Company's Electric Energy Requirements and Peak Demands, a report to the Maine Public Utilities Commission, ESRG No. 81-61, January 1982.

A Conservation Investment Scenario for the Northeast Utilities Connecticut Service Area, ESRG No. 81-12/1, October 1981.

The Conservation Investment Alternative for New York State, ESRG No. 80-42, September 1981.

A Conservation Investment Program for Alabama Power Company, a report to the Alabama Public Service Commission, ESRG No. 80-62/2, July 1981.

A Conservation Investment Strategy for Utah Power and Light Company: Cost-Benefit Analysis, Public Service Commission of Utah, Case No. 80-035-17, ESRG No. 81-06, February 1981.

The Conservation Alternative to the Power Plant at Shoreham, Long Island, ESRG No. 80-31, November 1980.

PAPERS

Follow the Money: A Method for Tracking Electricity for Environmental Disclosure," Bruce Biewald, David White, and Tim Woolf, The Electricity Journal, May 1999.

Book Review of "U.S. Utility Mergers and the Restructuring of the New Global Power Industry," in *Energy*, October 1998.

"Implications of Premature Nuclear Plant Closures: Funding Shortfalls for Nuclear Plant Decommissioning and Spent Fuel Transportation and Storage," Bruce Biewald and David White, prepared for the United States Association for Energy Economics and International Association for Energy Economics, 19th Annual North American Conference, Albuquerque, NM, October 1998.

"Efficiency, Renewables and Gas: Restructuring as if Climate Mattered," Tim Woolf and Bruce Biewald, *The Electricity Journal*, January/February 1998.

"Green Electricity: Tracking Systems for Environmental Disclosure," B. Biewald and J.A. Ramey, proceedings of WINDPOWER '97, the American Wind Energy Association's annual conference in Austin, Texas, forthcoming.

"Competition and Clean Air: The Operating Economics of Electricity Generation," *The Electricity Journal*, January/February 1997.

"Electric Industry Restructuring and Environmental Sustainability," proceedings of the United States Association for Energy Economics and International Association for Energy Economics, 17th North American Conference on (De)regulation of Energy, Boston, October 1996.

"Residential Real-Time Metering Technology for Electricity Restructuring," Daljit Singh and Bruce Biewald, presented at the National Training and Information Center conference, Chicago, September 1996.

"Competition and Environmental Impacts in the U.S. Electric Sector: Must Market Forces be Tamed?," presented at the International Society of Ecological Economics conference, Boston, August 1996.

"Stranded Risk: Nuclear Power Issues in Electricity Restructuring," for Energy Advocates meeting in Austin, Texas, May 1996.

"Counting the Costs: Scientific Uncertainty and Valuation Perspective in EXMOD," Stephen Bernow, Bruce Biewald, William Dougherty, and David White, presented at technical meeting of the International Atomic Energy Agency, Vienna, Austria, December 4-8, 1995.

"Environmentally Targeted Objectives for Reducing Acidification in Europe," *Energy Policy*, C.A. Gough, P.D. Bailey, B. Biewald, J.C.I. Kuylenstierna and M.J. Chadwick, December 1994.

"Environmental Externalities: Highways and Byways," NRRI Quarterly Bulletin, Vol. 15 No. 4, Bruce Biewald, Paul Chernick and Bill Steinhurst, December 1994. Also presented at NARUC's 5th National Conference on Integrated Resource Planning, Kallispell, Montana, May 15-18, 1994.

"From Social Costing to Sustainable Development: Beyond the Economic Paradigm," Stephen Bernow, Bruce Biewald, and Paul Raskin, in Social Costs of Energy: Present Status and Future Trends, Proceedings of an International Conference held at Racine, Wisconsin, September 8-11, 1992. Edited by Olav Hohmeyer and Richard Ottinger. Published by Springer-Verlag, September 1994.

"Modelling Renewable Electric Resources: A Case Study of Wind," Stephen Bernow, Bruce Biewald, Daljit Singh, and Jeff Hall, proceedings of the Ninth NARUC Biennial Regulatory Information Conference, Columbus, OH, September 7-9, 1994.

"Alternative Closed Cycle Cooling Systems for Power Plants: A Framework of Evaluation in Integrated Resource Planning," Daljit Singh and Bruce Biewald, in the proceedings of the Ninth NARUC Biennial Regulatory Information Conference, Columbus, OH. September 7-9, 1994.

"Misconceptions, Mistakes and Misnomers in DSM Cost-Effectiveness Analysis, Or What Do You Really Mean By T.R.C.?," Mark Fulmer and Bruce Biewald, ACEEE 1994 Summer Study, Pacific Grove, CA. August 28- Sept. 2, 1994.

"Modelling Renewable Electric Resources: A Case Study of Wind Power," Stephen Bernow, Bruce Biewald, and Daljit Singh, presented at WINDPOWER 1994, Sponsored by American Wind Energy Association, Minneapolis, Minnesota, May 9-13, 1994.

"National Climate Change Policy and Clean Air Act Compliance: A Case Study of Combined CO2/SO2 Reduction," Stephen Bernow, Bruce Biewald, Mark Fulmer, Tim Woolf, Kristen Wulfsberg, and Barry Solomon, in the proceedings of NARUC's 5th National Conference on Integrated Resource Planning, Kallispell, Montana, May 15-18, 1994.

"Modelling Renewable Electric Resources: A Case Study of Wind Reliability," Stephen Bernow, Bruce Biewald, and Daljit Singh, presented at the NARUC-DOE National Regulatory Conference on Renewable Energy, Savannah, Georgia, October 3-6, 1993.

“Environmental Sustainability as a Goal in Resource Planning and Policy," Stephen Bernow and Bruce Biewald, Office of Technology Assessment workshop, Washington, DC. April 1993.

"Climate Change and the U.S. Electric Sector," Bruce Biewald and Stephen Bernow, presented at NARUC's 4th National Conference on Integrated Resource Planning, Burlington, Vermont, September 1992.

"Coordinating Clean Air Act Compliance with Integrated Resource Planning: The Role of Externalities," Stephen Bernow, Bruce Biewald, and Kristin Wulfsberg, the Eighth NARUC Biennial Regulatory Information Conference, Ohio State University, Columbus, Ohio. September 9-11, 1992.

"Direct Environmental Impacts of Demand-Side Management," Stephen Bernow, Frank Ackerman, Bruce Biewald, Mark Fulmer, Karen Shapiro, and Kristin Wulfsberg, American Council for an Energy Efficient Economy (ACEEE) 1992 Summer Study, September 1992.

"Modelling Fuel Cycle and Site-Dependent Environmental Impacts in Electric Resource Planning," Stephen Bernow and Bruce Biewald, invited paper at OECD-IEA Expert Workshop on Life-Cycle Analysis of Energy Systems, Paris, France, May 18 and 19, 1992. Proceedings published OECD/IEA Paris, 1993.

"Computer Model Use in Energy Conservation Planning," presented at the Latin American Energy Organization (OLADE) Seminar on Power Systems Computer Modelling in Quito, Ecuador, September 23-25, 1991.

"Environmental Externalities Measurement: Quantification, Valuation and Monetization," Bernow, Biewald and Marron, in External Environmental Costs of Electric Power, proceedings of a German-American workshop, Ladenburg, FRG, October 23-25, 1991. Edited by Olav Hohmeyer and Richard Ottinger, published by Springer-Verlag (Berlin, Heidelberg, New York).

"Some Microcomputer Tools for Least Cost Integrated Energy Planning: ECO, LEAP and EDB," Bruce Biewald and Harvey Salgo, presented at workshop on Energy Pricing and Planning, Bratislava, Czechoslovakia, May 21-22, 1991.

”Confronting Uncertainty: Contingency Planning for Decommissioning,” Bruce Biewald and Stephen Bernow, Chapter 18 of “Nuclear Decommissioning Economics,” a special issue of *The Energy Journal* of the International Association for Energy Economics, Volume 12, March 1991.

“Avoided Emissions and Environmental Dispatch," Stephen Bernow and Bruce Biewald, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.

"Environmental Benefits of DSM in New York: Long Island Case Study," Bruce Biewald and Stephen Bernow, presented at the Conference on "Demand-Side Management and the Global Environment," Arlington, Virginia, April 22-23, 1991.

"Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," Stephen Bernow, Bruce Biewald and Donald Marron, the *Electricity Journal*, March 1991.

"EDB: A Flexible Database System for Energy-Environmental Analysis," Bruce Biewald, Michael Lazarus, and David Von Hippel, presented at International Atomic Energy Agency (IAEA) Technical Committee Meeting on "Development of a Database for Comparative Health and Environmental Impacts of Various Energy Systems," in Vienna, Austria, October 15-19, 1990.

"Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation," Stephen Bernow, Bruce Biewald, and Donald Marron, presented at NARUC Conference on Externalities, Jackson Hole, Wyoming, October 1990.

"An Assessment of Demand-Side Management Models and Their Use and Applicability in Canadian Utilities," Martin Adelaar and Bruce Biewald, in the proceedings of the Canadian Electrical Association Demand-Side Management Conference, Halifax, Nova Scotia, September 1990.

"Avoided Cost Contracts Can Undermine Least Cost Planning," Stephen Bernow, Bruce Biewald, and Donald Marron, Energy Policy, September 1990.

"Environmental Externalities Measurement: Quantification, Valuation, and Monetization," Stephen Bernow, Bruce Biewald, and Donald Marron, in the proceedings of the Seventh NARUC Biennial Regulatory Information Conference, September 1990.

"Do We Really Need Nuclear Generating Companies?," Public Utilities Fortnightly, June 7, 1990.

"Nuclear Power Economics: Construction, Operation and Disposal," Bruce Biewald and Donald Marron, March 1989.

"Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity," Stephen Bernow and Bruce Biewald, in the proceedings of the Sixth NARUC Biennial Regulatory Information Conference, September 1988.

"Nuclear Power Plant Decommissioning: Cost Estimation for Power Planning and Ratemaking," Stephen Bernow and Bruce Biewald, Public Utilities Fortnightly, October 29, 1987.

"Cost and Performance of Boiling Water Reactors," Stephen Bernow, Bruce Biewald and Tim Woolf, Public Utilities Fortnightly, August 1987.

PRESENTATIONS

(Note: Presentations that were accompanied by a written paper are listed in the section for "papers," above.)

Presentation on "How Green is Green? Verifying Energy Advertising Claims," at the New England Conference of Public Utility Commissioners Symposium, Bretton Woods, New Hampshire, May 25, 1999.

Presentation on "Consumer Perspectives on Market Power – Case Studies from New England, New York, PJM, and Mississippi," IBC Conference on Market Power, Washington DC, May 24, 1999.

Presentation on "Grandfathering and Environmental Comparability," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on "Tracking Electricity in the New England Market," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on "Tracking Electricity in the New England Electricity Market," at the National Council on Competition and the Electricity Industry National Executive Dialogue on Customers' Right to Know, Chicago, May 13, 1998.

Presentation on "Comparable Environmental Regulations in a Restructured Electricity Industry: The Grandfathering Effect," National Association of Regulatory Utility Commissioners meeting in Washington, D.C., March 1, 1998.

Presentation on "Market Power in Electricity Generation," National Consumer Law Center Conference, Washington, D.C., February 9, 1998.

Presentation on "Electricity Market Power in New England," Massachusetts Electric Industry Restructuring Roundtable, Boston, December 15, 1997.

Presentation on wind power development and air quality, National Wind Coordinating Committee New England Wind Issues Forum, Boston, November 7, 1997.

Invited speaker on market power, National Association of State Utility Consumer Advocates meeting in Boston, November 12, 1997.

Presentation on "Distortions to Future and Current Competitive Electric Energy Markets Due to Grandfathering Environmental Regulations of Electric Power Plants," National Association of Regulatory Utility Commissioners meeting in Boston, November 9, 1997.

Presentation on "Electric Industry Restructuring as if the Environment Mattered," Boston Area Solar Energy Association, October 9, 1997.

Invited speaker on "Modeling Market Power in Electricity Generation," National Association of Regulatory Utility Commissioners meeting in San Francisco, July 22, 1997.

Presentation on "Performance-Based Regulation in a Restructured Electric Industry," National Association of Regulatory Utility Commissioners meeting in San Francisco, July 20, 1997.

Presentation on "State Initiatives and Regional Issues," New England Governors' Conference Workshop on Restructuring and Environmentally Sustainable Technologies, Warwick, Rhode Island, March 25, 1997.

Invited speaker on stranded costs, National Association of State Utility Consumer Advocates meeting in San Francisco, November 1996.

Presentation on "Nuclear Power Plant Decommissioning Costs and Electricity Restructuring," Nuclear Decommissioning Trusts conference, New York City, November 18, 1996.

Invited speaker on stranded costs, Indiana Utilities Regulatory Commission Forum, Indianapolis, November 1, 1996.

Presentation on "Electric Industry Restructuring and the Environment," at the Indiana Energy Conference, Indianapolis, Indiana, October 10, 1996.

Presentation on "Small Customers in a Restructured Electricity Industry: Transaction Costs, Advanced Metering Technologies and Aggregation Options" to the Consumers' Energy Conference, South Portland, Maine, July 1996.

Presentation on "Electric Generation Market Power in New England" to New England Conference of Public Utility Commissioners, Manchester Village, Vermont, May 1996.

Presentation on "Advanced Metering for Residential Customers on Electricity Restructuring" to National Consumer Law Center's 10th Annual Conference in Washington, DC, February 1996.

Presentations on "Market Power," "Environmental Aspects of Restructuring" and "Market Access for Small Customers" to Vermont Public Service Board workshops on electricity restructuring, January and February 1996.

Presentation on "Environmental Impacts of Energy: Sustainability and Social Costing" to British Columbia Utilities Commission Workshop, Vancouver, BC, March 1995.

Presentation on "Competition and Economic Efficiency" to the National Council on Competition and the Electric Industry, December 1995.

Presentation on "Compliance Planning Under Regulatory Uncertainty," to EPA "Opportunities Conference: Energy Efficiency and Renewable Energy," Washington, DC, June 1993.

Presentation on "Energy and Sustainability" to Hydro-Quebec Conference, Hampshire College, Amherst, Massachusetts, April 1993.

Invited Speaker on environmental externalities, ASME "ECO World" conference in Washington, DC, June 1992.

Invited Speaker, Association of Energy Engineers, Boston, Massachusetts, February 1992.

Presentation of Acid Rain Abatement Optimization Model to the Swedish Environmental Protection Agency, Solna, Sweden, November 1991.

Presentation on Integrated Resource Planning to Boston Gas Company, July 1990.

Training on Methods for Calculating Electric System Avoided Costs, provided to energy planners and policy makers from five Southeast Asian countries sponsored by U.S. Agency for International Development and administered by the Institute of International Education, May 1990.

Invited Speaker, National Association of State Utility Consumer Advocates (NASUCA) Mid-Year Meeting, Annapolis, Maryland, and June 1988.

Invited Speaker, Conference on New Developments in Nuclear Decommissioning Costs and Funding Methods, sponsored by the Northeast Center for Professional Education, Washington, DC, April 1988.

Committee of Consumer Services

Witness: Bruce E. Biewald

Docket No. 98-2035-04

CCS Exhibit 2.2 (BEB)

US Electric Utilities Sorted by Average Residential Revenue per kWh

Rank	Company	Cents/kWh
1	Idaho Power Company	3.99
2	Kentucky Utilities Company	4.52
3	Avista Corp.	4.73
4	Avista Corp.	4.78
5	AEP (Kentucky Power Rate Area)	4.86
6	AEP (Kingsport Power Rate Area)	4.99
7	Old Dominion Power Company	4.99
8	Idaho Power Company	5.02
9	Idaho Power Company	5.18
10	PacifiCorp -- Washington	5.25
11	OG&E Electric Services	5.43
12	AEP (Appalachian Power Rate Area)	5.49
13	AEP (Appalachian Power Rate Area)	5.64
14	PacifiCorp -- Wyoming	5.73
15	Public Service Company of Oklahoma	5.88
16	Southwestern Public Service Company	5.89
17	Empire District Electric Company	5.90
18	South Beloit Water, Gas & Electric Company	5.94
19	Empire District Electric Company	5.98
20	Wisconsin Public Service Corporation	6.01
21	Puget Sound Power & Light Company	6.06
22	Northern States Power Company (Minnesota)	6.07
23	St. Joseph Light & Power Company	6.07
24	Portland General Electric Company	6.08
25	Otter Tail Power Company	6.09
26	Empire District Electric Company	6.14
27	PacifiCorp -- Oregon	6.15
28	Edison Sault Electric Company	6.16
29	Southwestern Electric Power Company	6.19
30	Southwestern Public Service Company	6.22
31	Gulf Power Company	6.22
32	Indianapolis Power & Light Company	6.23
33	Wisconsin Public Service Corporation	6.28
34	Southwestern Electric Power Company	6.29
35	Entergy Gulf States, Inc.	6.30
36	Otter Tail Power Company	6.30
37	KPL Company	6.30
38	Southwestern Public Service Company	6.33
39	Southwestern Electric Power Company	6.47
40	Southwestern Public Service Company	6.53

41	PSI Energy, Inc.	6.55
42	Otter Tail Power Company	6.56
43	Empire District Electric Company	6.57
44	Montana Power Company	6.58
45	PacifiCorp -- Idaho	6.59
46	Nevada Power Company	6.60
47	West Penn Power Company	6.60
48	AEP (Wheeling Power Rate Area)	6.65
49	AEP (Ohio Power Rate Area)	6.66
50	Potomac Edison Company	6.71
51	Monongahela Power Company	6.72
52	Wisconsin Power & Light Company	6.72
53	Interstate Power Company	6.77
54	Minnesota Power Company	6.77
55	CLECO Corporation	6.80
56	Union Light, Heat and Power	6.82
57	AEP - Indiana Michigan	6.86
58	PacifiCorp -- Utah	6.86*
59	OG&E Electric Services	6.87
60	Duke Power Company	6.90
61	PacifiCorp -- California	6.90
62	Montana-Dakota Utilities Company	6.90
63	Northern States Power Company (Wisconsin)	6.90
64	Potomac Edison Company	7.02
65	Entergy Louisiana, Inc.	7.06
66	AmerenUE	7.09
67	AmerenUE	7.09
68	Northern States Power Company (Wisconsin)	7.10
69	Savannah Electric & Power Company	7.10
70	Potomac Edison Company	7.16
71	Alabama Power Company	7.18
72	Black Hills Power & Light Company	7.22
73	Virginia Power	7.24
74	Montana-Dakota Utilities Company	7.29
75	Monongahela Power Company	7.34
76	Entergy Gulf States, Inc.	7.34
77	Duke Power Company	7.36
78	AEP (Indiana Michigan Power)	7.41
79	Kansas City Power & Light Company	7.41
80	Montana-Dakota Utilites Company	7.41
81	Kansas City Power & Light Company	7.44
82	Central Illinois Light Company	7.50
83	Nantahala Power & Light Company	7.61
84	Northwestern Wisconsin Electric Company	7.62
85	Georgia Power Company	7.63
86	Northern States Power Company (Minnesota)	7.66
87	Entergy Mississippi, Inc.	7.66
88	West Texas Utilities Company	7.68
89	Entergy New Orleans, Inc.	7.70

90	Cincinnati Gas & Electric Company	7.71
91	PacifiCorp - Wyoming West	7.72
92	AEP (Columbus Southern Power Rate Area)	7.76
93	TU Electric	7.77
94	Wisconsin Electric Power Company	7.79
95	Madison Gas & Electric Company	7.81
96	Carolina Power & Light Company	7.82
97	Black Hills Power & Light Company	7.84
98	Florida Power & Light Company	7.87
99	Northern States Power Company (Minnesota)	7.89
100	Carolina Power & Light Company	7.91
101	Tampa Electric Company	7.99
102	Central Power & Light Company	7.99
103	Potomac Electric Power Company	8.00
104	South Carolina Electric & Gas Company	8.01
105	Wisconsin Electric Power Company	8.04
106	USA Average	8.21
107	Black Hills Power & Light Company	8.28
108	Pennsylvania Power & Light Company	8.35
109	Houston Lighting & Power Company	8.47
110	Texas-New Mexico Power Company	8.48
111	Entergy Arkansas, Inc.	8.50
112	Consumers Energy	8.50
113	Potomac Electric Power Company	8.53
114	KG&E Company	8.53
115	Interstate Power Company	8.55
116	MidAmerican Energy	8.56
117	Interstate Power Company	8.62
118	Florida Power Corporation	8.62
119	IES Utilities, Inc.	8.73
120	Pennsylvania Electric Company	8.74
121	Sierra Pacific Power Company	8.76
122	UGI Utilities, Inc. (Electric Utilities Division)	8.76
123	Dayton Power & Light Company	8.77
124	Metropolitan Edison Company	8.88
125	MidAmerican Energy	8.88
126	Montana-Dakota Utilities Company	8.96
127	Upper Peninsula Power Company	9.07
128	Baltimore Gas & Electric Company	9.09
129	Detroit Edison Company	9.11
130	Pennsylvania Power Company	9.20
131	Arizona Public Service Company	9.22
132	Massachusetts Electric Company	9.33
133	Tucson Electric Power Company	9.35
134	PNM	9.35
135	Texas-New Mexico Power Company	9.71
136	Pike County Light & Power Company	9.81
137	Granite State Electric Company	9.95
138	San Diego Gas & Electric Company	10.14

139	Eastern Edison Company	10.19
140	Rockland Electric Company	10.33
141	Exeter & Hampton Electric Company	10.36
142	Cleveland Electric Illuminating Company	10.37
143	Ohio Edison Company	10.62
144	Blackstone Valley Electric Company	10.65
145	Commonwealth Edison Company	10.66
146	Concord Electric Company	10.69
147	El Paso Electric Company	10.73
148	Pacific Gas & Electric Company	10.77
149	Toledo Edison Company	10.80
150	Western Massachusetts Electric Company	10.83
151	El Paso Electric Company	10.92
152	Narragansett Electric Company	10.98
153	Central Hudson Gas & Electric Corporation	11.09
154	Southern California Edison	11.40
155	Green Mountain Power Company	11.56
156	Fitchburg Gas & Electric Light Company	11.56
157	GPU Energy	11.59
158	Connecticut Light & Power Company	11.69
159	Cambridge Electric Company	11.76
160	Newport Electric Corporation	11.90
161	Boston Edison Company	11.99
162	Central Vermont Public Service Corporation	12.45
163	Niagara Mohawk Power Corporation	12.46
164	Hawaiian Electric Company	12.56
165	Maine Public Service Company	12.63
166	Commonwealth Electric Company	12.74
167	Orange & Rockland Utilities, Inc.	12.79
168	PECO Energy	13.02
169	Central Maine Power Company	13.06
170	Bangor Hydro-Electric Company	13.66
171	United Illuminating Company	13.66
172	Maui Electric Company (Maui)	13.96
173	Public Service Company of New Hampshire	14.46
174	Consolidated Edison Company of New York	16.24
175	Maui Electric Company (Lanai)	17.97
176	Maui Electric Company (Molokai)	18.33
177	Hawaii Electric Light Company	18.62

Note: PacifiCorp's Utah rates were reduced by approximately 12 percent, effective early March 1999.
Source: Edison Electric Institute data for 1998.

Exhibit___(BEB-3)

Annual Bills Charged to Typical Standard Domestic Tariff Customers in Great Britain (£/year in real (April 1997) prices)

	1993/4	1998/9	Percentage Reduction
Eastern	290	230	21%
East Midlands	311	235	24%
London	315	237	25%
Manweb	329	256	22%
Midlands	298	232	22%
Northern	319	260	18%
Norweb	310	236	24%
Seeboard	313	230	27%
Southern	308	233	24%
South Wales	346	273	21%
South Western	336	251	25%
Yorkshire	310	233	25%
England & Wales Average	315	242	23%
Scottish Power	307	253	18%
Scottish Hydro	301	255	15%
Scottish Average	304	254	16%
Great Britain Average	314	244	22%

Source: Data provided by the Office of Electricity Regulation (Offer).

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Direct Testimony and Exhibits to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, on the 18th day of June, 1999.

Brian W. Burnett
CALLISTER NEBEKER & McCULLOUGH
Gateway Tower East, Suite 900
10 East South Temple
Salt Lake City, Utah 84133

William J. Evans
PARSONS BEHLE & LATIMER
201 South Main Street
PO Box 45898
Salt Lake City, Utah 84145-0898

Edward A. Hunter
STOEL RIVES LLP
201 South Main, Suite 1100
Salt Lake City, Utah 84111-4904

Roger O. Tew
60 South 600 East, Suite 200
Salt Lake City, Utah 84102

Michael Ginsberg
Assistant Attorney General
160 East 300 South 5th Floor
PO Box 140857
Salt Lake City, Utah 84114-0857

Lee R. Brown
Vice President
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Peter J. Matheis
Matthew J. Jones
BRICKFIELD BURCHETTE & RITTS, PC
1025 Thomas Jefferson Street NW
800 West Tower
Washington, D.C. 20007

Daniel Moquin
Assistant Attorney General
1594 West North Temple, Suite 300
Salt Lake City, Utah 84116

Bill Thomas Peters
David W. Scofield
PARSONS DAVIES KINGHORN & PETERS PC
185 South State Street, Suite 700
Salt Lake City, Utah 84111

Gary A. Dodge
PARR WADDOUPS BROWN GEE & LOVELESS
185 South State Street, Suite 1300
Salt Lake City, Utah 84111-1536

F. Robert Reeder
VAN COTT BAGLEY CORNWALL & McCARTHY
50 South Main Street, Suite 1600
PO Box 45340
Salt Lake City, Utah 84145

Eric Blank
Law Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Steven W. Allred
Salt Lake City Law Department
451 South State, Suite 505
Salt Lake City, Utah 84111

Matthew F. McNulty III
Stephen R. Randle
RANDLE DEAMER ZARR ROMRELL & LEE PC
139 East South Temple, Suite 330
Salt Lake City, Utah 84111-1004

David F. Crabtree
Deseret Generation & Transmission Co-operative
5295 South 300 West, Suite 500
Murray, Utah 84107

Paul T. Morris
3600 Constitution Boulevard
West Valley City, Utah 84119

Dr. Charles E. Johnson
Salt Lake Community Action Program &
Crossroads Urban Center
1338 Foothill Blvd., Suite 134
Salt Lake City, Utah 84108

Brian L. Farr
Assistant Attorney General
160 East 300 South
PO Box 140857
Salt Lake City, Utah 84114-0857

Arthur F. Sandack
8 East Broadway, Suite 620
Salt Lake City, Utah 84111

Cheryl Murray
____

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Direct Testimony and Exhibits to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, on the 18th day of June, 1999.

Brian W. Burnett
CALLISTER NEBEKER & McCULLOUGH
Gateway Tower East, Suite 900
10 East South Temple
Salt Lake City, Utah 84133

William J. Evans
PARSONS BEHLE & LATIMER
201 South Main Street
PO Box 45898
Salt Lake City, Utah 84145-0898

Edward A. Hunter
STOEL RIVES LLP
201 South Main, Suite 1100
Salt Lake City, Utah 84111-4904

Roger O. Tew
60 South 600 East, Suite 200
Salt Lake City, Utah 84102

Michael Ginsberg
Assistant Attorney General
160 East 300 South 5th Floor
PO Box 140857
Salt Lake City, Utah 84114-0857

Lee R. Brown
Vice President
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Peter J. Matheis
Matthew J. Jones
BRICKFIELD BURCHETTE & RITTS, PC
1025 Thomas Jefferson Street NW
800 West Tower
Washington, D.C. 20007

Daniel Moquin
Assistant Attorney General
1594 West North Temple, Suite 300
Salt Lake City, Utah 84116

Bill Thomas Peters
David W. Scofield
PARSONS DAVIES KINGHORN & PETERS PC
185 South State Street, Suite 700
Salt Lake City, Utah 84111

Gary A. Dodge
PARR WADDOUPS BROWN GEE & LOVELESS
185 South State Street, Suite 1300
Salt Lake City, Utah 84111-1536

F. Robert Reeder
VAN COTT BAGLEY CORNWALL & McCARTHY
50 South Main Street, Suite 1600
PO Box 45340
Salt Lake City, Utah 84145

Eric Blank
Law Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Steven W. Allred
Salt Lake City Law Department
451 South State, Suite 505
Salt Lake City, Utah 84111

Matthew F. McNulty III
Stephen R. Randle
RANDLE DEAMER ZARR ROMRELL & LEE PC
139 East South Temple, Suite 330
Salt Lake City, Utah 84111-1004

David F. Crabtree
Deseret Generation & Transmission Co-operative
5295 South 300 West, Suite 500
Murray, Utah 84107

Paul T. Morris
3600 Constitution Boulevard
West Valley City, Utah 84119

Dr. Charles E. Johnson
Salt Lake Community Action Program &
Crossroads Urban Center
1338 Foothill Blvd., Suite 134
Salt Lake City, Utah 84108

Brian L. Farr
Assistant Attorney General
160 East 300 South
PO Box 140857
Salt Lake City, Utah 84114-0857

Arthur F. Sandack
8 East Broadway, Suite 620
Salt Lake City, Utah 84111

Cheryl Murray

17243

RECEIVED

JUN 18 3 55 PM '99

SERVICE COMMISSION

Witness CCS-3
Exhibit CCS-3

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	Docket No. 98-2035-04 PRE-FILED DIRECT TESTIMONY OF PAUL CHERNICK FOR THE COMMITTEE OF CONSUMER SERVICES

June 18, 1999

TABLE OF CONTENTS

EXHIBITS

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, power supply planning, rate design, cost allocation, and utility industry restructuring. My resume is appended to this testimony as Exhibit CCS-3.1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maine Public Utilities Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Vermont Public Service Board, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: What materials did you review in preparing this testimony?

A: I have reviewed

- ScottishPower's direct testimony in this proceeding, particularly that of Mr. Richardson and Mr. Moir;
- the supplemental testimony of Mr. Richardson in this proceeding;

- the testimony of the Oregon PUC staff in Docket No. UM 918, particularly the Thornton-Riordan, Sipler-Murray and Olson-Harris panels;
- the rebuttal testimony of ScottishPower in Docket No. UM 918, particularly that of Mr. Richardson and the Moir-MacLaren-Rockney panel;
- numerous discovery responses;[1] and
- publications of the UK Office of Electricity Regulation (OFFER).

In addition, I participated in an introductory conference call with ScottishPower on March 26, and by telephone in a supplementary conference on performance standards between Utah DPU staff and Alec Burden of ScottishPower on May 7.

I. Introduction

Q: What is the subject matter of your testimony?

A: I discuss the performance standards and customer guarantees that ScottishPower offers as benefits of the merger. I concentrate primarily on the network performance standards, which deal with system

[1]Discovery is cited by requesting party, respondent (*S* for ScottishPower and *P* for PacifiCorp), set number, and question number. Most of the discovery is from Utah PSC Docket No. 98-2035-04, where the requesting parties are CCS, DPU, and UIEC. Other discovery is in response to IPUC questions in Idaho PUC Case No. PAC-E-99-1.

reliability issues, with secondary consideration of the value of the customer service standards and customer guarantees.

Q: Are these issues usually dominant in merger proceedings?

A: Not in general. Merger proceedings usually deal primarily with estimating the cost reductions resulting from the merger; allocating those savings between shareholders and ratepayers, between jurisdictions, and between classes; setting the level of rate reductions and the length of rate caps; and determining whether the merger raises problems of market power. Service improvements are usually a secondary issue.

Q: Why are service improvements a more significant issue in this proceeding than in most?

A: The proposed purchase of PacifiCorp by ScottishPower does not present opportunities for the usual magnitude of cost reductions, since the two companies operate in very different jurisdictions many time zones apart. ScottishPower has not offered a rate reduction or rate cap as part of the merger, and has presented service improvements as a major portion of the benefit to PacifiCorp customers.

Q: Do ScottishPower's proposed performance standards and customer guarantees represent a powerful argument for approving the merger?

A: No. As described in my testimony below, ScottishPower's proposals appear to be well-intentioned, and should move PacifiCorp in appropriate directions. However, there is no clear connection between improving PacifiCorp performance and the merger. In fact,

- PacifiCorp's performance in most areas is not particularly problematic.
- PacifiCorp should be able to obtain the skills necessary to improve performance in many ways, with or without the aid of ScottishPower.
- The proposed improvements are generally vague and minor.
- Some of the improvement targets cannot be set meaningfully until PacifiCorp has improved its data-collection system and determined the baseline from which improvements will be made.
- ScottishPower has not clearly defined portions of its proposal.
- ScottishPower does not appear to have thought through the cost-effectiveness of alternative levels of reliability at PacifiCorp, and may have made uneconomic investments for reliability in its UK service territories.

In summary, ScottishPower's service proposals, while superficially attractive, are not well thought through. ScottishPower has promised improvements without knowing the baseline performance level from which the improvement will be measured, and without being clear about what it is promising.

ScottishPower's failure to resolve the ambiguities in its service proposals may, in part, reflect the differences between the loose, evolving, consultative regulatory practice in the UK and the more precise, more established, adjudicatory regulatory practice in the US.

Q: How is the rest of your testimony structured?

A: The next section discusses PacifiCorp's current level of performance, and indications that PacifiCorp's performance may be likely to improve regardless of this merger proposal. Section III discusses the strengths and weaknesses of ScottishPower's offer of improved performance at PacifiCorp. Section V goes into greater detail regarding technical problems in ScottishPower's proposal and supporting analysis. Section VI considers whether a merger with ScottishPower would be likely to produce significantly better performance at PacifiCorp than could be achieved without the merger. Section VII summarizes my recommendations to the Commission.

II. PacifiCorp's Performance

Q: For what areas of PacifiCorp's performance do you have current information?

A: PacifiCorp has provided data on its T&D reliability, telephone service performance, and customer satisfaction. I discuss these three areas in turn.

A. T&D Reliability

Q: Is improvement in T&D reliability a major theme of the ScottishPower analysis of merger benefits?

A: Yes. Standards for T&D performance are the subject of five of the seven the proposed performance standards:

1. System average interruption duration index (SAIDI);
2. System average interruption frequency index (SAIFI);
3. Momentary average interruption frequency index (MAIFI);
4. Circuit Performance Indicator (CPI) for the five worst-performing circuits in each state; and
5. Supply restoration for 80 percent of customers within 3 hours

In addition, the company's Customer Guarantee 1 (a promise to restore power) also deals with T&D reliability.

Q: Is PacifiCorp's T&D performance problematic?

A: PacifiCorp's T&D reliability does not appear to be particularly troublesome compared to that of other utilities.

Q: Is the comparison of T&D performance across utilities straightforward?

A: No. Comparisons between utilities are difficult, due to differences in service territories and in data collection. Rural utilities tend to have more outages than urban utilities, since they have more line per customer, and those lines are overhead, rather than underground.[2] Some utilities are in areas that suffer frequent ice storms; others face tornadoes, hurricanes, landslides or corrosion induced by salt spray. Imposed on all these inherent differences is additional dimensions of variation with respect to each utility's definitions of outages (such as

---

[2]Overhead lines are much more subject to problems from wind, ice, and vehicle collisions than underground lines. On the other hand, once underground lines are damaged, locating and repairing the damage generally takes longer than for overhead lines.

how long an outage must be to count in SAIFI, or whether outages affecting only one customer count) and of excluded events (such as the definition of "extreme events"), and each utility's accuracy in reporting the number of customers disconnected.

Q: Given these limitations, how does PacifiCorp compare to other utilities?

A: PacifiCorp's performance is neither outstanding nor particularly bad. While the data on other utilities' performance provided by PacifiCorp (in CCS P9.29) is confidential, PacifiCorp appears to be better than average and better than median performance levels compared to US utilities, and better than average compared to UK utilities. The following table reproduces the data reported by the various utilities, in public documents:

	SAIDI	SAIFI	MAIFI
PacifiCorp Average 1994–98[3]			
Range across states	68–130[4]	0.69–1.65	3.9–7.7
Utah	87[4]	1.15	6.8
U.S. Data[4]			
Quartile 2	90–95[4]	1.10–1.40	5.4
Average	117–99[4]	1.26–1.49	6.6
UK Data[5]	88–97[4]	0.88–0.91	not reported

Since PacifiCorp serves a large geographical area that includes some very difficult terrain, it would be expected to have higher outage rates per customer compared to highly urbanized utilities. These utilities have less line per customer, and underground lines at that. The UK utilities as a whole are more urban, and serve a more-densely populated region, than PacifiCorp's service territory.

[3]CCS P2.7. ScottishPower has re-estimated some of these values; for consistency with other utility-reported data, I have used PacifiCorp's estimates.

[4]Attachment CCS S11.45: *Trial Use Guide for Electric Power Distribution Reliability Indices*, IEEE Working Group on System Design, IEEE P1366/D18, 1997. Range represents 1990 and 1995 national average reported values. Only 1995 data are reported for MAIFI.

[5]OFFER May 1999 Consultation Paper. I present the range of annual national averages, 1993/94-1997/98.

Population Density (People per Square Mile)

	Density
United Kingdom	
England	979[7]
Scotland	169[7]
Wales	361[7]
PacifiCorp States	
Oregon	32[7]
Washington	85[6]
Utah	26[7]
Wyoming	5[7]
Idaho	14[7]

In Oregon and Washington, PacifiCorp does not serve the largest cities; on the other hand, many of the lowest-density areas are served by co-ops and other utilities.

A recent report to the Washington State Legislature indicates that, at least in 1997, PacifiCorp had lower SAIDI and SAIFI values than the state average, both of the other investor-owned utilities in the state,[7] and even Seattle City Light.[8]

Q: Has PacifiCorp's T&D reliability been deteriorating in recent years?

---

[6]For the four Washington counties PacifiCorp serves, population density varies from 3.4 to 48.6, so clearly its part of Washington is less densely settled than the state as a whole.

[7]The data for Washington Water Power are for an earlier year.

[8]"Washington Electric Utility Service Quality, Reliability, Disclosure and Cost Report" submitted to the Washington State Legislature December 1, 1998.

A: Not strikingly. System-wide SAIDI has been stable, while state-specific values for SAIDI, SAIFI, and MAIFI have varied significantly from year to year, without any clear trend.[9]

Q: Has ScottishPower asserted that PacifiCorp's T&D performance is worse than normal for major utilities, or that its performance has been deteriorating?

A: No. ScottishPower has not raised that argument in this proceeding.

Q: Are PacifiCorp's T&D data particularly unreliable?

A: PacifiCorp's data do not appear to be very good, but they do not seem to be any worse than standard practice (IR CCS P11.38). ScottishPower has asserted that PacifiCorp has under-reported its outage frequency (SAIFI) by 80%, and its outage duration by 20% (SAIDI). This seems to be similar to ScottishPower's 21% under-reporting of SAIDI and SAIFI prior to installation of its new Prosper data-tracking system, which is "not widely used in the UK" (CCS S11.16).[10]

---

[9]Handout for May 7, 1999, ScottishPower presentation to DPU Staff; CCS P2.7.

[10]Even ScottishPower's new Prosper system does not record all faults on the secondary distribution system. "ScottishPower has stated that the number of LV [low voltage, or secondary] faults recorded by NaFIRS [National Fault and Interruption System] categories greatly underestimated the scale of the problem. They have also provided data from their own management system—Troublecall—which generates fault reports from information received from customers. This revealed a significantly higher number of supply interruptions than their Prosper system where NaFIRS data is recorded." ("Supply Interruptions Following the Boxing Day Storms, 1998," OFFER, May 1999, at 13–14)

Q: Is there any reason to believe that PacifiCorp's T&D performance will change over time?

A: There is reason to expect that PacifiCorp's performance will improve over the next few years.

- Since the failure of its effort to take over The Energy Group in the UK, PacifiCorp has announced a strategy of refocusing on providing excellent service in its Western US service territories:

> In October, we embarked on a significant change in our strategic direction, designed to optimize [our] strengths and to improve our financial performance. That strategy is to focus on our domestic western electricity business and sell or shut down all unrelated businesses except for Powercor, our Australian electricity distribution business...

> In addition to providing good value to our shareholders, we are equally dedicated to finding new and innovative ways to enhance customer service and system reliability. We have already taken significant steps since October 1998 to improve billing and collections, power outage management, community relationships and business center performance. We are committed to providing the best among utility basics: low-cost, reliable power and exceptional customer service. (PacifiCorp 1998 Annual Report to Shareholders, March 1999)

> In 1998 we made solid progress toward implementing a strategic refocus on our domestic western electricity business. We moved quickly to execute our new strategy by selling non-core businesses, implementing a cost reduction program and making changes designed to improve customer service and reliability. (ibid)

- Oregon has established an annual review and setting of performance standards as part of its Alternative Form of Regulation for PacifiCorp. While that process will not directly affect service in Utah, changes in data collection, maintenance procedures, and corporate culture are likely to be transmitted between states.

- The Utah PSC has initiated a proceeding (Docket No. 99-2035-01) to investigate quality of service issues for PacifiCorp.

Clearly, the company is focusing its attention on improving T&D performance.

B. *Telephone Performance*

Q: How does PacifiCorp's telephone performance compare to that of utilities in the United Kingdom?

A: PacifiCorp's performance in answering the telephone when its customers call is poor. PacifiCorp reports monthly average call-answering times for its two call centers that are occasionally under 20 seconds, but are usually over one minute, and sometimes over two minutes. It has been common for more than 10% of callers in a month to abandon their calls before getting a response (CCS P11.42, S11.21).

For the first three months of 1999, ScottishPower reports monthly abandonment rates for ScottishPower and Manweb of 3.1–6.8%, compared to PacifiCorp's 9.2–11.3%.

Q: Is there any reason to hope that PacifiCorp's telephone performance will improve?

A: Yes. I previously discussed PacifiCorp's recent statements of commitment to "exceptional customer service" in its retail service territories. In connection with improving the quality of telephone service, PacifiCorp has consolidated its customer service centers to two state-of-the-art facilities (in Portland and Salt Lake City) and spent $75 million system-wide in new customer-service software.[11] The purpose of these efforts was described in PacifiCorp's 1998 Report to Shareholders:

> Focusing on the needs of our 1.5 million customers is also an integral part of our strategy. We reorganized our service functions in 1998 to be more responsive to our customers and to the communities we serve.
>
> Our customers first point of contact with PacifiCorp is usually through our business centers in Salt Lake City, Utah and Portland, Oregon. To make that contact as pleasant and productive as possible, we are improving service levels at our business centers through employee training programs, the creation of more efficient work shifts and process improvement efforts.

While PacifiCorp's work in improving customer service is not complete, the company appears to have identified the importance of service. Only eight months have elapsed since the change in PacifiCorp's strategic direction was announced, and many other issues have competed for management attention in that time. Once the divestitures of non-core businesses and of the Montana and California service territories are complete, and the ScottishPower merger is resolved, PacifiCorp's commitment to improving customer service may become a reality.

[11]This investment is discussed in greater detail in Mr. Gimble's testimony.

C. *Customer Satisfaction*

Q: Are PacifiCorp customers generally satisfied with the utility's service?

A: It appears so. Residential customers seem to be fairly happy (CCS 11.43). Commercial and Industrial customers are less satisfied, but it is not clear that reliability or customer service is an important issue for them.

III. ScottishPower's Offers of Improved Performance

A. *T&D Performance Standards*

Q: Please describe ScottishPower's proposed T&D performance standards.

A: The five T&D performance standard are

- Reduce underlying System Average Interruption Duration Index (SAIDI) by 10%.
- Reduce underlying System Average Interruption Frequency Index (SAIFI) by 10%.
- Reduce underlying Momentary Average Interruption Frequency Index (MAIFI) by 5%.
- Reduce the Circuit Performance Indicator (CPI) for the five worst-performing circuits in each state by 20%.
- Restoration service to 80% of customers within 3 hours, except for major events.

Q: Has ScottishPower proposed standards covering all relevant dimensions of T&D performance?

A: No. The standards exclude measurements of power quality, which ScottishPower agrees is very important (CCS S11.17).[12] Excluded power-quality indicators include voltage stability, short-term (e.g., 6-cycle) voltage sags, voltage spikes, frequency stability, and harmonics.

Q: Are the performance improvements clearly defined?

A: No. The performance improvements associated with ScottishPower's proposals are unclear in at least three distinct ways: baselines for percentage reductions, definition of the CPI goal, and definition of major events to be excluded from the computation of the performance indices.

Clearly, ScottishPower filed its direct testimony without having completely thought through many aspects of its proposed performance standards. As a result, the details of the proposals have emerged only piecemeal, and various company testimony, presentations, and discovery responses in various jurisdictions have differed. It is still not clear that anyone (including ScottishPower)

---

[12]The MAIFI may be thought of as an indicator of power quality. In addition, Customer Guarantee 8 would require PacifiCorp to pay $50 to the customer, if the company failed to respond in some way within five to seven working days, depending on the type of the response. The Customer Guarantee does not require that PacifiCorp actually correct problems.

knows what the utility has offered, let alone what it might need to do to meet its commitments.

Q: Why are the baselines for the percentage reductions unclear?

A: ScottishPower proposes that the baselines for the SAIDI, SAIFI, and MAIFI standards be 1994–98 averages, but proposes to update and revise the historical data over a two-year period following the merger (CCS S11.5, 11.6; Moir-MacLaren-Rockney Rebuttal at 8).

Q: Why is ScottishPower proposing to update historical data?

A: The problem ScottishPower faces is that PacifiCorp's T&D reliability data (like that of most US and UK utilities) are not precise. PacifiCorp's data-collection methods do not seem to be particularly deficient. Its description of its data collection (CCS P2.8, P11.26, 11.38, 11.39) certainly sounds appropriate. In addition, ScottishPower's estimate of the size of the size of PacifiCorp's understatement of SAIDI is similar to the magnitude of the revision in outage data ScottishPower reports having experienced as a result of improving its own data-collection system in 1997 (DPU S17.5, CCS S11.16).[13]

---

[13]The attachment to DPU S17.5 was labeled confidential, as were a number of other documents for which ScottishPower's need for confidentiality is not clear. The unnecessary marking of information as confidential impedes the regulatory process and interferes with the ability of the public (and state legislatures) to follow the issues before the regulator, some of which are of great public import. One potential cost of PacifiCorp's purchase by a company whose operations are lightly regulated or unregulated is that the corporate attitude towards public access to utility information will deteriorate.

ScottishPower's inability to determine the baseline for improvements in reliability is understandable, given its plans to change data-collection procedures and revise historical data.[14] However, it was ScottishPower that decided to promise specific percentage improvements from those unknown baselines, without incremental expenditures. Should the merger proceed, ScottishPower should be held to those promises, even if new information indicates that those improvements will be more difficult or expensive than the utility has assumed.

Q: How would ScottishPower correct PacifiCorp's historical reliability data?

A: ScottishPower's proposal is vague, but it appears that ScottishPower expects to combine the following two methods:

- Some spot checking of manually-recorded historical data against the data in the Outage Reporting System, primarily to correct the number of outages.[15]
- Comparison of (1) the estimated number of customers disconnected in an historical outage with (2) the number of

[14]ScottishPower did not know what baseline performance it would be starting with for PacifiCorp when the merger was proposed, or when improvements were proposed, and does not know the baseline even now (CCS S11.2).

[15]It is my understanding, from my telephonic participation in a meeting between Utah DPU Staff and Alec Burden of ScottishPower, that ScottishPower has used this technique to estimate PacifiCorp's under-reporting of outages. I have not seen any formal re-computation of PacifiCorp's reliability measures, so I cannot be sure exactly what ScottishPower has done.

customers reported as disconnected in a future outage at the same piece of equipment (e.g., the same breaker) by an improved reporting system, such as the Prosper system that ScottishPower has installed in Scotland and is implementing at Manweb. This exercise would be used to estimate the extent to which PacifiCorp has mis-estimated the number of disconnected customers.

The results of both these analyses will need to be extrapolated to the entire PacifiCorp system. ScottishPower has not described this extrapolation in any detail.

Q: What is ScottishPower's schedule for correcting the historical reliability data?

A: In the May 7 meeting, Alec Burden estimated that the revisions could be complete within a year, but ScottishPower would not commit itself in writing to a time frame for these corrections (DPU S7.7). In Oregon, ScottishPower has committed to revising the baseline after "running the new and current reporting systems in parallel for up to two years" (Moir-MacLaren-Rockney rebuttal at 8), which might mean that the revisions would be completed late in 2002, depending on how fast the new reporting system could be implemented.

Q: Why is the definition of the CPI goal unclear?

A: ScottishPower's proposal for implementing the CPI standard is poorly defined. Clearly, ScottishPower is promising to identify five circuits that are poor performers, and to improve a composite performance index by 20%. ScottishPower's explanations leave the following questions unresolved:

- What happens if PacifiCorp achieves 20% reductions in the CPI of some of the five worst circuits, but smaller reductions in one or more of the circuits? The standard might then be interpreted in many ways: achieving the goal might require that the CPI of every one of the five circuits be reduced by at least 20% (so that the minimum achieved reduction determines whether the goal is met), or over-achievement on one circuit might be applied against under-achievement on other circuits (so that something like the average reduction determines whether the goal is met).

  In response to a request for clarification of this issue, ScottishPower rejected the suggestion that the minimum achievement establishes whether the goal is met, but asserted that the CPI standard would be evaluated for "each of the circuits selected individually" (CCS S11.10). If individual achievement is different than the standard being linked to minimum improvements, ScottishPower has not explained the distinction.

- What happens if PacifiCorp fails to achieve the 20% CPI savings for more than one year? ScottishPower has committed to including any one circuit in the CPI no more than once in every five years, so a new set of worst circuits will be identified each year. ScottishPower has not indicated how it would propose that the Commission deal with a circuit on which the CPI stays high beyond the year in which it is targeted for reduction.

- Whether the improvements are required to be persistent. For example, if a targeted circuit's CPI falls 20% for a year or two after the base period, but then rises again in the third and fourth year, it is not clear whether ScottishPower would be considered to have achieved its goal.
- Length of time PacifiCorp would have to achieve the 20% improvement. The CPI would be computed for a three-year base period, and ScottishPower asks for "two years after investment on the circuit" to achieve the 20% reduction from that three-year average (CCS S11.10). The deadline for improvement thus appears to depend on how fast PacifiCorp would move to correct the problem.

  Depending on whether the year that compliance was required started two years from the last year in which investment was made in the circuit, or ended two years from the beginning of investment, ScottishPower might have anywhere from two years to five years (or more) from the end of the base period to achieve its 20% reduction. In addition, while ScottishPower asks for two years to improve the performance of the worst circuits, the penalties would not be effective until five years after the merger, giving ScottishPower at least five years in the first round of standards.
- Whether the CPI is a one-time or continuing standard. Moir's (Direct at 7) speaks of the CPI standard becoming effective "within two years of implementation of the performance targets,"

which I interpret to refer to approval of the merger. In that case, the standard might apply only to the five circuits in each state with the worst performance in 1996–98.[16]

- Whether (1) circuits that are performing poorly in the baseline period due to PacifiCorp's "inability to obtain the appropriate planning consents" (Exhibit BM-3 at 2) will be excluded from the five selected circuits, or (2) they will be included, but no penalties will be levied if the permits are not forthcoming.[17]
- Whether circuits that are eliminated from the penalty scheme due to PacifiCorp's "inability to obtain the appropriate planning consents" will be replaced by the next-worse circuits.

Q: What is unclear about ScottishPower's proposed definition of major events?

---

[16]This initial baseline is defined (for the first time, so far as I can determine) in the Moir-MacLaren-Rockney rebuttal at 8. In Oregon, which already has annual performance reviews, ScottishPower has clarified that "ScottishPower will nominate five underperforming circuits in Oregon to be selected annually on the basis of the Circuit Performance Indicator (CPI). Corrective measures will be taken within 2 years of nomination to reduce the CPI on each selected circuit by 20%." It is not clear whether ScottishPower intends to apply the same approach in other jurisdictions; ScottishPower's thinking on these issues seems to still be in flux.

[17]While PacifiCorp's "ability to obtain the appropriate planning consents" depends in part on PacifiCorp's actions, it does not seem fair to hold PacifiCorp strictly liable for these risks. On the other hand, there is no point in setting up a standard and then letting permitting delays on some of the most problematic lines eviscerate the standard's potential effectiveness.

A: The definition of the types of extraordinary events, which would be excluded from the computations of compliance, are described in Section V, below. At this point, I would simply note that ScottishPower has proposed several inconsistent (and generally vague) standards, without discussing how conflicts between these standards would be resolved.

Q: Are the proposed improvements dramatic?

A: No. The 10% decreases in SAIFI and SAIDI are small, compared to reductions at Manweb.[18] At Manweb, ScottishPower started with a utility with worse performance than PacifiCorp, with an underlying SAIDI (not including storms) of about 105 minutes in 1993/94 (the last pre-merger year), and brought that index down to about 55 minutes by 1997/98, a 47% reduction in four years (Exhibit BM-4 at 1). Over the same four years, Manweb's SAIFI fell from 0.89 to 0.57 interruptions per customer (OFFER May 1999 Consultation Paper at 63), a 36% reduction.

The 10% reduction in SAIFI and SAIDI that ScottishPower offers over five years is comparable to inter-annual variation of PacifiCorp and various UK utilities. In other words, these reductions would be hard to identify against the noise of normal variability. The 5% improvement ScottishPower offers in MAIFI is an order of magnitude lower than the annual variation in PacifiCorp's MAIFI. Indeed, these

---

[18]Not enough is known about the potential for improvements in MAIFI to allow any meaningful assessment. The CPI measure is not widely used, and it is not clear that ScottishPower is actually proposing any improvement over existing conditions.

improvements are smaller than the roughly 20% under-reporting rate ScottishPower estimates for PacifiCorp outages.

Q: How did ScottishPower determine the improvement targets?

A: The targets are based on ScottishPower's judgment regarding the feasible reductions in these measures. ScottishPower does not offer any historical comparison to other companies' improvements, or any cross-sectional data on achievable performance for utilities with service territories comparable to PacifiCorp. ScottishPower still says that it does not know the level of historical performance from which PacifiCorp is starting (CCS S11.2).

Nor has ScottishPower used cost-effectiveness analysis, such as that presented in Mr. Richardson's Exhibit AVR-2, to determine how much PacifiCorp's T&D performance should be improved. Indeed, the analysis in Exhibit AVR-2 suggests that ScottishPower's proposal simply skims the cream from the cost-effective performance improvements. ScottishPower estimates that $31.1 million in investment and $10.4 million in operating cost over five years, or $2.1 million annually, will fund all the performance standards, including the telephone and complaint-resolution standards (DPU S9.2). Exhibit AVR-2 estimates that the SAIDI and MAIFI improvements alone will provide $61.2 million in annual reliability benefits. That is an annual return of

$$(61.2 - 2.1) \div 31.1 = 190\%$$

It is hard to see why, if Mr. Richardson's analysis is correct, further improvements would not be cost-effective. If the annual return on the first $31 million investment is 190%, the return on the next $30 million might be much less (100%, 50%, or even 25%), and still be cost-effective. Since ScottishPower has only a vague idea of the reliability level and physical situation it is starting with, it is unlikely to have identified a break-point in the cost-effectiveness curve.

The problems in the definition of the CPI (and hence with measuring improvement) are discussed in Section IV.

Q: Are the proposed penalties for non-compliance significant?

A: No. The penalties are small compared to ScottishPower's estimate of the cost to customers of poor performance, and are comparable to the costs of achieving the improvements.

ScottishPower proposes penalties of $1 per customer for each reliability measure it fails. Even if PacifiCorp failed every one of the five standards in every state it serves, that would result in an annual penalty of $7 million, or about 11% of the customer cost PacifiCorp estimates for failing just two of the standards.[19]

The $7-million penalty is roughly equal to ScottishPower's estimates of the annualized cost of the improvements, at a 15% annual fixed-charge rate:

$$\$31.1 \times 15\% + 2.1 = \$6.8 \text{ million}$$

Therefore, if PacifiCorp were not planning to file a rate case, and decided to retain the funds it would otherwise have spent on

[19] The maximum possible penalty is about 5% of PacifiCorp's 1998 US electric earnings, or roughly 0.5% return on equity.

improving service, the maximum penalty would be roughly balanced by the cost saving.

Small as the maximum penalty is, PacifiCorp is not likely to pay the maximum, even if it does nothing to improve service.

- The large inter-annual variations will often result in MAIFI, SAIFI, and SAIDI performance that are 5% (for MAIFI) or 10% (for SAIDI and SAIFI) better than the three-year historical average, at least for some states.
- Over the last five years, in the six states it reports (or a total of 30 observations), PacifiCorp exceeded 80% restoration within three hours 26 times, or 87% of the time, even before the exclusion of major events (IPUC 4 supplemental).
- For CPI, we do not know whether the proposal is better than historical performance. The CPI penalty would also not be enforced if PacifiCorp "is delayed due to the company's inability to obtain the appropriate planning consents" (Exhibit BM-3 at 1).

B. Telephone Performance Standard

Q: What is your assessment of ScottishPower's proposed Performance Standard 6 for telephone service?

A: PacifiCorp's telephone performance is not very good, and ScottishPower's proposed standard would be a significant improvement over current practice. The proposed standard is not associated with any penalty or reward.

The Commission should order PacifiCorp to implement Performance Standard 6 (or something similar), regardless of the outcome of this case.

C. *Customer Guarantees*

Q: What is your assessment of ScottishPower's proposed Customer Guarantees?

A: These guarantees may be valuable in the following two ways:

- Customers who are treated shabbily by PacifiCorp would receive a meaningful apology for their inconvenience and wasted time, in the form of a check. Missed appointments and inadequate response to customer inquiries are frequent and often irritating problems of dealing with large organizations; the customer guarantee payments should make the worst-affected customers feel better.
- The payments would make inadequate customer service very concrete within PacifiCorp. While the financial effect would likely be minor, judging from UK experience, the fact that a check must be cut will tend to increase the responsibility of the entire organization that delivers the service, from the service person who showed up late, to the dispatcher who did the scheduling, to their supervisors.

While the Customer Guarantees, by themselves, are unlikely to transform PacifiCorp's corporate culture, the decline in payments over time in the UK (Attachment UIEC 7.8a) suggests that there is some incentive effect from these modest penalties.

The Commission should order PacifiCorp to implement the Customer Guarantees (or something similar), regardless of the outcome of this case.

IV. Measurement and Valuation Issues

Q: What measurement and valuation issues do you discuss?

A: I discuss ScottishPower's weighting of SAIDI, SAIFI, MAIFI, and lockouts in the computation of the Circuit Performance Index (CPI); other CPI issues; the definition of "major events" that would be excluded from computation of the indices; and the valuation of outages in the cost-benefit analysis in Exhibit AVR-2.

A. CPI weighting

Q: How does ScottishPower weight the four components within its proposed CPI?

A: The CPI includes four components computed on a circuit-specific (rather than state-wide or utility-wide) basis: the familiar SAIDI, SAIFI, and MAIFI indices, and the number of lockouts (events that result in an entire feeder being shut off, or "locked out"). The company proposes to apply two weighting factors to the components. The following table lists the two weights, as well as the product of the two weighting factors for each component index. The product of the two weights determines the number of points of the CPI index produced by one point of the component (one minute of SAIDI, or one outage for the other indices). The table also shows how many minutes of SAIDI would receive the same CPI value as one outage of each type.

	Weight 1	Weight 2	CPI Points per unit [1×2]	Units	Value of an outage in SAIDI minutes
SAIDI	0.3	0.029	0.0087	per minute	
SAIFI	0.3	2.439	0.7317	per outage	84
MAIFI	0.2	0.700	0.1400	per outage	16
Lockouts	0.2	2.000	0.4000	per outage	46

The four values of Weighting Factor 1 are apparently selected to add to 1.0. ScottishPower has not provided a rationale for Weighting Factor 2.[20]

Q: Are these weights of the proper magnitude?

A: I doubt it. The following two aspects of the weighting raise the possibility that PacifiCorp might reduce the CPI index for high-CPI feeders, without necessarily improving service on the line.

- The CPI formula treats each SAIFI outage as being worth as much as 84 more minutes of SAIDI. PacifiCorp might meet its CPI

[20]In PacifiCorp's version of CPI, the second sets of weights totaled the reciprocal of the worst performance by any circuit on this measure. Consequently, the maximum contribution to CPI for each component was the same (CCS P11.32). That cannot be the origin of ScottishPower's weights, since the inverses of the proposed weights are 34.5, 0.4, 1.4, and 0.5 for the four measures, which is better than average performance for the first three criteria. In any case, the PacifiCorp approach would have resulted in constantly changing weights, meaning that CPI comparisons over time would be meaningless.

requirement on some circuits by reducing the number of outages, even if the length of the outages increased dramatically.

- An outage that affects every customer on the circuit due to a breaker lock-out at a substation is weighted 50% more than three outages that each affect one third of the customers on the circuit. The lockouts may be worth flagging, if they are easier to prevent and more likely to recur than other problems, but it is not clear that they are really much more important in determining the quality of power supply. Sectionalizing a feeder may dramatically reduce the number of lockouts, without reducing the number or duration of outages experienced by most customers.

B. Other CPI Issues

Q: What other issues have you identified with respect to the proposed CPI standard?

A: In Section III above, I discuss the lack of clarity in ScottishPower's proposal for the CPI standard, including issues of timing, the treatment of partial success on multiple circuits, and the effect of permitting difficulties on the selection of circuits and the determination of success or failure.

In addition, it is not possible to determine how much improvement over past practice is represented by a commitment to improve the CPI index for the worst circuits in 1996–98 by 2000 (for example). It appears that PacifiCorp's past practice has improved most of its worst feeders.[21] In CCS P11.33, PacifiCorp provides the Utah feeders with the highest values on its CPI measures for the three-year periods end with 1992 through 1998.[22] Of some 14 feeders that appear in the lists once or more through 1996 (the last year for which we have two years of follow-up data), only three show up on the list two years after their first appearance. One of these three improved by more than 20% (from a CPI of 515 to 363), even though it was still the second-worst feeder in the state. [23]

C. *Major Events*

Q: What is the role of major events in the computation of the performance indices?

A: ScottishPower proposes to exclude major events (also sometimes called "extreme" or "extraordinary" events) from the computation of the

---

[21]I discuss only Utah data here, because PacifiCorp has not yet responded to a broader request for CPI data by state.

[22]Even though PacifiCorp provided these data for seven years, it claimed in other discovery to have determined the worst-performing Utah feeders only once, for calendar year 1997 (CCS P11.41).

[23]Similarly, many of the "worst-performing feeders" in 1997 identified in Appendix A to Attachment UPSC P2.1 were performing much better by the third quarter of 1998 (CCS 11.40(a)), due to equipment additions or replacements. One circuit (Wallsburg 12) was already performing above average. The problems on this line were caused by mudslides and highway construction; in 1998, the line was relocated away from the mudslide area. Highway construction may often contribute to poor performance of feeders in the construction area. If so, the problems would routinely clear up once the lines are relocated onto new permanent poles.

SAIFI, SAIDI, MAIFI, and CPI indices, and the supply-restoration time standard.

Q: How does ScottishPower propose to define the major events that would be excluded?

A: That definition has changed. In Exhibit BM-3, ScottishPower equated extreme events with "storms." In DPU S7.8, ScottishPower admitted that it did not have a working definition of major events. ScottishPower's current proposal is

> a catastrophic event which exceeds the design of the power system or imposes an extreme workload on local resources, characterized as:
>
> - Exceeds the design limits of the electric power system;
> - Causes extensive damage to the electric power system;
> - Results in more than 10% of the customers in an operating area out of service; and
> - The total outages in an event exceed three standard deviations above the daily mean. (CCS S11.11)

This four-fold definition raises a number of questions. For instance,

- Does ScottishPower mean that all four criteria must be met to create an extreme event? Or, is any one criterion sufficient?
- What "design limits of the electric power system" means, and whether a truck running into a pole "exceeds the design limits" of the pole?

- How large an "operating area" is used in the third criterion?[24]
- Who decides what "extensive damage" means?[25]

In the May 7 meeting, Mr. Burden agreed that the first criterion was too vague, and that it at least needed to be clarified to refer to "electrical design limits."

Q: Which definition should the Commission adopt?

A: I believe that either the third or fourth criterion, suitably clarified, could be a reasonable definition of excluded events. In any case, the definition should be clear and objective. The Commission has ample time to consider this issue, since the standards will not mean much for some years, until the new reporting system is in place and a new baseline established.

D. Cost-Benefit Analysis

Q: What comments do you have regarding the cost-benefit analysis In Exhibit AVR-2?

A: I have four basic comments. First, while ScottishPower presents this study as estimating the value of the SAIDI and MAIFI standards, it also incorporates the value of the SAIFI standard. Exhibit AVR-2 approximates the cost of extended outages by assuming that each customer experiences one 78-minute outage, and estimates the value

[24]Mr. Burden indicated in the May 7 meeting that the "operating area" used here refers to "districts," of which there are about 20 in Utah. The concept is still open to dispute.

[25]This issue is explored in DPU S17.3 and S17.4.

of a 10% reduction in SAIDI as 10% of that estimated cost. This is equivalent to assuming that outages will continue to be 78 minutes long, but that the average customer will experience annually only 0.9 outages, rather than 1.0 outage. In other words, Exhibit AVR-2 assumes that SAIFI is reduced 10%. If SAIDI were reduced 10% with no change in SAIFI, ScottishPower would need to estimate the cost of 1.0 outage of 70.2 minutes for each customer. With ScottishPower's input assumptions, its 10% reduction in SAIDI and SAIFI is worth $37 million; a 10% reduction in SAIFI with no change in SAIFI would be worth only $10 million. Consequently, about 70% of ScottishPower's claimed benefits from SAIDI (and about 43% of the claimed total benefits) are actually due to SAIFI.

Second, ScottishPower's use of data from the Bonneville Power 1990 survey (cited extensively by Richardson at AVR-2) makes an inherently uncertain exercise particularly unreliable. ScottishPower did not attempt to adjust for such differences as the size of commercial and industrial customers in the Bonneville study and in the PacifiCorp service territory, or the change in technology over time. (For example, increasing computer use may increase the costs of momentary outages for smaller businesses.) The Commission should address the value of T&D reliability in an appropriate proceeding.

Third, ScottishPower's assumed value of momentary outages for residential customers ($3.41/outage) is very high, in the light of all the other data ScottishPower has offered. This value was not estimated by Bonneville, and ScottishPower extrapolated back from Bonneville's estimates for 1-, 4-, and 8-hour outages.[26] The following information from ScottishPower suggests that the company values these outages too much:

- ScottishPower estimates that the value to residential customers of a momentary outage is 80% of value of the 78-minute typical extended outage. ScottishPower assumed that the corresponding ratios of momentary-to-extended outage values for commercial and industrial customers are 10% and 31%, respectively. This pattern makes no sense, since residential customers lose much less from momentary outages than do commercial or industrial customers dependent on computers and delicate electronics and machinery.

  Most residential customers will lose little from a momentary outage, other than needing to reset some clocks. A one-hour outage, on the other hand, can impose problems and inconveniences such as inability to cook dinner, utilize a home computer, or do laundry. The residential momentary-to-extended outage ratio should be much less than the other classes, not greater.[27]

- ScottishPower's extrapolation method for valuing residential momentary outages is unreliable. If applied to Bonneville's data

[26]For commercial and industrial customers, ScottishPower used ratios of the values of momentary and 1-hour outages from unidentified "other studies."

[27]Either ScottishPower's estimate of residential momentary costs is overstated, or its estimate of the value of longer outages to residential customers is understated.

for sustained commercial and industrial outages, the ScottishPower method would produce estimated values of momentary outages for commercial and industrial customers several times as much as Bonneville's survey results.

- The EPRI study that ScottishPower provided in response to LGC S1.37 estimates a much smaller residential momentary cost and momentary-to-extended outage ratio compared to those of ScottishPower.
  - OFFER estimates a residential momentary-to-extended outage ratio of about 1%. This is much less than the ratios OFFER estimates for commercial and industrial customers, which appear to be similar to ScottishPower's estimates (May 1999 Consultation Paper at 109).
  - ScottishPower's proposed CPI index treats each momentary outage as being worth about 20% of a sustained outage. This is consistent with the Bonneville estimates for commercial and industrial customers.

Fourth, even with the inflated value for residential momentary outages, Table 2 of Exhibit AVR-2 indicates that improvements in T&D reliability primarily benefit C&I customers; only 4% of the benefits are from the residential class.[28] It is also clear that ScottishPower concentrates its efforts at T&D power-quality improvement to benefit its largest customers (CCS S11.18). Since the benefits of improved

---

[28]If momentary outages are valued at $1 per customer, which seems plausible, the residential share of benefits falls to 2%.

reliability accrue primarily to the C&I classes, the costs of the improvements justified by those benefits should be borne primarily by the C&I classes.

V. ScottishPower's Contribution to Improving PacifiCorp's Performance

Q: What would ScottishPower contribute to PacifiCorp's performance?

A: Mostly, ScottishPower comes into this proceeding expressing a positive attitude toward customer service and improving service quality (Moir Direct; CCS S11.18). In addition, ScottishPower appears to be committed to improving the quality of data on PacifiCorp's performance and to implementing a new outage-tracking system (CCS S11.15).

As noted above, PacifiCorp has been expressing similarly positive attitudes toward customer service and service quality since well before the merger proposal from ScottishPower.

Q: Has ScottishPower demonstrated that the merger would provide service- or reliability-related resources to PacifiCorp that PacifiCorp could not obtain elsewhere?

A: No. In some cases, the resource that ScottishPower would bring to the merger seems to be little more than familiarity with available commercial products, such as improved databases for collecting and processing reliability data. In other cases, ScottishPower is offering little more than a can-do attitude and a determination to improve the operation of systems (such as distribution line maintenance) that PacifiCorp already understands well.

PacifiCorp may need to bring in some new, customer-oriented (or results-oriented) managers from other companies or other industries, to shake up aspects of the corporate culture.[29] If so, some of the ScottishPower managers who are prepared to relocate to PacifiCorp's service territory may be good candidates for those jobs. But it is far from clear that PacifiCorp lacks much of the technical and managerial resources needed to achieve the goals ScottishPower has proposed, and in much the same time frame.

A. The Record in the United Kingdom

Q: Has ScottishPower's performance in its UK electric utilities been outstanding?

A: ScottishPower's record has been good, but not outstanding.[30] Post-privatization performance has improved at most UK utilities

[29]Answering phones for a utility should not be very different than answering phones in many other consumer-oriented industries.

[30]Assessing ScottishPower's performance is complicated by inconsistencies in its reporting. Various company presentations show historical data with and without retroactive adjustments for the changes in the data system, and with and without adjustments for major events. For example, in 1996/97, a year with major storms, ScottishPower reported its performance with and without major events; in 1997/98, without any major storms, ScottishPower dropped the storm adjustment, which would have shown its SAIDI rising from 62 minutes to 77 minutes ("Distribution System Performance," PES License Condition 7, 1996/97 and 1997/98, ScottishPower).

(Attachment UIEC 7.8b, Figures 3 and 6). Manweb's improvements, for which ScottishPower takes credit, may have occurred later than several other utilities' improvements, but are not extraordinary.

ScottishPower itself shows no consistent improvement in SAIDI or SAIFI in the OFFER data (ibid.). Exhibit BM-4 reports improvement in SAIDI from 93/94 to 97/98, but this display depends on the accuracy of the exclusion of major events (which SP apparently started in 1995) and on the retrospective upward adjustment to pre-1995 data for consistency with ScottishPower's new data system.

OFFER indicates that Manweb and ScottishPower both have low SAIFI, given the density of their systems, but that Manweb SAIDI is well above the norm (May 1999 Consultation Paper at 66). OFFER also states (at 65), "on present indications, ScottishPower is unlikely to achieve its own 1999/2000 targets for improvements in numbers of interruptions and duration of interruptions."

According to OFFER, ScottishPower's historical and projected expenditures on improved reliability are not cost-effective in reducing outages. (May 1999 Consultation Paper at 76, 77).[31]

B. ScottishPower's Assessment of its Proposal

Q: What is ScottishPower's assessment of its proposal for performance standards and customer guarantees?

[31]The historical results may have been influenced by the changes in ScottishPower's data-collection system; the projected cost-benefit ratios will not be.

A: ScottishPower asserts that it is offering a superior package of standards and guarantees, which would provide significant value to PacifiCorp customers (Moir Direct at 1–2, Richardson Supplemental at 1–6, Moir-MacLaren-Rockney panel at 2–3).

Q: How substantial is ScottishPower's basis for its glowing assessment of its offer?

A: I have previously discussed some of the problems with the cost-benefit analysis in Mr. Richardson's supplemental testimony: the valuation of momentary residential interruptions appears overstated; the computation represents the benefits of all three major standards (SAIDI, MAIFI, and SAIFI), not just SAIDI and MAIFI; and if the assumptions in the analysis are even to be believed, much larger reliability improvements than those proposed by ScottishPower are likely to be cost-effective.

ScottishPower provides comparisons to other utilities' performance standards and customer guarantees in Moir's Exhibit BM-1, and in the report "Customer Service Standards and Guarantees: a Nationwide Survey and Comparison to the ScottishPower/PacifiCorp offer," prepared for ScottishPower by Gayatri Schilberg of JBS Energy, Inc.[32] As I have noted above, ScottishPower's promises regarding its performance standards are not very meaningful, given the uncertainty in the baseline value, the

[32]Ms. Schilberg's report was filed as an attachment to ScottishPower's June 2 rebuttal testimony in Oregon, and has therefore not been subject to any intensive scrutiny.

long time frame for compliance, and the many uncertainties in the definitions of the standards.

Q: Does the Schilberg report contradict your assessment of the performance standards?

A: No. Ms. Schilberg (at 1–2) lists eleven "elements that differentiate the [ScottishPower] proposal." Of those eleven elements, none mentions the principal reliability standards, SAIFI, SAIDI, or MAIFI. Five elements concern only the customer guarantees, which as I note above are not related to the merger. Two are essentially procedural, having to do with whether ScottishPower sought Commission approval or asked for rewards.[33] Two more "differentiating elements" concern the telephone goals and the goal for response time to Commission complaints, neither of which is associated with any consequence for the utility.[34]

All that is left of Schilberg's eleven differentiating elements are the standard of 80% restoration within three hours and the poorly-defined CPI standard. As noted above, it is not clear how much better

[33]The distinction between a reward and the absence of a penalty may be largely semantic. A regulator may grant higher rates, assuming good performance, and impose penalties for anything less, or grant lower rates and allow the utility to increase its revenues with rewards. The two schemes could yield exactly the same earnings for the utility, for any given performance level.

[34]Elsewhere, Ms. Schilberg correctly notes the importance of financial consequences for utility performance, as in her second "element." It appears that Ms. Schilberg would agree that the telephone and complaint standards, without penalties, are less meaningful than standards with financial penalties. While the telephone standards are aggressive, they are not binding; for the long-term goal, ScottishPower has not even proposed a time frame.

these standards are than PacifiCorp's current performance. While Ms. Schilberg is pleased with the financial consequences in the CPI standard, she does not comment on the five-year period ScottishPower would give itself to correct performance problems, or on the peculiar weighting of factors within the CPI.[35]

Indeed, the study is interesting to read for what it does not say about particular standards, but what is implied by Ms. Schilberg's selective silences and her observations about other standards. She does not comment of the absence of consequences for five years, the lack of consequences for two of the standards, the weighting and delay in the CPI standard, the magnitude of the penalties, or the appropriateness of the reduction targets. The praise in the Schilberg report must be read as faint in many areas, if not outright damning.

VI. Recommendations

Q: What are your recommendations to the Commission in this proceeding?

A: My most important recommendation with regard to the application in this proceeding is that nothing that ScottishPower has offered with respect to the performance standards and customer guarantees demonstrates any significant benefit from the merger. ScottishPower

---

[35] Interestingly, Ms. Schilberg notes that the Texas standard calls for no feeder to be in the worst category two years in a row, a considerably more stringent requirement than the five-year cycle proposed by ScottishPower.

can probably improve PacifiCorp's performance in at least some of these areas; PacifiCorp can probably achieve much the same results without the merger.[36] Neither improved attitude, nor better data-management technology, nor better phone-center operation requires the merger.[37]

Q: What should the Commission do with respect to the reliability and customer-service issues ScottishPower raised in this proceeding?

A: If the Commission has the authority, it should simply impose the proposed customer guarantees as part of the order in this docket, regardless of the outcome. Otherwise, the Commission should incorporate the guarantees into PacifiCorp's terms and conditions in

---

[36]If certain of the risks identified in the testimony of other CCS witnesses come to pass, ScottishPower may be in a worse situation to make good on its promises than a free-standing PacifiCorp would be. ScottishPower's analyses, promises, and thinking about regulatory goals and regulatory accountability in this docket have been vague. ScottishPower appears to be honestly confused about the nature and benefits of what it is offering. This confusion courts future disputes, if parties interpret the commitments differently, and as parties seek to clarify the nature and extent of the commitments, in the future. Despite the best of intentions, ScottishPower may not be as well prepared as it thinks for dealing with US utility regulation, or for solving PacifiCorp's problems. If ScottishPower has made a mistake, and the merger goes through, future disputes over unclear promises, and conflicting expectations, may result in high costs for both ScottishPower and PacifiCorp customers. If ScottishPower finds that it cannot do what it promised customers and regulators, as well as shareholders, unforeseen consequences could result.

[37]Metaphorically, the merger is the equivalent of a heart transplant to solve a problem that can be treated with diet and exercise.

its next rate proceeding. PacifiCorp has accepted the customer guarantees in this proceeding, and would be hard-pressed to oppose their imposition.[38]

The Commission should also instruct PacifiCorp to

- improve the quality of the data it collects on outages, and report semi-annually to the Commission on its plans and progress;
- improve its telephone service to customers, including reducing time for answering the phone.

In addition, the Commission should conduct a full review of reliability and service issues, including

- Determining the value of improvements in reliability, including a refinement of ScottishPower's finding that the bulk of the benefits of improved reliability are received by commercial and industrial customers;
- Establishing rules and procedures for improved measurement of momentary and sustained outages, including auditing procedures;
- Determining the feasible and cost-effective improvements in reliability, and setting up standards requiring those improvements;[39]

---

[38]In CCS P11.27, PacifiCorp says that it can achieve the goals set by ScottishPower, but asserts that the process of improving service would be faster with ScottishPower. PacifiCorp offers no basis for that assertion.

[39]PacifiCorp believes the standards ScottishPower proposed in this proceeding are feasible and cost-effective (CCS P11.24 and P11.25).

- Establish clear standards for eliminating major events from performance data, historical and future;
- If composite indices are found to be valuable, determine the appropriate weighting of their components; and
- Determine the level of penalties necessary to provide adequate incentives for improved performance, and establish penalties that vary with the severity of the failure to meet standards.

These reliability and customer service issues could be fully examined in a separate proceeding focusing on those issues, or (depending on timing and resource limitations) as part of PacifiCorp's next general rate case. The open reliability proceeding (Utah PSC Docket No. 99-2035-01) could be expanded to include the reliability and customer service issues raised in the current docket.

Q: Does this conclude your testimony?

A: Yes.

Committee of Consumer Services

Witness: Paul Chernick

Docket No. 98-2035-04

CCS Exhibit 3.1 (PLC)

17244

Qualifications of

PAUL L. CHERNICK

Resource Insight, Inc.
347 Broadway
Cambridge, Massachusetts 02139-1715

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

"Determining the Marginal Value of Greenhouse Gas Emissions" (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

"Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs" (with E. Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

"Accounting for Externalities" (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

"Methods of Valuing Environmental Externalities" (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

"The Valuation of Environmental Externalities in Energy Conservation Planning" (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link.* American Council for an Energy-Efficient Economy; Washington: 1991.

"The Valuation of Environmental Externalities in Utility Regulation" (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

"Externalities and Your Electric Bill," *The Electricity Journal*, October 1990, p. 64.

"Monetizing Externalities in Utility Regulations: The Role of Control Costs" (with Emily Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

"Monetizing Environmental Externalities in Utility Planning" (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

"Capital Minimization: Salvation or Suicide?," in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

"Power Plant Performance Standards: Some Introductory Principles," *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

"Opening the Utility Market to Conservation: A Competitive Approach," *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

"Distributed Integrated-Resource-Planning Guidelines." 1997. Appendix 4 of "The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets," submitted to the Vermont PSB in Docket No. 5854. Montpelier: Vermont DPS.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations," vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Plunkett, John, and Jonathan Wallach), December 1992.

"Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro," December 1992.

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.), February 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with Emily Caverhill), January 1991.

"Comments on the 1991–1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with John Plunkett et al.), September 1990.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22.1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference; June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop; April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C.; October 21 1991;

"Least Cost Planning and Gas Utilities." Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context," NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

"Increasing Market Share Through Energy Efficiency." New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies," District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22–23 1989.

"Assessment and Valuation of External Environmental Damages," New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans," Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

"Power Plant Performance," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **MEFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **New Mexico PSC** 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Massachusetts Division of Insurance** 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vermont PSB** Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vermont PSB** Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

Prudence of BECo's decision of spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **MDPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24 1989. Rebuttal, October 3 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Maryland PSC** Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Virginia State Corporation Commission** Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **MDPU** Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13 1991.

NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **South Carolina PSC** Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Maryland PSC** Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **MDPU** Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Florida PSC** Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Florida PSC** Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Pennsylvania PUC** Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **South Carolina PSC** Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **MDPU** Docket No. 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **South Carolina PSC** Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** Docket No. 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Maryland PSC** Case No. 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** Docket No. 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** Case No. 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** Case No. 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

112. A **Michigan PSC** Case No. U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

113. **Ohio PUC** Dockets No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati, City of Cincinnati, April 1993.

DSM planning, program designs, potential savings, and avoided costs.

114. **Michigan PSC** Case No. U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

115. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

116. **FERC** Projects Nos. 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

117. **Vermont PSB** Dockets No. 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

118. **Florida PSC** Dockets 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

119. **Vermont PSB** Docket No. 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

120. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

121. **Michigan PSC** Case No. U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

122. **Michigan PSC** Case No. U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **New Jersey Board of Regulatory Commissioners** Docket No. EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

124. **Michigan PSC** Case No. U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

125. **Michigan PSC** Case No. U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **FERC** Projects Nos. 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

127. **North Carolina Utilities Commission** Docket No. E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

128. **New Orleans City Council** Docket No. UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

129. **DCPSC** Formal Case No. 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

130. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

131. **New Orleans City Council** Docket No. CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

132. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

133. **Maryland PSC** Case No. 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

134. **North Carolina Utilities Commission** Docket No. E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

135. **Arizona Commerce Commission** Docket No. U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

136. **Ohio PSC** Case No. 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

137 **Vermont PSB** Docket No. 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

138. **Maryland PSC** Case No. 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

139. **MDPU** in Docket No. DPU 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

140. **MDPU** Docket No. DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

141. **Maryland PSC** Case No. 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

142. **New Hampshire PUC** Case No. DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges

143. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

144. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

145. **Vermont PSB** Docket No. 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

146. **MDPU** Docket No. 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

147. **Vermont PSB** Docket No. 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

148. **MDPU** Docket No. 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

149. **MDTE** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

150. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

151. **Maryland PSC** Case No. 8774; APS-DQE merger; Maryland Office of People's Counsel. February, 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

152. **Vermont PSB** Docket No. 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

153. **Maine PUC** Docket No. 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

154. **MDTE** Docket No. 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

155. **Vermont PSB** Docket No. 6107, Green Mountain Power rate increase, Vermont Department of Public Service. September 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

156. **MDTE** Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October, 1998. Joint surrebuttal with Jonathan Wallach, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

157. **Maryland PSC** Case No. 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December, 1998; rebuttal, March, 1999.

Implementation of restructuring. Stranded cost or gain. Valuation of generation assets.

158. **Maryland PSC** Case No. 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December, 1998.

Implementation of restructuring. Stranded cost or gain. Valuation of generation assets.

159. **Maryland PSC** Case No. 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January, 1999; rebuttal, March, 1999.

Implementation of restructuring. Stranded cost or gain. Valuation of generation assets.

160. **Connecticut DPU** Docket No. 99-02-05; Connecticut Light and Power Company Stranded Costs; Connecticut Office of Consumer Counsel. April, 1999.

Projections of market price; valuation of purchase agreements and nuclear and non-nuclear assets.

161. **Connecticut DPU** Docket No. 99-03-04; United Illuminating Company Stranded Costs; Connecticut Office of Consumer Counsel. April, 1999.

Projections of market price; valuation of purchase agreements and nuclear assets.

17234

RECEIVED

JUN 18 3 53 PM '99

UTAH PUBLIC
SERVICE COMMISSION

Witness CCS-1
Exhibit CCS-1

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	Docket No. 98-2035-04
In the Matter of the Application	)	
of PacifiCorp and ScottishPower plc	)	PRE-FILED DIRECT TESTIMONY OF
for an Order Approving the Issuance	)	DANIEL E. GIMBLE
of PacifiCorp Common Stock	)	FOR THE
	)	COMMITTEE OF CONSUMER SERVICES

June 18, 1999

TABLE OF CONTENTS

I. Introduction

Q: PLEASE STATE YOUR NAME, JOB POSITION AND QUALIFICATIONS TO APPEAR AS A WITNESS ON BEHALF OF THE COMMITTEE OF CONSUMER SERVICES IN THIS PROCEEDING.

A: My name is Daniel E. Gimble. I am presently employed in the position of Energy Group Manager with the Committee of Consumer Services ("Committee" or "CCS"). My qualifications are included in Appendix 1 to this testimony.

Q: PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A: As the Committee's Energy Group Manager, I provide the Committee's recommendation on ScottishPower's proposal to acquire PacifiCorp ("the proposed merger"). My testimony is structured as follows:

- Recommendation
- Background
- Merger Review Standard
- Merger Base Line
- "Applicants' Case"
- Committee "Response"
- Rate Plan

II. Committee Recommendation

Q: WHAT IS THE COMMITTEE'S RECOMMENDATION REGARDING THE APPLICANTS' MERGER PROPOSAL?

A: The Utah Commission should deny the Applicants' proposal to merge the two companies. The Applicants have yet to put forward tangible and verifiable evidence showing that the proposed merger is in the public interest. Thus, we are compelled to recommend against approving the proposed merger at this time.

III. Background

Q: PLEASE BRIEFLY DESCRIBE THE "INTERNATIONAL CONTEXT" ACCOMPANYING THIS PROPOSED MERGER.

A: Over the past decade there has been a trend toward ever-greater diversification in energy markets; a development that increasingly transcends national borders as energy companies seek profitable opportunities abroad. Stated succinctly, a globalization of energy markets. For example, many U.S. energy companies have an international presence on continents ranging from Asia to South America to Europe.

In the United Kingdom (U.K.) alone, U.S. companies have acquired eight of the twelve regional electricity companies. And all of these transactions have occurred since 1995; a period of only three years. The prospect of incredibly high earnings attracted many U.S. companies to the U.K. electricity market, including PacifiCorp in its failed bid to acquire The Energy Group. Earnings levels became so high in the U.K. utilities industry that Her Majesty's Treasury levied a 5.2 billion pound windfall profits tax on all utilities to return some of the "excess profit" to U.K. citizens.[1] Moreover, recent news reports suggest that OFFER (the U.K. Regulator) will further tighten the rein on profits through significant rate reductions.[2] This is in addition to new regulations requiring the "ring-fencing" or separation of the supply part of the business from the "wires" part of the business–a transition that U.K. electric companies say will cost them 1.6 billion pounds over six years, with ongoing annual costs of 325 million

---

[1]Interestingly enough, the U.K. Company with the largest tax liability was the ScottishPower Group (ScottishPower, Manweb and Southern Water). Their tax liability totaled nearly $320 million pounds.

[2]According to Power Marketer: "Standard and Poor's current ratings on the U.K. RECs (regional operating companies) reflect the expectation that initial price reductions will be between 6% and 10%, with an ongoing 'X' factor of 2%. OFFER has indicated that these rate re-sets will be effectuated by April 2000.

pounds.[3] Consequently, some U.S. companies foresee a profit squeeze and are thinking about exiting the U.K. energy market.[4]

The context, therefore, is the emergence of a global energy market that is increasingly dynamic, but also potentially volatile. PacifiCorp's recent woes on the global front attest to an inconstancy that can have deleterious financial repercussions. To wit: PacifiCorp's stock price sharply declined from $27 per share on January 2nd, 1998, to approximately $18 3/4 per share by November 30th, 1998.

Q: **WHY IS SCOTTISHPOWER INTERESTED IN ACQUIRING PACIFICORP?**

A: ScottishPower has been exploring the possibility of acquiring a U.S. energy company for some time. In addition to PacifiCorp, recent merger candidates have included Florida Progress and Cinergy.[5] ScottishPower finds PacifiCorp an appealing merger target for a variety of reasons.

- PacifiCorp has a large cash balance on its books of over $583 million stemming primarily from the sale of non-core assets during 1997 and 1998. PacifiCorp has also sold, or is in the process of selling, its equity interest in the Centralia and Hazelwood (Australia) generation plants and its service territories in Montana and California. Net revenues from those sales will increase the present cash balance. Thus, the large cash balance could be used for further acquisitions or to underwrite

---

[3]In response to CCS Data Request 14.1, ScottishPower estimates separation costs at 23 million pounds for ScottishPower and 20 million pounds for Manweb.

[4]The Scotsman, "The New World Power," June 2nd, 1999.

[5]See Company response to CCS 9.9 which includes various financial reports prepared by investment firms on the proposed merger. Specifically, see page 6, of the Warburg Dillon Read Report.

ScottishPower's stock buyback program.[6]

- PacifiCorp has low cost generation assets with no nuclear exposure.
- PacifiCorp has a diverse and growing customer base.
- According to the financial community's assessment of the proposed merger, PacifiCorp has a poor earnings record associated with its regulated operations that can be reversed through a confluence of cost-cutting programs and rate increases. The financial community bluntly refers to this as "sweating the assets."
- PacifiCorp provides ScottishPower with a "U.S. platform" for further multi-utility expansion into electricity, natural gas and telecommuncations; industries where services are increasingly open to competition.
- The current disconnect between PacifiCorp's low stock price and its solid asset base. Financial analysts consistently refer to PacifiCorp as an undervalued asset with "classic turnaround potential."

Q: **WHEN DID SCOTTISHPOWER AND PACIFICORP ("THE APPLICANTS") FILE AN APPLICATION AND TESTIMONY WITH THE UTAH COMMISSION PROPOSING TO COMBINE THE TWO COMPANIES? IN ADDITION, WHAT IS THE FOCUS OF THE APPLICANTS' TESTIMONY IN THIS MATTER?**

A: On December 7th, 1998, ScottishPower publicly announced its proposal to acquire PacifiCorp. ScottishPower and PacifiCorp ("the Applicants") filed an application with the Utah Commission on December 31st, 1998, proposing to merge the two companies. On February 26th, the Applicants submitted an initial round of testimony supporting the application. That testimony is largely centered on a "benefits-commitment package" encompassing the areas of network reliability, customer service, low income initiatives, community service and

---

[6]According to ScottishPower's response to CCS 13.6, the buy-back will be through on-market purchases up to a total amount of 500 million pounds. ScottishPower states that the buy-back will occur prior to closing the merger transaction. They also convey that it will be funded from ScottishPower's own current resources. However, whatever resources are used to buy back stock will be replenished from the cash funds ScottishPower obtains in acquiring PacifiCorp.

renewable resources. On April 16th, ScottishPower filed supplemental testimony in an attempt to sharpen certain aspects of their initial testimony.

Q: **IN DEVELOPING A RECOMMENDATION IN THIS PROCEEDING, WHAT STEPS DID THE COMMITTEE TAKE IN EXAMINING THE APPLICANT'S PROPOSAL?**

A: The Committee retained a consulting firm, Synapse Energy Economics, to assist Staff in analyzing the merits of the proposed merger. Members of the "Synapse team" (Bruce Biewald, Neil Talbot, Paul Chernick and Peter Bradford) have testified in a considerable number of recent merger cases involving electric utilities and, therefore, bring a wide range of experience and expertise to this proceeding. Specifically, Mr. Biewald, Mr. Talbot and Mr. Chernick are filing expert testimony underpinning the Committee's recommendation in this matter. Mr. Biewald's testimony addresses ScottishPower's cost savings estimates; Mr. Talbot's testimony addresses mainly financial issues; and Mr. Chernick's testimony addresses customer service and reliability issues. In addition, sections of their testimony are devoted to analyzing ScottishPower's U.K. track record (e.g., rates, earnings, customer service and reliability).

The Committee also submitted 16 sets of discovery, reviewed the discovery responses to data requests submitted by parties in Utah and other PacifiCorp states, met with the applicants several times to discuss various facets of the proposed merger, made contact with OFFER to obtain information relating to ScottishPower's U.K. operations and performance record, and discussed merger-related issues with regulatory staffs in other PacifiCorp states. Lastly, we reviewed testimony filed by parties in Oregon, Idaho and Wyoming.

Q: **ARE PARTIES IN THOSE STATES UNANIMOUSLY IN FAVOR OF THE PROPOSED MERGER?**

A: No. Support for the proposed merger in those states is mixed. For example, in Oregon, the PUC Staff, the Citizens Utility Board, and industrial customers all filed direct testimony opposing the merger. The lack of an explicit "rate plan" ensuring either rate stability or rate decreases, appears to be a key issue in Oregon. In Wyoming, the Consumer Advocate Staff (whose statutory mandate is in line with the Utah DPU's) filed direct testimony which conditionally supports the proposed merger. Two interlocking stipulations are attached to Staff's testimony that specify merger-related conditions and limit the magnitude of future rate increases to $12 million in 1999 and $8 million (plus any change in depreciation rates ordered by the Wyoming PSC) in 2000. Conversely, Wyoming industrial customers oppose the proposed merger. Idaho is also divided with Staff endorsing the proposed merger and industrial and irrigation customers opposing it.

IV. <u>Merger Review Standard</u>

Q: **WHAT MERGER REVIEW STANDARD DID THE COMMITTEE RELY ON TO DETERMINE WHETHER OR NOT THE APPLICANTS' MERGER PROPOSAL IS IN THE PUBLIC INTEREST?**

A: The Committee relied on the positive net benefits standard.

Q: **ON WHAT BASIS DID YOU RELY ON THAT STANDARD?**

A: The Order regarding "Standard of Approval For Merger" issued by the Utah Commission on November 20th, 1987. That Order was one of a series of orders issued in the Pacific Power-Utah Power merger case, Docket No. 87-035-27. In my view the Order establishes a strong precedent for applying the standard of net positive benefit to the current merger application. I have included a copy of the Order as CCS Exhibit 1.1 (DEG).

Q: **WHAT UNDERLYING REASONS DID THE COMMISSION GIVE IN ADOPTING THE NET POSITIVE BENEFITS STANDARD?**

A: On page 2 of the Order the Commission plainly states its rationale:

> " Here, as in Re CP National Corp.,43 PUR 4th 315 (Utah PSC 1981) Case No. 80-023-01, we are of the view that the necessary predicate for a determination that the proposed merger is "in the public interest" is some net positive benefit to the public in this State. Applicants seek strict adherence to the Utah decision, Collett v. Public Service Commission, 116 Utah 413, 211 p.2d 185 (1949) which they cite in favor of the "no harm" standard. We rejected this argument in CP National as we do now. Such a standard is too narrow for use in a fixed utility situation such as that before us. Also, we believe Applicants acknowledged this fact in their oral arguments and application wherein they have voluntarily offered to accept the burden of showing a positive benefit."

In short, the Commission gave a clear signal that the importance of the Pacific Power-Utah Power merger case required a more exacting merger review standard. ScottishPower and PacifiCorp should likewise be held to the standard of net positive benefits.

Q: **IN THE CONTEXT OF THE NET POSITIVE BENEFITS STANDARD, SHOULD THE COMMISSION GIVE WEIGHT TO THE "MATERIALITY" OF NET BENEFITS?**

A: Yes. I believe that the Applicants shoulder a heavy burden to demonstrate that the positive net benefits are both *significant* and *sustainable* over time.

Q: **DO YOU HAVE ANY COMPELLING EVIDENCE TO POINT TO WHICH SUPPORTS YOUR POSITION THAT POSITIVE NET BENEFITS SHOULD BE SIGNIFICANT AND SUSTAINABLE?**

A: Yes I do. In the Pacific Power-Utah Power merger case, cost-benefit studies were prepared detailing five-year merger benefit estimates by area. Those merger benefit estimates were not singularly limited to cost savings flowing from resource deferral and power supply, but included approximately <u>$250 million</u> in cost savings in the areas of manpower and administration. A summary of those merger benefit estimates are provided in the chart below (excludes resource deferral cost savings which were estimated, on a 19-year NPV basis, at $352 million).

Five-Year Merger Benefit Estimates

Area	Year 1	Year 2	Year 3	Year 4	Year 5	Totals
Labor	**$10 M**	**$20 M**	**$30 M**	**$42 M**	**$53 M**	**$155 M**
Admin	**$19 M**	**$20 M**	**$20 M**	**$20 M**	**$20 M**	**$99 M**
Constr	**$1 M**	**$3 M**	**$5 M**	**$8 M**	**$11 M**	**$28 M**
Econ Dev	**$1 M**	**$2 M**	**$6 M**	**$11 M**	**$17 M**	**$37 M**
NPC**	**$18 M**	**$23 M**	**$36 M**	**$42 M**	**$43 M**	**$162 M**
Total	**$49 M**	**$68 M**	**$97 M**	**$123 M**	**$144 M**	**$481 M**

*Source: Utah Commission Report and Order in Docket 87-035-27 issued on September 28th, 1988, page 19.

**NPC =Net Power Cost.

In that case, Pacific Power and Utah Power witnesses were firmly convinced the merger would produce net benefits and they proffered a "merger rate guarantee" to reduce rates in Utah by a minimum of 5% within four years after the merger. In fact, they testified that rate reductions in this period would likely fall between 5%-10%.[7]

[7] See pages 72-73, point 7 in the Utah Commission's Pacific Power-Utah Power Merger Order issued on Sept. 28th, 1988.

Q: **DID HISTORY BEAR OUR THEIR MERGER BENEFITS ESTIMATES?**

A: Yes. In addition to the 5% rate reduction stemming from the merger rate guarantee, rates in Utah were further reduced by approximately 3.7% as the outcome of the 1990 rate case (Docket No. 90-035-06). Thus, the total rate decrease in the five-year period totaled about 8.7% – a decrease within the expected range.

Q: **DO YOU HAVE ANY ADDITIONAL EVIDENCE TO PRESENT ALONG THESE LINES?**

A: Yes. In recent mergers involving U.S. energy companies, many of those companies have offered rate plans which include rate decreases or rate caps for customers.

Q: **HAVE THE APPLICANTS DELINEATED A RATE PLAN SIMILAR TO THAT DEVISED BY PACIFIC POWER-UTAH POWER OR APPLICANTS IN RECENT U.S. ENERGY MERGERS?**

A: No, they have failed to delineate a credible rate plan in Utah that would either reduce or cap existing rates over a specified period of time.

Q: **WHY HAS SCOTTISHPOWER FAILED TO OFFER A CONSTRUCTIVE RATE PLAN IN UTAH?**

A: ScottishPower has indicated that they have not performed detailed cost-benefit analyses relating to the proposed combination. ScottishPower has asserted that they have not yet had full access to PacifiCorp's books and records.[8] They maintain that the potential cost savings (merger benefits) will only be known after transition teams are assembled and begin a fastidious, department-by-

[8] In response to CCS DR 15.1, PacifiCorp states: "Until the transaction closes, ScottishPower is not entitled under the Merger Agreement to unrestricted access to PacifiCorp's books, records or personnel, nor is PacifiCorp entitled to such access to ScottishPower's books, records, or personnel. Providing ScottishPower with sufficient access to books, records and personnel for transition planning would interfere with PacifiCorp's day-to-day operations..."

department review. In his Oregon Rebuttal Testimony, Mr. Richardson commits to "develop and share our transition plan within six months after closing of the merger, identifying the specific areas in which ScottishPower expects to achieve cost savings, the plan for achieving them, and the expected costs and benefits of such initiatives." [Richardson, Oregon Rebuttal, pg. 4, lines 10-13.] I will have further remarks on the lack of a constructive rate plan for Utah later in my testimony.

V. Merger Base Line

Q: **GIVEN THE MERGER REVIEW STANDARD OF POSITIVE NET BENEFITS, WHAT IS THE APPROPRIATE BASE LINE OR BENCHMARK TO MEASURE THE PROPOSED MERGER AGAINST?**

A: PacifiCorp as a stand-alone, ongoing business. The materials I have examined indicate that PacifiCorp has made significant strides in rebounding from its past ventures into the sargasso sea of energy diversification–ventures that turned out to be extremely dicey and unprofitable. PacifiCorp's financial future appears to be reasonably sound as long as management sticks to its "new western strategy."

Q: **PLEASE EXPLAIN IN GREATER DETAIL WHY YOU BELIEVE THAT THIS IS THE PROPER BASE LINE. AS PART OF YOUR EXPLANATION PLEASE DESCRIBE THE MAJOR FEATURES OF PACIFICORP'S "NEW WESTERN STRATEGY."**

A: Only two-and-half years ago, PacifiCorp's corporate philosophy mirrored that of ScottishPower: PacifiCorp aspired to morph into a prominent multi-utility with a considerable global presence. PacifiCorp's failed bid to acquire The Energy Group (TEG), along with mounting losses in other ventures, led PacifiCorp management to embark on a retrenchment strategy. The new business strategy is to focus on its core western retail and wholesale electricity business and is comprised of the following major features.

First, PacifiCorp's senior management was reorganized. For example, Keith McKennon supplanted Fred Buckman as CEO, Richard O'Brien assumed the post of chief operating officer and Rich Walge was assigned to oversee Utah operations. Under the direction of Mr. O'Brien, new management teams were formed to address critical areas such as customer service and to begin the process of reshaping the Company's organizational structure to fit the new western strategy.[9]

Second, management quickly moved to streamline PacifiCorp by shedding the vast majority of its non-core business holdings and operations. The following is a list of companies sold and operations discontinued during 1998:[10]

- PPM's eastern U.S. electric trading operation;
- The natural gas marketing and storage operations of TPC Corp.;
- EnergyWorks (a joint venture with Bechtel); and
- Business interests in Turkey.

Third, management decided to sell its regulated service territories in Montana and California. Flathead Electric Cooperative purchased the Montana service territory for $89 million (pre-tax) and Nor-Cal Electric Authority has offered to buy PacifiCorp's California service territory for $174 million (pre-tax). As indicated in a April 9th, 1999, press release issued by PacifiCorp, these sales would allow management to "better focus on states where it had a larger customer base and more significant investment in assets."

[9]In response to CCS Data Request 9.25, PacifiCorp provided a series of internal correspondence written by Mr. O'Brien. Some of these "memos" were generally circulated among PacifiCorp employees and others were specifically designated to managers. Organizational change to comply with the new western strategy is the prime topic of these memos.

[10]Sources: PacifiCorp's SEC Form 10-K for the fiscal year ending December 31st, 1998; and a Company Press Release issued March 31st, 1999 which is entitled, "PacifiCorp Makes Early Progress on Refocused Strategy."

Fourth, management advanced cost-cutting initiatives. In the first and fourth quarters of 1998, PacifiCorp implemented work force reduction programs that eliminated 926 positions, or approximately 10% of its U.S.-based employees.[11] This fostered cost savings of about $48 million (pre-tax) in 1998.[12] According to PacifiCorp, the $48 million (pre-tax) cost savings associated with work force reductions are in addition to the $30 million (pre-tax) annual cost savings target announced by Keith McKennon in an October 1998 press release.[13]

Fifth, there is a renewed commitment by management to improve customer service and reliability. As CCS Exhibit 1.2 (DEG) shows, PacifiCorp has spent in excess of $100 million over the past five years to upgrade its customer service and reliability systems.[14] These include two new customer service centers and a new computer software system. Further, Dick O'Brien has repeatedly emphasized customer service in his directives to PacifiCorp managers and employees.[15] In a "Priority Actions Update" circulated on September 4th, 1998, Mr. O'Brien states:

> "Within the distribution business, a single customer care organization for the U.S. regulated business will be formed. This organization will provide account services for all retail customers served by the U.S. regulated business and will not be involved in competitive business activities. The

---

[11]Sources: same as footnote 10. In particular, see pages 18 and 31 of PacifiCorp's SEC Form 10-K for year-end 1998.

[12]Source: PacifiCorp's December 1998 Results of Operations (i.e., Semi-annual Report) filed with the Utah Commission May 1999.

[13]Source: PacifiCorp's response to CCS Data Request 9.8. Refer also to the attachment included in PacifiCorp's response to CCS Data Request 9.22. This attachment is a presentation on "The New Strategic Direction" given to financial analysts/investment firms in New York on Oct. 28th, 1998. The presentation includes a cost savings estimate of $30 million (pre-tax).

[14]It must be noted that in PacifiCorp's 1997-1998 rate case in Utah, the partial revenue requirement stipulation adopted by the Utah PSC includes a disallowance of 1/3rd of the costs attendant to PacifiCorp's new computer software system. The CCS concluded that a substantial portion of those costs were incurred for purposes of positioning the Company for the opening of retail competition.

[15]Source: PacifiCorp response to CCS Data Request 9.25.

> primary advantage of a single customer care organization is focus: on customer satisfaction and on low cost high-leverage improvement of processes to deliver satisfaction in key areas.
>
> The customer care organization will include the current account management, sales support, and marketing functions of GSMET, as well as the general business managers and the energy efficiency representatives from Electric Operations. I have chosen 'customer care' rather than sales and marketing to specifically take into account the valuable contribution this organization can make to the customers and communities we serve..."[16]

Customer service and reliability are clearly important components of the new western strategy.

Q: ARE THERE OTHER BENCHMARKS THE UTAH COMMISSION COULD USE TO MEASURE SCOTTISHPOWER'S PROPOSAL AGAINST?

A: If there was a competing bid to win PacifiCorp, another point of reference would be available against which to evaluate ScottishPower's proposal. At this time, however, there are obviously no other offers on the table.

VI. Merger Benefits and Costs

A. The Applicants' Case

Q: STARTING WITH PACIFICORP'S SHAREHOLDERS, WHAT DO THEY STAND TO GAIN FROM THE PROPOSED MERGER?

A: ScottishPower's offer to PacifiCorp shareholders totals $11.1 billion in shares and assumed debt. The offer includes a sizable premium that has ranged between about $800 million and $1.6 billion since the merger was announced. The premium tends to fluctuate daily because the amount is correlated to changes in relative share prices and the number of shares in circulation. The wider the disparity between ScottishPower's and PacifiCorp's respective share

---

[16]Source: Same as footnote 15.

prices, the greater the premium. Thus, the actual size of the premium will not be determined until the proposed deal closes.

Q: **TURNING TO UTAH RATEPAYERS, WHAT ARE THE MAIN MERGER-RELATED BENEFITS AND COSTS IDENTIFIED BY THE APPLICANTS' IN THEIR TESTIMONY?**

A: The principal benefits of the merger are set forth in Alan Richardson's Exhibit SP (AVR-1), pgs. 1-10, which is attached to his Utah Supplemental testimony filed April 16th, 1999. I have included it as CCS Exhibit 1.3 (DEG) for reference purposes. In his Oregon Rebuttal Testimony filed June 2nd, 1999, Mr. Richardson provides the following capsule summary of the alleged merger benefits:

> "ScottishPower has committed to transform PacifiCorp into a leading U.S. electric utility. We will introduce an unmatched package of system performance and customer service standards that will significantly raise the level of service to PacifiCorp customers. ScottishPower will also achieve efficiencies and cost savings in PacifiCorp that will lead to prices lower than they would have been without the merger. ScottishPower has also made significant commitments to environmental programs, including developing an additional 50 megawatts of renewable resources and introducing a 'green tariff.' In addition, ScottishPower has made substantial commitments to the communities PacifiCorp serves. These include: adding $5 million to the PacifiCorp Foundation; developing educational programs; and providing new funding to develop programs for conservation efforts and to assist low-income customers." [Page 2, lines 11-21]

The principal costs associated with the merger are provided by the Applicants in response to Oregon Staff's DR SP 34. I have included the response in CCS Exhibit 1.4 (DEG). The five major areas where the Applicants identify merger-related benefits and costs are illustrated in the matrix on the next page. A brief description of the Committee's assessment of merger-related benefits and costs is provided in the matrix.

Benefit Area	$ (Millions) Benefit	$ (Millions) Cost	Benefit-Cost Result
Non-Generation: Testimony lacks specificity on areas.	"External Benchmarking" places benefits at $140 M annually. Not a figure that SP is committed to.	N/A	Net Benefit: Not quantified or assured. Not demonstrated to be incremental to PC cost reduction on stand-alone basis.
Financial: Cost-of capital, taxes, etc.	No Cost-Benefit Study. SP testimony asserts lower capital costs for PC predicated on size.	Increased financial risk associated with multi-utility diversification.	Net Risk: Risks of multi-utility strategy exceed unquantified impact on PC cost-of-capital.
Corporate Overhead	$10 M ($15 benefit -$5 cost) within 3 years after closing.	$5 million cost included in the "netting."	Net Benefit: $10 M "guarantee." However, PC already reducing work force levels via "new western strategy."
Reliability and Customer Service	No cost-effectiveness study. $60 M Benefit extrapolating 1990 BPA Study to PC.	$55.5 M Total. $32 M capitalized. $23.5 M expensed.	Benefit: Not determined. Cost: $55.5 M Not shown to be incremental to PC improvements on a stand-alone basis
Renewable Resources (50 MW)	No RAMPP studies provided to support this commitment.	$60 million	Benefit: Not determined Cost: $60 M
Cost-Benefit Summary	$10 M	$115.5 M	$115.5 M Costs exceeds $10 M Benefits

B. The Committee's Response

Summary

Q: **WHAT OVERALL CONCLUSION DID THE COMMITTEE ARRIVE AT AFTER EXAMINING THE APPLICANTS' CASE?**

A: In terms of evaluating the Applicants' case, the absence of detailed and reliable cost-benefit studies has been problematic. The Applicants have yet to submit cost-benefit studies in key operational areas. In response to CCS DR S3.12, ScottishPower candidly admits that without "unfettered" access to PacifiCorp's books and records, "It is...not possible to quantify the impact of merger-related changes on PacifiCorp." ScottishPower's U.K. track record is an additional source of information, but this information has only limited relevance to the merger review at hand.

Based on our examination of the Applicants' case, the Committee concludes that the costs and risks of the merger outweigh the asserted benefits. As the table above shows, merger-related costs are at least $115.5 million and merger-related benefits are $10 million. While shareholder benefits are large ($750 million-plus), immediate and known, ratepayer benefits appear to be small ($10 million), distant and unverifiable.

Finally, we conclude that PacifiCorp, as a stand-alone company, has already implemented, or could develop and implement, programs to achieve benefits in the majority of "merger benefit" areas identified by the Applicants.

Non-Generation Cost Savings

Q: **PLEASE DESCRIBE THE BENEFITS DEPICTED BY SCOTTISHPOWER IN THE NON-GENERATION AREA.**

A: Based on an unsophisticated "external benchmarking" exercise comparing PacifiCorp's non-generation operating costs to other electric utilities, ScottishPower posits that annual cost savings in this area may be upwards of $140 million. As evidence that such efficiency gains are feasible, ScottishPower alludes to its management's capabilities in transforming underperforming companies and points to substantial cost reductions achieved at ScottishPower, Manweb and Southern Water. The "Manweb Experience" is particularly emphasized in Mr. Richardson's Utah Supplemental Testimony [Richardson, pages 9-17]. In a nutshell, ScottishPower plans to apply the Manweb "formula" to PacifiCorp and, over a five-year period, improve PacifiCorp's ranking in the area of non-generation operating costs to a position within the top ten of U.S. electric utilities. [MacRitchie Direct Testimony, pages 4 and 13.]

Q: **WHAT IS THE COMMITTEE'S ASSESSMENT OF ANY CLAIMS OF MERGER BENEFITS IN THE AREA OF NON-GENERATION OPERATIONAL COSTS?**

A: Any benefit claims in this area are unsubstantiated and, therefore, unverifiable. The Commission should give little or no weight to benefits in this area. This assessment is supported by Mr. Biewald's testimony.

Q: **PLEASE BRIEFLY DESCRIBE THE CHIEF CONCLUSIONS REACHED BY MR. BIEWALD IN HIS TESTIMONY.**

A: Mr. Biewald found the benchmarking exercise performed by ScottishPower to be unreliable for estimating merger benefits in the area of non-generation costs. As discussed in Mr. Biewald's testimony, it is riddled with significant problems that limit its value as an analytical tool.

He also concluded that the Manweb track record is unexceptional and that ScottishPower's own track record is below average. In comparing residential bill information among U.K. electric utilities over a five-year period, he found that Manweb's residential bills had declined by approximately 22%, which is in step with the industry average of 22%.[17] However, ScottishPower's residential bills had only decreased by 18% over the same period.

Q: **DO YOU HAVE ANY FURTHER COMMENTS IN THIS AREA?**

A: Yes, I would like to embellish a point made in Mr. Biewald's testimony that the Manweb experience may have only limited applicability to PacifiCorp. Specifically, Manweb was owned and operated by the British Government until privatization in 1991. There were likely greater opportunities to reduce costs at Manweb versus a utility such as PacifiCorp that had already implemented cost reduction programs shortly after the Pacific-Utah merger was consummated. Past cost reductions in the non-generation operational area underlie, in part, rate decreases in Utah totaling over 20% since the Pacific-Utah merger. Finally, as I discussed earlier in my testimony, PacifiCorp has unrolled a new western strategy that targets annual cost savings in excess of $75 million (pre-tax). It appears that a large slice of those cost savings are in the area of non-generation operations.

Corporate Overhead

Q: **PLEASE DESCRIBE THE MERGER BENEFIT IDENTIFIED BY SCOTTISHPOWER IN THE AREA OF CORPORATE OVERHEAD COSTS.**

A: ScottishPower commits to reduce corporate overhead costs by $10 million by the end of the third year after the merger. [Richardson Utah Supplemental Testimony, pg. 2] ScottishPower also indicates that it will include the $10 million decrease in reported operational results at that time.

Q: **WHAT IS THE COMMITTEE'S ASSESSMENT OF MERGER BENEFIT ESTIMATES PERTAINING TO CORPORATE OVERHEAD?**

A: ScottishPower has provided no studies supporting the $10 million commitment.

---

[17] Because company-specific cost information is unavailable, residential bill information was used as a surrogate for cost reductions.

As discussed in Mr. Biewald's testimony [pages 7-8], it is also a commitment that will not have an immediate impact on rates.

Q: **DOES THE COMMITTEE HAVE ADDITIONAL CONCERNS REGARDING COST REDUCTIONS RELATING TO CORPORATE OVERHEAD?**

A: Yes, and they are enumerated below.

- First, we are mystified that it will take ScottishPower three years to effect cost reductions in the area of corporate overhead. A more reasonable commitment in this area would be to reduce rates by $10 million within one year.
- Second, PacifiCorp has jettisoned a large portion of their non-core assets and operations, and simultaneously implemented programs to reduce work force levels. Common sense suggests that PacifiCorp is already trimming corporate overhead costs. Hence, the $10 million commitment should be over and above the manpower reductions in the corporate area attendant to PacifiCorp's new western strategy.[18]
- Third, with regard to corporate management services, it is unclear at what level within the post-merger corporate structure those services would be performed and at what cost.
- Fourth, ScottishPower has yet to propose a method for allocating corporate costs.

Q: **WHEN DOES SCOTTISHPOWER PLAN TO DEVELOP A METHOD FOR ALLOCATING CORPORATE COSTS?**

A: ScottishPower initially proposed to develop a method for allocating corporate costs ("method") within three months after the merger closes. Oregon and Wyoming Staffs found that proposal to be unacceptable and ScottishPower is

[18] If the merger is approved, the "post-merger" cost savings in this area will have to be carefully documented to avoid double-counting.

now committed to develop a method for consideration by June 18th, 1999. [Richardson, Oregon Rebuttal, pg. 14] Obtaining consensus among the states (and possibly OFFER) on any method will be a key issue for ScottishPower as it moves forward.

Financial Issues

Q: **WHAT ISSUES ARE ADDRESSED BY COMMITTEE WITNESS TALBOT IN HIS TESTIMONY?**

A: Mr. Talbot's testimony addresses primarily financial issues, including the potential effect of the merger on PacifiCorp's cost-of-capital, issues relating to taxes and currency exchange, corporate structure, affiliate costs, loss of local control and ScottishPower's earnings in the U.K.

Q: **PLEASE DESCRIBE THE MAIN FINANCIAL BENEFIT IDENTIFIED BY SCOTTISHPOWER STEMMING FROM THE PROPOSED MERGER.**

A: ScottishPower asserts that by folding PacifiCorp into the financially stronger ScottishPower Group, PacifiCorp will have access to cheaper sources of capital. [Richardson, Utah Supplemental, pg. 2, lines 22-26 and pg. 3, lines, 1-3]. Despite that claim, ScottishPower has produced no studies attempting to quantify the impact of the proposed merger on PacifiCorp's cost-of-capital.

Q: **WHAT IS MR. TALBOT'S ASSESSMENT OF THIS PURPORTED BENEFIT?**

A: Mr. Talbot notes that PacifiCorp is already one of the largest U.S. electric utilities and that the "size factor" is irrelevant. According to Mr. Talbot, what is relevant is the "financial risk factor" and he concludes that the merger poses increased financial risks and uncertainties that may negatively impact PacifiCorp's cost-of-capital.

Specifically, in 1998, PacifiCorp management launched a relatively conservative, "back-to-basics" business plan that distances the Company from the inherent risks attendant to a multi-utility strategy on a global level. The proposed merger would make PacifiCorp a subsidiary within the greater ScottishPower Group–a "hyper-utility" that continues to demonstrate a penchant for fueling financial growth through acquiring underperforming companies, engineering the financial balance sheet, "sweating the asset base" and moving in the direction of unregulated activities. On this point, Mr. Talbot concludes that: "...continued expansion by the ScottishPower Group could bring increased debt or financial distress to the parent company, could distract management, and could affect such features of PacifiCorp management as dividend policy and the availability of capital for PacifiCorp's core operations."[19]

Q: **WHAT ARE MR. TALBOT'S VIEWS ON PACIFICORP'S BUSINESS RISK AND FINANCIAL RISK AS A STAND-ALONE COMPANY?**

A: Based on his analysis, he believes that (stand-alone) PacifiCorp's business risk is low and financial position is sound.

Q: **ARE THERE POSSIBLE FINANCIAL IMPLICATIONS FOR PACIFICORP RESULTING FROM SCOTTISHPOWER'S CAPITAL STRUCTURE?**

A: Yes, and Mr. Talbot addresses those potential impacts at length in his testimony. In particular, he postulates that a "double-leveraged" capital structure may serve to "siphon off a financial subsidy from PacifiCorp to the parent company" in the form of a tax shield. For illustrative purposes, Mr. Talbot constructs a scenario showing a potential tax benefit that could be used to reduce PacifiCorp's overall revenue requirement by about $109 million.

Q: **IN ITS TESTIMONY, HAS SCOTTISHPOWER IDENTIFIED THE POTENTIAL TAX GAINS FROM A DOUBLE-LEVERAGED CAPITAL STRUCTURE AS A POTENTIAL MERGER BENEFIT?**

---

[19]Talbot, Direct Testimony, pg. 6.

A: No. A confidential response to a Committee data request indicates that ScottishPower is not blind to the potential for merger-related tax gains. There also may be additional benefits and risks associated with "engineering the financial balance sheet" that have yet to be identified by the Company or discovered by regulators.

Q: **DID MR. TALBOT COMPARE SCOTTISHPOWER'S AND MANWEB'S EARNINGS RECORD TO COMPARABLE PUBLIC ELECTRICITY SUPPLIERS (PECs) IN THE U.K.?**

A: Yes. ScottishPower's earnings have been slightly higher than the average of comparable companies whereas Manweb's earnings have historically trailed behind the average. The high earnings levels (as compared to U.S. standards) imply that efficiency gains have disproportionately benefitted investors over ratepayers in the U.K.

Network Reliability and Customer Service

Q: **PLEASE PROVIDE AN OVERVIEW OF SCOTTISHPOWER'S PLANNED IMPROVEMENTS IN THE AREAS OF NETWORK RELIABILITY AND CUSTOMER SERVICE.**

A: As perhaps the most tantalizing feature of its merger proposal, ScottishPower plans to implement various new standards and measures designed to improve network reliability and customer service. Mr. Richardson's Exhibit SP (AVR-1), pgs. 1-5, identifies the major elements comprising this "package." ScottishPower also alleges that its network reliability and customer service package is "best-in-class" among U.S. electric companies and retained a consultant to confirm that opinion.

Q: **WHAT ARE THE COSTS ASSOCIATED WITH THE ABOVE INVESTMENT IN NEW SYSTEMS AND PROTOCOLS RELATING TO NETWORK RELIABILITY AND CUSTOMER SERVICE?**

A: As Exhibit CCS 1.2 (DEG) indicates, ScottishPower has penciled the capital and operating costs at roughly $55 million over a five-year period.

Q: **IS SCOTTISHPOWER WILLING TO ASSUME RESPONSIBILITY FOR THE $55 MILLION COST OR IS THIS A COST THAT WILL BE EVENTUALLY BORNE BY RATEPAYERS?**

A: ScottishPower initially inferred that these costs would be passed on to ratepayers as an "incremental" cost. In his Utah Supplemental Testimony, Mr. Richardson strives to clarify the Company's proposed "cost treatment" with the following:

> The $55 million...is not an incremental cost, but will be achieved through efficiencies within the existing spending plans of PacifiCorp. Overall costs will therefore not increase as a result of these expenditures, as they will be offset by efficiencies we will achieve in PacifiCorp's operations." [Richardson, Utah Supplemental Testimony, page 2, bullet 3]

Since ScottishPower has been unable to quantify merger-related cost savings in other areas, the $55 million must be viewed as a ratepayer cost.

Q: **HAS SCOTTISHPOWER MADE ANY ATTEMPT TO QUANTIFY BENEFITS ASSOCIATED WITH EXPENDITURES IN THE AREA OF NETWORK RELIABILITY AND/OR CUSTOMER SERVICE?**

A: Relying on a1990 study prepared by BPA-EPRI for utility customers in the Pacific Northwest, ScottishPower extrapolated the results to PacifiCorp and submits that improvements to SAIDI and MAIFI engender customer benefits of about $60 million annually.

Q: **DID SCOTTISHPOWER PROVIDE A PACIFICORP-SPECIFIC STUDY DEMONSTRATING THAT THE $55 MILLION EXPENDITURE WAS COST-EFFECTIVE?**

A: No. To my knowledge no such study was performed. Prior to undertaking such a study, ScottishPower would need reliable data upon which to establish PacifiCorp's historical baseline. And apparently there is a problem with

PacifiCorp's data-collection system that prevents ScottishPower from accurately setting a baseline.[20]

Q: **DOES THAT GIVE YOU PAUSE FOR CONCERN?**

A: Yes, I am deeply concerned about the prospect of Utah's residential and small business customers funding improvements in network reliability and customer service that may not pass cost-effectiveness tests. Even OFFER questions the cost-effectiveness of ScottishPower's and Manweb's projected expenditures on improving network reliability.[21]

Q: **WHAT CONCLUSIONS DID COMMITTEE WITNESS CHERNICK REACH AFTER ANALYZING SCOTTISHPOWER'S PROPOSAL TO IMPROVE NETWORK RELIABILITY AND CUSTOMER SERVICE?**

A: Mr. Chernick generally concluded:

- PacifiCorp's performance in most areas is satisfactory;
- PacifiCorp should be able to obtain the requisite skills to improve network reliability and customer service independent of the merger;
- ScottishPower's proposed improvements are somewhat nebulous and generally minor;
- ScottishPower has promised percentage improvements in performance, without establishing either the baseline performance level from which improvements will be measured, or the target level to be achieved;
- ScottishPower's U.K. record in these areas has been good, but not exceptional; and
- Network reliability and customer service issues could be examined more fully in the context of PacifiCorp's next general rate case or a separate

[20]See ScottishPower's response to CCS S11.2.

[21]OFFER Consultation Report, May 1999, pages 76-77.

proceeding. (On pages 44 and 45 of his testimony, Mr. Chernick lists a myriad of issues that could be explored in such a proceeding.)

Q: **WHAT IS THE COMMITTEE'S POSITION ON SCOTTISHPOWER'S PLAN TO SPEND $55 MILLION TO IMPROVE NETWORK RELIABILITY AND CUSTOMER SERVICE?**

A: ScottishPower has not adequately demonstrated that the $55 million outlay is cost-effective for Utah's residential and small business customers. Moreover, PacifiCorp could make improvements in these areas (if shown to be cost-effective) independent of the proposed merger. The Utah Commission may want to consider broadening the scope of PacifiCorp's next general rate case to include issues pertaining to network reliability and customer service.

Renewable Resources

Q: **PLEASE DISCUSS THE BENEFITS AND COSTS ASSOCIATED WITH THIS MERGER COMMITMENT.**

A: As one of its environmental commitments, ScottishPower has pledged to develop an additional 50 MWs of renewable resources (wind, solar and/or geothermal) at an expected cost to PacifiCorp ratepayers of $60 million. [Richardson Utah Supplemental Testimony, Ex. SP (AVR-1), p.7]. These renewable resources will be developed within five years following the merger.

Q: **WHAT IS THE COMMITTEE'S POSITION ON THIS PURPORTED MERGER BENEFIT?**

A: Whether or not 50 MW of renewable resources --at a $60 million pricetag-- should be developed is an issue for consideration in PacifiCorp's RAMPP integrated resource planning process. The Committee firmly believes that RAMPP is the proper forum to examine competing resource options–not this merger.[22] If rigorous economic analysis establishes that 50 MW of renewables are the most cost-effective resource options, then these generation technologies should be pursued. Moreover, there is no reason why PacifiCorp as a stand-alone company could not invest in renewables that are shown to be cost-effective. The Utah Commission should, therefore, dismiss any claimed merger benefit in the renewables area.

Green ResourceTariff and Low Income Initiatives

Q: **MR. RICHARDSON'S EXHIBIT SP (AVR-1) INDICATES THAT SCOTTISHPOWER COMMITS TO FILE A GREEN RESOURCE TARIFF WITHIN 60 DAYS AFTER THE MERGER IN EACH STATE AND COMMIT $1.5 MILLION TO ASSIST LOW-INCOME CUSTOMERS IN VARIOUS AREAS (HEAT ASSISTANCE PROGRAMS, DEBT COUNSELING, AND ENERGY EFFICIENCY EDUCATION). WHAT IS THE COMMITTEE'S REACTION TO THESE COMMITMENTS?**

A: The Utah Commission has established a task force to study a spate of environmental issues, including whether a green resource tariff makes sense for Utah. It is premature, therefore, for ScottishPower to commit to file a green resource tariff in Utah until the task force report is submitted to the Commission. In any event, PacifiCorp could develop and file a green resource tariff independent of the proposed merger.

ScottishPower's pledge of $1.5 million to assist low-income customers is a noble gesture. However, the Utah Commission has already established a task force to

[22]ScottishPower's response to the Utah DPU's DR 8.2 implies that ScottishPower no longer views its pledge to develop renewables as a "merger benefit" per se. The response states: "ScottishPower's commitment to develop an additional 50 MW of new renewable resources is conditioned on resources meeting cost-effectiveness standards derived from PacifiCorp's integrated resource planning process."

study a number of low-income issues. The Committee has allocated "professional and technical" funds to retain a consultant whose mission will likely be to: report on the "pros and cons" of low-income programs in other states; guide the task force's study efforts; and aid in the development of a viable low-income program for Utah. With a total retail revenue level eclipsing $2 billion, PacifiCorp could easily double its present systemwide commitment of $1.5 million to low-income programs, independent of the proposed merger.

Regulatory Costs

Q: **WILL THE PROPOSED MERGER POTENTIALLY INCREASE COSTS ASSOCIATED WITH EFFECTIVELY REGULATING PACIFICORP?**

A: Yes, I think regulatory costs will possibly increase as a result of the proposed merger.

Q: **PLEASE EXPLAIN WHY YOU BELIEVE REGULATORY COSTS MAY INCREASE.**

A: Utilities are generally in a position to attempt to control, and possibly manipulate, the quantity, quality and timing of information provided to regulatory agencies.[23] As the Utah Commission is keenly aware, adequate information is a cornerstone of effective regulation. Under the proposed corporate structure, PacifiCorp will become a subsidiary within the greater ScottishPower Group. Ready access to ScottishPower's books, records, strategic business plans, etc., is certainly a very real concern and there are early signs that obtaining information may prove to be difficult.

---

[23] The Utah Commission has explicitly noted this concern in prior Orders addressing test year issues. In its May 24th, 1993 Order in Docket No. 92-049-05, the Commission stated: "...the Company has unequaled access to the financial and accounting information describing its operations. It could, therefore, propose adjustments strategically."

Q: **WHAT EVIDENCE CAN YOU POINT TO THAT INDICATES ACCESS TO INFORMATION MAY BE DIFFICULT OR EVEN BLOCKED?**

A: First, in response to DPU DR S.11.6, ScottishPower indicates it is willing to furnish its own records "to the extent that those records relate to transactions with PacifiCorp or affect the results of PacifiCorp." The Committee believes that the response exemplifies an initial attempt by ScottishPower to control the flow of information to U.S. state regulators. To the contrary, we think it is crucial that Utah regulators have easy access to <u>all information</u> at the ScottishPower Corporate Group level. For instance, ScottishPower's strategic business plan will likely include elements that directly, and indirectly, impact PacifiCorp.[24]

Second, in their respective responses to CCS DR 3.15, PacifiCorp furnished a detailed budget report by operational area whereas ScottishPower provided its annual reports to shareholders which has highly aggregated budget information. We re-submitted the request to ScottishPower in CCS DR 10.7 and asked them to put the budget information in the same format used by PacifiCorp. ScottishPower's response to CCS DR 10.7 is as follows:

> "ScottishPower objects to this data request as unduly burdensome to the extent it requires ScottishPower to create documents that compile information in a particular format...ScottishPower does not compile the data in the same manner as PacifiCorp and thus the information in the requested format is not available."

Does this response reflect a harbinger of what U.S. regulators can expect from ScottishPower or does it simply reflect cultural differences that need to be overcome?

---

[24]Particularly as ScottishPower moves into unregulated activities to "grow the firm;" activities that pose potentially higher risks for PacifiCorp ratepayers. (See Section 5 of Committee witness Talbot's testimony for a deeper discussion.)

Third, the Committee was unsuccessful in its attempt to acquire information from OFFER on ScottishPower's cost estimate to comply with OFFER's new "ring-fencing" requirement. In response to CCS DR 14.1, ScottishPower projects the transition costs to be roughly 23.1 million pounds. But we were unable to confirm that estimate with OFFER because such information is deemed to be confidential. If the merger is approved, U.K. and U.S. regulators will have to work together to ensure that confidential information is reasonably accessible.

Q: **HAS THE COMMITTEE ESTABLISHED A WORKING RELATIONSHIP WITH OFFER AND, IF SO, HOW WOULD YOU DESCRIBE THAT RELATIONSHIP?**

A: I am happy to report that the Committee has established a very cooperative and productive working relationship with OFFER. Kelly Francone of Committee Staff has established links to exchange information with OFFER representatives. We have found representatives of OFFER to be highly professional and competent. With the exception of commercially-sensitive documents, OFFER has provided a considerable amount of information on the ScottishPower Group and developments in the U.K. energy market.

VII. Rate Plan

Q: **EARLIER IN YOUR TESTIMONY YOU RECOMMENDED THAT THE UTAH COMMISSION SHOULD DENY THE PROPOSED MERGER BETWEEN SCOTTISHPOWER AND PACIFICORP. WHAT STEPS COULD THE APPLICANTS TAKE TO REMEDY THE DEFICIENCIES IN THEIR CASE?**

A: There are at least two courses of action available to the Applicants. PacifiCorp could allow complete access to their books so that the Applicants could prepare and file meaningful cost-benefit analysis supporting the proposed merger. This would likely delay the schedule by months. Alternatively, the Applicants could develop and file a constructive rate plan.

Q: **WHAT PRINCIPAL FEATURE SHOULD BE INCLUDED IN A RATE PLAN FOR UTAH?**

A: A credible rate plan should ensure either rate reductions or cap current rates in Utah over a specified period of time.

Q: **HAS A SIMILAR RATE PLAN BEEN FILED IN OTHER STATES?**

A: No. In his Utah supplemental direct testimony, Mr. Richardson merely offers vague and unsubstantiated assurances that the merger "will lead to rates lower than they would have been without the transaction."[25] In his June 2nd Oregon Rebuttal testimony, Mr. Richardson only "commit[s] to file a general rate case in Oregon, with rates to be effective no later than July 1, 2001 [that] will reflect cost savings achieved as a result of the merger...including at a minimum the guaranteed amount of corporate cost savings."[26] Once again, what is conspicuously absent in Mr. Richardson's testimony is a firm commitment, on the part of ScottishPower, to reduce or cap current rates for a time certain.

Q: **DO YOU HAVE ANY FINAL REMARKS?**

A: Yes I do. A stark asymmetry presently exists between what ScottishPower is offering PacifiCorp's shareholders (a premium in excess of $750 million) and executive management (prospective "golden handshakes" totaling $7 million for PacifiCorp's top executives)[27], and what ScottishPower is offering PacifiCorp's ratepayers ($10 million in corporate overhead and "soft promises" in other areas). The lack of a credible rate plan shifts the lion's share of merger-related risks to

---

[25]Richardson, Utah Supplemental Direct Testimony, page 2.

[26]Richardson, Oregon Rebuttal Testimony, page 4..

[27]The shareholder proxy statement indicates that 26 PacifiCorp executives have severance packages. According to a May 11th, 1999 article in The Independent, PacifiCorp's top executives will receive severance payments worth $7 million, in addition to their stock options, if they are terminated within two years. The Committee has submitted a discovery request to PacifiCorp to ascertain the exact amount of severance payments to these 26 PacifiCorp executives.

ratepayers while channeling benefits to shareholders and management. The Committee concludes that such risk-shifting is unacceptable. Specifically, management should have a stake in merger-related outcomes and there should be an appropriate sharing of the benefits and the risks. In its Utah Rebuttal Testimony, the Committee invites ScottishPower to develop and file a constructive rate plan for Utah. Such a rate plan should provide for rate reductions or rate caps over a specified time period.

Q: **DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes it does.

Qualifications

June 1999

Name: Daniel Edmund Gimble

Work Address: 160 E. 300 S. Heber Wells Bldg., Room 408
Salt Lake City, Utah

Work Telephone: (801) 530-6798

Education: Ph.D. Program in Economics, 1981 - 1984; University of Utah, Salt Lake City, Utah.

<u>Fields of Specialization</u>
--Economics of Industrial Organization;
--Labor Economics;

M.A. Degree in Economics, 1980; Western Michigan University, Kalamazoo, Michigan.

<u>Areas of Specialization</u>
–Economic Development;
–Institutional Economics

B.S. Degree in Economics and History, 1978 (cum laude); Western Michigan University, Kalamazoo, Michigan.

Professional Experience: <u>Energy Group Manager</u>, Utah Committee of Consumer Services, Heber Wells Bldg. 160 E. 300 S., SLC, Utah: March 1998-Present.

<u>Utility Economist</u>, Utah Committee of Consumer Services, Heber Wells Bldg. 160 E. 300 S., SLC, Utah: October 1990 - February 1998.

<u>Utility Analyst</u>, Utah Public Service Commission, Heber Wells Bldg. 160 E. 300 S., SLC, Utah: January 1987 - September 1990.

Intern Economist, Utah Public Service Commission, Heber Wells Bldg. 160 E. 300 S., SLC, Utah: July 1985 - December 1986.

Instructor, Department of Economics, University of Utah: Academic years 1983 - 1986.

Course Responsibilities
--Economics as a Social Science
--Principles of Microeconomics
--Principles of Macroeconomics
--Intermediate Microeconomics

Co-editor of the **Economic Forum**, Graduate School of Economics University of Utah: January 1983 - August 1983.

Expert Witness Testimony In Regulatory Proceedings:

(1) In The Matter Of The Investigation Into The Reasonableness Of Allocations And Rates And Charges For Utah Power & Light Company, Docket No. 90-035-06.

(2) In The Matter Of The Application Of Mountain Fuel Supply Company For An Increase In Rates And Charges , Docket No. 93-057-01.

(3) In The Matter Of The Application Of Mountain Fuel Supply Company For An Increase In Rates And Charges, Docket No. 95-057-02.

(4) In The Matter Of The Application Of PacifiCorp To Establish Avoided Cost Prices For The 50 MW ACME Qualifying Facility Project, Docket No. 95-2035-05.

(5) In The Matter Of The Application Of Mountain Fuel Supply Company to Adjust Rates For Natural Gas Service in Utah, Docket Nos. 97-057-11, 96-057-12, 95-057-30.

(6) In The Matter Of the Investigation Into The Reasonableness of the Rates and Charges of PacifiCorp, dba Utah Power & Light Company, Docket No. 97-035-01.

Regulatory Seminars: During my tenure with the Utah Commission and the CCS, I have attended various national, regional and local regulatory seminars on ratemaking, integrated resource planning, electric and gas restructuring, energy efficiency, marginal cost pricing, etc.

Publications: "Institutionalist Labor Market Theory and the Veblenian Dichotomy." The paper was presented at the Western Social Science Association's Annual Conference, April 1990. The paper was published as the lead article in the **Journal of Economic Issues**, September 1991.

"The PURPA Paradox." The paper was presented at Solar '89: **The Proceedings of the 1989 Annual Conference on Solar Energy**, American Solar Energy Society (ASES). The paper was published as part of conference proceedings, Editor: M.J. Coleman, Denver, Colorado.

Committee of Consumer Services

Witness: Dan Gimble

Docket No. 98-2035-04

CCS Exhibit 1.1 (DEG)

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

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., Authorizing the Issuance of Securities, Adoption of Tariffs and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith.)	CASE NO. 87-035-27 ORDER RE STANDARD OF APPROVAL FOR MERGER

ISSUED: November 20, 1987

SYNOPSIS

By this Order the Commission establishes the "positive benefits" test as the standard for adjudging the merits of the proposed merger and assigns the burden for showing positive benefits or negative impacts.

BY THE COMMISSION:

Pursuant to motion filed by Applicants, the parties in the above-entitled matter appeared before the Commission on Tuesday, November 10, 1987, to argue the issue of the appropriate standard by which the proposed merger of Utah Power & Light Company and PacifiCorp should be adjudged by this Commission. The simplest statement of the issue is whether the Applicants must show only the absence of adverse impacts from the proposed merger ("no harm" standard) or whether they must demonstrate that on balance the merger as proposed will result in benefits not otherwise enjoyed ("positive benefits" standard).

Here, as in Re CP National Corp., 43 PUR 4th 315 (Utah PSC 1981) Case No. 80-023-01, we are of the view that the necessary predicate for a determination that the proposed merger is "in the public interest" is some net positive benefit to the public in this State. Applicants seek strict adherence to the Utah decision, Collett v. Public Service Commission, 116 Utah 413, 211 P.2d 185 (1949) which they cite in favor of the "no harm" standard. We rejected this argument in CP National as we do now. Such a standard is too narrow for use in a fixed-utility situation such as that before us. Also, we believe Applicants acknowledged this fact in their oral arguments and application wherein they have voluntarily offered to accept the burden of showing a positive benefit.

We do not think it reasonable to assume that the result of the merger will be entirely positive or entirely negative. In all likelihood there will be some positive benefits and some negative impacts. Our task is to consider them all, giving each its proper weight, and determine whether on balance the merger is beneficial or detrimental to the public.

With respect to considerations outside our normal regulatory jurisdiction and enforcement powers, for example the health of the coal mining industry, antitrust effects, et cetera, which nonetheless bear on the public interest, Applicants bear no affirmative burden to demonstrate benefits or even an absence of harm. In those areas other parties will carry the burden of demonstrating either some benefit or some substantial harm by reason of the merger.

However, Applicants do carry the burden in all areas subject to our jurisdiction to show that on balance the merger will be beneficial and those areas will be our primary focus in the case.

We anticipate publishing shortly an order setting forth in more detail the sub-issues that we would expect to be addressed in this case.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, That the "positive benefits" standard is hereby established for approval of the Applicants merger proposal in this case as above discussed.

DATED in Salt Lake City, Utah this 20th day of November, 1987.

/s/ Brian T. Stewart, Chairman

(SEAL) /s/ Brent H. Cameron, Commissioner

/s/ James M. Byrne, Commissioner

Attest:

/s/ Stephen C. Hewlett, Commission Secretary

Committee of Consumer Services

Witness: Dan Gimble

Docket No. 98-2035-04

CCS Exhibit 1.2 (DEG)

20000-EA-98-141/PacifiCorp
April 29, 1999
CAS Data Request PC 159

CAS Data Request PC 159:

Please list and summarize in brief detail all significant programs, procedures, or other efforts that have been incorporated or otherwise "rolled out" by PacifiCorp on a permanent or trial basis to improve maintenance practices, customer service practices, and facility investment practices for transmission, distribution, and customer service facilities (Descriptions may be limited to those efforts that were implemented on or considered for a system-wide application). Please describe the objectives of each effort, the results of each effort, and the costs to implement (actual or estimated as applicable). Information provided shall be for efforts undertaken within the past 7 years. (EB)

Response to CAS Data Request PC 159:

Principal programs are as follows:

Description	**Objective**	**Results**	**Implementation Costs**
Customer Service Information System (CSS)	Develop and implement a system wide, Y2K compliant customer information system to replace legacy systems	System was developed and deployed commencing in 1996.	$72.7 million
Establish business centers in Portland and Salt Lake	Improved customer service through extended hours of operation, economies of scale, and reduced costs	Centers were established and staffed in 1996 and 1997. Local customer counters closed throughout 1996 and 1997. Customers can now call PacifiCorp on outages or business matters 24 hours/day	$22.2 million

20000-EA-98-141/PacifiCorp
April 29, 1999
CAS Data Request PC 159

Description	Objective	Results	Implementation Costs
Distribution Management System (DMS)	Respond to customer outage incidents by processing "trouble tickets" that are initiated by customers through Business Centers and electronically forwarded to appropriate dispatchers located throughout the service territory.	System was developed and deployed at staged intervals during 1997. Numerous enhancements were made during 1998. The system has not implemented any significant functional changes for several months. Processes approximately 300,000 "trouble tickets" per year.	$2.5 million
Operations Visualization System (OVS)	Give operating managers and Business Centers employee's information access to outage restoration events by combining maps, circuitry and customer "trouble ticket" data in a web-reporting tool.	System was developed and deployed the beginning of 1998. Added functionality was incorporated in a later release towards the end of 1998. Another release is slated for mid-1999. Approximately 300 users access the system at various times during outage events and normal day-to-day activities.	$350,000
Facilities Management	Increase the life of electric facilities, improve system reliability, and meet National Electric Safety Code.	The program includes several major components: pole test & treat, safety inspection, detail facility inspection, tree trimming,	$19.4 million per year over the last 5 years.

Committee of Consumer Services

Witness: Dan Gimble

Docket No. 98-2035-04

CCS Exhibit 1.3 (DEG)

BENEFITS TO CUSTOMERS FROM THE TRANSACTION

I. CUSTOMER SERVICE

A. Network Performance

1. System Availability. On the five-year anniversary of the completion of the transaction,[1] the underlying System Average Interruption Duration Index (SAIDI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

2. System Reliability. On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Frequency Index (SAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

3. Momentary Interruptions. On the five-year anniversary of the completion of the transaction, the Momentary Average Interruption Frequency Index (MAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 5%.

4. Worst Performing Circuits. The 5 worst performing circuits in the State of Utah will be selected annually on the basis of the Circuit Performance Indicator (CPI),[2] as calculated over a three-year average excluding extreme events. Corrective measures will be taken within 2 years of implementation of the performance targets to reduce the CPI by 20%.

5. Supply Restoration. For power outages because of a fault or damage on PacifiCorp's system, PacifiCorp will restore supplies on average to 80% of customers within 3 hours.

6. Penalties. For each of the standards not achieved in the State of Utah at the end of the five-year period, ScottishPower will pay a financial penalty equal to $1.00 for every customer served by PacifiCorp in Utah.

---

[1] Reference to "completion of the transaction" throughout this document means the closing of the transaction pursuant to the Amended Merger Agreement.

[2] The CPI is a weighted, composite index based on the following four factors: (1) MAIFI, (2) SAIDI, (3) SAIFI, and (4) number of lockouts.

7. Implementation. Specific terms and conditions relating to the implementation of the Network Performance Standards are set forth in Appendix A.[3]

B. Customer Service Performance

1. Telephone Service Levels. Within 120 days after completion of the transaction, 80% of calls to PacifiCorp's Business Centers will be answered within 30 seconds. This target will be increased to 80% in 20 seconds by January 1, 2001 and 80% in 10 seconds by January 1, 2002.

2. Complaint Resolution.

a. Non-Disconnect Complaints. Within 90 days after completion of the transaction, PacifiCorp will investigate and provide a response to all complaints referred by the Commission within 3 business days.[4]

b. Disconnect Complaints. Within 90 days after completion of the transaction, complaints related to service disconnection will be responded to within 4 business hours.[5]

c. Commission Complaints. Within 90 days after completion of the transaction, ninety percent of complaints referred to PacifiCorp by the Commission will be resolved within 30 days. This percentage will be increased to 95 percent by 2001.

3. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Performance Standards are set forth in Appendix A.

---

[3] Initial benchmarks for SAIDI, SAIFI and MAIFI will be established based upon PacifiCorp's historical performance, adjusted as necessary where the change in measurement and monitoring accuracy results in a change in the reported (but not actual) reliability indices, as discussed in Mr. Moir's testimony at page 7.

[4] Business days are defined as Monday through Friday excluding company holidays.

[5] Business hours are defined as 8:00 a.m. to 5:00 p.m.

C. Customer Service Guarantees

1. Restoring the Customer's Supply.

a. Guarantee. If the customer loses electricity supply because of a fault in PacifiCorp's system, PacifiCorp will restore the customer's supply as soon as possible.

b. Penalty. If power is not restored in 24 hours, customers can claim $50 for residential customers and $100 for commercial and industrial customers. For each extra period of 12 hours the customer's supply has not been activated, the customer can claim $25.

2. Appointments.

a. Guarantee. PacifiCorp will keep all mutually agreed appointments with the customer, whether over the phone or in writing. Beginning in the year 2001, PacifiCorp will offer the customer a morning appointment, between 8 AM and 1 PM, or an afternoon appointment, between 12 Noon and 5 PM.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50.

3. Switching On the Customer's Power.

a. Guarantee. Upon customer request, PacifiCorp will activate the power supply within 24 hours provided no construction is required and all government requirements are met.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50. In addition, for each extra period of 12 hours the customers power supply has not been activated, PacifiCorp will automatically pay-out $25 to the customer.

4. Estimates for Providing a New Supply.

a. Guarantee. Upon request by a customer for new power supply, PacifiCorp will call the customer back within 2 business days of the customer's initial call and schedule a mutually agreed appointment with an estimator. If PacifiCorp needs to change its network, it will provide a written estimate to the customer within 15 business days of the customer's initial meeting with the estimator. If PacifiCorp does not need to change its network, it will provide an estimate to the customer within 5 business days of the customer's initial meeting with the estimator.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

5. Response to Bill Inquiry.

a. Guarantee. PacifiCorp will investigate and respond within 15 business days of a customer's inquiry about its electric bill.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

6. Problems with the Customer's Meter.

a. Guarantee. PacifiCorp will investigate and report back to the customer within 15 business days if the customer suspects a problem with its meter.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

7. Planned Interruptions.

a. Guarantee. PacifiCorp will give the customer at least 2 days notice if it is necessary to turn the customer's power supply off for planned maintenance work or testing.

b. Penalty. If PacifiCorp fails to meet its guarantee, customers can claim $50 for residential customers and $100 for commercial and industrial customers.

8. Power Quality Complaints.

a. Guarantee. Upon notification from a customer about a problem with the quality of electric supply, PacifiCorp will either initiate an investigation within 7 days or explain the problem in writing within 5 business days.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50.

9. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Guarantees are set forth in Appendix B. Data calculations to measure performance will be audited by the company and an outside auditor.

10. Reporting.

a. To Customers. PacifiCorp will issue a report to the customer by June 30 of each year regarding its record in improving Performance Standards and how well it has performed against its Customer Guarantees. Each report will contain an overview of standards, targets and guarantees and describe the performance results for that year. The report will also discuss any new targets PacifiCorp will be applying in the coming year.

b. To Commission. PacifiCorp will provide an annual report to the Commission by May 31 of each year that will discuss implementation of ScottishPower's programs and procedures for providing improved performance. The report will provide a general summary of how PacifiCorp performed according to the standards, targets and guarantees. The report will: (i) provide performance results for each standard, target or guarantee; (ii) identify excluded exceptions; (iii) explain any historical and anticipated trends and events that affected or will affect the measure in the future; (iv) describe any technological advancements in data collection that will significantly change any performance indicator; (v) discuss any "phase in" of new standards, targets or guarantees; and (vi) include the name and telephone numbers of contacts at PacifiCorp to whom inquiries should be addressed. If the company is not meeting a standard, target or guarantee, the report will: (i) provide an analysis of relevant patterns and trends; (ii) describe the cause or causes of the unacceptable performance; (iii) describe the corrective measures undertaken by the company; (iv) set a target date for completion of the corrective measures; and (v) provide details of any penalty payments due.

II. REGULATORY OVERSIGHT

A. Access to Books and Records

1. PacifiCorp will maintain its own accounting system, separate from ScottishPower's accounting system. All PacifiCorp financial books and records will be kept in Portland, Oregon, and will continue to be available to the Commission upon request at PacifiCorp's offices in Portland, Salt Lake City, Utah, and elsewhere in accordance with current practice.

B. Cost Allocation, Affiliated Interest Transactions

1. By the end of the third year following the completion of the transaction, ScottishPower will have achieved a net reduction of $10 million annually in PacifiCorp's corporate costs ($15 million of annual cost savings in corporate costs which, when offset by $5 million of cost increases, will produce a net reduction of $10 million annually in corporate costs). ScottishPower will commit to reflecting this reduction in PacifiCorp's results of operations filed with the Commission.

2. ScottishPower will provide an analysis of its proposed allocation of corporate costs within ninety days after completion of the transaction.

3. To determine the reasonableness of allocation factors used by ScottishPower to assign costs to PacifiCorp and amounts subject to allocation or direct charges, the Commission or its agents may audit the records of ScottishPower which are the bases for charges to PacifiCorp. ScottishPower will cooperate fully with such Commission audits.

4. ScottishPower and PacifiCorp will provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interest, which pertain to any transactions between PacifiCorp and its affiliated interests.

5. ScottishPower and PacifiCorp agree to comply with all existing Commission statutes and regulations regarding affiliated interest transactions, including timely filing of applications and reports.

6. ScottishPower will not subsidize its activities by allocating to or directly charging PacifiCorp expenses not authorized by the Commission to be so allocated or directly charged.

7. Neither ScottishPower nor PacifiCorp will assert in any future Commission proceeding that the provisions of the Public Utility Holding Company Act of 1935 preempt the Commission's jurisdiction over affiliated interest transactions.

C. Transaction Costs

1. ScottishPower and PacifiCorp will exclude all costs of the transaction from PacifiCorp's utility accounts.

D. Financial Issues

1. ScottishPower intends to achieve an actual capital structure equivalent to that of comparable, A-rated electric utilities in the U.S., with a common equity ratio for PacifiCorp of not less than 47%.

2. PacifiCorp will maintain separate debt and, if outstanding, preferred stock ratings.

3. ScottishPower and PacifiCorp will provide the Commission with unrestricted access to all written information provided to common stock, bond, or bond rating analysts, which directly or indirectly pertains to PacifiCorp.

III. COMMITMENT TO THE ENVIRONMENT

A. Renewable Resources

1. PacifiCorp will develop an additional 50 MW of renewable resources (wind, solar and/or geothermal) at an anticipated cost of approximately $60 million within five years after completion of the transaction.

2. Within 60 days after completion of the transaction, PacifiCorp will file applications in each state for a "green resource" tariff.

3. PacifiCorp will contribute $100,000 to the Bonneville Environmental Foundation for use in the development of new renewable resources and fish mitigation projects.

B. Environmental Management

1. PacifiCorp will have environmental management systems in place that are self-certified to ISO 14001 standards at all PacifiCorp operated thermal generation by the end of 2000.

2. ScottishPower will include PacifiCorp operations in ScottishPower's comprehensive annual environmental report with appropriate specific goals.

3. ScottishPower will include a PacifiCorp officer on the Environmental Policy Advisory Committee.

4. ScottishPower will develop a process to gather outside input on environmental matters, such as the establishment of an Environmental Forum.

IV. COMMITMENT TO COMMUNITIES

A. Financial Contribution

1. ScottishPower will contribute $5 million to the PacifiCorp Foundation upon completion of the transaction.

2. ScottishPower will maintain the existing level of PacifiCorp's other community-related contributions, both in terms of monetary and in-kind contributions.

B. Programs

1. ScottishPower will develop, in consultation with the appropriate Utah state educational authorities and the local business community, a "School to Work" initiative. Skill development opportunities will be made available through the Open Learning Centers, work experience mentoring, and work shadowing.

2. ScottishPower will maintain the existing Regional Advisory Boards.

C. Low-Income Customers

1. ScottishPower will commit $1.5 million per year (in addition to PacifiCorp's existing commitment of $1.5 million annually) to programs that encourage the economic well-being of communities, including the following:

a. ScottishPower will double the number of customers assisted by the heat assistance funding program for those customers who qualify under the Federal Low Income Energy Assistance Program and will reintroduce the matching concept with PacifiCorp matching customer donations to heat assistance programs annually.

b. ScottishPower will establish a debt counseling service for those customers who have difficulty in paying their monthly electric bills.

c. ScottishPower will expand the commitment to educate customers regarding energy efficiency in order to help customers with payment difficulties, and to promote electricity safety for all customers.

V. COMMITMENT TO EMPLOYEES

A. Existing Labor Agreements

1. ScottishPower will honor existing labor contracts with all levels of staff.

B. New Programs

1. ScottishPower will introduce the following programs in the PacifiCorp service territory, upon completion of the transaction, at a start-up cost of approximately $3 million and estimated annual expenditures of approximately $1 million:

a. ScottishPower will develop one "best-in-class" training center in each of Oregon and Utah. These centers will provide employees with opportunities to improve their work-related skills.

b. ScottishPower will phase in the introduction of the ScottishPower Open Learning centers. At these Open Learning centers, employees will be able to supplement their work-related skills with other skills designed to enhance their overall knowledge.

c. ScottishPower will establish partnerships with local colleges and universities to develop management training programs.

C. Occupational Health

1. ScottishPower will examine the appropriateness of introducing for PacifiCorp employees its successful programs already adopted in the U.K. to encourage a healthy lifestyle for employees.

Committee of Consumer Services

Witness: Dan Gimble

Docket No. 98-2035-04

CCS Exhibit 1.4 (DEG)

ScottishPower's Estimate of Cost of Merger Commitments

	Above-the-line			Below-the-line		Total		Ratepayer's Share	
	Capitalized	Expensed		Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed
Customer Guarantees									
Implementation/Set-up	$900,000	$0		$0	$0	$900,000	$0	100.00%	
Operating Costs	$0	$13,200,000		$0	$0	$0	$13,200,000		100.00%
Provision for Customer Payments	$0	$0		$0	$1,000,000	$0	$1,000,000		0.00%
Total-Customer Guarantees	$900,000	$13,200,000		$0	$1,000,000	$900,000	$14,200,000	100.00%	92.96%
Performance Standards									
Additional Network Investment	$27,500,000	$0		$0	$0	$27,500,000	$0	100.00%	
Implementation/Set-up	$3,600,000	$0		$0	$0	$3,600,000	$0	100.00%	
Operating Costs	$0	$10,400,000		$0	$0	$0	$10,400,000		100.00%
Total-Performance Standards	$31,100,000	$10,400,000	$0	$0	$0	$31,100,000	$10,400,000	100.00%	100.00%
Training/Open Learning Initiatives									
Development Cost		$3,000,000		$0	$0	$0	$3,000,000		100.00%
Operating Cost		$3,000,000		$0	$0	$0	$3,000,000		100.00%
Total-Training/Open Learning	$0	$6,000,000		$0	$0	$0	$6,000,000		100.00%
PacifiCorp Foundation Contribution	$0	$0		$0	$5,000,000	$0	$5,000,000		0.00%
Customer Care Initiatives (Source of funding not yet determined)						$0	$7,500,000		0.00%

ScottishPower's Estimate of Cost of Merger Commitments

	Above-the-line		Below-the-line		Total		Ratepayer's Share	
	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed	Capitalized	Expensed
Environmental Commitments								
Bonneville Foundation				$100,000	$0	$100,000		0.00%
Renewable Generation	$60,000,000				$60,000,000	$0	100.00%	
Total-Environmental	$60,000,000	$0	$0	$100,000	$60,000,000	$100,000	100.00%	0.00%
Total Merger "Commitments"	$92,000,000	$29,600,000	$0	$6,100,000	$92,000,000	$43,200,000	100.00%	68.52%
					$135,200,000			

	Percentage Contribution	Total Capital & Expense
Above-the-line	89.94%	$121,600,000
Below-the-line	4.51%	$6,100,000
Undecided	5.55%	$7,500,000
Total	100.00%	$135,200,000

Source: Applicants' Response to Oregon Staff Request SP34

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Direct Testimony and Exhibits to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, on the 18th day of June, 1999.

Brian W. Burnett
CALLISTER NEBEKER & McCULLOUGH
Gateway Tower East, Suite 900
10 East South Temple
Salt Lake City, Utah 84133

William J. Evans
PARSONS BEHLE & LATIMER
201 South Main Street
PO Box 45898
Salt Lake City, Utah 84145-0898

Edward A. Hunter
STOEL RIVES LLP
201 South Main, Suite 1100
Salt Lake City, Utah 84111-4904

Roger O. Tew
60 South 600 East, Suite 200
Salt Lake City, Utah 84102

Michael Ginsberg
Assistant Attorney General
160 East 300 South 5th Floor
PO Box 140857
Salt Lake City, Utah 84114-0857

Lee R. Brown
Vice President
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Peter J. Matheis
Matthew J. Jones
BRICKFIELD BURCHETTE & RITTS, PC
1025 Thomas Jefferson Street NW
800 West Tower
Washington, D.C. 20007

Daniel Moquin
Assistant Attorney General
1594 West North Temple, Suite 300
Salt Lake City, Utah 84116

Bill Thomas Peters
David W. Scofield
PARSONS DAVIES KINGHORN & PETERS PC
185 South State Street, Suite 700
Salt Lake City, Utah 84111

Gary A. Dodge
PARR WADDOUPS BROWN GEE & LOVELESS
185 South State Street, Suite 1300
Salt Lake City, Utah 84111-1536

F. Robert Reeder
VAN COTT BAGLEY CORNWALL & McCARTHY
50 South Main Street, Suite 1600
PO Box 45340
Salt Lake City, Utah 84145

Eric Blank
Law Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Steven W. Allred
Salt Lake City Law Department
451 South State, Suite 505
Salt Lake City, Utah 84111

David F. Crabtree
Deseret Generation & Transmission
Co-operative
5295 South 300 West, Suite 500
Murray, Utah 84107

Dr. Charles E. Johnson
Salt Lake Community Action Program &
Crossroads Urban Center
1338 Foothill Blvd., Suite 134
Salt Lake City, Utah 84108

Arthur F. Sandack
8 East Broadway, Suite 620
Salt Lake City, Utah 84111

Matthew F. McNulty III
Stephen R. Randle
RANDLE DEAMER ZARR ROMRELL &
LEE PC
139 East South Temple, Suite 330
Salt Lake City, Utah 84111-1004

Paul T. Morris
3600 Constitution Boulevard
West Valley City, Utah 84119

Brian L. Farr
Assistant Attorney General
160 East 300 South
PO Box 140857
Salt Lake City, Utah 84114-0857

Cheryl Murray

17238

Witness CCS-4
Exhibit CCS-4

RECEIVED

JUN 18 3 50 PM '99

UTAH PUBLIC
SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	Docket No. 98-2035-04 PRE-FILED DIRECT TESTIMONY OF NEIL H. TALBOT FOR THE COMMITTEE OF CONSUMER SERVICES

June 18, 1999

TABLE OF CONTENTS

1. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Neil H. Talbot. I am self-employed as an economic and financial consultant specializing in the electricity industry. My business address is 81 Grand Street, New York, New York 10013.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am a member of a consulting team assembled by Synapse Energy Economics. The team has been retained by the Committee of Consumer Services, State of Utah Department of Commerce, on whose behalf I am testifying.

Q. PLEASE OUTLINE YOUR QUALIFICATIONS.

A. I have masters degrees in economics and finance from Cambridge University, England, and Boston College, respectively. From 1968 to 1994 I was employed as an economist with The Economist Intelligence Unit of London, Arthur D. Little, Inc. of Cambridge, Mass., and Tellus Institute, Boston. Since 1995 I have been self-employed as an independent consultant. My resume is attached as Exhibit CCS-4.1 (NHT).

Q. HAVE YOU TESTIFIED IN OTHER MERGER PROCEEDINGS?

A. Yes. I have testified in some six merger proceedings in various states including Utah and Washington. In 1989 I testified before the Utah Commission on the merger of Utah Power & Light Company into PacifiCorp. In that proceeding, I addressed the merged company's financial situation and cost of capital, and the appropriate treatment of UP&L's Energy Balancing Account. In 1996 I testified before the Washington Commission on the merger of Puget Sound Power & Light Company and Washington Energy Company. My focus was on financial impacts of the merger and I developed and applied a corporate financial model to the utilities. The other merger proceedings on which I have testified include the take-over of Long Island Lighting Company by the Long Island Power Authority; the proposed acquisition of Kansas Gas & Electric by Kansas Power & Light/ KPL Gas Service; and the proposed take-over of Public Service Co. of New Hampshire by Northeast Utilities. Regarding the proposed hostile take-over of UNITIL Corp. by Eastern Utilities Associates, I testified that the financial condition of EUA made the acquisition risky from a ratepayer standpoint, an opinion that was accepted by the New Hampshire PUC, which turned down the acquisition.

Q. WHAT ISSUES WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I will address financial and corporate concerns raised by the proposed acquisition of PacifiCorp by ScottishPower.

Q. HOW DOES YOUR TESTIMONY RELATE TO THAT OF THE OTHER WITNESSES FOR THE COMMITTEE OF CONSUMER SERVICES?

A. My testimony complements that of Mr. Bruce Biewald and Mr. Paul Chernick. We all support the recommendation proposed by Mr. Dan Gimble of the Committee of Consumer Services.

2. Summary of Testimony

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. With regard to financial issues, I first address PacifiCorp's financial outlook on a stand-alone basis. Second, I review the financial track record of ScottishPower in the U.K. Third, I consider ScottishPower's reasons for seeking to acquire PacifiCorp. Finally, I consider the financial outlook for PacifiCorp under a ScottishPower regime and contrast it with the outlook for PacifiCorp on a stand-alone basis. With regard to corporate issues, I will address corporate structure and corporate cost allocation, and some of the difficulties that will be encountered in trying to monitor and regulate a utility that is part of a complex international corporate structure.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. First, I conclude that the financial situation of PacifiCorp as a stand-alone utility serving electricity markets in the Pacific Northwest and Intermountain regions is fundamentally sound. I don't believe there is any dispute about this conclusion. It is certainly true that PacifiCorp stumbled financially during 1998 after it embarked on an unsuccessful diversification strategy. While PacifiCorp's management problems harmed the Company's stockholders more than its ratepayers, the latter may have been affected by financial weakness, management distraction, and operating cost increases. However, PacifiCorp's management has put that episode behind it and is now renewing its focus on its core western electricity business, its associated wholesale electricity business, and the business of Powercor, its regulated Australian distribution utility. The simple financial test from a customer standpoint is that PacifiCorp's cost of capital is low and its rates, already among the lowest in the country, have been further reduced by 12% by the Utah Public Service Commission. As a regulated electric utility, the outlook is for PacifiCorp to continue to provide low-cost service to customers. Furthermore, with a low-cost generation mix, no nuclear power commitments, a strategically placed transmission network and a growing customer base, PacifiCorp is well positioned to benefit from any future changes in the western electricity market.

Q. PLEASE TURN TO SCOTTISHPOWER'S SITUATION.

A. The financial track record of ScottishPower in the U.K. in the 1990s has to be assessed in the context of privatization, incentive regulation and increasing competition. ScottishPower was formed as an investor-owned utility when the electricity industry was privatized by the Electricity Act of 1989. Unlike the utilities in England and Wales, ScottishPower was allowed to remain vertically integrated. A liberal regulatory framework was introduced for distribution utilities: rates were permitted to increase annually according to a formula and there were regulatory reviews only every five years. Within this framework, electricity companies achieved considerable gains in efficiency and made high profits. However, the record suggests that ScottishPower did not share any more of the gains with ratepayers than other companies did. The same appears to be true of Manweb, the subsidiary ScottishPower acquired in 1995.

Q. WHY IS SCOTTISHPOWER SEEKING TO ACQUIRE PACIFICORP?

A. ScottishPower has been described as the most acquisitive utility in the U.K. It has embarked on a multi-utility acquisition strategy in which it is seeking to acquire electric and other utilities in the U.K. and overseas. In furtherance of this strategy, it acquired Manweb in 1995 and Southern Water in 1996. Its initial objective is to increase profits by increasing the operating efficiency of the acquired company, thereby maintaining a high rate of profit and dividend growth for the ScottishPower group. Its more fundamental objective, however, appears to be to use the utility as a base for expansion into mostly unregulated businesses. It seems that the proposed acquisition of PacifiCorp is intended to fit into this corporate strategy of ScottishPower. It is part of a reversal of the earlier trend of acquisitions of U.K. utilities by U.S. utilities seeking to cash in on the high profits permitted by the U.K. electricity regulator. The reverse trend of acquisitions reflects the impending decline of profitability of U.K. utilities as regulation is tightened, and the prospects for deregulation in the U.S.

Q. WHAT IS THE OUTLOOK FOR PACIFICORP'S RETAIL CUSTOMERS UNDER A SCOTTISHPOWER REGIME AND HOW DOES IT CONTRAST WITH THE OUTLOOK UNDER PACIFICORP ON A STAND-ALONE BASIS?

A. In my opinion, a ScottishPower acquisition would bring financial costs, risks and uncertainties to PacifiCorp and its customers that are not offset by a possible improvement in PacifiCorp's operating efficiency. No doubt, ScottishPower will attempt to improve PacifiCorp's operating efficiency, but it has refused to provide customers or regulators with any rate guarantees. PacifiCorp itself has already embarked on a program of efficiency improvements and it is not clear that ScottishPower will significantly improve the efficiency outlook. By refusing to provide any rate guarantees, ScottishPower appears to be attempting to retain prospective cost savings in order to maintain its high dividend growth. The operation of "regulatory lag" can allow a utility to delay the re-setting of rates to reflect efficiency gains for a period of approximately three years.

Q. WHAT RISKS TO RATEPAYERS WOULD RESULT FROM THE PROPOSED ACQUISITION?

A. It is indisputable that a corporate strategy of expansion and diversification brings risks. Even when such a strategy succeeds, there is some degree of risk resulting from the attendant uncertainty. When such a strategy fails, as it did in the case of PacifiCorp in 1998, there is obviously considerable risk. Ratepayers as well as investors may suffer. There is a risk that the cost of capital to PacifiCorp as a subsidiary of ScottishPower could rise in the future as a result of uncertainty or, in the case of missteps, financial weakness. And there is also a risk of management distraction and operating cost increases.

Q. SCOTTISHPOWER HAS CLAIMED THAT PACIFICORP'S COST OF CAPITAL WOULD *DECLINE*. WHY DO YOU DISAGREE?

A. ScottishPower has argued that the cost of capital to PacifiCorp would decline because ScottishPower is in a financially stronger situation than PacifiCorp today, and would create a larger utility system after the merger. This argument does not withstand scrutiny. First, the size factor is irrelevant when PacifiCorp on a stand-alone basis is already one of the larger utilities in the U.S. Second, it seems certain that as PacifiCorp's back-to-basics strategy begins to show results, any lingering concerns of the financial community about PacifiCorp's 1997-1998 diversification strategy will be laid to rest. Under a ScottishPower regime , there would be greater financial risk in a renewed acquisition strategy which might or might not be successful.

Q. CAN PACIFICORP BE PROTECTED FROM THE FINANCIAL VICISSITUDES OF SCOTTISHPOWER?

A. No, not completely. Expansion using PacifiCorp as a platform could bring risk directly to PacifiCorp. And continued expansion by the ScottishPower group could bring increased debt or financial distress to the parent company, could distract management, and could affect such features of PacifiCorp management as dividend policy and the availability of capital for core operations.

Q. PLEASE SUMMARIZE YOUR CONCERNS ON CORPORATE ISSUES.

A. Additional corporate costs would be incurred at the ScottishPower plc holding company or the ScottishPower U.K. levels. ScottishPower would seek to allocate these costs and a portion of its existing corporate costs to PacifiCorp. ScottishPower already has a cost allocation problem with Southern Water, where its allocation formulas had to be overridden by a cap on the subsidiary's total corporate costs. It appears a similar type of cap would be necessary for PacifiCorp. It would seem to be unwise to create a situation where a parent company is unable to apply a standard allocation method that is universally acceptable among its subsidiaries.

Q. WILL STATE REGULATION OF PACIFICORP BECOME MORE DIFFICULT?

A. Yes. The more complex corporate management and financial structure will add to the burdens of state regulation and make it more difficult for regulators to monitor corporate costs and financial issues that affect PacifiCorp.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

I support Mr. Gimble's recommendation that the merger application be rejected. From a financial and corporate standpoint, absent a constructive rate proposal by the Applicants or other convincing showing of benefits, the merger brings financial risks and corporate cost allocation problems without having any significant gain to ratepayers.

3. PacifiCorp's Financial Outlook on a Stand-Alone Basis

Summary of PacifiCorp's Current Situation

Q. PLEASE SUMMARIZE PACIFICORP'S CURRENT BUSINESS AND FINANCIAL SITUATION.

A. PacifiCorp is primarily a regulated and integrated electric utility serving customers in five states – Oregon, Utah, Washington, Idaho and Wyoming. PacifiCorp is selling the distribution assets that serve its small Montana and California service territories. PacifiCorp does business as Utah Power in Utah and Pacific Power in other western states.

Q. PLEASE DESCRIBE THE COMPANY'S DIVERSIFIED ACTIVITIES.

A. Prior to mid-1998, PacifiCorp had embarked on an ambitious acquisition program. It raised funds for that program by selling its subsidiary Pacific Telecom, Inc. (PTI) for $1.5 billion in cash in December 1997. It also sold its independent power venture, Pacific Generation Co. The acquisition program culminating in the Company making successive bids to acquire The Energy Group, a British utility and energy company with operations in the U.K., U.S. and Australia. The acquisition was blocked by a U.K. government antitrust review and eventually PacifiCorp's final bid was topped by a successful Texas Utilities' bid for The Energy Group in April 1998. During 1998, PacifiCorp also suffered losses in electricity trading in the eastern U.S. through PacifiCorp Power Marketing. In October it decided to exit that business, closing the operation down and selling TPC Corporation through which it had natural gas interests. Finally, PacifiCorp suffered from reduced margins on its wholesale market sales in the West in 1998 owing to adverse hydro-electric power conditions and increased purchased power costs.

Q. WHAT REMAINS OF PACIFICORP'S DIVERSIFIED ACTIVITIES AT THIS POINT?

A. After the resignation of PacifiCorp's former CEO in August 1998 and a fundamental review of its alternatives, the Company decided on a "back to basics" strategy in October. PacifiCorp would pull back from its diversification strategy and concentrate on its regulated western U.S. electricity business and its associated wholesale market business. It would, however retain its Australian distribution utility subsidiary, Powercor.

Q. DOES PACIFICORP'S INVOLVEMENT IN OTHER BUSINESSES STILL INCREASE ITS LEVEL OF BUSINESS RISK?

A. No. While there is a residual concern in the investment community regarding the risks of these businesses, it is clear that PacifiCorp is exiting these businesses. PacifiCorp's continued ownership of the Australian utility Powercor, and its participation in the competitive wholesale power markets that are growing in the western U.S., do not significantly affect this assessment.

Q. HOW WOULD YOU CHARACTERIZE PACIFICORP AT THE PRESENT TIME?

A. PacifiCorp is and will continue to be a vertically-integrated electric utility. Changes in PacifiCorp's business that could occur over time as a result of the evolution of the U.S. electric utility industry include increasing sales of generation in competitive markets including competitive retail markets to the extent they are deregulated. For the time being, however, PacifiCorp will remain essentially a traditional regulated electric utility.

Q. HOW WOULD YOU CHARACTERIZE PACIFICORP'S FINANCIAL SITUATION AT THE PRESENT TIME?

A. PacifiCorp is recovering from a period of relatively low earnings, both in its diversified activities and in parts of its regulated business. However, flush with cash freed up from its intended purpose as a war chest to use in the acquisition of The Energy Group, and with a reasonable proportion of debt in its capital structure, PacifiCorp is in a strong financial position.

PacifiCorp's Cost of Capital

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF PACIFICORP'S COST OF CAPITAL IN THIS PROCEEDING.

A. In assessing a regulated utility's financial situation, the bottom line for customers is the utility's cost of capital. The reason is of course that the utility's rates are set at a level that is intended to recover this cost. The Utah Commission recently determined that PacifiCorp's cost of capital is 8.84% on rate base, using a hypothetical capital structure based on that of a group of comparable utilities with single-A bond ratings. The cost of equity capital to PacifiCorp was set at 10.5% and the weighted average rate of 8.84% was calculated as follows:

Component	Weight	Cost Rate	Cost Contribution
Debt	46.7%	7.518%	3.51
Preferred Stock	5.7%	5.794%	0.33
Common Equity	47.6%	10.5%	5.00
		100.0%	8.84%

Q. IN YOUR OPINION, IS THIS A REASONABLY LOW COST LEVEL?

A. Yes. It reflects relatively low rates for all three components of long term capital. The Utah Division of Public Utilities found that "PacifiCorp's actual capital structure is close to the recommended hypothetical one and the embedded costs of the Company's long-term debt and preferred stock are near the average (for the group of comparable single-A utilities)."[1] The average cost rate of 8.84% is below the U.S. electric utility composite of 9.0% earned on net plant (Electric Utility Week, March 8, 1999). Essentially, the Utah Commission's finding is that PacifiCorp fits the financial profile of a sound single-A utility.

PacifiCorp's Financial Prospects

Q. WHAT IS THE FINANCIAL OUTLOOK FOR PACIFICORP ON A STAND-ALONE BASIS?

A. The financial outlook for PacifiCorp is good, with low risk for investors.

Q. PLEASE EXPLAIN THIS VIEW.

A. Investment risk is usually divided into two parts: business risk and financial risk. Business risk is the inherent risk of the underlying business, in this case the risk of the Company's vertically-integrated electric utility business. Financial risk is the additional risk to investors resulting from debt and other fixed financial commitments. The higher the level of these commitments, the greater the risk for both stockholders (whose claims are residual) and bondholders (who have a smaller equity cushion).

Q. WHAT IS PACIFICORP'S LEVEL OF BUSINESS RISK?

A. PacifiCorp is correctly regarded by the financial community as having a low level of business risk. There are several reasons for this: PacifiCorp has a low-cost generation mix; it does not have any exposure to nuclear power risks; it has a strategically located transmission network; and its service territory has a growing economy and customer base.

Q. WHAT IS PACIFICORP'S FINANCIAL RISK PROFILE?

A. As regards financial risk, PacifiCorp's situation is sound. It has a well-balanced capital structure. The availability of the proceeds of the sales of unrelated businesses is also a favorable feature.

[1] Public Service Commission of Utah *Report and Order* issued March 4, 1999 in Docket No. 97-035-01, p. 47.

Q. BEFORE IT MADE THE DECISION TO MERGE WITH SCOTTISHPOWER, PACIFICORP WAS PLANNING A STOCK BUY-BACK. HOW WOULD THE BUY-BACK HAVE AFFECTED THE COMPANY'S STAND-ALONE BALANCE SHEET?

A. On the assets side of the Company's balance sheet, the sale of unrelated businesses has resulted in the accumulation of a large amount of cash. As of December 31, 1998, PacifiCorp recorded $583 million of cash and cash equivalents on its balance sheet. The money came from the sale of assets and was intended as a war chest for the Company to use in its acquisition of The Energy Group. When that plan fell through, and the Company decided to abandon its acquisition strategy, the cash became an under-performing asset on which low returns were being earned. The Company planned to use that cash to reduce its capitalization on the liabilities-and-capital side of its balance sheet. And the assets remaining on the assets side of the balance would be expected to perform better than cash. The Company had and still has an opportunity to buy back equity and redeem debt in the proportions that it chooses in order to fine tune its capital structure as well as reduce its overall capitalization. However, as I note later in my testimony, PacifiCorp's plan to focus on the buy-back of stock, thereby reducing the amount of equity on the balance sheet, raised concerns at the rating agencies because of a perceived increase in risk to bondholders.

4. Financial Track Record of ScottishPower in the U.K.

Q. HOW DO SCOTTISHPOWER'S RATES COMPARE WITH THOSE OF OTHER BRITISH UTILITIES?

A. As shown by Mr. Biewald, the rates of ScottishPower and its subsidiary Manweb do not appear to be any lower than those of other British utilities, in fact the opposite may be true.

Q. HOW HAVE THE *INVESTORS* OF SCOTTISHPOWER FARED, COMPARED WITH THOSE OF OTHER BRITISH UTILITIES?

A. ScottishPower's investors appear to have fared relatively well compared with those of other British utilities, as measured by rate of return on capital employed. This view is based on information I have reviewed from the Centre for the Study of Regulated Industries, University of Bath School of Management, to which I was referred by the Office of Electricity Regulation. Manweb has also performed very well by U.S. standards, but has fallen short of its peers in Britain in recent years. Financial returns are compared in the following table:

Comparative Returns of British Public Electricity Suppliers

	1990/91	1996/97	1997/98
ScottishPower	22%	30%	29%
Manweb	15%	20%	19%
Average PES	19%	23%	25%

Notes: Average PES is the simple average for the 14 companies reported – 12 regional electricity companies (RECs) in England & Wales, plus ScottishPower and Scottish Hydro. Capital is measured at historical cost.

Source: Centre for the Study of Regulated Industries (CRI), *The UK Electricity Industry Financial and Operating Review, 1997/98.*

ScottishPower's own financial report gives an average 26% return on equity company-wide during the five-year period 1994-1998 (years ended March). (*Group Activities: Investing for Growth*, November 1998)

Q. WHAT CONCLUSION DO YOU DRAW FROM THIS FINANCIAL DATA?

A. One would expect superior corporate performance to be reflected in lower rates for customers or higher profits for investors or some combination thereof. In the case of ScottishPower, it appears that *if* the company did indeed achieve greater efficiency gains than its peers, the gains were reflected in higher profits for investors, not lower rates for customers, during the past five or ten years.

5. The Role of PacifiCorp in ScottishPower's Corporate Strategy

ScottishPower's Corporate Strategy

Q. HOW WOULD YOU DESCRIBE SCOTTISHPOWER'S CORPORATE STRATEGY?

A. ScottishPower describes itself as a "multi-utility," by which it means a company which is primarily focused on ownership and operation of a variety of utility businesses – electric, gas, water and telecom. It has been described by Warburg Dillon Read as the most acquisitive utility in the U.K. In 1992, it decided on a multi-utility acquisition strategy in which it is seeking to acquire electric and other utilities in the U.K. and overseas. This strategy got into high gear with the acquisition of Manweb, a regional electricity company (REC) in 1995 and Southern Water in 1996. Its fastest-growing subsidiary is Scottish Telecom.

Q. WHAT IS THE BREAKDOWN OF SCOTTISHPOWER'S CURRENT BUSINESSES?

A. As measured by assets and contribution to corporate income, the breakdown of ScottishPower's businesses today, prior to the PacifiCorp acquisition, is shown in the following table:

Breakdown of ScottishPower Turnover (Revenue) by Business

	(percentages as of March 1998)
Energy & Power (including Manweb)	74%

Southern Water	13%
Other (including Scottish Telecom)	13%

Source: Adapted from Warburg Dillon Read report on ScottishPower, September 1998, p. 43.

Q. LOOKING FORWARD, WHERE IS SCOTTISHPOWER'S STRATEGY HEADED?

A. ScottishPower's strategy can be summarized in a two-dimensional chart with territorial expansion on one axis and type of business on the other:

Chart: ScottishPower Multi-Utility Expansion Strategy

Scotland	Electricity (Scottish Power)	Telecom, Gas
England	Electricity (Manweb)	Water (Southern Water), Gas
West. U.S.	Electricity (PacifiCorp)	?
Australia	Electricity (Powercor)	?
?	?	?

Source: Adapted from Warburg Dillon Read report on ScottishPower, September 1998, page 10.

Q. WHAT ARE SCOTTISHPOWER'S OBJECTIVES IN EACH ACQUISITION?

A. It appears that ScottishPower's objectives are similar to those of other companies that seek to expand their businesses by acquisition. The financial objective is usually to "create value" which means to increase the value of the corporation to shareholders. In some cases value is increased as a result of corporate synergies, as in the case of mergers of businesses that can be operated more efficiently together than separately. In other cases, including the present one, the argument is that better management will unlock shareholder value by turning an "under-performing" asset into one that is fully performing from a financial standpoint. This has been called "sweating the asset base" in ScottishPower's "'cash is king' culture" by the London investment house Warburg Dillon Read. One of the principal features of this strategy is that it is intended to maintain a momentum of financial growth as measured by earnings, dividends or stock price. This strategy may involve balance-sheet engineering and tax reduction measures designed to increase stockholder returns.

Decline in ScottishPower's Profit Outlook in the U.K.

Q. ABSENT ACQUISITIONS, WOULD SCOTTISHPOWER LOSE ITS FINANCIAL MOMENTUM?

A. Yes, it appears that it will be difficult for ScottishPower to maintain its financial momentum. Warburg Dillon Read in a September 1998 report on ScottishPower was forecasting a significant slow-down in momentum prior to the PacifiCorp announcement in December 1998:

	Past 3 Years	Next 3 Years
Dividends per Share	15.0%	10.5%
Earnings per Share	8.4%	-0.8%

Source: Adapted from Warburg Dillon Read report on ScottishPower, September 1998, p. 43.

Q. WHAT ARE THE FACTORS THAT ACCOUNT FOR THIS EXPECTED SLOW-DOWN IN SCOTTISHPOWER GROWTH?

A. The principal factor is the expectation that the price caps on ScottishPower's regulated electricity and water businesses in the U.K. will be reduced by Offer, the Office of Electricity Regulation, and Ofwat, the water utility regulator, in the upcoming five-year pricing reviews that will be effective in 2000.

Q. ARE THERE OTHER FACTORS THAT MAY CONTRIBUTE TO THE EXPECTED SLOW-DOWN?

A. Yes. ScottishPower appears to have attempted to sustain a high rate of dividend growth by increasing its earnings payout and by increasing the share of debt in its capital structure, what could be called "balance sheet engineering." By increasing dividends faster than earnings during the past four years – 13.2% per year versus 7.4% per year -- it has increased its payout ratio from 40% to 50%, admittedly still not a high ratio. It has also increased its "gearing" – the ratio of net debt to net capital – from zero in 1994 to 114% in 1998. (In U.S. terms, the 114% ratio in 1998 is a debt:assets ratio of 53-54%, somewhat high by U.S. standards.) Obviously, these past trends are not sustainable indefinitely because the company would become financially stretched.

Q. WHAT IS SCOTTISHPOWER'S COMMITMENT WITH RESPECT TO DIVIDEND GROWTH AT THIS POINT?

A. In its May 6, 1999, document entitled *The Scheme of Arrangement*, ScottishPower makes the following statement:

> New ScottishPower is committed to ScottishPower's stated aim of achieving 7% to 8% *real* dividend growth per annum until *at least* the UK regulatory reviews which take effect in the year 2000, whilst maintaining a prudent level of dividend cover. It is New ScottishPower's current aim to deliver real dividend growth thereafter and this will be re-examined once the outcome of these regulatory reviews is known. (emphasis added)

Q. WHY IS IT IMPORTANT FOR SCOTTISHPOWER TO TRY TO MAINTAIN ITS FINANCIAL MOMENTUM?

A. Warburg Dillon Read noted in its September 1998 report (page 4) that:

> ScottishPower's share price performance since 1995 has been dominated by perceptions of its acquisitive multi-utility strategy. Underperformance in 1996 was a result of negative sentiment surrounding the Southern Water acquisition. Subsequently, the

> underperformance has been clawed back, as the market has begun to appreciate the merits of the multi-utility strategy, including Scottish Telecom.

This suggests that the financial community is hoping for and expecting a successful continuation of the ScottishPower expansion strategy.

Q. HAVE OTHER ANALYSTS TAKEN THIS APPROACH TO SCOTTISHPOWER'S FINANCIAL OUTLOOK?

A. Yes. Bankers Trust/ Alex Brown is quite explicit about this.

> Without an acquisition, ScottishPower's earnings will stagnate until 2003 when the Scottish interconnector upgrade comes fully online. By acquiring PacifiCorp, ScottishPower can enhance earnings by 10% (before goodwill) and give EPS (earnings per share) growth to fill the gap between now and 2003." (Report on ScottishPower, 2/19/99)

As noted elsewhere in my testimony, the Bankers Trust/ Alex Brown report also believes that "the central challenge facing ScottishPower in this deal is to navigate seven sets of US regulators without giving away the efficiency upside."

Q. DOES THIS PUSH FOR FINANCIAL GROWTH ENTAIL RISK?

A. Yes. There is a risk that the financial imperative can outweigh more prudent financial and business considerations.

Q. DO ANY OTHER RECENT STEPS INDICATE HOW SCOTTISHPOWER MAY TRY TO MAINTAIN OR REGAIN ITS FINANCIAL MOMENTUM?

A. Yes. ScottishPower is considering new ways in which it can utilize its investment in Scottish Telecom. It has already used Scottish Telecom as a platform for expansion and further acquisitions including Demon Internet, the U.K.'s largest internet service provider, in April 1998. Panmure Gordon expects that "further expansion is likely to follow." (Report on ScottishPower, 9/30/98) Warburg Dillon Read noted in its September 1998 that "Recent market speculation has focused on the future ownership of Scottish Telecom" and predicted that ScottishPower would float a minority stake in Scottish Telecom. On February 16, 1999, ScottishPower issued a press release that announced the appointment of a new managing director for ScottishTelecom and included the following rather opaque statement:

> Scottish Telecom has grown rapidly since its launch in 1994. ScottishPower has recently appointed Goldman Sachs to explore the options open to optimise value for ScottishPower shareholders from its investment in Scottish Telecom. The review is at a preliminary stage and an announcement will be made if and when appropriate.

The point I am making is that ScottishPower's financial strategy requires it to make major decisions about its various subsidiaries from time to time that are driven primarily by financial growth considerations. *The (Manchester) Guardian* reported the day after the ScottishPower news release that:

> ScottishPower is keen to emulate National Grid, which recently sold a third of its 74 per cent stake in its publicly-quoted telecoms arm, Energis, for more than pounds 1 billion. ScottishPower, like National Grid, could use cash to support an ambitious overseas expansion programme which includes the agreed all-share bid for PacifiCorp.

(National Grid is the other U.K. company that is currently making a bid to acquire a U.S. utility, in its case New England Electric System.)

Unregulated Businesses Offer Higher Profit Prospects

Q. WILL SCOTTISHPOWER REMAIN PRIMARILY FOCUSED ON REGULATED UTILITY BUSINESS?

A. No. There is every indication that ScottishPower will become increasingly dependent on faster-growing unregulated businesses, of which Scottish Telecom is the leading example. This conclusion is unaffected by the possibility that ScottishPower will perhaps sell part of its interest in Scottish Telecom. Merrill Lynch has predicted that the share of ScottishPower profits derived from its unregulated businesses will rise from 24% in the year ended March 1999 to 33% in the year ended March 2002. (Merrill Lynch report on ScottishPower, 10/2/98) HSBC Securities had a similar expectation:

Operating Profits	1999	2001	Profit Growth Rate
(millions of pounds)			
Generation Wholesale	134	206	24%/yr
Energy Supply	30	62	44%/yr
Developing Businesses	22	65	72%/yr
Unregulated total	186	333	33.8%/yr
Regulated	622	579	-3.5%/yr
Total Operating Profits	808	912	6.2%/yr
Percentage Unregulated	23%	36%	

Source: HSBC Securities, *ScottishPower: Value Added*, May 1998, p.9.

Q. THOSE REPORTS WERE WRITTEN BEFORE THE ANNOUNCEMENT OF THE PACIFICORP ACQUISITION. HOW WOULD THIS ACQUISITION AFFECT THE PICTURE?

A. The acquisition of PacifiCorp would, of course, increase the regulated portion of ScottishPower's portfolio, at least initially.

Q. HOW WOULD THE ACQUISITION OF PACIFICORP FIT INTO SCOTTISHPOWER'S STRATEGY?

A. If, as the financial analysts suggest, the way to look at the ScottishPower strategy is in terms of *growth*, ScottishPower will try to turn PacifiCorp into a growth business or a platform for growth, in the way that telephone companies have grown into "telecom" companies in the U.S. In a nutshell, I think that ScottishPower's growth ambitions could break through the financial constraints that are inherent in a strictly-defined "multi-utility" strategy. The chart describing ScottishPower's acquisition strategy needs to be extended along the "type-of-business" access to include an increasing amount of unregulated business.

Q. PLEASE EXPLAIN.

A. ScottishPower's financial imperative is likely to lead to a two-stage approach to PacifiCorp. I believe that ScottishPower's primary near-term objective will be to increase the profitability of PacifiCorp by cutting costs or trying to leverage PacifiCorp's profits. However, as is evident in the U.K., there are likely to be limits to the profit growth of the regulated utility business. Longer term, ScottishPower is likely to "create (shareholder) value" in other ways by proposing incentive regulation, deregulation of electricity generation and supply, partial sale of PacifiCorp, and not least, using PacifiCorp as a platform for further acquisitions or expansion in the U.S. or Australia.

Q. IS THIS OPINION SUPPORTED BY FINANCIAL ANALYSTS?

A. Yes. According to stockbrokers Panmure Gordon & Co., "under ScottishPower's (acquisition) criteria any international acquisition has to both add value itself as well as create future growth opportunities." (Report on ScottishPower, 9/30/98) WestLB Panmure, in a report dated 11/5/98, says: "For ScottishPower the utility business is not just about cost cutting, it is about growth... Its strategy is to sell as many additional utility services as it can to both its existing customers as well as new ones." I would reiterate that the new services, like those ScottishPower is diversifying into in the U.K., are likely to be unregulated services including sale of electrical appliances, unregulated gas supply and unregulated electricity supply (as an ESP or energy service provider in the deregulated retail energy markets in the U.S.), unregulated telecom services, etc. Morgan Stanley Dean Witter, in its 9/23/98 report on ScottishPower considering the prospect of a U.S. utility acquisition by

ScottishPower, says the following under the heading "Multi-utility evolves into international utility":

> We believe that the logic of a multi-utility company is only justified if it can be shown that:
>
> synergy benefits are created, such that cost-cutting achieved by the multi-utility is at least in line, if not superior, to that achieved by pure regulated utilities; and
>
> synergy benefits are created through increased top-line sales, so that *growth in market share by the multi-utility, in areas such as competitive gas and electricity markets, is seen to be faster and more profitable than that of pure regulated utilities.* (emphasis added)

HSBC, in a December 1988 report titled *ScottishPower...prospects for gold in the Wild West*, characterizes the company's strategy as follows:

> ScottishPower enhances value by acquiring under performing assets; engineering the balance sheet to maximize financial efficiency; sweating the asset base; and using the customer base to sell a multi-utility product. The deregulating US market is the logical next step for this strategy.

Warburg Dillon Read says simply "Acquisition of a US utility provides a new platform for growth. ScottishPower's scope to grow in its 'home' markets of UK and Continental Europe is limited..." (December 1998 report on the merger, p.7)

Q. WILL THE TERM "MULTI-UTILITY" STILL FIT SCOTTISHPOWER IF ITS ACQUISITION PROGRAM SUCCEEDS?

A. No. ScottishPower's likely expansion into unregulated businesses, and the deregulation of electricity generation and energy supply will increasingly change the nature of the company. It will become a multi-utility-based company or what has been termed a "hyper-utility."

Q. PLEASE SUMMARIZE YOUR VIEWS ON THE ROLE OF PACIFICORP IN SCOTTISHPOWER'S ACQUISITION STRATEGY.

A. My fundamental view is that ScottishPower is viewing PacifiCorp as something different from a traditional utility operation. On the one hand, the utility business has been ScottishPower's base of operations in the U.K., and it was apparently able to squeeze high profits out of it during the 1990s. Now that the phase of high profit growth appears to be ending in the U.K., ScottishPower is looking for ways to maintain the growth of profitability. The acquisition of a company such as PacifiCorp is likely based on a view of the target company as a *utility platform*. They would hope to *both* repeat their experience of cost cutting, balance sheet engineering, etc., with U.K. regulated utilities *and* use the financial and managerial capability, name recognition, and customer base of the utility business to expand into mostly unregulated businesses, as they are doing in the U.K. with Scottish Telecom, electrical appliance retailing and unregulated energy supply.

Implications for PacifiCorp Investors

Q. WHAT KIND OF U.S. INVESTOR WOULD INVEST IN SCOTTISHPOWER STOCK?

A. Currently, at the height of an investment boom, perhaps even a bubble, in U.S. financial markets, investors who normally would be more cautious are being increasingly attracted to growth-oriented stocks. Internet stocks are the extreme example. However, when this boom ends, as every boom must sooner or later, investors will likely return to more traditional investment patterns. Income-oriented, risk-averse investors will tend to shift to bonds, utility stocks such as PacifiCorp would be on a stand-alone basis, and other relatively safe investments. Those investors who remain more growth-oriented and less risk-averse, will continue to be more interested in growth situations. If ScottishPower continues to be growth-oriented – with the perception of its stock influenced more by its acquisition strategy than its steady utility earnings growth – its stock will increasingly be more attractive to growth-oriented investors. If, however, ScottishPower suffers setbacks in its acquisition strategy, as PacifiCorp did with *its* acquisition strategy last year, it may also at some time in the future revert to a "back-to-basics" strategy.

Q. HOW MANY OF PACIFICORP'S STOCKHOLDERS RESIDE IN THE STATES SERVED BY THE COMPANY?

A. According to the Company, 33,817 PacifiCorp stockholders reside in the five states that will continue to be served by PacifiCorp. They represent 32% of the Company's holders of common and preferred stock, and their holdings represent 10% of the total stock outstanding. (Response to CCS Data Request, Attachment Response 9.44)

Q. HOW DO YOU THINK CURRENT PACIFICORP INVESTORS WILL BE AFFECTED BY THE MERGER?

A. PacifiCorp's stockholders appear to be underwhelmed by the prospect of the merger, judging by the fact that PacifiCorp stock is languishing in the bottom half of its twelve-month price range. Although PacifiCorp's stockholders were offered a 21% premium over the value of their PacifiCorp stock, based on the relative valuations of PacifiCorp and ScottishPower stock at the time, stockholders in target companies usually fare even better. Assuming the merger goes through, I suspect that over time income-oriented U.S. investors will shift away from ScottishPower stock, to the extent they have not already done so after PacifiCorp ran into financial difficulties last year. Although offering the *expectation* of higher returns, investment in a growth-oriented company always comes with greater risk. Its attraction lies more in future returns than in current ones, and the future is inherently uncertain. Not only is a utility-based or hyper-utility company inherently more risky than a pure utility company, but there is the currency risk issue to be taken into account.

Q. PLEASE EXPLAIN THE CURRENCY RISK ISSUE FOR U.S. INVESTORS.

A. PacifiCorp shareholders will receive ScottishPower stock in the form of American Depositary Shares (ADS's) traded on the New York Stock Exchange. Each ADS will represent, as it does now, four shares of ScottishPower common stock. The value, dividends, and earnings underlying these ADS's will be those of ScottishPower, the majority of which will originate from the U.K. Thus, in addition to the impact on its investors of the value of Australian dollars because of PacifiCorp's ownership of Powercor, ScottishPower's U.S. investors will be affected by the value of the British pound in terms of U.S. dollars. The pound has dropped about 4% since the merger was announced, from $1.665 to about $1.60, but it is still a strong currency although not as strong as the U.S. dollar. The only thing one can say with any generality about floating exchange rates like those between the British pound and the U.S. dollar is that they go up and down. This adds a new dimension of variability to an investment in PacifiCorp by anybody who is primarily concerned about income in U.S. dollars. This results in somewhat more risk for a traditional U.S. utility investor.

The Significance of the Acquisition Premium

Q. PLEASE EXPLAIN HOW THIS MERGER IS BEING CHARACTERIZED FROM AN ACCOUNTING STANDPOINT.

A. The purchase method of accounting is being used. In this case, where there is an exchange of stock, rather than a cash payment, the price being paid depends upon the relative prices of the stocks of the acquiring company and the target company.

Q. HOW LARGE IS THE ACQUISITION PREMIUM THAT SCOTTISHPOWER IS PAYING FOR PACIFICORP STOCK?

A. Because the acquisition is by means of an issuance and exchange of ScottishPower stock for PacifiCorp stock, the premium depends on the relative market prices of the stocks. At the time of the merger announcement, the premium was $1.3 billion.

Q. DOES THE ACQUISITION PREMIUM BEING PAID BY SCOTTISHPOWER FOR PACIFICORP'S STOCK AFFECT SCOTTISHPOWER'S FINANCIAL SITUATION?

A. Yes. The acquisition adjustment or premium puts extra pressure on ScottishPower to make a success of the acquisition. First, it reflects the reality that ScottishPower is in fact paying a premium for PacifiCorp's stock, *i.e.*, it is paying more than the *market* value of that stock prior to the merger, let alone the *book* value. (The market to book ratio of PacifiCorp stock at year end 1998 was about 1.4.) The acquisition adjustment is recorded as an "asset" on ScottishPower's books and has to be depreciated over a number of years. This means that ScottishPower's *reported* earnings are reduced during that period. This is not a real drain on cash flow, and in that sense should not matter to the financial community, which is in theory supposed to focus more on cash than on reported earnings. However, reported earnings figures carry weight with investors. For example, dividend payout is standardly calculated as the percentage of reported earnings that is paid out to stockholders and the higher that percentage, the smaller the amount of earnings that is apparently being plowed back into the business. In any event, the net result is that ScottishPower will be under pressure to overcome the reduction in reported earnings per share that results from the acquisition.

Q. HOW DOES SCOTTISHPOWER BELIEVE THE ACQUISITION ADJUSTMENT SHOULD BE RECOVERED?

A. ScottishPower is not requesting recovery of the premium in PacifiCorp rates. However, ScottishPower believes that merging companies should ideally be given the opportunity to recover the premium. It complains about the regulatory treatment of mergers and acquisitions in the U.K. "(T)he regulatory community in the United Kingdom may have the effect of eroding too quickly the shareholder benefits arising from mergers and acquisitions. This results in the customer gaining the great majority of the present value of future cost savings." In the U.S., I would point out, there is typically a sharing of quantified merger benefits between the companies and their customers. In the present case, since there are no quantified net benefits, ScottishPower could not very well ask for recovery of a portion of the acquisition premium. This leaves the premium to be amortized against ScottishPower profits.

Financial Implications of the Merger for PacifiCorp

Q. YOU HAVE POINTED OUT THAT SCOTTISHPOWER MUST TRY TO CREATE VALUE OR UNLOCK VALUE FOR ITS STOCKHOLDERS FROM THE ACQUISITION OF PACIFICORP. HOW COULD IT DO THIS?

A. Partly, there is an element of timing. ScottishPower has been actively looking for a U.S. utility to acquire. It entered into discussions with at least two utilities, Florida Progress and Cinergy, during the past year and finally settled on PacifiCorp. It saw value in PacifiCorp that the financial markets had not yet seen; it anticipated –correctly, I believe -- that PacifiCorp's' back-to-basics strategy was likely to be successful financially. ScottishPower has stated that it believes it can operate PacifiCorp in the future more efficiently than PacifiCorp's existing management could on its own. At least, recognizing that PacifiCorp is already planning to improve efficiency as part of its back-to-basics strategy, ScottishPower states that it will bring about efficiency gains more quickly and more certainly than PacifiCorp's management could on a stand-alone basis. In any event, one of ScottishPower's primary objectives is to benefit from profit increases resulting from improvements in the operating efficiency of PacifiCorp, whether or not they were caused by the acquisition.

Q. PLEASE DISCUSS SCOTTISHPOWER'S NEAR-TERM GOALS FOR PACIFICORP IN TERMS OF RATE OF RETURN REGULATION.

A. Dealing with the near term, I would leave to one side the likelihood that at some point in time ScottishPower will use PacifiCorp as a platform for expansion into other businesses in the U.S. Initially, it seems clear that ScottishPower's financial objective will be to benefit from a reduction in PacifiCorp's costs and an increase in its profitability, in an attempt to maintain a high rate of earnings and dividend growth for the ScottishPower group. ScottishPower has acknowledged this to a limited degree by articulating the goal of bringing PacifiCorp's earnings up to the level allowed by regulators. This in itself is a somewhat ambiguous objective, because the cost of capital today is significantly lower than it was at the time of the rate cases in most of the states served by PacifiCorp.

Q. BY HOW MUCH HAS THE COST OF CAPITAL DECLINED SINCE THE LAST RATE CASES IN PACIFICORP'S VARIOUS JURISDICTIONS?

A. PacifiCorp's allowed rate of return, prior to the recent Utah rate decision, was approximately 11.36% on a weighted average basis, as shown in the following table, which excludes the Montana and California distribution assets.

State	Rate Base	Percent of Rate Base	Allowed Return on Equity
Idaho	$0.2b.	3%	13.40%
Oregon	$2.5b.	38%	10.00%
Utah	$2.3b.	35%	12.10%
Washington	$0.7b.	11%	13.25%
Wyoming	$0.9b.	13%	11.50
Weighted Average			11.36%

Source: Based on PacifiCorp's Investor/ Analyst Presentation, New York, October 28, 1998. Rate base data are for 12/31/97. ROEs are updated to reduce Oregon allowed ROE of 15.8% set in 1984 to the 10.0% alternative form of regulation (AFOR) benchmark in May 1998.

The most recent estimate of PacifiCorp's cost of common equity is the Utah Commission's finding of 10.5%, nearly one percentage point below PacifiCorp's average allowed level before the recent Utah Power rate case, and more than two percentage points below the level before the Oregon Commission set a 10% benchmark in May 1998. At the time ScottishPower was evaluating the merger and agreeing on the terms in late 1998, the Utah order had not been issued. The average ROE allowed and actually earned by U.S. electric utilities is about 10-11% which, given the high market-to-book ratios of utility stocks, does not seem to be too low. (For the 17 western utilities covered by Value Line, the average market-to-book ratio at year-end 1998 was 168%.)

Q. HOW DOES THIS DECLINE IN ALLOWED ROE AFFECT SCOTTISHPOWER'S STRATEGY?

A. There is less upward potential for regulated ROE than there previously appeared to be. Further, if it is planning to match its past U.K. performance, or sustain its corporate financial performance by acquisition, ScottishPower would have to achieve higher rates of return than would currently be allowed in the U.S.. Alternatively, it would have to leverage allowed returns by balance sheet engineering to create a more efficient capital structure or lower effective tax rate, or some other means.

Q. PLEASE PROVIDE INFORMATION TO SUPPORT THIS VIEW.

A. During the 1990s, ScottishPower's stockholders have benefited from a high rate of return on their investment, including increases in dividends and earnings that are far higher than those of U.S. electric utilities. Return on equity has averaged 26% during the five-year period 1994 to 1998. Earnings per share and especially dividends per share have grown rapidly.

	Growth Rate 1994-1998
Earnings per Share	7.4%
Dividends per Share	13.2%

Source: ScottishPower, *Investing for Growth*, Nov. 1998.

Q. HOW DOES FINANCIAL PERFORMANCE OF U.S. UTILITIES COMPARE WITH THAT OF SCOTTISHPOWER?

A. As noted earlier, the average ROE actually earned by U.S. utilities is approximately 11% (composite 10.8% for 1998 according to Electric Utility Week, March 8, 1999), less than half that achieved by ScottishPower over the last five years. As regards dividend and earnings growth, the comparison is even more striking. For the 17 western U.S. utilities covered by Value Line, the average growth rates of earnings and dividends over the last five years and Value Line's expectations regarding growth rates in the future are as follows:

	Past Five Years	Expected 1995/97 to 2001/03
Earnings per Share	2.2%	3.0%
Dividends per Share	-0.6%	2.4%

Source: Value Line, Feb. 19, 1999. Simple averages of all meaningful estimates. Past Five Years Earnings per Share exclude Public Service Co. of New Mexico which had 29%/year earnings growth. With PSNM, the average would be 4.0%.

Q. GIVEN THESE DISPARITIES, DO YOU BELIEVE THAT PACIFICORP'S FINANCIAL MANAGEMENT UNDER SCOTTISHPOWER IS LIKELY TO RESULT IN LOWER RATES FOR CUSTOMERS?

A. No. In my opinion, it is likely that ScottishPower will be disappointed by PacifiCorp's earnings and dividends prospects under business-as-usual regulation. If ScottishPower wants to increase the contribution of

PacifiCorp to its profit growth, it will find it difficult to do so without changes in the regulatory framework, such as incentive regulation or deregulation, or leveraging PacifiCorp profits in some way.

Q. HOW MIGHT SCOTTISHPOWER TRY TO CREATE ADDITIONAL SHAREHOLDER VALUE IN THE NEAR TERM?

A. As I note elsewhere in my testimony, there are other ways in which ScottishPower might try to realize its financial imperatives by or through PacifiCorp. There is scope for balance sheet engineering to create a more efficient capital structure and reduced tax rate.

Q. WHAT MIGHT THE ALTERNATIVES BE IN THE LONGER TERM?

A. In the longer term, other ways include incentive regulation or deregulation. It is clear that PacifiCorp is positioned to do well in a deregulated electricity generation market in the West. PacifiCorp's low-cost generation mix and strategically located transmission network will be very valuable assets in an increasingly deregulated and competitive market. Other ways in which ScottishPower could benefit financially would be to use PacifiCorp as a platform for growth into other markets, many of which are likely to be deregulated. Sale or partial sale or spin-off of some or all of PacifiCorp's generating assets or transmission assets could be very profitable at some point. ScottishPower has acknowledged that in the longer term, it "intends to investigate opportunities relating to multi-utility service provision." (Response to Wyoming Industrial Energy Consumers, Request No. 14.) ScottishPower has also stated its preference for creating a new holding company because it would facilitate acquisition of new businesses. This could bring financial risks to PacifiCorp, increase its cost of capital, reduce the allocation of capital to PacifiCorp, and over-extend or distract management. A strategy of this nature involves risk, even if it is eventually successful. If it runs into difficulties, the level of risk would of course be greater.

Q. HAVE FINANCIAL ANALYSTS COMMENTED ON THE DIFFERENT OUTLOOK FOR UTILITY REGULATION AND PROFITS IN THE U.K. AND U.S.?

A. Yes. It has been noted that the tide of Transatlantic mergers and acquisitions has turned. During the 1990s, while U.K. electric utilities have been outperforming those in the U.S., there have been a number of acquisitions of U.K. companies by U.S. companies. Now, financial analysts believe that the time may be ripe for a reversal of this trend. The expected decline in profit growth in the U.K. contrasts with prospects for increasing returns in the U.S. Merrill Lynch, in a June 1998 report entitled *Transatlantic Consolidation: The Empire Strikes Back*, describes the evolving situation in the U.S. as follow:

> Regulation has hitherto been based on cost-recovery-plus-return-on-invested-capital, but is now moving towards U.K.-style price cap mechanisms. The (U.S. electric utility) industry is also slowly moving to a similar type of *structure* to the U.K. The competitive generation and supply sectors will become more and more separated from regionalized wires businesses subject to regulation. This should help U.K. predators focus on acquisitions that fit.

It is a moot point whether PacifiCorp fits this deregulation scenario. What seems clear, though, is that this type of thinking affects British companies looking for higher returns, and they can be expected to push for deregulation. ScottishPower has stated its preference for price-cap regulation over strict rate of return regulation. Deregulation of generation and supply also offers clear advantages for PacifiCorp, but not for its customers who enjoy low rates from its regulated rate base.

6. The Outlook for PacifiCorp's Financial Situation and Regulation With and Without the Merger

Q. WHAT IS THE FINANCIAL OUTLOOK FOR UTAH POWER & LIGHT ON A PACIFICORP STAND-ALONE BASIS?

A. Utah Power and its customers should continue to enjoy the benefits of low cost of capital and some of the lowest electric rates in the country. Utah Power's rates were already among the lowest in the country before the recent rate case. They were reduced by a further 12% by the Utah Commission in March of this year, reflecting a reduction in the authorized rate of return on common equity from 12.1% to 10.5%, a change in the interjurisdictional allocation method, and other adjustments.

Q. ABSENT THE MERGER, WILL PACIFICORP'S EFFICIENCY IMPROVE?

A. Yes. Nobody disputes the fact that PacifiCorp has already embarked on a program to enhance efficiency as part of its back-to-basics strategy. Moreover, I anticipate that PacifiCorp will be under increasing financial pressure to bring about improvements in the way it does business. There are several sources of pressure. First, the electricity market is becoming more competitive. There will be pressure on PacifiCorp to respond to the needs of customers who face competitive alternatives in the marketplace. Second, PacifiCorp's stockholders, through the board of directors, can be expected to exert considerable pressure on the Company. They are already dismayed at the poor financial results of the last year, and they will also want to be assured that PacifiCorp retains the competitive edge that it already has as a low-cost producer. Third, it is reasonable to expect that regulatory pressure on the company will be maintained.

Q. WOULD PACIFICORP'S RATEPAYERS IN UTAH STAND TO BENEFIT FROM THE FINANCIAL CONSEQUENCES OF THE ACQUISITION?

A. No. On the contrary, I believe there are financial risks that are more likely to increase than reduce rates over time. "Creation of value" for stockholders is not the same as benefits for ratepayers. Mr. Biewald has testified on the cost savings issue, and I will not address that issue further here.

Q. TURNING TO COST OF CAPITAL, COULD SCOTTISHPOWER MANAGEMENT ACHIEVE A LOWER LEVEL OF CAPITAL COSTS FOR PACIFICORP?

A. No. It would be difficult for ScottishPower to achieve a lower weighted average cost rate without increasing the proportion of debt in the capital structure. However, this would increase investors' level of financial risk. It would probably be unwise to do this at a time when the electricity industry is experiencing structural changes and it would reduce the Company's degree of financial flexibility. Indeed, ScottishPower has said that its intention would be to slightly strengthen PacifiCorp's capital structure by bringing the common equity ratio up a bit, to 47%, which is the average for the comparable group of single-A rated companies.

Q. SCOTTISHPOWER HAS CLAIMED THAT PACIFICORP'S COST OF CAPITAL WOULD *DECLINE* AS A RESULT OF THE MERGER. WHY DO YOU DISAGREE?

A. ScottishPower has argued that the cost of capital to PacifiCorp would decline because ScottishPower is in a financially stronger situation than PacifiCorp today, and would create a larger utility system after the merger. This argument does not withstand scrutiny. First, ScottishPower has not presented any estimate of the cost reduction. "No additional analyses or studies that quantify the impact of the transaction on PacifiCorp's financial strength have been undertaken. No such studies could be undertaken that could precisely quantify this effect." (response to CCS Data Request No. 9.40) Second, the size factor is irrelevant when PacifiCorp on a stand-alone basis is already one of the larger utilities in the U.S., the 25th as measured by capitalization, 24th by installed capacity and 6th by sales, according to Warburg Dillon Read. (Dec. 1998 report on the merger, p.19) Third, it seems very likely that when PacifiCorp's back-to-basics strategy begins to show results, any lingering concerns of the financial community about PacifiCorp's 1997-1998 diversification strategy will be laid to rest. It is interesting to note that when Moody's Investors Service changed its outlook from stable to negative on October 23, 1998, when PacifiCorp announced its new strategy, a Moody's vice president expressed concern about the planned stock buyback. He said: "Although refocusing activities at the U.S. utility reduces overall business risk, the increase in leverage resulting from the stock buyback reduces financial flexibility and puts downward pressure on ratings." (Electric Utility Week, Nov. 2, 1998) With the merger, the stock buyback has been put on hold. However, it is now ScottishPower that is considering a stock buyback at the parent company level. Moody's put ScottishPower under review for a downgrade Nov. 3, 1998, put it under review for a further downgrade and cut ScottishPower's long-term senior debt rating from Aa2 to Aa3 on December 7, citing the outlook for lower U.K. regulated earnings and "the perceived likelihood of a substantial U.S. acquisition that could weaken debt protection measures." (Electric Utility Week, Dec. 14, 1998) Fourth, in my opinion there would be greater financial risk in the long run from a renewed ScottishPower acquisition strategy, which might or might not be successful.

Q. ASSUME FOR THE SAKE OF ARGUMENT THAT THE MERGER WERE TO RESULT IN AN UPGRADING OF PACIFICORP'S BONDS. WOULD THAT BENEFIT PACIFICORP CUSTOMERS?

A. If PacifiCorp's debt rating were upgraded, it would mean that the Company could issue new bonds at slightly more favorable interest rates. This would affect the new bonds issued in the next few months, perhaps a year. I believe that after that period one cannot predict that PacifiCorp's borrowing costs would be lower as a result of the merger, because I do not believe that PacifiCorp will be stronger financially as a result of the merger in the longer run. Meanwhile, if borrowing costs were indeed lower during the next year or so, PacifiCorp's embedded cost of debt would be slightly lower at its next rate case. This would be a second-order effect, because it would only reflect interest rates on debt issued during a period of up to a year.

Q. HOW SIGNIFICANT WOULD THAT EFFECT BE?

A. Assuming, for the sake of argument, that PacifiCorp debt could be upgraded by one full grade, from single-A to double-A – an optimistic assumption – the decline in interest rate might be 20 basis points or 0.2 percentage points. For each $100 million of PacifiCorp long-term debt issued, the reduction in annual cost of debt would be $200,000. From information contained in PacifiCorp's SEC Form 10-K for 1998, it appears that the Company expects to raise about $150 million during 2000. (Capital spending of $479 million plus refunding of $170 million of maturing debt, less operating cash flow of about $500 million.) A hypothetical reduction of $300,000 in annual debt costs would be insignificant when one considers that PacifiCorp's annual cost of debt is approximately $235,000,000 (PacifiCorp's 1998 FERC Form 1, p. 117) and retail revenues are currently around $2,200,000,000.

Q. IS THE *AVAILABILITY* OF CAPITAL TO PACIFICORP LIMITED?

A. No. PacifiCorp reported to the SEC that as of December 31, 1998, it had unused borrowing capability of $2.5 billion based on its credit agreements. Furthermore, the excess cash that PacifiCorp has amassed from the sale of businesses creates a source of capital that can be used to optimize its capital structure and retain a reasonable cash reserve. Recently, for example, PacifiCorp has entered into a sale of its interest in Centralia.

Q. ASSUME FOR THE SAKE OF ARGUMENT THAT SCOTTISHPOWER *DOES* SUCCEED IN BRINGING INCREMENTALLY MORE EFFICIENT MANAGEMENT TO PACIFICORP, NET OF THE COST. WILL THIS BENEFIT CUSTOMERS?

A. By refusing to make any significant rate guarantees, I believe that ScottishPower has signaled its intention to retain for as long as possible any efficiency gains in the form of profits rather than flowing them through to customers in lower rates.

Q. HOW WOULD THIS APPROACH TO INCREASING PACIFICORP'S PROFITABILITY ENABLE SCOTTISHPOWER TO ACHIEVE ITS FINANCIAL OBJECTIVES?

A. A key financial objective of ScottishPower is to maintain dividend growth. It currently targets dividend growth of 7-8% in real terms through at least 2000. It would be a shock to ScottishPower's stockholders to have that dividend growth prospect notched down substantially.

Q. PLEASE EXPLAIN THE IMPORTANCE OF DIVIDEND GROWTH.

A. Dividend decisions are among the most important decisions made by any corporation. This is not difficult to understand; the dividend payout is after all the only regular payment by a company to its stockholders. The standard discounted cash flow (DCF) method of valuing a stock is based on the current dividend yield and the expected growth rate of dividends in the future. There is always a situation of information asymmetry between a company and the financial community; the company knows many things about its business that others do not. In these circumstances, a dividend announcement is often seen as a signal about a company's prospects. A cut in dividend, or in prospective dividend growth, leads to a re-assessment of a company's prospects by the financial community.

Q. IN LIGHT OF YOUR EARLIER DISCUSSION OF DIVIDENDS AND EARNINGS GROWTH TRENDS IN THE U.S. AND U.K., HOW COULD

PACIFICORP SUSTAIN ITS RELATIVE HIGH RATE OF DIVIDEND GROWTH THROUGH PACIFICORP?

A. I believe that the only way it could do so would be to squeeze as much profit as it could out of PacifiCorp during the next few years.

Q. IS THE FINANCIAL COMMUNITY EXPECTING SCOTTISHPOWER TO ADOPT AN APPROACH OF THIS KIND?

A. Yes. One of the main themes in the financial community's assessment of the merger is the conflict between the interests of ScottishPower stockholders and PacifiCorp ratepayers. This conflict has been bluntly stated as follows:

> ScottishPower can only create value from this deal if it can cut costs at PacifiCorp and keep the benefits away from the multitude of US regulators ... The central challenge facing ScottishPower in this deal is to navigate seven sets of US regulators without giving away the efficiency upside. Already Utah and Oregon (PacifiCorp's two biggest states) are making unhelpful noises about getting something for customers out of the merger. (Bankers Trust/ Alex Brown 2/19/99)

Q. TO SUMMARIZE, IS IT YOUR OPINION THAT SCOTTISHPOWER'S FINANCIAL GOALS WILL INCREASE THE PRESSURE FOR HIGHER RATES FOR PACIFICORP CUSTOMERS?

A. Yes. I believe the considerations I have described above will result in PacifiCorp becoming a more financially driven utility. Further, the financial risks of its acquisition strategy will tend to increase PacifiCorp's rates.

Q. CAN PACIFICORP BE PROTECTED FROM THE FINANCIAL VICISSITUDES OF SCOTTISHPOWER?

A. No, not entirely. Expansion using PacifiCorp as a platform could bring risk directly to PacifiCorp. And continued expansion by the ScottishPower group through other subsidiaries of a parent company could bring increased debt or financial distress to the parent company, could distract management, and could affect such features of PacifiCorp management as dividend policy and the availability of capital for core operations. These eventualities may seem remote at the present time, when the financial community in the U.S. and U.K. is bullish and mergers and acquisitions are commonplace. When financial markets are buoyant, expansion and diversification tend to look good, but if there is financial turbulence the financial community's assessment of ScottishPower's situation could deteriorate. It is interesting that even today the stock of ScottishPower and PacifiCorp are under some pressure.

New ScottishPower's Proposed Corporate Structure

Q. PLEASE DESCRIBE THE PROPOSED ACQUISITION.

A. The proposed acquisition essentially takes the form of an exchange of shares rather than a cash purchase. PacifiCorp will become an operating subsidiary of a U.K. corporation. The headquarters of the group will be in Glasgow, Scotland, and PacifiCorp's headquarters will remain in Portland, reporting to Glasgow.

Q. WHAT WILL THE NEW SCOTTISHPOWER CORPORATE STRUCTURE BE?

A. Various alternatives have been discussed. Initially, the idea was to make PacifiCorp a direct subsidiary of ScottishPower. It seems reasonably clear at this point, however, that ScottishPower will create a holding company called ScottishPower plc (also called New Scottish Power or Holdco) that will own *both* ScottishPower U.K. and, through subsidiaries in the U.K. and a partnership in Nevada, PacifiCorp. When I refer to "ScottishPower" in my testimony, I am using the name in a non-legalistic sense to apply to the entity that owns and manages PacifiCorp. My assumption is that ScottishPower *management* will continue to be located in Glasgow, whatever corporate structure is created from a formal or legal standpoint. When necessary to be more precise, I will refer to ScottishPower plc to refer to the new holding company and ScottishPower U.K. to refer to ScottishPower's British operation and overall corporate management.

Q. HOW DOES THE PROPOSED CORPORATE STRUCTURE AFFECT REGULATORY CONCERNS?

A. The structure has been devised in part to address the concerns of the Office of Electricity Regulation (Offer). The equivalent U.S. concerns include the need to ensure that electricity supply is adequately funded and managed and will remain reliable, the appropriate pricing of affiliate transactions, and facilitation of competition. Those concerns are addressed in part by what is called "ring-fencing" in the U.K. and is similar to corporate or functional separation of business segments coupled with affiliate codes of conduct, etc. The creation of a holding company of which PacifiCorp is a separate subsidiary responds in part to these concerns.

Q. HOW WOULD THE NEW CORPORATE STRUCTURE AFFECT PACIFICORP'S FINANCIAL SITUATION AND SOURCES OF CAPITAL?

A. It is not clear at this point what the *financial* ramifications of the new corporate structure will be. Where will equity or debt be issued and held, where will taxes be paid, etc.? Further, will there be a service company in the ScottishPower group or will corporate management services be performed by ScottishPower U.K.? These issues, some of which have not been finally determined as far as I know, could affect the financial situation and state regulation of PacifiCorp. I will show that it is essential for U.S. regulators to be able to monitor and take into account the financial and tax situation of the parent company and possibly the whole group in order to effectively regulate PacifiCorp's financial situation, capital structure and rate of return.

Affiliate Transactions and the Allocation of Corporate Costs

Q. WILL THE NEW MANAGEMENT STRUCTURE RESULT IN INCREASED CORPORATE COSTS?

A. Yes. There is no dispute that the new corporate structure will add new layers of corporate costs at the parent company, ScottishPower U.K. or possibly corporate service company levels. "Corporate costs will be allocated from both ScottishPower plc (the HoldCo) and from ScottishPower UK plc. The HoldCo structure is only a recent development and, as such, decisions on where corporate functions reside have yet to be made." (response to Utah DPU Merger Data Request S8.10) The only question is whether and how any cost savings at the PacifiCorp level are netted against these additional costs. In any event, there is the problem of a new level of corporate costs to be accounted for and allocated to PacifiCorp. It is not clear what amount of corporate costs is involved. (An initial data response was erroneous.) The total amount of ScottishPower corporate management costs could be somewhere in the range of $50-100 million.

Q. HAS IT BEEN DETERMINED HOW THOSE COSTS WILL BE ALLOCATED TO PACIFICORP?

A. No. The problem of allocating ScottishPower corporate costs has already resulted in some inconsistencies in the U.K. Apparently the method applied to Manweb – what could be called the "standard" method -- would, if applied to Southern Water, have significantly increased the level of corporate costs. Accordingly, a deal was done with the regulator, Ofwat, to cap or fix Southern Water's corporate costs including the ScottishPower allocation at a level "consistent with" Southern Water's previous level of corporate costs.

Q. IS IT PROPOSED TO APPLY THE STANDARD METHOD TO PACIFICORP?

A. No. The standard method, which apparently relies significantly on the proportions of assets of subsidiary operations, would have resulted in PacifiCorp bearing more than half of ScottishPower's corporate cost allocation. Accordingly, some new allocation method needs to be devised, but none has yet been devised. Meanwhile, a limit has been proposed according to which there would be a small net reduction of $10 million in PacifiCorp corporate costs including the ScottishPower allocation.

Q. DOES THIS CAP RESOLVE THE ISSUE?

A. No, not entirely. I believe there is a continuing problem if ScottishPower cannot recover the full amount of corporate costs in the rates of its operating subsidiaries. ScottishPower stockholders, who would have to bear the costs that are not recovered, can be expected to take this into account in determining the value of ScottishPower's stock. And sooner or later I would expect the issue to come up again, maybe at the time of ScottishPower's next acquisition. At some point, ScottishPower might create a service company which would contract with PacifiCorp to provide certain services. To the extent that such services included what is now covered by corporate management services, this would make it more difficult to figure out the total cost allocation to PacifiCorp.

Q. DOES THE ADDITION OF ANOTHER LAYER OF MANAGEMENT TO THE EXISTING MANAGEMENT STRUCTURE OF PACIFICORP RAISE POTENTIAL MANAGEMENT PROBLEMS?

A. Yes. Coordination between countries and over a long distance will represent a challenge. Warburg Dillon Read notes that management depth will be vital:

> (the integration of PacifiCorp) will be made more difficult by the extent of PacifiCorp's operations in five U.S. states and the physical distance from ScottishPower's head office. Conversely, (ScottishPower) management will need to ensure that the management of the UK core businesses remains focused on

> delivering results at a time when both regulatory and competitive pressures are expanding. (Dec. 1998 report on the merger, p.32)

There is always the danger that management resources will be stretched too thin. Among the reasons Bankers Trust/ Alex Brown believes that "this particular acquisition is more risky than (Manweb and Southern Water)" is the management challenge:

> The key operational manager responsible for implementation at both Manweb and Southern Water, Mr. Mike Kinski, has left the group to be Chief Executive of Stagecoach plc. Mr. Alan Richardson, the ScottishPower executive charged with being the new CEO of PacifiCorp, while clearly having a track record, faces a daunting task of relocating to the north west of the USA in order to aggressively cut costs and boost efficiency. (Bankers Trust/ Alex Brown report on the merger, p. 3)

Of course, the hope and intention is that the new management structure will strengthen PacifiCorp management. But there is the potential downside of management friction and duplication when an overseas management that is operating in a different national context with different regulation, different work practices, etc., is introduced. Strong personalities can find it difficult to share power. Differences in management philosophies and corporate cultures can lead to tensions. These differences are more likely to occur between managements which have had different histories of regulation, labor relations, etc., in different countries. Many PacifiCorp corporate functions will remain in Portland. The principal conduit through which Glasgow will assert its authority over Portland management on a continuing basis will be a group of Scottish executives relocated to Portland.

Q. DOES THE ACQUISITION RAISE AFFILIATE TRANSACTION CONCERNS?

A. Yes. Admittedly, the remoteness of PacifiCorp from the rest of ScottishPower's existing operations suggests that there will initially be little scope for affiliate transactions. However, affiliate relationships may grow over time. Initially, the primary affiliate concerns relate to the corporate cost allocation problem. The Applicants acknowledge that "the insertion of a HoldCo will probably expand the scope of affiliated interest activities because certain corporate activities will probably remain, and be allocated from, ScottishPower UK plc." (response to Utah DPU Merger Data Request S8.11) These affiliate activities could take a further affiliate form if ScottishPower chose to create a service company and contract with PacifiCorp for the provision of management services.

Financial Concerns Arising From Parent Company Capital Structure

Q. IF THE ACQUISITION TAKES PLACE, HOW WOULD THE FINANCIAL STRUCTURE OF SCOTTISHPOWER AFFECT PACIFICORP'S CAPITAL STRUCTURE?

A. The effect would be that PacifiCorp would become a wholly-owned operating subsidiary of a ScottishPower holding company. PacifiCorp's stock, in other words, would be owned by ScottishPower. This means that the cost of debt and the capital structure of ScottishPower could have a significant effect on PacifiCorp.

Q. PLEASE EXPLAIN.

A. According to ScottishPower, "The entities ScottishPower plc (the holding company), ScottishPower UK plc and PacifiCorp may issue debt, as required, to external parties following the completion of the transaction so as to fund the business in the course of carrying out their operations. The enlarged group will seek funding at the best rates possible." (response to UIEC Merger Data Request No. 6, Q. 91) This departs from the usual situation of holding companies in the U.S. Usually, debt is issued only at the subsidiary or operating company level, *e.g.*, first mortgage bonds backed by the assets of the operating utility. To the extent that ScottishPower finances its holdings of PacifiCorp stock by a mix of debt and equity as opposed to 100% common equity, it would be leveraging its ownership of PacifiCorp and indirectly affecting the capital structure and cost of capital to PacifiCorp. It seems essential to me that U.S. state regulators should be able to monitor the financial situation of the parent company and perhaps the whole group in order to determine that the financial policies of the company are reasonable, the level of financial risk is not excessive, and the cost of capital is appropriate.

Q. PLEASE EXPLAIN WHY THIS SHOULD BE A MATTER OF CONCERN TO THIS COMMISSION.

A. There are two related reasons. First, with PacifiCorp no longer a stand-alone utility, it becomes necessary for the Commission to review the capital structure of the parent company, and possibly the group, in order to satisfy itself that it is reasonable.

Q. WHAT IS A "REASONABLE" CAPITAL STRUCTURE?

A. A reasonable capital structure is one that is within the optimal range in the sense of achieving an appropriate balance between the amount of debt and the amount of equity. Debt typically has a lower cost rate and debt interest costs provide a shield against corporate income taxes. Equity strengthens the balance sheet by providing a cushion against earnings variations and increasing a company's financial flexibility. While a good deal of judgement has to be exercised by a company and its financial advisors in these matters, PacifiCorp's capital structure is probably very close to optimal for a regulated utility. In the recent rate case, the Utah Commission took comfort from the fact that PacifiCorp's financial profile is similar to that of other single-A rated utilities.

Q. HOW WOULD THIS CHANGE IF PACIFICORP WERE A SUBSIDIARY OF SCOTTISHPOWER?

A. With PacifiCorp stock owned by ScottishPower, the true capital structure of PacifiCorp could no longer be determined without taking into account the types of ScottishPower securities that finance ScottishPower's ownership of PacifiCorp common equity.

Q. COULD YOU GIVE AN EXAMPLE?

A. Yes, a hypothetical example would be as follows. Suppose that in the next rate case the Commission determines that PacifiCorp's debt-equity ratio is 50-50 and is reasonable. That would be the end of the matter if PacifiCorp were a stand-alone company. With ScottishPower ownership of PacifiCorp's equity, however, the PacifiCorp equity could be financed in part by debt at the parent company level. Suppose that ScottishPower plc, the holding company, has a 20-80 debt-equity ratio. The true capital structure of PacifiCorp, direct and indirect, is 60% debt and only 40% equity.

Q. AGAIN, WHY SHOULD THIS BE OF CONCERN TO THE COMMISSION?

A. There are two reasons. First, the ScottishPower group would be taking on greater risk than U.S. regulators such as this Commission might regard as reasonable. In these circumstances, for example, a downturn in earnings or a failed venture by the group could result in financial distress to the parent company and reduce the capital available to PacifiCorp.

Q. WHAT IS THE OTHER REASON?

A. The other reason is that the double-leverage structure could effectively serve to siphon off a financial subsidy from PacifiCorp to the parent company. There are two ways in which this could work, both related mostly to taxes.

Q. PLEASE EXPLAIN.

A. According to ScottishPower, the corporate structure to which PacifiCorp is held as an indirect subsidiary of an owned partnership "is for corporate income tax and foreign tax credit management purposes."

(response to UIEC Data Request No. 6 (Question 88). PacifiCorp's allowed rate of return on equity in state jurisdictions is grossed up for corporate income taxes. It is divided by (1-t) where "t" is the tax rate. For example, with an income tax rate of 40% or 0.40, an equity return of 12% has to be grossed up to 20% in the revenue requirement calculation, which is what customers have to pay (12/(1-.40) = 20). Assume hypothetically that ScottishPower's holding of PacifiCorp stock is backed 20-80 by debt and equity respectively. The 20% debt component has a cost rate that does *not* have to be grossed up for income taxes. Put differently, the debt interest provides an income tax shield. However, the cost savings from this tax shield goes to the parent company and is not reflected as an offset to the revenue requirement of PacifiCorp. In other words, PacifiCorp is subjected to the financial risk resulting from greater leverage, but the benefit of greater leverage is captured by the parent company. I compare these situations illustratively in the following table. I also add a difference in effective tax rates between the subsidiary and the parent, and show how this too results in discrepancy between regulated returns, which are supposed to be cost-based, and the actual capital costs and tax costs incurred by ScottishPower.

Q. IN THIS COMPARISON, PLEASE DESCRIBE YOUR PACIFICORP STAND-ALONE CASE.

A. The PacifiCorp stand-alone case is the familiar one used to determine cost-of-capital revenue requirements in a rate case. I assume 50-50 debt and equity, an effective tax rate of 40%, and cost rates for debt and equity of 8% and 12% respectively:

			Gross-of-Tax	Cost
Component	% of Capital	Cost Rate	Cost Rate	Contrib.
Debt	50%	8%	8%	4.0
Equity	50%	12%	20%	10.0

Weighted average cost of capital: 14.0%

Ratepayers pay the full 14.0% and the Company receives 12% on equity after tax.

Q. HOW DOES THE SITUATION CHANGE IF PACIFICORP BECOMES A SUBSIDIARY OF A FOREIGN COMPANY?

A. The 20% earned on equity before tax, which would previously have accrued to the before-tax equity positions of various investors, accrues as before-tax earnings to the parent company in the U.K.

Q. HOW DO DEBT ISSUANCE AND TAX SAVINGS AT THE PARENT COMPANY LEVEL AFFECT THE SITUATION?

A. Two new factors can enter into the picture. First, the parent capital structure may not be 100% equity but could for example be only 80% equity, and the remaining 20% debt with an interest rate of 8%. The debt interest is tax-deductible and reduces earnings by 0.8% on the PacifiCorp investment (20% X 50% X 8%). Second, if the parent can reduce the effective tax rate below 40% to say 35%, depending on the terms of double-taxation agreements between the two countries, it stands to further improve its position.

Q. WHAT WOULD BE THE NET COST RATE TO THE PARENT?

A. The 20 percentage points received by the parent from the subsidiary would be reduced by 0.8 percentage points representing the debt interest cost, leaving 19.2 percentage points taxable. At an effective 35% tax rate, tax would be 6.72 percentage points (19.2 X 35%).

Q. WOULD THE PARENT COMPANY BENEFIT AT THE EXPENSE OF RATEPAYERS?

A. Yes. The parent would retain 13.28 percentage points after tax (20 – 6.72). This would be a return on equity 1.28 percentage points above the 12% cost of equity.

Q. IN YOUR OPINION, WHAT WOULD BE THE FAIR WAY TO CALCULATE COST OF CAPITAL TO PACIFICORP IN THESE CIRCUMSTANCES?

A. I believe it would be fair in this illustrative example to calculate the capital structure and tax rate on a combined parent-subsidiary basis, using combined 60% debt, 40% equity and an effective tax rate of 35%, as follows:

			Gross-of-Tax Cost	
Component	% of Capital	Cost Rate	Cost Rate	Contrib.
Debt	60%	8%	8%	4.8
Equity	40%	12%	18.46%	7.38
Weighted average cost of capital:				12.18%

Q. WHAT WOULD BE THE SAVINGS FOR RATEPAYERS?

A. In this illustrative example, the revenue requirement savings would be based on a reduction in the gross-of-tax rate of return on rate base of 1.82 percentage points (14 – 12.18). For a combined PacifiCorp equity base of approximately $6 billion in the five western states, the revenue requirement reduction in this illustrative example would be $109.2 million per year (6 billion X 1.82%).

Q. HAS SCOTTISHPOWER ADDRESSED THIS ISSUE?

A. No. It has not raised the possibility of flowing through to ratepayers any tax or cost-of-capital savings related to the new corporate structure. In answers to a number of data responses, it appears to be defining rather narrowly the areas of ScottishPower's business that it regards as appropriate for scrutiny by U.S. state regulators.

Q. YOU HAVE DESCRIBED POTENTIAL COST SAVINGS AT THE PARENT COMPANY LEVEL THAT SHOULD BE FLOWED THROUGH TO CUSTOMERS. IS THERE ANY DOWNSIDE TO THE ISSUANCE OF DEBT AT THE PARENT COMPANY LEVEL?

A. Yes. As I noted earlier, the issuance of debt at another corporate level increases the leverage of the group and, other things being equal, could increase the cost of both debt and equity capital to the parent company and possibly the subsidiary too. This is not a matter of solely theoretical interest. It would arise if the parent company were to issue debt and it may arise in the near term if the parent company effects a stock buy-back.

Q. HOW DOES THE MERGER AFFECT THE USE OF PACIFICORP'S EXCESS CASH?

A. In PacifiCorp's financial planning last year, the excess cash was going to be used for a stock buyback. This was regarded as desirable to create a more efficient capital structure, although it raised concerns with bond rating agencies. With the merger, the buyback has been put on hold. ScottishPower, meanwhile, has announced that it plans a stock buyback of pounds 500 million (about $800 million) in order to create a more efficient capital structure *for ScottishPower*. Although, according to ScottishPower, the PacifiCorp cash is not to be used for this purpose, the use of cash to buy back stock would reduce the equity ratio of the ScottishPower group, leaving the group capital structure more highly leveraged. The buyback has been characterized by some financial analysts as part of a ScottishPower plan to create a more efficient capital structure. However, it raises the very issues of tax rates, cost of capital and financial risk that I am discussing here. These should be subject to state review in the U.S. and should be taken into account in determining PacifiCorp's capital structure and cost of capital.

Loss of Local Control

Q. IS THE LOSS OF LOCAL CONTROL AN ISSUE THAT SHOULD CONCERN THE COMMISSION?

A. Yes. I believe that loss of local control is important because it underlies some of the concerns that I have addressed, related to the role of

PacifiCorp in ScottishPower's corporate strategy. With the acquisition, PacifiCorp's western electric utility business would be more like a pawn in a larger financial game, rather than being the primary focus of PacifiCorp management. Of course, local control is no guarantee that management will remain focused. Under PacifiCorp's stand-alone management in 1997-1998, a failed expansion strategy created risks for PacifiCorp's western electric utility business. However, at this juncture local control would be associated with management retaining an appropriate focus.

7. Conclusions

Q. TO SUMMARIZE, WHAT IS THE OUTLOOK FOR PACIFICORP'S RETAIL CUSTOMERS UNDER A SCOTTISHPOWER REGIME AND HOW DOES IT CONTRAST WITH THE OUTLOOK UNDER PACIFICORP ON A STAND-ALONE BASIS?

A. In my opinion, a ScottishPower acquisition would bring financial risks and uncertainties to PacifiCorp and its customers. ScottishPower has embarked on an aggressive strategy of expansion and acquisition. It is clear to the financial community that this strategy is leading increasingly in the direction of unregulated businesses. The profitability of unregulated businesses can be greater than that of regulated businesses, but greater risk always accompanies the hope of higher returns. The core regulated utility business of PacifiCorp could be jeopardized by the financial risks and uncertainties that ScottishPower is likely to bring. ScottishPower has not provided any tangible economic benefits for customers to offset these risks and uncertainties, merely the vague prospect of rate relief as a result of possible cost savings in the future.

Q. PLEASE SUMMARIZE THE FINANCIAL RISKS TO RATEPAYERS THAT WOULD RESULT FROM THE PROPOSED ACQUISITION?

A. There is a risk that the cost of capital to PacifiCorp could rise or the capital available to PacifiCorp might be limited if ScottishPower continues to pursue an acquisition strategy. The ironic feature of this acquisition is that the ambitions of ScottishPower's management today are quite similar to those of PacifiCorp's management in 1997 and early 1998 when it embarked on a roller-coaster acquisition strategy which turned out to be unsuccessful. Here is how PacifiCorp described its "Strategic Rationale" for the acquisition of The Energy Group in February 1998:

> Large step toward becoming a premier global energy company
>
> Presents growth opportunities on three continents as retail competition accelerates
>
> Unlock significant revenue and cost benefits across the business
>
> Sharpens strategic focus through sale of non-core assets
>
> From: PacifiCorp Analyst/Investor Presentation, New York, February 3, 1998.

After it turned out only eight months later that the strategic focus had not been sharpened enough, and PacifiCorp had lost a lot of money, the story was quite different with hindsight:

> Weaknesses of PacifiCorp
>
> - Poor earnings track record in recent years ...
> - Preoccupation with "transforming" transaction
> - Too many underperforming businesses distracting and detracting from the core business

Conclusions

- PacifiCorp needed a new cogent, clear, achievable and fully focused strategy

The Western Strategy

- Our chosen strategy is to focus on .. our "western" electric business …
- Implement a cost reduction program …

Why we chose the "Western" strategy:

- Most achievable
- Lowest risk/most predictable financial results
- Focuses on what we do best
- Most acceptable to our shareholders
- With focus, should bring the most value

Implementing the strategy

- Focus on being a western U.S. electricity company – eliminate external distractions
- Reduce risk in western wholesale business

From: PacifiCorp Investor/Analyst Presentation, New York, October 28, 1998.

Q. WHAT ARE YOUR CONCLUDING COMMENTS, IN LIGHT OF THESE "BEFORE" AND "AFTER" QUOTES?

A. I believe that PacifiCorp's present strategy is sound and low-cost from a financial standpoint, for the reasons outlined by the Company in its October 1998 presentation and discussed in my testimony. Regarding the ScottishPower alternative, my point is that an aggressive diversification strategy is inherently risky. There is no knowing in advance how it is going to work out. There is always the risk that a corporate management will overreach itself. It seems to me likely, in the present case, that ScottishPower will be disappointed by the slow growth of earnings at PacifiCorp. It will try to squeeze more profits out of PacifiCorp and will be tempted to use PacifiCorp as a platform for expansion into more profitable businesses which would be inherently more risky. Quite possibly, it will divest itself of PacifiCorp in the future, as some U.S. companies are now considering divesting themselves of U.K. utilities whose earnings are turning out to be disappointing.

Q. ARE THERE ANY BENEFITS THAT WOULD COMPENSATE PACIFICORP'S CUSTOMERS FOR THE ADDITIONAL RISK?

A. No. My overall assessment is that ScottishPower has not made its case with respect to net benefits. Other witnesses will address the benefits claims. My contribution has been to show that the financial features, contrary to PacifiCorp's claims, will result in costs and risks, not benefits, for customers. I support Mr. Gimble's recommendation that the acquisition be rejected.

17239

Committee of Consumer Services

Witness: Neil H. Talbot

Docket No. 98-2035-04

CCS Exhibit 4.1 (NHT)

NEIL H. TALBOT

Economic & Financial Consultant

Education

M.S.F.	Finance, Boston College, 1992
M.A.	Economics, Cambridge University, England, 1968

Employment History

1995 -	Independent economic and financial consultant.
1980-1994	Tellus Institute, Boston, Mass. Member of Energy Group responsible for utility economic, financial and regulatory analyses.
1973-1979	Arthur D. Little, Inc., Cambridge, Mass. Member of Managerial Economics Section responsible for public utility economic and planning studies and energy economics.
1968-1973	The Economist Intelligence Unit Ltd., London, England. Project leader of Caribbean economic development studies; research and consulting on industrial and utility economics.

Summary of Relevant Experience

Talbot has masters degrees in economics and finance from Cambridge University and Boston College respectively. He has had 30 years' experience as an economic and financial consultant focusing primarily on utility company economic, financial and regulatory issues with the Economist Intelligence Unit of London, Arthur D. Little, Inc. of Cambridge, Mass., and Tellus Institute. He has undertaken a wide range of studies and has testified on rate of return, utility mergers and acquisitions, incentive regulation of utilities, financial modeling of utilities under alternative rate scenarios, valuation of utility assets and evaluation of utility projects and contract buyouts.

In recent years, Talbot has focused on the new issues facing the electric utility industry. He is a consultant to the Arkansas Public Service Commission and the New Jersey Division of Ratepayer Advocate on the restructuring of the electric utility industry. His recent articles include *The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation* (The Electricity Journal, January/February 1999) and *A Stranded Cost Recovery Alternative* (Electricity Journal, May 1988).

Talbot has recently (March 1999) been retained by the Utah Committee of Consumer Services to review the financial aspects of the proposed acquisition of PacifiCorp by ScottishPower. On behalf of the Attorney General of Washington State, he testified in 1996, on the financial impacts of the proposed merger of Puget Sound Power & Light Company and Washington Energy Company. His focus was on financial impacts of the merger and he developed and applied a corporate financial model to the utilities.

Talbot has testified frequently on cost of capital for regulated utilities. In 1995, he presented testimony on behalf of the Illinois Citizens Utility Board (CUB) on the cost of capital of Northern Illinois Gas Company. His testimony also opposed the company's proposed incentive regulation plan, which the company withdrew during the proceedings. Also for CUB, he testified on the cost of service and cost allocations of Commonwealth Edison Company.

In other financial and rate work, Mr. Talbot has testified on the incentive regulation plan (Alternative Rate Plan) for Central Maine Power Company, in testimony before the Maine Public Utilities Commission. And he has testified in Delaware and New Mexico on state implementation of the Energy Policy Act of 1992. He is the author of an AARP position paper entitled *Evaluating Price Cap Proposals in the Electric Utility Industry*. In 1998, he completed a *Sunset Review of the Energy Center of Wisconsin*.

Selected Testimony

Agency	**Case or Docket No.**	**Date**	**Topic**
Arkansas Public Commission	97-451-U	May 1998	Testified as Staff Expert in Electric Service Industry Restructuring Proceeding
Arkansas Public Service Commission	96-360-U	July 1997	Changes in Retail Rates and Transition to Competition Plan
Washington U.T.C.	UE-960195	Sept. 1996	Proposed Merger of Puget Sound P&L and Washington Natural Gas Co.
Maine Public Utilities Commission	96-187	Aug. 1996	Proposed Interim Competitive Transition Charge Tariff of Central Maine Power Co.
Illinois Commerce	95-219	Nov.	Incentive Regulation and Rate of Return

Commission		1995	for Northern Illinois Gas Company
Maine Public Utilities Commission	95-901	April 1995	Evaluation of Purchased Power Contract Buyout Proposals of Bangor Hydro
California Public Utilities Commission	A.93-12-029	Sept. 1994	Performance Based Ratemaking for Southern California Edison Company
N. Hampshire Public Utilities Commission	93-179	June 1994	Eval. of proposed buyouts by Public Service Company of New Hampshire of long-term purchased power contracts
Illinois Commerce Commission	94-0065	June 1994	Division among customer classes of an increase (or decrease) in revenue requirements for Commonwealth Edison Company, focusing on cost-of-service studies, both marginal and embedded
Kansas Corporation Commission	176,716U	Oct. 1991	Fair rate of return for KPL's Kansas gas operations
Kansas Corporation Commission	172,745-U 174,155-U	Jan. 1991	Proposed merger of Kansas Gas & Electric Company and Kansas Power & Light Company
New Hampshire Public Utilities Commission	DF 89-085	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation
New Hampshire Public Util. Com.	DR-89-244	March 1990	Rate impact of Northeast Utilities take-over of Publ. Serv. Co. of N.H.
Pennsylvania Public Utility Commission	R-891364	Oct. 1989	Fair rate of return and financial impact of rate recommendations on Philadelphia Electric Company
West Virginia P. S. Com.	Case No. 89-173-E-GI	Aug. 1989	Annual fuel review of Appalachian Power Company
Connecticut D. P. U. C.	89-02-16	June 1989	Fair Rate of Return and Rate Design for Connecticut Water Company

New York Public Service Commission	29484 and 88-E-084	July 1988	10-Year Rate Plan of Long Island Lighting Company
Public Service Commission of Utah	87-035-27	Apr. 1988	Effects of the Proposed Merger on UP&L's Energy Balancing Account and on Its Financial Sit. and Cost of Capital
New Mexico Public Service Commission	1811	Jan. 1988	Fair Price for Coal Resources
Public Service Com. of Indiana	38045	Nov. 1986	Evaluation of a power plant for Northern Indiana Public Service Company
Public Service Commission of Maryland	8522	July 1986	Management Audit of Potomac Electric Power Company's Fuel Procurement Practices
West Virginia Public Service Commission	86-081-E-GI 86-082-E-GI	May 1986	Economic Analysis of Pumped Storage Facility
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224	June 1985	The Financial Impact of Alternative Rate Treatments of Wolf Creek on Kansas City Power & Light Company
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U	April 1985	Concerning Wolf Creek Fuel Procurement and Nuclear and Other Fuel Costs
State of Connecticut D. P. U. C.	84-02-09	June 1984	Fair Rate of Return for Connecticut Natural Gas Company
Public Service Commission of Utah	80-035-17	Jan. 1981	Long-range Forecast: Electric Energy Requirements and Peak Demand
Ohio Power Siting Commission		July 1978	CAPCO Power Pool Load Forecast
Idaho Public Utilities Commission		March 1976	Evaluation of Pioneer Power Plant

Consulting, Research & Papers

Ongoing	Consultant to the Arkansas Public Service Commission on electric utility industry restructuring and competitive retail access.
Ongoing	Consultant to New Jersey Division of Ratepayer Advocate on electric utility industry restructuring and competition, working regularly in client□s office as staff consultant drafting position papers
January 1999	*The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation*, Electricity Journal, Vol.12, No. 1
May, 1998	*A Stranded Cost Recovery Alternative*, Electricity Journal, Vol.11, No. 4
October, 1996	*A Consumer's Skeptical Perspective on Multi-Year Price Cap Plans*, Presentation to Washington, D.C. Conference on *Performance-Based Ratemaking for Electric & Gas Utilities* (Int. Bus. Communications)
August, 1996	*Evaluating Price Cap Proposals in the Electric Utility Industry*, published by American Association of Retired Persons.
July, 1996	*Appraisal of New England Power Company's Moore Station*, a report for Town of Waterford, Vermont
February, 1996	Consultant of Pennsylania Office of Consumer Advocate on Multi-Year Rate Plan of Pennsylvania Power Company
1995	Consultant to City of Wynnewood, Oklahoma, on Long-Term Power Contract with Oklahoma Municipal Power Assoc.
December, 1995	Support for Great Bay Power Corp. with Regard to Cost of Equity Capital in its Cost-of-Service Filing with F. E. R. C.
February 1995	Comments on Retail Competition in the Electric Power Industry Filed with New Hampshire PUC on Behalf of the Office of the Consumer Advocate
December 1994	Assistance on public utility holding company and diversification proposal of Pennsylvania Power & Light Company
November	Preparation of Comments on Electricity Competition filed with the

1994	Pennsylvania PUC by the Office of Consumer Advocate
June 1994	"Establishing Market-Based Performance Standards for Gas Distribution Utilities," presented at: Public Meeting on Market-Based Performance Standards, Salt Lake City, Utah, June 21. Co-author.
December 1993	Discussion Draft - *State Implementation of 1992 Energy Policy Act 1992: IRP, Rate Design, and the PURPA Standards*. Principal investigator.
1992-1993	Co-ordinator of Energy and Environmental Alternatives Planning Assistance Program - Africa. For Stockholm Environment Institute.
1993:	*Zambia: Resuming the Energy Transition.* A report to: Zambia Department of Energy. Co-author. For Stockholm Environment Institute, funded by Swedish International Development Agency.
1994:	*Zimbabwe: Energy End-Uses and End-Use Efficiency.* A report to: Zimbabwe Department of Energy. For Stockholm Environment Institute and Swedish International Development Agency. Co-author.
Oct. 1993	*Financial Economics and Renewable Energy*, presented at: NARUC-DOE National Conference on Renewable Energy, Savannah, Georgia, Oct. 3-6.
July 1992	*Integrated Energy - Environment Planning: Experiences from the United States and Africa*, paper presented with Michael Lazarus, at South African Energy Policy Research and Training Project Workshop, Cape Town.
December 1991	Appraisal of Harriman Hydroelectric Plant of New England Power Co. A report to Town of Whitingham, Vermont. Principal author. 89-047.
Jan.-June 1991	U.S. Agency for Int. Development. Senior Econ. for energy price reform studies for Romania. Provided advice to government regarding energy price reform, energy planning and environmental impacts.
July 1977	*Management Effectiveness and Operating Efficiency of Kansas Gas and Electric Company,* a report to the Kansas Corporation Commission. Co-author.
Feb. 1976	*Idaho Power Company's Need for Additional Generating Capacity,* a report to Idaho Public Utilities Commission. Principal investigator.
Apr. 1974	*Inflation and Economic Growth in the U.S. Virgin Islands,* a report to the Legislature of the U.S. Virgin Islands. Principal investigator.

Jan. 1974 *A Study of International Inflationary Trends, with Special Emphasis on Algeria,* a report to the Algerian Government. Co-author.

Sept. 1973 *Long Term Load Forecast,* a report to Potomac Electric Power Co. Author.

Oct. 1976 Speech on *Load Forecasting for Electric Utilities* published in Proceedings of Need for Power Conference, Columbus, Ohio.

Professional Societies

Member, American Economic Association
Member, Financial Management Association
Member, National Association of Business Economists

5/99

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Direct Testimony and Exhibits to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, on the 18th day of June, 1999.

Brian W. Burnett
CALLISTER NEBEKER & McCULLOUGH
Gateway Tower East, Suite 900
10 East South Temple
Salt Lake City, Utah 84133

Edward A. Hunter
STOEL RIVES LLP
201 South Main, Suite 1100
Salt Lake City, Utah 84111-4904

Michael Ginsberg
Assistant Attorney General
160 East 300 South 5th Floor
PO Box 140857
Salt Lake City, Utah 84114-0857

Peter J. Matheis
Matthew J. Jones
BRICKFIELD BURCHETTE & RITTS, PC
1025 Thomas Jefferson Street NW
800 West Tower
Washington, D.C. 20007

Bill Thomas Peters
David W. Scofield
PARSONS DAVIES KINGHORN & PETERS PC
185 South State Street, Suite 700
Salt Lake City, Utah 84111

F. Robert Reeder
VAN COTT BAGLEY CORNWALL & McCARTHY
50 South Main Street, Suite 1600
PO Box 45340
Salt Lake City, Utah 84145

William J. Evans
PARSONS BEHLE & LATIMER
201 South Main Street
PO Box 45898
Salt Lake City, Utah 84145-0898

Roger O. Tew
60 South 600 East, Suite 200
Salt Lake City, Utah 84102

Lee R. Brown
Vice President
Magnesium Corporation of America
238 North 2200 West
Salt Lake City, Utah 84116

Daniel Moquin
Assistant Attorney General
1594 West North Temple, Suite 300
Salt Lake City, Utah 84116

Gary A. Dodge
PARR WADDOUPS BROWN GEE & LOVELESS
185 South State Street, Suite 1300
Salt Lake City, Utah 84111-1536

Eric Blank
Law Fund Energy Project
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Steven W. Allred
Salt Lake City Law Department
451 South State, Suite 505
Salt Lake City, Utah 84111

Matthew F. McNulty III
Stephen R. Randle
RANDLE DEAMER ZARR ROMRELL & LEE PC
139 East South Temple, Suite 330
Salt Lake City, Utah 84111-1004

David F. Crabtree
Deseret Generation & Transmission Co-operative
5295 South 300 West, Suite 500
Murray, Utah 84107

Paul T. Morris
3600 Constitution Boulevard
West Valley City, Utah 84119

Dr. Charles E. Johnson
Salt Lake Community Action Program &
Crossroads Urban Center
1338 Foothill Blvd., Suite 134
Salt Lake City, Utah 84108

Brian L. Farr
Assistant Attorney General
160 East 300 South
PO Box 140857
Salt Lake City, Utah 84114-0857

Arthur F. Sandack
8 East Broadway, Suite 620
Salt Lake City, Utah 84111

Cheryl Murray