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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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COMMISSIONERS
KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN

DOCKET NO. E-01773A-09-0472

STAFF'S NOTICE OF FILING REPLACEMENT DIRECT TESTIMONY PRUDENCE REVIEW

PUBLIC VERSION

Staff of the Arizona Corporation Commission ("Staff") hereby files the REPLACEMENT Public Version of the Direct Testimony (concerning Prudence Review) of John Antonuk, Richard Mazzini, and Randall Vickroy on behalf of the Utilities Division in the above docket. At Staff's request, the Public Version of this Direct Testimony, filed on Friday, July 30, 2010, was withdrawn from Docket Control today because Staff was informed that page 14 of the Public Report Review of AEPCO Fuel, Purchased Power, Generation, and FPPAC Management, Operations, and Prudence attached to Mr. Antonuk's testimony inadvertently contained confidential information. The REPLACEMENT Public Version of Staff's Direct Testimony (concerning Prudence Review) has been corrected to remove the confidential information that had been inadvertently disclosed on page 14 of the earlier version.

Although the confidential information is limited to one page, Staff requests all individuals who received a copy of the Public Version filed on Friday July 30, 2010 to destroy any electronic or hard copies of this version to avoid any further disclosure or confusion. Please use this REPLACEMENT version of the Direct Testimony and Report (concerning Prudence Review) in its place.

The Unredacted version of John Antonuk's Direct Testimony was provided under seal to the Commissioners, the assigned Administrative Law Judge and the parties that have signed the Protective Agreement in this case on July 30, 2010.

RESPECTFULLY SUBMITTED this 6th day of August 2010.

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Kaye Christine

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-09-0472

(REDACTED)

DIRECT

TESTIMONY

(PRUDENCE REVIEW)

OF

JOHN ANTONUK

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 30, 2010

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EXHIBIT

INTRODUCTION

Q State your name, position, and business address.

A. My name is John Antonuk. I am president of The Liberty Consulting Group ("Liberty"). My business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Antonuk, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I began my career in service with the Commonwealth of Pennsylvania, first as an investigator with the Attorney General's Office (investigating major issues in pending civil litigation cases involving that office), and then as Assistant Counsel to the Pennsylvania Public Utilities Commission. Then, for several years, I headed a group in the Regulatory Affairs Department of Pennsylvania Power & Light Company (now PPL). After serving for a number of years as the head of the litigation consulting practice for a major west coast management consulting firm, I was one of the founders of Liberty, which is now approaching a quarter century of service. I have managed or provided executive direction in two hundred or more Liberty projects, working in virtually every State and serving two-thirds of the State utility regulatory authorities in the United States. My work has involved investor-owned, cooperative, public authority and municipally-owned electricity, natural gas, and telecommunications utilities. I have led or conducted work involving nearly every facet of utility governance, management, operations, finance, rate and regulatory, and corporate support.

Addressing energy utility fuel and energy management and operations performance has been an area of particular emphasis for me, not only in my assignments with Liberty, but also in my tenure with the public utility commission and a major electric utility in Pennsylvania.

My work in fuel procurement and management began in the immediate aftermath of the first Mideast oil embargo in the early 1970s; it has continued throughout many engagements across my time with Liberty.

I am an honors graduate of Dickinson College and the Dickinson School of Law.

Q. Have you prepared a more detailed summary of your background?

A. Yes; it is contained in Exhibit JEA-1 provides it.

Q. What is the purpose of your testimony?

A. Liberty performed under my overall direction: (a) an examination of the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), and (b) an engineering review of AEPCO's facilities. Liberty prepared a report addressing the findings, conclusions, and recommendations of that examination. It is attached to my testimony as Exhibit JEA-2. While the entire report was prepared under my direct supervision; Randall Vickroy is appearing as a witness to address questions about the portions of Exhibit JEA-2 addressing Power Transactions (Chapter VI) and Richard Mazzini is appearing as a witness to address questions about the portions of Exhibit JEA-2 addressing Engineering Analysis/Plant Operations (Chapter VII). They had direct responsibility for conducting the activities which underlie the conclusions and recommendations described in those chapters.

Q. What was the scope of the Liberty review described in Exhibit JEA-2?

A. Liberty addressed the following 18 areas that were identified by Staff in the Request for Proposals that set the scope for the examination that Liberty performed:

- Overall fuel and purchased power procurement policy, goals, and strategies
- Organization and decision making structure
- Fuel and purchased power procurement policies and procedures
- Fuel and purchased power costs (test year and historical)
- Plant availability and capacity factor data and trends
- On-site inspection of major Apache Station Generation Plant facilities
- Modeling to develop forecasts of fuel and purchased power requirements
- Dispatch modeling and effectiveness
- Fuel and purchased power contracts and compliance with terms and conditions
- Hedging
- Off-system sales
- AEPCO audits of fuel procurement and purchased power
- Historical fuel and purchased power prices
- Sample review of contract entry and administration processes and activities
- Calculation of base cost of fuel and purchased power
- FPPAC historical performance and continuation
- Potential FPPAC modification
- FPPAC Plan of Administration changes.

Liberty divided the work required by these 18 specific scope items into the following overall areas:

- Organization, Staffing, and Controls
- Fuel Contracting
- Fuel Supply Management
- Gas Hedging
- Power Transactions
- Engineering Analysis/Plant Operations
- FPPAC.

Q. Please summarize what Liberty concluded in the area of organization, staffing, and controls?

A. In my opinion AEPCO's fuel and energy management division is organized appropriately and it includes capable individuals. All personnel involved in fuel and energy procurement and management activities operate under appropriate job descriptions. An appropriate set of procedures, policies, guidelines, approval authorities, and trading controls address technical and ethical performance. AEPCO has made effective use of ACES Power Marketing to provide a range of capabilities and services that are generally difficult for relatively smaller organizations to replicate. One area requiring improvement is in the conduct of internal audits regarding fuel and energy procurement and management. The magnitude of fuel and purchased power costs and the risks they pose in any organization like AEPCO's calls for more frequent and robust examinations of costs and performance.

Q. Please summarize Liberty's conclusions in the area of fuel contracting.

A. AEPCO's fuel procurement has been supported by reasonable consumption forecasts. There has, however, been a recent increase in inventory due to less availability of the two Apache steam units. Procurements have considered an appropriate range of alternatives, included proper analysis of those alternatives, properly considered the potential for significant changes in freight rates, and produced sufficient justification and approval documentation. AEPCO has pursued coal resales and swaps, which have produced savings for members, permitted opportunity for testing new sources of supply, and mitigated the effects of increased rail costs. The Cooperative's actions in these cases are commendable. AEPCO has also taken appropriate action to contest proposed increases in rail transportation rates from the Union Pacific.

AEPCO has also appropriately developed, and is properly maintaining its gas-supply relationships. The Cooperative uses appropriate standard agreements, operates a proper transaction recording and tracking system, makes effective use of ACES Power Marketing (an enterprise established initially by a group of cooperative G&Ts) and has established effective transportation and storage arrangements and agreements.

AEPCO makes its forward purchases from [redacted] major suppliers: [redacted] Liberty believes, however, that AEPCO should solicit interest from other suppliers, as a means of assuring that its traditional sources continue to offer the best available terms in a dynamic marketplace. AEPCO's forward purchases amount to [redacted], even under current, depressed market prices. This level of business should be sufficient to induce interest from other suppliers who may be in a position to serve AEPCO's needs. Liberty does not predict that this effort will reduce costs, but believes it will verify that best costs continue to be obtained.

Liberty's review of gas contract decisions demonstrated sound analysis, appropriate documentation, and proper approvals.

Q. **Please summarize your recommendations with respect to fuel contracting.**

A. Liberty recommended that AEPCO's future solicitations for forward gas purchases solicit interest from additional suppliers beyond its traditional sources for AEPCO's forward gas purchases.

Q. Please summarize what Liberty concluded in the area of fuel supply management.

A. AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache. AEPCO's coal contracts make provisions sufficient to support these activities. AEPCO independently analyzes samples at reasonable intervals, and has observed no unusual trends. Variations between physically-measured and book coal inventory values have historically fallen into a normal range, but recently, the majority have consisted of physical measurements that are less than book values. The lack or randomness in variations merits examination.

AEPCO has effectively administered its coal contracts to assure quantity and quality control, while appropriately maintaining effective supplier relationships. AEPCO has taken steps to monitor quality and assess applicable adjustments for quality deviations. AEPCO has effectively communicated internally on all aspects of coal scheduling and deliveries.

AEPCO decided to increase certain coal inventories, in order to address the prospect of substantially increased coal transportation rates. This decision was effective; AEPCO supported it with appropriate economic analysis.

Inventories continued to build even beyond increased expectations under this decision. That increase, however, resulted from external circumstances (subsequently reduced Apache availability) that did not reflect on the soundness of the strategy. Nevertheless, AEPCO coal inventories have now reached levels that should be considered unacceptable. An inventory level of approximately 75 days would conform to the increased stockpile strategy. The 137-day level reached as of the end of 2009 has become too high; AEPCO needs to develop a strategy to address the situation.

Liberty also found gas-supply management to be generally effective. AEPCO has sufficient and not excessive resources (e.g., power-purchase contracts, generating units, fuel-purchase arrangements). Liberty also observed effective management practices and mechanisms for managing gas supply. Liberty did not, however, find significant efforts to measure results. AEPCO needs to explore the creation of specific performance measurement for gas traders to improve performance measurement and inducement.

Q. With respect to fuel supply management, please summarize the recommended actions on AEPCO's part to address your concerns.

A. We made three recommendations. First, AEPCO should undertake a formal process for examining the causes of differences between physical and book inventory, and take corrective action, as appropriate. Second, AEPCO should develop a plan for reducing the coal inventory level at the Apache Station. Third, AEPCO should explore the creation of a set of specific performance measures for its traders

Q. Please summarize what Liberty concluded in the area of gas hedging.

A. AEPCO's objective for its gas hedging program is [redacted] Liberty understands that the member cooperatives, through their representatives to AEPCO's Board of Directors, understand and support this objective, which is certainly an appropriate one. AEPCO does not, however, formally assess its effectiveness in meeting this objective. At a minimum, AEPCO should conduct annual assessments to determine whether the hedging program is meeting its stated objective: [redacted] Many utilities also use assessments of their hedging program to try to improve performance.

In pursuing its hedging objective, AEPCO applies effective strategies, and uses appropriate instruments. The Cooperative uses [redacted] Hedging personnel are adequately qualified and AEPCO makes effective use of ACES Power Marketing to support hedging activities.

AEPCO applies appropriate risk-management policies and procedures. They address hedging for electric power and for natural gas. These policies and procedures cover all important areas, and are soundly constructed. AEPCO's transaction-tracking capabilities and systems are also strong. AEPCO has not, however, subjected trading to regular audits. Liberty found no indication of improper activity here, but both our examinations at other enterprises and industry experience generally confirm that trading is a high-risk, high-consequence area of operation. Therefore, good practice, regardless of the lack of a history of problems, requires periodic testing of controls on trading.

Q. Please summarize your recommendation with respect to AEPCO's gas hedging program?

A. We made two recommendations. First, AEPCO should adopt a program that will provide for measurement of hedging program results. Second, the Internal Audit group at AEPCO should periodically review the processes and systems for tracking of transactions.

Q. Please summarize what Liberty concluded in the area of power transactions.

A. AEPCO effectively manages the scheduling, real-time dispatch, and trading functions associated with making power purchases and sales. There exist clear lines of responsibility, established operating routines, and a qualified work force. AEPCO regularly takes advantage of hourly market opportunities to purchase power when it will displace more costly internal sources. Day-ahead and real-time operations effectively use market information. AEPCO's large members, however, fail to provide to AEPCO on a timely basis the pre-scheduling information that AEPCO needs to produce its daily, day-ahead schedule. Potentially wide swings in what these members expect AEPCO to schedule can thus produce significant daily over- or under-supply. AEPCO schedulers have to make their "best estimate" of the pre-schedules of these large members in order to provide AEPCO's schedule to the Inter-Continental exchange ("ICE"). AEPCO needs to require more timely submissions from the members involved, and evaluate if any past harm may have resulted to AEPCO and other members from the lack of timely information.

AEPCO's power trading operations have established effective processes and methods for arranging economic term purchases of power. The Cooperative has primarily arranged power trades on an hourly, real-time basis, and also under its long-term contracts, using market power information effectively to analyze opportunities. AEPCO's processes for soliciting long-term power resources have been thorough and effective. AEPCO has solicited proposals for power supply resources several times since 2001, using solicitation processes that Liberty found to be thorough and robust. AEPCO has taken advantage of overbuilt power supply markets in the Southwest region to benefit its members. AEPCO's information gathering and analysis demonstrated its purchases to have been superior at the time to self build and other purchase options. AEPCO has appropriately decided to join in Southwest Public Power Resources power supply solicitations since 2006, recognizing that its future needs for power supply resources will be much smaller (89 percent of AEPCO's future member load will be for partial requirements customers).

AEPCO's internal audit reports show an insufficient attention to detail regarding the fuel and purchased power adjustment clause ("FPPAC"), which the Cooperative has only recently resolved. AEPCO also lacks written processes and procedures for calculating and reconciling information and reports. Significant AEPCO changes to its processes that resulted from the internal audit report should minimize or eliminate the errors experienced in 2007 and 2008. AEPCO's schedule for completing written procedures, however, (mid-2011) needs to be accelerated. Moreover, upon completion of the process documentation, AEPCO should demonstrate to the Commission that its changes do in fact address all causes of its past errors and that it is taking continuing actions, including frequent internal audits, to verify their sufficiency.

Q. Please summarize your recommendations related to AEPCO's power transactions?

A. We made two recommendations. First, AEPCO should require its partial requirements members and Salt River Project ("SRP") to make timely submissions of pre-scheduling power requirements. Second, AEPCO should undertake a series of steps to assure the Commission that it has effectively completed, can demonstrate, and will periodically audit the effectiveness of the new adjustment clause processes.

Q. Please summarize what Liberty concluded in the area of engineering analysis/plant operations.

A. Technical performance, personnel and facilities are generally sound, and AEPCO's management team is capable, knowledgeable, and supported with appropriate tools. AEPCO's power plant operations are generally appropriate and typical of the industry, AEPCO's investment in new and upgraded facilities has been appropriate for the demands placed on the Cooperative, and maintenance practices and spending appear to be consistent with the station's needs and good utility practice. However, despite reasonably effective performance historically, AEPCO faces significant questions about the future of its units. Apache Steam Units 2 and 3, the coal-fired units that currently produce more than 95 percent of the station's output, have operated in a base-load mode for about 30 years, but now appear more likely to cycle. This change has resulted from a decline in the units' market competitiveness. Increased unit cycling may be having impacts on equipment, contributing to a significant drop in availability in 2009. Management needs to examine the potential for continuing lower station output which, if it continues, suggests a limited future for these units. The key question at this time is whether 2009 conditions are anomalous or a warning of continuing deterioration.

As to AEPCO's other generation sources, first, Steam Unit 1 ("ST1"), a gas-fired boiler that operates in combined cycle with gas turbine 1 ("CC1"), also had low 2009 availability, but AEPCO has addressed unit needs and has completed an analysis that justifies further investment in ST1 (the boiler re-tube). Management's recent study of future options concluded that continued use of CC1 for reserve and seasonal peaking capacity remained AEPCO's most economic alternative. If AEPCO can succeed in: (a) stabilizing availability at high levels going forward, and (b) holding maintenance costs at reasonable levels, it would appear that continued operation of the unit makes sense. The three gas turbines are peaking units; they have had good availability over time. Deviations in performance give no reason to conclude that operating problems have arisen or that they will not remain useful to AEPCO.

Liberty's review of maintenance found that AEPCO employs good practices in preparing for and managing outages. However, the Cooperative's consistent overruns in outage durations is not typical, and warrants a structured examination and the adoption of a more formal and structured approach that would nevertheless remain consistent with the comparatively small size of AEPCO's fleet. Spending on maintenance has generally been consistent for many years. There were some years of comparatively lower spending in the late 1990s, but Liberty found no reason to conclude that any spending reductions have had a material impact on plant performance.

Liberty found that the Apache station suffers a particularly high number of trips due to personnel errors. The numbers are high enough to warrant root cause analysis of these trips. AEPCO has not suffered significant cost penalties due to forced outages. The 13 forced outages of 2008 and 2009 combined have caused AEPCO to experience total replacement costs less fuel costs of [redacted] million. Fuel and purchased power expenses in these two years are in the range of $140 million.

AEPCO's recent investments in plant have been justified and appropriate. The review underlying this conclusion included all of the capital project justifications for large projects. Liberty found them to be in order and supportive of management's decision-making needs. Liberty found the listing of projects typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable. In summary, historical capital and O&M spending appears to have been appropriate; however, questions should be raised concerning future spending. Actual and forecasted spending from 2008 to 2014 is more than double the annual levels between 2004 and 2007. Considering the uncertainties on the future role of the station as discussed above, the appropriateness of a much higher and sustained level of capital investment in the future is not clear.

Q. Please summarize your recommendations in the area of engineering analysis/plant operations.

A. Liberty made three recommendations. First, AEPCO should conduct a study of the future role of Apache and how that role relates to member needs for future power supply. Second, AEPCO should examine methods to create more structured and formal outage planning and management. Third, AEPCO should examine the root causes of trips resulting from personnel errors.

Q. Please summarize what Liberty concluded about the FPPAC.

A. AEPCO's FPPAC, approved in 2005, and changed in 2008 to accelerate the recovery of a growing under collection balance has served to mitigate the effects of over and under collections of fuel and purchased power costs. Some states have taken a different approach to adjustor clause design; *e.g.*, using forecasted rather than historical costs, and using shorter periods to recover or refund under or over collected balances. The Commission expressed concern about balances in the range of $5 million in shortening the balance-recovery period to six months. Current market indications create the very real possibility that AEPCO balances could rise to or above that level in the future, although the balance has been dropping steadily through a period of depressed energy prices. It is therefore appropriate to consider a further shortening of the balance-recovery period, but that consideration should take place in a manner that allows the members to consider what corresponding changes they may need to make in the means for recovering costs from their members at the end-use level.

For reasons particular to AEPCO's circumstances, Liberty does not recommend the use of forecasted costs for setting an FPPAC rate or the inclusion of the costs and revenues from transactions in SO2 allowances.

Liberty found appropriate AEPCO's proposed FPPAC change whose purpose is to align amounts recovered from individual members more closely with the hourly costs they impose on AEPCO. Should the Commission approve this modification, editorial revision of AEPCO's proposed Plan for Administration of the FPPAC should take place through a joint Staff/AEPCO process. In the event of acceptance of the proposed FPPAC change, AEPCO should also provide for a temporary surcharge intended to recover balances accrued under the current FPPAC (up to the date of the new FPPAC effectiveness) and to provide for that recovery through a mechanism that essentially continues the same balance recovery methods that apply under the current FPPAC.

Q. Please summarize your recommendations with respect to the FPPAC.

A. Liberty made two recommendations. First, AEPCO should address through focused discussions with the Class A members the means for introducing in an orderly fashion a change that will produce more current FPPAC recovery. Second, assuming that AEPCO's proposed FPPAC continuation and changes are found by the Commission to be generally appropriate, the Cooperative needs to establish a temporary surcharge mechanism, and clarify the proposed plan for administering it. The most direct means for closing out old FPPAC balances would be to continue the Bank Account feature of the current clause.

Q. Should the FPPAC continue?

A. Yes, for the reasons discussed in the FPPAC chapter of Liberty's report attached as an exhibit to this testimony.

Q. Does that conclude your Direct Testimony?

A. Yes.

John Antonuk Resume

Areas of Specialization

Executive management; management audits and assessments; service quality and reliability management and measurement, utility planning and operations; litigation strategy; management of legal departments; human resources; risk management; regulatory relations; affiliate transactions and relations; subsidiary operations; and testimony development and witness preparation.

Relevant Experience

Electricity

Project Manager and lead consultant on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Project Manager for Liberty's audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Liberty completed audits relating to fuel procurement and management and on rate and regulatory accounting for related costs at Arizona Public Service Company for the Arizona Corporation Commission. The fuel and purchased power audit included extensive reviews of all physical and financial transactions of both the utility and a wholesale marketing affiliate, including the relationship between the two entities.

Project Manager for Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission. Scope included compliance with regulatory conditions and code of conduct imposed by the Commission after the merger with Cinergy, and affiliate transactions and cost allocation methods.

Project Manager for Liberty's audit of affiliate transactions of Nova Scotia Power on behalf of the Nova Scotia Utility and Review Board.

Project Manager for Liberty's audit for the New Jersey Board of Public Utilities of the competitive service offerings of the state's four major electric companies. Scope included corporate structure, governance, and separation, service company operations and charges, inter-affiliate cost allocations, arm's-length dealing with respect to a variety of code-of-conduct requirements, and protection of customer and competitor proprietary information.

Project Manager and witness for the staff of the Arizona Corporation Commission addressing the merits of the proposed acquisition of UniSource by a group of private investors.

Project Manager and witness before the Oregon Public Utility Commission addressing the merits of the proposed acquisition of Portland General Electric by a group of private investors.

Engagement Director for Liberty's provision of engineering and technical assistance to the Vermont Public Service Board in connection with review of public necessity and convenience related to the Northwest Reliability Project, which would add a major new 345kV transmission plan to provide an additional source of electricity to serve Vermont's major load growth in its northwest region. The project involved transmission reinforcements at lower voltages and significant substation upgrade work. The proceedings had numerous public, private, and government interveners, who raised issues regarding project need, available electrical alternatives, routing and design, and electromagnetic radiation.

Project Manager for Liberty's support for the New Hampshire Public Utilities Commission in its charge to oversee the divestiture of the Seabrook nuclear plant as part of a major restructuring settlement. The sale produced record high compensation for nuclear facilities in the country.

Project Manager and witness for Liberty's assessment of fuel procurement, affiliate transactions, and automatic adjustment clause implementation for the staff of the Nova Scotia Utility and Review Board in rate case of Nova Scotia Power.

Project Manager for Liberty's engagement on behalf of Boston Edison to examine the company's affiliate relations, including issues of the valuation of assets transferred to an affiliate. Testified in proceedings before the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities) on several telecommunications issues, including: (a) development of competition, and legislative and regulatory-policy changes supporting it, (b) electric-utility entry into telecommunications markets, (c) costs, prices, and market value of network elements, (d) requirements of the Telecommunications Act of 1996, (e) assessment of compliance with commission orders, company procedures, and service agreements regarding limits on affiliate interactions, (f) inter-company loans, guarantees, and credit support among utilities and their affiliates, (g) accounting for affiliate transactions, (h) obligations to allow nondiscriminatory access to network infrastructure to third parties, and (i) cost pools, overhead factors, and allocation of common costs among utility and non-utility affiliate activities and entities.

Project Manager for Liberty's major consulting engagement for the New Hampshire Public Utilities Commission. Liberty examined management, operations, and costs at Public Service Company of New Hampshire/Northeast Utilities, which is engaged in the operational and cost-accounting separation of its network into segments, for the purposes of restructuring service offerings to allow competition in certain aspects of electric-energy supply. This engagement included an assessment of valuations of nuclear and fossil units, as well as supply contracts with independent-power producers. Liberty also assisted in efforts to settle rate case and restructuring disputes involving, among other issues, stranded costs associated with power plants. The scope of Liberty's work included the development of plans and protocols for power plant (fossil, hydro, and nuclear) and power supply contract assets, as well as the oversight of activities associated with asset auctions.

Engagement Director for Liberty's evaluation of corporate relations and affiliate arrangements of Dominion Resources, Inc. and Virginia Power for the Virginia State Corporation Commission. This project addressed all significant aspects of corporate governance, operating relationships, and affiliate arrangements between the two entities.

Project Director for Liberty's evaluation of a report prepared by a consultant to the Hawaii Public Utilities Commission on the relationship between Hawaiian Electric Industries (HEI), a diversified utility-holding company, and Hawaiian Electric Company (HECO), its principal subsidiary and operating electric utility.

Project Director for all aspects of Liberty's comprehensive management and operations audit of West Penn Power Company for the Pennsylvania Public Utility Commission (PAPUC). Managed focused reviews of the Company's affiliated costs, power dispatch and bulk power transactions, customer services, finance, and corporate services. Presented testimony before the PAPUC on behalf of the Office of Trial Staff regarding the results of the audit in West Penn's rate case.

Lead Consultant for affiliate relations for Liberty's assignment of providing assistance to Delmarva Power & Light Company in developing and implementing self-assessment and continuous-improvement processes.

Project Director for Liberty's reviews of fossil-fuel procurement and administration in Liberty's management/performance audits of the Centerior Energy Company's operating companies- Cleveland Electric Illuminating Company and Toledo Edison Company- and Ohio Edison, Monongahela Power (an Allegheny Power System operating company), and Cincinnati Gas & Electric, for the Public Utilities Commission of Ohio.

Served as advisor to the administrative law judge of the Delaware PSC responsible for hearing cases regarding the implementation of the new law that restructures the electric-utility industry in Delaware.

Engagement Director for nuclear-plant performance-improvement projects that Liberty conducted for Duquesne Light Company, Centerior Energy, Nebraska Public Power District, and Pennsylvania Power & Light Company (PP&L).

Engagement Director for a Liberty assignment for Florida Power Corporation, regarding a proposal by the Tampa Electric Company to construct transmission lines to serve the cities of Wauchula and Fort Meade, Florida. Liberty's testimony helped convince the Florida Public Service Commission that Tampa Electric Company's proposed line was uneconomic.

Directed Liberty's engagement to assist a regional electric generation and transmission cooperative, whose members' combined operations make it a major competitor in the state's electricity business, to conduct its first-ever comprehensive and formal strategic-planning process.

Natural Gas

Project Manager for Liberty's examination of safety programs and activities of NiSource's Maine subsidiary Northern Utilities for the Maine Public Service Commission.

Project Manager for Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager on a major focused audit of Peoples Gas/Integrys that Liberty performed for the Illinois Commerce Commission. Audit topics included natural gas forecasting, portfolio design and implementation, gas purchase and sale transactions, controls, organization and staffing, asset management, off-system sales, storage optimization, and all other issues related to gas supply over a period of eight years.

Project Manager and witness on three recent audits of fuel (primarily coal and natural gas) procurement and management practices of Nova Scotia Power, a review of the merits and mechanics of a company-proposed automatic recovery method for energy costs, and an audit of affiliate relationships (including coal, electric power, and natural gas procurement activities) performed for the Nova Scotia Utility and Review Board.

Project Manager for Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager for Liberty's work with staff of the Virginia State Corporation Commission to evaluate the services of an affiliate providing gas portfolio management services under an asset management agreement with Virginia Natural Gas, an operating utility subsidiary of Atlanta-based AGLR.

Project Manager for Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. Also examined performance of telecommunications, engineering services, customer-information-system, environmental, and international affiliates. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Project Manager for Liberty's comprehensive management audit of United Cities Gas Company for the Tennessee Public Service Commission. Responsible for the focused reviews of affiliate interests, executive management and corporate planning, and vehicle management.

Lead Consultant in Liberty's management audit of Connecticut Natural Gas Company for the Connecticut Department of Public Utility Control (DPUC). Responsible for reviews of organization and executive management and legal management.

Lead Consultant in Liberty's management audit of Southern Connecticut Gas Company for the DPUC. Responsible for organization and executive management, affiliates, and legal management. Included valuation of a major, rate-based LNG facility being offered for sale.

Directed Liberty's management audit of Yankee Gas Services Company for the DPUC.

Engagement Director for Liberty's evaluation of regulatory needs and alternatives for the Georgia Public Service Commission in regulating the state's local-gas-distribution companies in the aftermath of FERC Order 636.

Project Director for Liberty's review of gas-purchasing policies and practices at Pike Natural Gas Company and Eastern Natural Gas Company for the Public Utilities Commission of Ohio. Responsible for the review of organization and staffing and regulatory-management issues.

Combination Utilities

Engagement Director for Liberty's examination of the cost-allocation methods of Baltimore Gas & Electric Company and its affiliates for the Maryland Office of People's Counsel.

Project Director for Liberty's focused management audit of affiliate transactions of Public Service Electric & Gas Company (PSE&G) and the unregulated subsidiaries of Public Service Enterprise Group, Inc., the parent, for the New Jersey Board of Regulatory Commissioners. Task leader for the review of organization and planning, and executive management.

Project Director for Liberty's management and operations audit of New York State Electric & Gas Corporation for the New York Public Service Commission (NYPSC). Responsible for managing the review of corporate planning and organization, service centralization, specific corporate services, and finance and accounting.

Project Director for Liberty's management and operations audit of Central Hudson Gas & Electric Corporation for the NYPSC.

Telecommunications

Arbitrator named by the District of Columbia Public Service Commission to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for assistance being provided to the Administrative Law Judge of the Delaware Public Service Commission hearing the arbitration to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for Liberty's engagement to serve as advisors to commissioners of the District of Columbia Public Service Commission in their review of the Section 271 application of Verizon to provide in-region, interLATA service in the District.

Project Manager for Liberty's engagement to serve as advisor to the administrative law judge of the Delaware Public Service Commission in the review of the Section 271 application of Verizon to provide in-region, interLATA service in the state.

Retained by the Idaho PUC to serve as administrative law judge in complaint proceedings involving three paging companies and Qwest, involving a variety of financial disputes arising out of interconnection and tariff purchases.

Conducted wholesale performance metrics training for staff members and commissioners of the Pennsylvania Public Utility Commission as part of efforts to monitor service quality and payments under the Verizon Performance Assurance Plan adopted in connection with the RBOC's entry into the in-region inter-LATA market in Pennsylvania.

Engagement Director for Liberty's comprehensive financial review of Verizon New Jersey Inc. *(VNJ)* for the New Jersey Board of Public Utilities. The review had three parts: a financial evaluation; a review of merger costs and savings; and an assessment of affiliate costs and transactions.

Engagement Director for Liberty's audit of Ameritech-Ohio policies, procedures and compliance with service quality performance requirements under Ohio's Minimum Telephone Service Standards.

Engagement Director for Liberty's audit of Qwest's performance measures for the Regional Oversight Committee *(ROC)*. Responsible for the evaluation of the processes and data tracking of several hundred wholesale and retail performance indicators including service areas such as provisioning, OSS access, maintenance and repair, and billing.

Project Manager and hearing administrator for Qwest's 271 hearings for the commissions of Idaho, Iowa, Montana, New Mexico, North Dakota, Utah, and Wyoming.

Engagement Director for Liberty's assistance provided to the Staffs of the Virginia State Corporation Commission and the New Jersey Board of Public Utilities in the implementation of the 1996 Telecommunications Act.

Project Manager for Liberty's assistance to Delaware PSC arbitrators in seven different interconnection cases arising out of the Telecommunications Act.

Served on an arbitration board in Mississippi, and as the sole arbitrator in two cases in Idaho regarding interconnection agreements between incumbent local-exchange companies and new entrants to the local telephone market.

Engagement Director for Liberty's work determining permanent prices for the unbundled-network elements of Southwestern Bell Telephone for the Oklahoma Corporation Commission.

Engagement Director for Liberty's provision of arbitration services to the North Dakota Public Service Commission and Nebraska Public Service Commission in cases involving implementation of the Telecommunications Act of 1996.

Engagement Director for Liberty's combined comprehensive management/affiliate-relations audit of Bell Atlantic - Pennsylvania for the PAPUC, and affiliate relations audit of Bell Atlantic - District of Columbia for the Public Service Commission (DCPSC) of the District of Columbia. Served as team leader with responsibility for the coordination of the review of executive management, finance, and support services.

Engagement Director for Liberty's examination of the accounting and allocation on lobbying costs of Bell Atlantic for an 8-year period for the DCPSC. Engagement included an examination of the propriety of policies and procedures for assigning and allocating lobbying costs.

Engagement Director for a management audit of GTE South, Inc. for the Kentucky Public Service Commission. This examination included a review of GTE's affiliate transactions.

Project Director for Liberty's evaluation of New York Telephone's transactions with affiliates for the NYPSC. Responsible for the review of affiliates involved in directories publishing, government affairs, international activities, information services, and the legal-affairs entity.

Project Director for Liberty's management audit of the affiliated interests of C&P Telephone of Maryland performed on behalf of the Maryland Public Service Commission.

Engagement Director for Liberty's two assignments for the DCPSC in reviewing Bell Atlantic - District of Columbia's construction-program planning and quality-of-service standards.

Other Companies

Set up and managed service and facilities section of the PP&L Regulatory Affairs Department. Counseled utility management on regulatory and legislative matters. Litigated rate related and facility construction proceedings before agencies and the courts.

Attorney for the PAPUC. Assigned as counsel to the Commission's Audit Bureau in developing a comprehensive management-audit system. Negotiated contracts for the first commission-ordered management audits in Pennsylvania. Revised Commission organization and practice to conform to regulatory-reform legislation.

Testimony

Nova Scotia Utility and Review Board – testimony on the prudence of fuel procurement, affiliate relationships associated with fuel management, and use of an automatic adjustment clause to recover fuel costs.

Arizona Corporation Commission – testimony on the merits and conditions of the proposed acquisition of UniSource by private investors.

Oregon Public Utility Commission – testimony on the merits and conditions of the proposed acquisition of Portland General Electric by private investors.

Virginia State Corporation Commission - testimony in arbitration cases regarding interconnection agreements between Bell Atlantic - VA and competing local exchange companies.

PAPUC - presentation of management-audit recommendations and benefits for selected conclusions in West Penn Power Company request for rate increase.

Maryland Public Service Commission - presentation and defense of management-audit conclusions, recommendations, and cost implications in C&P Telephone Company of Maryland (Bell Atlantic) rate case.

Illinois Commerce Commission - testimony about fuels organization, procurement, and management in fuel-cost reconciliation proceedings.

Maryland Public Service Commission - testified regarding Baltimore Gas & Electric Company's affiliate relations.

Tennessee Regulatory Authority - testified regarding Liberty's recommendations in a management audit of United Cities Gas Company.

Education

J.D., with academic honors, Dickinson School of Law
B.A., cum laude, Dickinson College

Public Report
Review of AEPCO Fuel, Purchased Power, Generation, and FPPAC Management, Operations, and Prudence

Shaded Portions are Confidential

Presented to the:

Arizona Corporation Commission

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Table of Contents

I. Introduction

A. Background

The Liberty Consulting Group ("Liberty") conducted for the Staff of the Arizona Corporation Commission ("the Commission") an examination of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), based in Benson, Arizona. AEPCO serves six Class "A" distribution cooperative members in the Southwest region:

- Graham County Electric Cooperative ("GCEC"); Pima, Arizona (8,904 meters)
- Sulphur Springs Valley Electric Cooperative ("SSVEC"); Willcox, Arizona (51,849 meters)
- Mohave Electric Cooperative ("Mohave"); Bullhead City, Arizona (43,042 meters)
- Trico Electric Cooperative ("Trico"); Marana, Arizona (38,811 meters)
- Duncan Valley Electric Cooperative ("DVEC"); Duncan, Arizona (2,375 meters)
- Anza Electric Cooperative ("ANZA"); Anza, California (4,962 meters).

AEPCO divides these members further into two classes:

- All-requirements members ("ARMs") who purchase all the requirements necessary for serving their distribution cooperative members: ***DVEC, GCEC, Trico, and ANZA***
- Partial-requirements members ("PRMs"), who purchase both from AEPCO and from other market sources: ***Mohave and SSVEC***.

AEPCO also has served some of the requirements of what it terms Class "B" and Class "D" members:[1]

- Salt River Project ("SRP"); Tempe, Arizona: will be a Class "B" member through December 31, 2010, when its firm 100 MW purchase from AEPCO will expire
- City of Mesa: ceased to be a Class "B" member upon the December 31, 2008 expiration of its 15 MW power and energy purchase from AEPCO
- Class "D" member Valley Electric Association ("VEA"); Pahrump, Nevada: Class "D" member through a service contract under which AEPCO provides scheduling and trading services.

There are no Class "C" members. AEPCO also made sales to the City of Mesa, Arizona, under a contract that expired on December 31, 2008. The accompanying table shows sales levels in the past two full years.

Category	2008 MWH	2009 MWH
Class A	2,346,706	2,201,798
Total	3,518,193	2,791,236

Liberty is a management, operations, technical, and regulatory consulting firm that specializes in the energy and telecommunications utility businesses. Liberty has served more than two-thirds of the country's utility regulatory authorities (and a number of others in North America) over a life that is approaching a quarter century. Liberty's work has included many examinations of electric utility fuel, power purchase, and power production management, operations, and prudence for regulators across the country. Liberty has also performed extensive work in the examination of fuel and purchased power cost recovery through adjustment clauses, focusing on clause design, operation, and accuracy.

Liberty conducted this review in the context of an AEPCO rate filing before the Commission at Docket No. E-01773A-09-0472. AEPCO initially sought a modest increase in rates, and later revised its filing to call for a small decrease. AEPCO also seeks to change its Fuel and Purchased Power Adjustor Clause("FPPAC"), in order to segregate more fully the costs of power between its ARMs and PRMs.

B. Project Objectives and Scope

The objective of Liberty's review was to verify that AEPCO has acted prudently and reasonably in assuring cost and operational effectiveness in these areas. Liberty's examination included the following areas identified in the Request for Proposals ("RFP"):

1. Overall fuel and purchased power procurement policy, goals and strategies
2. Organization and decision making structure to and including the board of directors
3. Fuel and purchased power procurement policies and procedures and the potential for conflicts of interest
4. Fuel and purchased power costs during the test year and since FPPAC implementation
5. Plant operating availability, equivalent availability, and capacity factors and impacts of any observed declines
6. On-site inspection of the Apache Station Generation Plant, including fuel handling, quality control, inventory surveying methodologies and results, performance monitoring, and maintenance
7. Modeling used to develop forecasts of fuel and purchased power volume requirements
8. Dispatch modeling and effectiveness
9. Reasonableness of fuel and purchased power contracts and compliance with terms and conditions
10. Use of hedging
11. Test-year off-system sales
12. Audits (and management responses) of procurement of fuel and purchased power
13. Historical fuel and purchased power prices and comparison to industry data
14. Sample review of contract entry and administration
15. Calculation of base cost of fuel and purchased power to be used prospectively
16. FPPAC historical performance and continuation
17. Potential FPPAC modification
18. FPPAC Plan of Administration changes.

C. Task Structure

Liberty created the following task structure to facilitate its examination of the 18 included areas:

- Organization, Staffing, and Controls (Elements 1, 2, 3, 4 and 12)
- Fuel Contracting (Portion of Elements 9 and 14, Element 13)
- Fuel Management (the portion of Element 6 that deals with fuel-related matters)
- Gas Hedging (Element 10)
- Power Transactions (Elements 7, 8, 11, and portions of Element 9 and 14)
- Engineering Analysis/Plant Operations (Element 5 and remainder of Element 6)

- FPPAC Continuation/Amendment (Elements 16 through 18)

With respect to Element 15, the work in these areas disclosed no reason for adjusting claimed test-year fuel and purchased power expenses. Liberty therefore proposed no adjustment to them. They establish a base that is consistent with the vintage of other expenses. Moreover, as costs change in dynamic markets, continuation of the FPPAC will reconcile revenues and expenses over time.

D. Recent Financial Results

The following table summarizes and compares key AEPCO capital, revenue, and expense items for 2008 and 2009.[2]

AEPCO Capital and Expense Summary (2008 vs. 2009)

Capital Item	**2009**	**2008**	**Change**
Plant in Service	$429,448,020	$402,042,682	6.8%
CWIP	$9,354,610	$20,108,331	-53.5%
Depreciation	$212,515,354	$204,728,929	3.8%
Net Utility Plant	$226,287,276	$217,422,084	4.1%
Membership Capital	$84,514,994	$74,558,069	13.4%
Long-Term Debt	$ 177,094,771	$ 177,195,623	-0.1%
Revenue/Expense Item	**2009**	**2008**	**Change**
Class A Firm Sales	$121,129,138	$ 123,646,648	-2.0%
Class B Sales	$30,945,711	$ 42,938,769	-27.9%
Class D Sales	$995,289	$ 1,593,208	-37.5%
Underrecovery (fuel/power)	$46,434,309	$ 38,638,375	20.2%
Non-Member Sales	$9,054,338	$ 8,402,255	7.8%
Other Revenues	$593,432	$ 728,133	-18.5%
Total Operating Revenues	**$209,152,217**	**$ 215,947,388**	**-3.1%**
Fuel Expense	$79,520,400	$69,854,969	13.8%
Operations Expense	$8,824,265	$10,581,716	-16.6%
Maintenance Expense	$18,589,005	$15,322,190	21.3%
Purchased Power and Interchange	$38,386,804	$52,328,850	-26.6%
A&G	$11,595,386	$10,843,391	6.9%
Depreciation, amortization, accretion	$8,936,845	$8,054,263	11.0%
Transmission	$18,512,248	$18,526,791	-0.1%
Taxes	$2,879,532	$2,934,495	-1.9%
Total Operating Expense	**$187,244,485**	**$ 188,446,665**	**-0.6%**
Operating Margin	**$21,907,732**	**$ 27,500,723**	**-20.3%**
Interest and other	($11,950,807)	($10,144,953)	17.8%
Net Margin	***$9,956,925***	***$17,355,770***	***-42.6%***

E. Senior AEPCO Leadership

AEPCO was founded in 1961. Through a major restructuring in 2001, AEPCO was organized into three entities: 1) AEPCO, as a power supply organization; 2) Southwest Transmission Cooperative ("SWTC") as the transmission entity for serving the needs of member cooperatives; and 3) Sierra Southwest Cooperative Services ("Sierra"), which provides services and personnel for both AEPCO and SWTC. This structure was originally designed to match the changing requirements in the industry, in particular to position the enterprise to address market opening measures, which at the time looked to be emerging. The original allocation of personnel placed most staff at Sierra, but assigned staff directly to the other two entities to align with a RUS requirement that the CEO described as requiring each of the three entities to have intellectual capital.

AEPCO's most senior leadership consisted during the test year of the following directors and senior executives:

- Board Officers
  - President: Reuben B. McBride; Graham County Electric Cooperative
  - Vice President: Gene Robert Larson; Graham County Electric Cooperative
  - Secretary: Tom Powers; DVEC
  - Treasurer: George P. Davies; Trico
- Other Board Members
  - Gloria Britton; ANZA
  - Ryall Stewart; ANZA
  - Joe D. Croom; DVEC
  - Robert E.Broz; Mohave
  - Lyn R. Opalka; Mohave
  - Kathy Thatcher; SSVEC
  - Gene Manring; SSVEC
  - C. Brad DeSpain; Trico
  - Thomas Husted; VEA
  - Timothy Roberts; SRP
- Senior Executive Management
  - Donald W. Kimball, Executive Vice President & Chief Executive Officer
  - Gary G. Grim, Senior Vice President & Chief Operating Officer
  - Dirk C. Minson, Chief Financial Officer

II. Organization, Staffing, and Controls

A. Scope

This chapter of Liberty's report addresses the following subjects as they relate to fuel and power procurement and management:

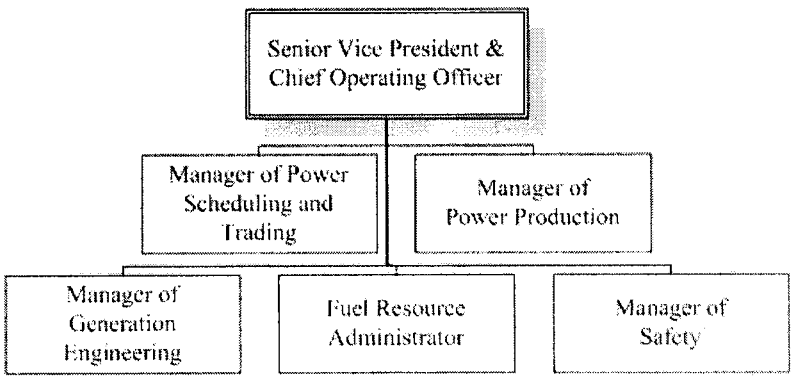
- Organization
- Staffing
- Procedures
- Goals and Objectives
- Controls.

B. Findings

1. Organization

a. *Structure*

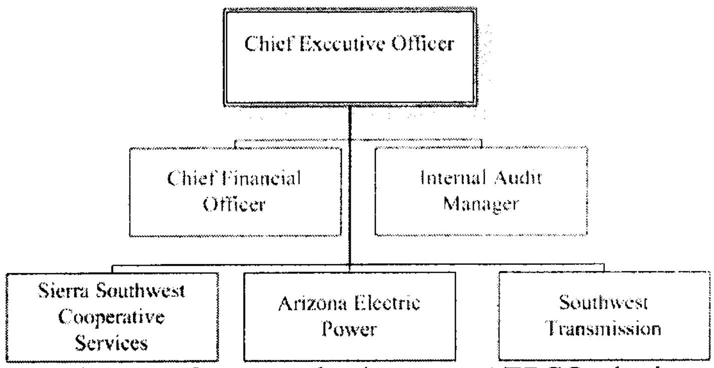
Overall responsibility for fuel and power management within AEPCO rests with the Senior Vice President & Chief Operating Officer ("COO"). Specific day-to-day responsibilities for fuel management fall under the Fuel Resource Administrator. The Administrator reports directly to the COO, who, in turn, reports directly to the CEO (titled the Executive Vice President & Chief Executive Officer). The CEO reports directly to the AEPCO Board of Directors. The chart shows all of the operating groups that report to the COO.



The Fuel Resource Administrator has responsibility for management and administration of all coal and transportation contracts. This individual plans and directs daily operational coal transportation activities, and assists with planning and development of coal and transportation strategic goals and objectives. The Fuel Resource Administrator also has responsibility for analysis of coal and transportation costs and procurement strategy and for the provision of recommendations on coal supply and transportation matters. The Administrator assists in the negotiation of coal supply and other coal and transportation agreements and related service terms and conditions. The current Fuel Resource Administrator has been in this position since early 2000. The Administrator did not then have a background in the coal business, but has undertaken concerted efforts to learn it since, including personal visits with coal suppliers, and tours of supplier coal mines in Wyoming, Colorado and New Mexico. The Administrator is active as a Director of the National Coal Transportation Association ("NCTA"), and serves on various of its committees. The NCTA exists to provide education and to facilitate resolution of coal transportation issues. It sponsors activities designed to exchange knowledge and viewpoints. It operates through a variety of committees that address problems that arise in getting coal from producers to consumers, sponsor conferences, testify before regulatory authorities, and award scholarships.3

The Power Scheduling and Trading group buys and sells electric power, and buys natural gas. This part of the AEPCO organization compares the price of power available on the grid to AEPCO's own incremental cost of generation, and decides whether to run one of AEPCO's plants or to buy power.

AEPCO obtains a number of staff services (accounting, finance, legal, administrative services, etc.) from Sierra. SWTC provides substation, transmission, and power delivery functions necessary to transmit power to end-use members served by AEPCO's Class A distribution-cooperative members. The relationship between AEPCO and the other two entities is illustrated by the chart below. They share management and many employees, having been created from the same, formerly integrated organization. They were split into generation and transmission entities, with a third existing to provide them common services, in anticipation of industry restructuring.



AEPCO has an equity position in ACES, and is one of 17 member/owners. AEPCO obtains a number of specific and valuable services from ACES Power Marketing. An ACES Power Marketing representative is resident in AEPCO's offices and devotes 100 percent of her time to AEPCO matters. AEPCO obtains risk-management and certain scheduling and related services from ACES Power Marketing. Many of these services are provided from ACES Power Marketing's National Service Center in Carmel, Indiana. Effective with a new agreement signed at the end of 2007, ACES Power Marketing provides the following services to AEPCO:[4]

- Trading and counterparty controls and risk policies:
  - Credit:
    - Credit analysis and counterparty monitoring
    - Credit exposure monitoring and management
    - Credit negotiations
  - Contracts:
    - Master agreement (North American Energy Standards Board, International Swaps and Derivatives Association, etc.) negotiations
    - Contract administration – master agreements
    - Contract monitoring – master agreements
    - Structured/customized contract evaluations
    - Emission allowance contract negotiations
  - Trading control:
    - Deal capture and validation
    - Limits and authority policy compliance monitoring
    - Mark-to-market valuation

    - Reporting: transaction activity, mark-to-market data, forward pricing, historical pricing and portfolio cost tracking
  - Risk management and training:
    - Risk management policy development
    - Education and training
- Portfolio management and operations:
  - Portfolio management:
    - Origination (four months to five years)
    - Coal strategy development
  - Transmission and market development:
    - Regulatory participation (rule-making with existing and emerging Regional Transmission Organizations/Independent System Operators)
    - Reporting: trading and operational activities, market trends, Regional Transmission Organization/Independent System Operator developments
- Settlements:
  - Bilateral power and transmission settlements
  - Bilateral natural gas, transportation settlements
  - Reporting: as specified by AEPCO
- Portfolio modeling and risk analytics:
  - Portfolio modeling and transaction analysis:
    - Financial Transmission Rights/Congestion Revenue Rights evaluations
    - Pricing evaluation – standard/structured products
- Ad hoc consulting.

ACES Power Marketing also acts as AEPCO's agent for scheduling, accounting, and settlement relating to Anza Electric Cooperative, Inc., whose loads are within the California Independent System Operator's control area. In 2010, ACES Power Marketing has also started a financial-hedging program for AEPCO, to assist with managing AEPCO's exposure to power-purchase agreements that are tied to natural-gas prices. ACES Power Marketing works with AEPCO to structure the program, and then places the trades for AEPCO.[5]

b. Job Descriptions

Liberty reviewed job descriptions for positions related to fuel and power management. This review found them to be complete and in a format typically encountered in the utility industry.

2. Procedures

a. Procedures

AEPCO team members operate under a set of policies and procedures and models that guide the organization's activities. A complete set of fuel procurement procedures covers coal, natural gas, and power. The *Fuel Management* chapter of this report discusses these procedures. The procedures involving coal have been supplemented by specific Board Resolutions that address coal procurement, and establish specific authority transaction limits in an authority matrix. Extensive procedures also exist for natural gas and power trading and procurement practices. These procedures include a detailed trading authority matrix for short-term natural gas trading and for natural gas hedging activities.

The policies and procedures applicable to natural gas trading and to power trading include the following:

- Who has authority to execute transactions
- The commodities and products that can be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations
- Other relevant factors associated with due diligence in authorizing transactions to be executed.

AEPCO Trading Sanctions define the procedures by which non-compliance with electric power and transmission, and natural gas trading practices will be addressed, and the consequences of non-compliance. The Trading Sanctions include general guidelines for determining appropriate disciplinary action, to ensure disciplined and consistent enforcement of the policies and procedures. The ACES Power Marketing on-site representative has responsibility for monitoring compliance with the trading practices limits and for reporting all non-compliance incidents to appropriate AEPCO staff and senior officers. The Natural Gas Trading Authority Practices and the Electric Power and Transmission Trading Practices each undergo updating as necessary. The most-recent versions of both bear a date of March 29, 2010.

AEPCO's power and gas traders fill out deal tickets as they agree to transactions. The real-time power traders fill out MS Excel™ spreadsheets. The transaction data from the deal tickets and the spreadsheets are entered into Allegro transaction-tracking software, which ACES Power Marketing operates and maintains. The ACES Power Marketing on-site representative then uses the transaction-tracking system to manage application of authority limits to AEPCO personnel, and to manage credit limits for authorized counterparties.

Transactions in Allegro are matched daily with the traders' deal tickets. Any differences between the deal-ticket data and the data in Allegro is resolved the next day.

ACES Power Marketing analyzes the credit of counterparties of all its members and clients in its National Service Center in Indiana. Limits for each counterparty are entered directly into the Allegro data base for each member or client.

b. Standards of Ethical Conduct

Several sets of procedures related to ethical conduct guide AEPCO employees. The first set of procedures seeks to ensure adherence to trading practices, and it sets forth the consequences of non-compliance by any individual employees. The sanctions provide general guidelines for determining appropriate disciplinary action, ensuring disciplined and consistent enforcement procedures as they pertain to trading. The ACES Power Marketing Trading Control Specialist monitors compliance with the Trading Practices Limits, and reporting all non-compliance incidents to the appropriate AEPCO staff, and the Risk Management Committee, as set forth in the procedures. Employees involved in these types of activities must sign a statement stating that they have read, understand, and will comply with these procedures.

All AEPCO employees must also comply with Corporate Policy No. 3-5, *Code of Employee Conduct.* This code establishes comprehensive procedures for ethical conduct, established by the Board of Directors. The CEO has management responsibility for this policy, and for assuring compliance with a procedure requiring all employees to acknowledge in writing that they have received, understand, and will comply with the policy.

c. *Goals and Objectives*

AEPCO does not have specific documents titled as Business Plans, or Goals and Objectives, relating to coal, natural gas, or purchased power. It does have detailed hedging plans developed yearly with the objective of stabilizing natural gas prices. The *Gas Hedging* chapter discusses this subject. AEPCO did not have any long-term power purchase plan for the 2008 or 2009 time period, due to previously procured purchased power agreements and existing resources. The only power purchases committed to in this time period related to unit outages and short-term economy purchases.

AEPCO's coal-related goals and objectives, starting in 2007, related to replacing its primary long-term coal contract. Prior to January 1, 2009, AEPCO's coal supply originated primarily from the Colowyo Mine in Colorado and from the Jacob's Ranch Mine in the Powder River Basin area of Wyoming, under a five-year contract with Kennecott Colorado Coal Company, a subsidiary of Rio Tinto America. This contract was to expire on December 31, 2008. The coal from Wyoming was transported under a rate established by the Union Pacific Railroad (UP), and modified from time to time. Part of AEPCO's planning challenge arose from notification by the rail carrier in 2008 that transportation rates would increase dramatically beginning in 2009. Thus, the contract replacement planning process that had begun in 2007 gained even more urgency in 2008 with this information from UP. AEPCO has provided a log of its multiple meetings with railroads and coal companies related to its planning for coal contract replacement that started in early 2007. The *Fuel Contracting* chapter discusses contracting in more detail. Overall, the planning and negotiation process in 2007 and 2008 covered a period of 21 months before the final contract was executed in late 2008 for a new coal supply from New Mexico for the Apache Station.

C. Conclusions

1. The AEPCO organization is staffed with competent individuals in the fuel and power procurement and management areas.

The organization of the Senior Vice President & Chief Operating Officer, who has overall responsibility for procurement and management of fuel and power, is staffed with competent individuals who have demonstrated dedication to their work, and a sound understanding of the important dimensions of their individual jobs. Liberty found the organizational abilities of these individuals, and the detailed information that they have been able to provide, upon request, to be appropriate and sufficient.

2. Job descriptions for positions in the fuel and power procurement and management areas are satisfactory.

Job descriptions for the positions in the fuel and power procurement and management area are current, and typical of what is normally encountered in this area of activity in electric utility organizations.

3. The procedures for fuel and power management and procurement are satisfactory.

The procedures for activities in the fuel and power procurement and management area are current, and typical of what is normally encountered in this area of activity in electric utility organizations.

4. AEPCO has satisfactory procedures related to code of conduct and ethical behavior of employees.

AEPCO's procedures for code of conduct have recognized the particular risks to which the Company is exposed in the areas of fuel and power procurement and management, including hedging. The Cooperative has developed detailed procedures that thoroughly cover this area. The Cooperative also has a separate code of conduct procedure that all employees must sign, and confirm their understanding and compliance with the tenets of ethical behavior.

5. AEPCO has maintained a strong and effective relationship with ACES Power Marketing.

AEPCO had a relationship with ACES Power Marketing for many years, proceeding until recently as a customer only. However, four years ago, AEPCO became a member/owner of ACES Power Marketing with an equity position. There is now in residence a full-time ACES Power Marketing representative in AEPCO offices. AEPCO has made use of a valuable range of services for AEPCO that relate to trading and counterparty controls and risk management, and provision of valuable industry data and mark-to-market analyses.

6. AEPCO's approval-authorities matrix and trading controls are appropriate.

AEPCO documents related to policies and procedures for trading, and approval authorities are thorough. These documents exhibit the expertise to which AEPCO has access through its relationship with ACES Power Marketing. These materials are all first-rate, and demonstrate that AEPCO is benefiting from its relationship with ACES Power Marketing.

D. Recommendations

None.

III. Fuel Contracting

A. Background

This chapter addresses the following areas related to coal procurement, coal pricing and contracts:

- Coal Fuel Burned
- Coal Sources
- Coal Prices
- Contract Purchases and Summaries
- Contract Actions
- Transportation

In addition, this chapter addresses the natural gas contract status in the following areas:

- Commodity supply
- Commodity delivery
- Commodity storage

B. Findings

1. Coal Forecasted Versus Actual Burns

Rail transportation provides the primary transport method for coal consumed by AEPCO to generate electricity at its Apache Generating Station. AEPCO receives coal under a combination of long-term and short-term (or "spot") contracts. Long-term contracts consist of obligations whose term equals or exceeds one year; spot agreements have durations of less than a year. The Apache coal units (ST2 and ST3) each has a net rating of 175 MW. Together, their annual coal consumption has run in the 1.5 million ton range.

AEPCO burns low sulfur western coals from the Wyoming Powder River Basin ("PRB"), from Western Colorado, and from New Mexico. These coals range in sulfur content from a low of approximately 0.36 percent for Western Colorado coal to 0.93 percent for New Mexico coal.

The following table summarizes the annual comparisons between coal burn forecasts and actual coal burned at Apache.

Coal Consumption: Forecast Versus Actual

Item	2006	2007	2008	2009
Forecast Tons	[redacted]	[redacted]	[redacted]	[redacted]
Actual Tons	[redacted]	[redacted]	[redacted]	[redacted]
Difference – Tons	[redacted]	[redacted]	[redacted]	[redacted]
Difference - Percent	[redacted]	[redacted]	[redacted]	[redacted]

The next graph shows total coal consumption in tons, by month from September 2005 through December 2009. The graph compares this actual burn information with AEPCO's forecasts of burns for each month.

[redacted]

[redacted]

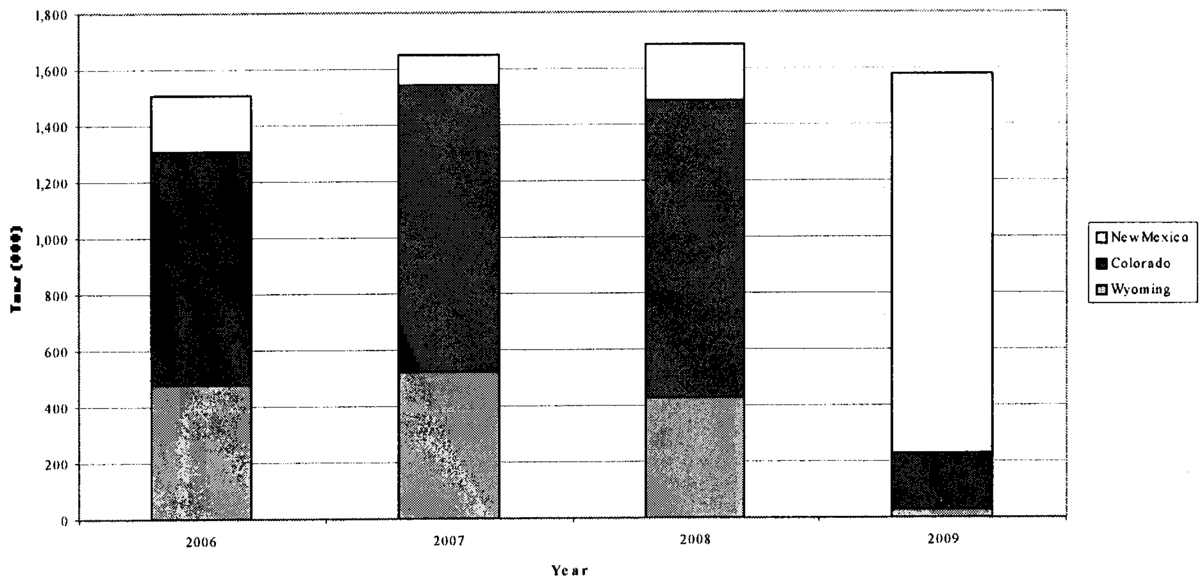
The preceding graph and table show a fairly normal variance between forecasts and burns. There are two exceptions: (a) AEPCO made the decision to postpone planned maintenance for two months in late 2007, and (b) actual coal consumption has been significantly less than planned since October 2008. Load has been reduced due to maintenance issues on the generating units and due to decline in market competitiveness for power from the coal-fired units, and consequently less off-system sales. The *Engineering Review/Plant Operations* chapter of this report addresses plant maintenance issues.

2. Coal Sources

The following graph shows the relative distribution of AEPCO's three supply sources: the Powder River Basin of Wyoming, Western Colorado, and New Mexico. The graph makes apparent the dramatic shift in coal supply sources that took place in 2009 because of overall coal supply economic considerations. Section 4 below discusses the economic issues underlying this shift.

For the years 2006 through 2008, Wyoming supplied approximately 500,000 tons per year, Colorado 1,000,0000 tons per year and New Mexico 200,000 tons per year. However, in 2009, the New Mexico proportion shifted to approximately 1,350,000 tons per year, with Colorado at 200,000 tons per year, and Wyoming supply negligible.

Geographic Distribution of Coal Supply



3. Coal Prices

The next graph shows delivered coal prices for coal consumed at the Apache Generating Station.

[redacted]

[redacted]

AEPCO prepared in 2005 a coal-price forecast for the years 2005 through 2009. AEPCO has updated the forecast annually (in either the 3rd or 4th quarter) as the Cooperative prepared its operating plan for the following year.

4. Contract Purchases and Summaries

During the period from September 1, 2005 through 2009, AEPCO made five purchases of coal under contracts with terms of one year or greater, as the following table displays:

AEPCO Term Coal Procurement: September 2005 – December 2009

Supplier	Term	mTons/ Yr	Year	Price $/T*	BTU/lb	%S
Term Coal Contracts						
COALSALES, LLC El Segundo & Lee Ranch Mines New Mexico	1/1/09-12/31/11	1,100 1,150 1,150	2009 2010 2011	[redacted]	9,200	0.93
Chevron Mining, Inc. McKinley Mine New Mexico	1/1/09-12/31/09	250	2009	[redacted]	9,800	0.45
Kennecott Colorado Coal Rio Tinto Energy America Colowyo Mine - Colorado	1/1/09-12/31/09	200	2009	[redacted]	10,400	0.36
Rio Tinto America Jacob's Ranch Mine Wyoming	1/1/08-12/31/08	300	2008	[redacted]	8,800	0.80
COALSALES, LLC Twentymile Mine - Colorado	1-1-08-12/31/08	100	2008	[redacted]	11,300	0.49

AEPCO applies a structured process to purchasing its coal supplies. The procurement process starts with development of an RFP that specifies the details of the required coal supply. The specified parameters include desired length of term, preferred source of supply, delivery point, pricing provisions, quality and quantity. For example a 2008 procurement resulted in a contract with COALSALES, LLC for delivery of approximately 1,000,000 tons of coal per year for the years 2009 through 2011. AEPCO sent the RFP to a list of five potential coal suppliers. These potential suppliers (covering coal from Wyoming, Colorado and New Mexico) comprised those suppliers that AEPCO believed were capable of providing the desired coal supply.

Multiple bids came from all potential suppliers. AEPCO began a detailed analysis process that considered all alternatives of supply and various blends of coals to achieve optimum economics and performance at Apache. The analysis included a three-year projection of estimated costs from various combinations of suppliers. As a result, for each year of potential supply, four different supply scenarios came under consideration. The different supply scenarios also included different rail-sourcing possibilities. The Vista Model has formed an important part of the AEPCO evaluation process. The Vista Model analyzes the effects of various coal qualities on coal-fired generating units. AEPCO conducted all evaluations on the basis of final delivered cost to Apache in dollars per MMBtu.

After AEPCO identified the most optimum economic package of coal supply, it began a negotiation process with the lowest cost supplier, which in this case was COALSALES. Several offers and counter offers ensued, before finally converging on a deal that both parties could abide. At this point, management provided the details of the potential coal supply agreement to the AEPCO Board of Directors meeting in executive session, for approval. The potential procurement underwent detailed discussion, and the Board approved management discussions with the vendor about contractual details. On November 24, 2008, AEPCO signed the agreement with COALSALES.

AEPCO generally followed a similar process for most coal procurement, with occasional exceptions. For example, in late 2007, AEPCO was preparing to issue an RFP for procurement of 300,000 tons of coal for 2008 delivery. AEPCO was aware of potential supplies available, and of prices that were being offered by suppliers at this time. [redacted]

Liberty examined all of AEPCO's coal procurement between September 2005 and December 2009, including both term and spot purchases. In all cases, AEPCO performed detailed analyses, followed appropriate procedures, obtained proper approvals, and fully justified the procurement.

5. Contract Actions

During the period from September 1, 2005 through 2009, AEPCO actively sought on three different occasions to modify its coal supply arrangements through coal resales and swaps. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

These transactions produced both the financial benefit just described and the avoidance of high rail charges. The procurement of high-Btu and low-sulfur New Mexico coal addressed the need for AEPCO to secure shipment of Colowyo coal at Union Pacific's high rates in 2009. Instead, AEPCO was able to ship New Mexico coal under a more attractive BNSF common carrier agreement.

During the period from September 1, 2005 through 2009, there were no coal contract price redeterminations, no force majeure provisions invoked by AEPCO or its vendors. There were no coal-contract terminations for reasons other than normal contract date expirations. Currently, no open or unresolved coal contract issues exist.

6. Transportation

Apache receives coal from sources on the Union Pacific Railroad and on the BNSF Railway. For the years 2004 through 2008, AEPCO's only contracted fuel transportation was with the Union Pacific Railroad. It provided for a minimum volume of 1,000,000 net tons of coal per year.

Volumes of coal shipped via the BNSF Railway moved under common-carrier pricing authorities (tariffs). After 2008, AEPCO shipped coal solely under railroad tariffs, and has not had any open or uncontracted coal transportation.

The following tables show the coal shipped under contract and under tariff from 2005 through 2009.

Coal Shipped under Union Pacific Contract

Year	Origin	Actual Volume	Minimum UP Annual Volume
2005	Colorado &Wyoming	1,235,899	1,000,000
2006	Colorado &Wyoming	1,300,874	1,000,000
2007	Colorado & Wyoming	1,577,383	1,000,000
2008	Colorado & Wyoming	1,444,751	1,000,000
2009	N.A.	N.A.	N.A.

Coal Shipped Under BNSF Tariff

Year	Origin	Actual Volume	Minimum BNSF Annual Volume
2005	New Mexico	279,312	200,000
2006	New Mexico	203,032	N. A.
2007	New Mexico	107,419	N. A.
2008	New Mexico	197,845	N. A.
2009	New Mexico	1,353,916	N. A.
2009	Montana	27,850	N. A.

Rates for rail transportation of coal have formed a matter of significant attention for AEPCO in 2008 and 2009. In 2008, the Union Pacific issued a 2009 transportation rate proposal that would resulted in potential, dramatic price increases for AEPCO. At the same time, AEPCO was considering a new coal-supply agreement to run for three years from 2009 through 2011. Primarily due to expected large increases in transportation costs, AEPCO's 2008 coal RFP process threatened to produce an increase in total coal and transportation costs for 2009 [redacted]

This dramatic potential increase in transportation costs influenced AEPCO fuel strategies in a number of ways, which the report chapter titled *Fuel Management* addresses. Briefly, the potential increase in 2009 transportation costs led to [redacted]

The proposed, dramatic increase in transportation rates led AEPCO to file a rate-complaint case with the U.S. Surface Transportation Board ("STB"). The case remains ongoing; at the same time, AEPCO is negotiating with the Union Pacific to reach a rail settlement agreement. AEPCO would like to produce a result that makes PRB/Colorado coal competitive with New Mexico coal. There have been offers and counter offers, and rail-rate negotiations with the Union Pacific continue. Failing an agreeable settlement with the Union Pacific, AEPCO would continue the pursuit of the STB case in an attempt to reach an ordered resolution of its complaint.

7. Natural Gas Commodity Supply

AEPCO buys all of its natural gas under a standard form contract developed by the North American Energy Standards Board ("NAESB"). The NAESB contract was originally developed in the 1990s as the Gas Industry Standards Board ("GISB")() contract. In 2002, it was modified and re-named, as the GISB expanded its role to include standards and business practices in the wholesale and retail segments of the electric-power industry. The NAESB contract was updated again in 2006. It is widely used by suppliers and users of natural gas throughout the U.S. and Canada. The NAESB contract specifies general terms and conditions, under which counterparties agree to individual transactions (with transaction-specific details such as price, delivery location, and firmness, for example), and then "confirm" each specific transaction's unique terms with a one-page statement. The Buyer usually sends to the Seller such confirmations, which the counterparties often refer to as "Schedule A." These confirmations allow the parties to assure mutual agreement on the details of the agreed transaction, which the confirmation documents.

AEPCO has NAESB contracts in place with [redacted] counter-parties.[6] It buys its gas under those contracts in two ways:

- Up to [redacted] percent of its gas is bought on a "forward" basis; *i.e.*, contracted for some months in advance of its intended use, as part of AEPCO's hedging program. AEPCO buys this gas pursuant to an informal quotation process.
- AEPCO buys the other [redacted] percent daily, using an electronic trading platform.

AEPCO fills its forward supply requirements from [redacted] suppliers: [redacted]. The Cooperative limits its requests to quotations from these [redacted] counterparties because [redacted]

[redacted] suppliers also provide other conveniences as part of maintaining a relationship with AEPCO. One example arises in cases where [redacted]

AEPCO's daily purchases come through the Intercontinental Exchange ("ICE"), which is a standard industry practice for such acquisitions. Buyers and sellers post offers electronically on ICE; the platform then matches them with each other. Both buyer and seller can restrict valid offers to counterparties with whom they have in-place standard contracts. AEPCO, as do a number of other Generation and Transmission cooperatives (among others), uses the services of ACES Power Marketing to manage transaction activities. An ACES Power Marketing representative on-site at AEPCO maintains information about approved AEPCO counterparties and authorized credit limits, to assure that transactions are with approved counterparties and remain within pre-established credit limits.[7]

8. Gas Transportation Contracts

AEPCO's Apache Generating Station is served exclusively by the El Paso Natural Gas Pipeline system ("El Paso"). The U.S. Federal Energy Regulatory Commission ("FERC") regulates El Paso's rates and terms of service. Until 2006, AEPCO was an "all-requirements" customer of El Paso: AEPCO has always bought its own gas, but El Paso managed the pressures and flows to ensure that the Apache Station received the amount of gas needed at all times.

At that time, as part of a rate case, El Paso was required to restructure its service offerings and rates. AEPCO has since used conventional gas-transportation contracts with El Paso, supplemented with contracts for "premium" services. These supplemental agreements allow it to take the maximum delivery quantity over 8 or 12 hours, rather than the usual 24 hours.

[redacted]

[redacted]

AEPCO participated actively in negotiation of these contracts. AEPCO examined the patterns in its gas usage, and then sought contract quantities to match that usage. El Paso offered certain quantities, but AEPCO adjusted and added to El Paso's initial offerings in order to improve the "fit" between its contracts and its operational requirements. Among other things, [redacted]

[redacted] All of the contracts expire in September 2016.

9. Gas Storage Contract[8]

AEPCO has a gas storage agreement with [redacted] The pipeline may have a separate rate schedule for services of this type, or it may bill for them at its normal rates for transportation service.

AEPCO's agreement with [redacted] provides for [redacted] The contract was originally entered in [redacted]

AEPCO reports [redacted]

Park-and-loan services are essentially short-term storage services offered by pipelines. "Parking" is analogous to storage injection, but essentially amounts to withdrawing less gas from the pipeline than scheduled. "Loaning" is analogous to storage withdrawal. It occurs when a customer withdraws more than its scheduled quantity from the pipeline. Park-and-loan services are inherently interruptible because the pipeline is not always able to accommodate additional volumes in the pipeline in response to a customer's request to withdraw less than scheduled, or to allow a customer to withdraw more than its scheduled quantity. Park-and-loan services are also inherently short-term, as pipelines must keep receipts and deliveries essentially in balance over time in order to operate properly.

10. Gas Contract Documentation

For most major decisions, the investigation and analysis performed by AEPCO personnel and consultants are summarized in an Executive Staff Summary submitted to the Board of Directors. Minutes of Board Meetings contain Board Resolutions setting forth the decision made by the Board. Materials provided to Liberty included the Staff analysis and Board Resolution regarding the [redacted] contract as an example of the Cooperative's documentation processes.

Gas purchase decisions are supported by Board approval of AEPCO's hedging policy. Individual purchases are documented through a transaction-tracking system administered for AEPCO by ACES Power Marketing. Those latter purchases are monitored continually by ACES Power Marketing.[9]

C. Conclusions

1. AEPCO's forecasts for coal consumption have remained relatively stable compared to actual consumption, with two major exceptions.

AEPCO had done a reasonable job of forecasting coal consumption, but there have been two outlying sets of circumstances. The first involved two months in late 2007, when AEPCO made the decision to postpone planned maintenance. The second exception has been ongoing since October 2008. Actual coal consumption has been significantly less than planned. Load has been reduced due to maintenance issues on the two Apache coal-fired generating units, and due to decline in market competitiveness for power from the coal-fired units, consequently less off-system sales.

2. AEPCO has taken effective coal contract action, through coal resales and swaps, to optimize coal supply.

AEPCO has conducted coal resales and swaps in order to improve its coal supply situation. [redacted]

[redacted]

[redacted]

3. Documentation maintained by AEPCO in support of its coal procurement is thorough, and meets the standards expected from electric utility fuel procurement organizations.

Liberty found that the documentation necessary to support coal procurement decisions was available and satisfactory in content.

4. AEPCO acted appropriately in 2008 to enter a three-year coal supply agreement with COALSALES for coal sourced from New Mexico.

AEPCO's initial considerations associated with evaluation of a potential new three-year coal supply was affected by the possibility that costs could increase by as much as 124 percent because of dramatic increases in transportation costs on the Union Pacific. AEPCO continued its pursuit of alternatives, and engaged in negotiations with alternate suppliers in an effort to maintain reliable coal supply, at the best available prices. The Cooperative identified that New Mexico coal might offer be reasonable alternative to Wyoming and Colorado coals. After exchanging numerous offers and counter offers, a deal was reached with COALSALES for coal from the New Mexico El Segundo and Lee Ranch Mines.

5. AEPCO has acted appropriately in dealing with the dramatic increase in coal rail transportation rates.

Faced with the potential of unrealistic increases in rail transportation rates from the Union Pacific, AEPCO has acted appropriately. It has shifted its major coal supply contract from Union Pacific sourced coal to BNSF sourced coal. It has filed suit with the STB in protest of the high Union Pacific rates. Concurrently, AEPCO has attempted to negotiate with the Union Pacific in an effort to keep all of its options open.

6. AEPCO has appropriately developed, and is properly maintaining, its gas-supply relationships.

The natural gas industry, and more recently the electric-power industry, has invested considerable effort in standardizing its energy-supply contracts and business practices at the wholesale and retail levels. AEPCO benefits from this effort in having standard form supply agreements available for use. AEPCO accesses this benefit through its use of the NAESB standard form contract for its gas supplies.

Maintenance of this benefit requires current information regarding the creditworthiness of gas-trading counterparties. This is one of the functions that AEPCO obtains through its relationship with ACES Power Marketing. This relationship strikes Liberty as an efficient way to discharge this vital function.

7. AEPCO's method for buying its forward gas supplies offers advantages, but the Cooperative should try to expand the number of suppliers for those purchases. *(Recommendation #1)*

AEPCO buys its forward gas supplies from [redacted] suppliers, [redacted] The more uncertain issue is whether other suppliers would offer similar inducements. At recent, depressed market prices, AEPCO's forward purchases amount to [redacted] It is reasonable to consider the possibility that more suppliers would be interested in a share of that business. It is appropriate that AEPCO formally solicit interest from others in participating in its RFPs while providing similar advantages to those offered by the [redacted], existing forward suppliers.

8. AEPCO was effective in negotiating its gas-transportation contracts.

Like many other gas pipeline systems, El Paso was required to restructure its service offerings in response to concern raised by its non-electric-generation customers that electricity generators were not paying their "fair share" of pipeline costs. Creation of premium products that allow hourly variation in gas flows, for example, has been a common pipeline industry response to those concerns.

AEPCO's response to these developments was appropriate and effective. AEPCO analyzed the patterns in its usage in terms of the services that El Paso was offering, and knew what it was seeking when it went into its negotiations with El Paso. The results were satisfactory from the perspective of AEPCO's customers.

9. AEPCO's gas storage service is appropriate.

As discussed in the chapter on Fuels Management, AEPCO makes good use of this storage capability, as part of its hedging program and to provide operational flexibility. [redacted]

The storage-service contract between AEPCO and its service provider, [redacted]

10. Gas contract documentation is satisfactory.

For major contracts, the decision materials presented to the Board contain adequate information to support regulatory review. For commodity-purchase decisions, the transaction-tracking system maintained by ACES Power Marketing provides a sufficient record to support an after-the-fact review.

D. Recommendations

1. Solicit interest in additional suppliers for AEPCO's forward gas purchases. *(Conclusion #7)*

Liberty believes that AEPCO's forward purchases of natural gas supplies may be large enough to generate interest from more than [redacted] suppliers. AEPCO's gas-transportation contracts give it access to purchasing points in both San Juan and West Texas supply basins. [redacted] are not the only sellers with gas supplies available in those places.

[redacted] are material. Nevertheless, there is reason to believe that AEPCO is a sufficiently attractive buyer to attract others willing to offer such terms. In any event, solicitation of additional participation will resolve any uncertainty in that regard. It is generally sound to expand participation in purchase solicitations.

IV. Fuel Management

A. Background

This chapter addresses the following areas related to fuel supply management:

- Coal Receipt Information
- Coal Weighing, Sampling and Analysis
- Coal Contract Administration
- Coal Inventory Control
- Natural Gas Supply Management.

B. Findings

1. Coal Receipt Information

Apache Station coal arrives in unit trains, which AEPCO unloads at its coal-unloading facility. AEPCO manages receipt information with a variety of internally developed spreadsheet programs developed specifically for the purpose of monitoring receipt of coal. These programs track coal delivery quantities and qualities, and enable AEPCO to monitor contract compliance. The programs indicate the trainload quantities of coal as received, and the corresponding coal quality. AEPCO cross-checks data in the spreadsheets against contractual requirements for coal quantity and quality.

AEPCO maintains an estimated train delivery schedule in the Station Control Room, and regularly logs into the Union Pacific Web site in order to confirm specific train status and expected arrival time. When the unit train of coal arrives at the unloading facility, the facility operator uses a "Train Unloading Data Log" (Log) that is specific for each train. The Log contains a complete record for the train unloaded, including car numbers, coal weights from the belt scales, and appropriate arrival and departure times. The log also contains information on any coal cars that failed to open and unload coal. At completion of train unloading, the facility operator sends this Log to the Station Control Room.

In the Station Control Room, data from the Log is transferred to a Union Pacific summary sheet (the "Union Pacific Railroad NCSC"). AEPCO personnel fax the Union Pacific Railroad NCSC form and the Log to the Union Pacific Railroad and to the AEPCO Fuel Resource Administrator ("Administrator"). The Administrator uses this coal receipt information as primary information for coal received dates, quantities, and train numbers. The Administrator cross-checks information on the Log with tonnage information provided by the coal mines. The only problem Liberty observed with the Log is that it does not indicate the source of the coal.

2. Coal Weighing, Sampling, and Analysis

AEPCO's coal contract arrangements provide that weighing, sampling, and analysis of coal delivered to AEPCO will come from information collected at the coal mines, as coal is loaded into unit trains. Coal weighing and sampling takes place during the loading of coal into unit trains. ASTM standards govern the sampling. A split of the sample collected goes to AEPCO for its own use in cross-checking analytical information. Several times a year, AEPCO sends these sample splits to an independent laboratory to provide verification of the sample analysis information provided by the coal mines.

AEPCO's coal contracts require the vendor to analyze coal sampled, in accordance with ASTM standards, and send a report of its coal sample analysis within 48 hours after the loading of each trainload of coal to AEPCO by email. The vendor also determines the weights of coal loaded into each railcar in each shipment of coal to AEPCO, using either certified scales or a certified batch weight system maintained by the coal mine. The sum of the railcar net weights for each train of coal comprises the accepted contractual weight of the coal delivered in each shipment. The vendor provides, on departure from the mine, a trainload manifest identifying the total weight of each railcar of coal for each trainload shipped to AEPCO. Liberty examined the scale calibration records provided by each coal mine, and found them to be satisfactory.

3. Coal Contract Administration

The Fuel Resource Administrator ("Administrator") has responsibility for contract administration. The Administrator, who reports directly to the Senior Vice President and Chief Operating Officer, follows a comprehensive set of policies and procedures designed to provide guidance in the procurement of coal supply and coal transportation as necessary to support energy generation at Apache. These procedures also contain a separate section specifically focused on maintenance of target coal inventory levels. Inventory procedures include specific plans to be implemented should any unforeseen event prohibit AEPCO from obtaining normal coal supply.

The coal procurement procedures contain the following specific sections:

- Coal Supply and Transportation Analysis and Forecasting
- Development of Coal and Transportation Objectives and Strategy
- Coal Transportation Request for Proposal Process
- Coal Transportation Approvals and Finalization of Agreements
- Coal Supply Request for Proposal Process and Analysis
- Coal Supply Approvals and Finalization of Agreements
- Coal Supply and Transportation Delivery Planning and Management.

The Administrator daily administers coal contracts, and provides regular input of fuel information into the fuel accounting system. The Administrator communicates daily with fuel personnel at the Apache Station, and meets monthly at the station to discuss fuel management issues with a group that includes representatives from all disciplines including Maintenance, I&C, Process Control, Environmental, Engineering, and Station Fuel Management.

4. Coal Contract Compliance

a. Quantity Administration

During the period from September 1, 2005 through 2009, AEPCO did not experience any situations where quantities of contracted coal were not delivered.

b. *Quality Administration*

During the period from September 1, 2005 through 2009, AEPCO did experience some situations where some coal delivered did not meet quality requirements. The next table summarizes these occasions.

Coal Quality Variations

Year	Month	Company/Mine	Btu/lb	Description
2009	May	COALSALES El Segundo	8,734	Below 8,900 Btu/lb reject limit. Train rejected; buyer could not be found. AEPCO accepted train, negotiated $4.00/ton discount.
2008	Multiple: 31 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2008	September	Entergy Services Colowyo Mine	9,851	Below 10,000 Btu/lb reject limit. AEPCO accepted train and received $10.00/ton discount.
2007	Multiple: 10 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2006	Multiple 4 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2005	November	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.

5. Coal Inventory

a. *Targets*

AEPCO has established an inventory policy. The Coal Supply Group reviews it annually, taking into consideration the industry average of coal inventory, coal market conditions, coal blending objectives, transportation pricing, financial considerations (such as carrying costs), and other strategic objectives. The current inventory target is 40 days of burnable coal available in the stockpile at a two-unit nominal capacity factor of 95 percent. The policy states that inventory will be no more than 25 percent above or below this level. The 40-day target equates to an inventory of approximately 176,000 tons of coal, exclusive of the amount (approximately 15 days, or approximately 66,000 tons) deemed not recoverable.

b. *Recent Coal Inventory Growth*

AEPCO decided to permit inventory to grow in 2008, in order [redacted]

[redacted]

[redacted]

Coal Inventory Levels (Days)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005									9	12	25	18
2006	18	13	19	25	21	15	15	15	18	25	27	23
2007	16	16	18	15	26	23	21	30	27	27	40	40
2008	39	45	66	70	70	66	69	60	57	49	68	76
2009	75	77	94	111	119	116	116	120	128	125	134	137

Coal Inventory Levels (Tons)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005									39,269	52,635	105,112	74,232
2006	77,035	57,965	80,884	108,869	90,789	64,504	64,612	65,462	77,544	109,754	115,273	99,679
2007	68,870	71,083	79,185	66,360	113,890	99,333	92,470	127,201	114,590	117,763	171,697	169,930
2008	167,663	190,882	278,336	297,801	296,195	279,600	283,455	253,441	241,583	208,135	290,584	323,248
2009	319,596	327,955	397,124	470,806	500,838	492,181	489,430	506,796	540,759	526,848	567,071	576,743

AEPCO's growth in coal inventory exceeded its expectations. For the last several months of 2008, AEPCO's generation load was less than anticipated, which led to lower than estimated coal burn at Apache. Decreased Apache generation continued into and through 2009. Reduced energy demand from AEPCO's members contributed to this result. In addition, during 2009, AEPCO experienced unplanned coal unit outages and experienced unit derates at Apache. [redacted] The report chapter titled *Engineering Analysis/Plant Operations* discusses Apache performance.

6. Physical Coal Inventory Measurements

Since 2005, AEPCO has been conducting annual coal inventory surveys to confirm coal inventory levels, and to ensure correspondence between book and physical inventory amounts. Starting in mid-2008, AEPCO began biannual physical surveys, because of the significant amount of coal in inventory, as compared to previous levels. Physical inventory measurements have been conducted using aerial flyover techniques and density measurements obtained through bore-hole samples. AEPCO has made adjustments to book inventory if the difference between book and physical inventory exceeds 1.5 percent. In making the adjustment, AEPCO subtracts the 1.5 percent measurement uncertainty from the difference in tons between physical and book inventory before any adjustment is made. For example, in the 2005 measurement, the difference between physical and book inventory was 3,592 tons. The 1.5 percent degree of uncertainty represents 2,067 tons, which AEPCO subtracted from the tonnage difference of 3,592, to obtain the adjustment quantity of 1,525 tons to add to book inventory.

The following table shows the results of coal pile physical inventory measurements since 2005.

Coal Inventory Comparison – Physical vs. Book Inventory

Date	Book Inventory	Physical Inventory	Difference (tons)	Difference (%)	Adjustment (tons)
12/05	134,232	137,824	3592	2.6	1525
12/06	159,679	149,113	(10,566)	(7.1)	(8305)
12/07	229,021	213,294	(15,727)	(7.4)	(12,492)
7/08	352,952	338,379	(14,574)	(4.3)	(9,498)
12/08	383,248	387,398	4150	1.1	-0-
6/09	552,181	516,963	(35,218)	(6.8)	(27,464)
12/09	636,743	606,144	(30,599)	(5.0)	(30,599)

7. Natural Gas

AEPCO has steam units that run on coal and combustion turbines that run on natural gas. AEPCO also has a combined-cycle unit that runs on gas. In the late 1980s or early 1990s, the steam units were retrofitted to be able to run on gas, but at current prices they are running on coal. The steam units generally have run in the base-load position; *i.e.*, they run steadily (unless they are down for maintenance) year-round. The gas turbines have generally run more in the summer and less in the winter. AEPCO generally does not run the combined-cycle unit outside the months from June through September.

AEPCO's Resource Planning group takes load forecasts from the member cooperatives, and assembles them into a forecast of requirements for power. The group then runs these forecasts through a dispatch-simulation computer model (PROMOD) to forecast:

- Generation by each of AEPCO's generating units
- Purchase requirements under each of AEPCO's long-term power-purchase contracts.

The forecasts initially cover the next five years, and then undergo multiple updates during the year as part of AEPCO's budgeting and business-planning processes.

The generation forecasts also produce estimates of requirements for generating fuels. Fuel prices and forward power prices within AEPCO's power-coordination area serve as inputs to the forecasting process. Outputs therefore include possible economy power purchases and sales, as well as quantities of fuel required, if power purchases or sales are indicated by relative price levels. Through this process, AEPCO generates fuel requirement forecasts by month for the next five years.

AEPCO's current hedging strategy calls for the Cooperative to begin to buy the gas forecast to be needed [redacted] ahead of the month when it will be needed. The strategy is [redacted] The report chapter on Fuel Supply Contracting describes how AEPCO secures much of this gas from [redacted] vendors [redacted]

That chapter also discusses AEPCO's contract for gas storage. The storage available under that contract is sufficient to meet [redacted]

Once [redacted] AEPCO buys the balance of its gas [redacted] The Cooperative balances these purchases against [redacted] If AEPCO can buy the power cheaper than it can buy the gas and generate the power, it will do so. Conversely, if it can buy the gas and generate the power for less than it can buy the power, it will do that, instead.

AEPCO generally [redacted]

AEPCO uses its gas storage [redacted]

8. Fuel Oil

AEPCO's Gas Turbines No. 1 and 2 can use diesel fuel as an alternative to natural gas. Gas Turbine No. 3 can burn a range of fuel oils, from No. 2 (diesel fuel) to No. 6 (heavy fuel oil). Steam Unit No. 1 could burn fuel oils, and fuel oils were used in the igniters for the coal units. However, natural gas has been available; therefore, there has been no need to use fuel oils for back-up fuels. Also, the igniters were switched to natural gas in the 1980s. Thus, while Gas Turbine No. 2 is reported to have burned small amounts of No. 2 fuel oil in recent years, none of the other units has burned fuel oil of any type in "many" years – perhaps as long as 40 years, in the case of Gas Turbine No. 1.[10]

AEPCO has substantial fuel-oil storage at its Apache Generating Station, perhaps [redacted] gallons, according to Management.[11] All of these tanks are empty, however.

AEPCO's new LM6000, Gas Turbine No. 4, has some smaller tanks for fuel-oil storage. Those tanks are sized to [redacted] Management[12] estimates the size of those tanks at [redacted] gallons. "Minimal" quantities of diesel fuel are kept in those tanks, as natural gas has been available to fuel the unit. The oil in the tanks is used primarily to power trucks and loaders moving coal at the Station. AEPCO contacts fuel oil dealers in the area occasionally to make sure that they could re-supply these tanks quickly if necessary.

Inventory management is conducted at station storage locations. The warehouse is responsible for tracking fuel level in the tanks and use. Warehouse personnel track meter readings during each month, then "stick the tank." This process uses a graduated tool to measure the amount of oil in the tank. This physical measurement is compared to the meter readings, and any discrepancy is required to be explained.

C. Conclusions

1. AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache.

AEPCO's coal contracts sufficiently provide for sampling and analysis of fuel delivered to Apache. Coal weights are determined by certified scales at the coal mines, and coal qualities are determined by samples taken at the coal mines in accordance with ASTM procedures.

Several times a year, AEPCO conducts an independent analysis of its split of coal samples provided from the coal mines. No unusual trends have been observed.

2. Coal inventory variations between physically measured values and book values are fairly normal, but have been exhibiting a trend meriting investigation. *(Recommendation #1)*

AEPCO coal inventory variations between book value and physical measurements have ranged from positive 2.6 percent to negative 7.4 percent. This is not an unusual variation range, but the majority of variations have shown that physical measurements are less than book values. There are multiple sources of variations between book inventory and physical measurements, and with coal inventory now representing a more significant asset than in the past, efforts need to be made to understand the reason for the consistent trend in differences, with corrective action as necessary.

3. AEPCO has effectively administered its coal contracts.

Contracts must be managed in ways that ensure delivery of the appropriate quantities and qualities of coal in accordance with agreed upon schedules, while at the same time maintaining appropriate relationships between the Cooperative and its coal suppliers. The tasks involved require experience and skill, and good communication. AEPCO has been effective in communicating internally on all aspects of coal scheduling and deliveries on a regular daily basis. Overall, AEPCO has demonstrated that it has been effective in all aspects of coal contract administration.

AEPCO has acted appropriately to manage the various quality provisions of its coal contracts, and has taken action as necessary to monitor quality and assess penalties, when coal quality variations have warranted such actions.

4. **AEPCO acted appropriately in developing a strategy to increase certain coal inventory, in an effort to better manage the prospect of high coal transportation rates in the future.**

AEPCO's basic strategy to increase inventory of [redacted] AEPCO conducted the appropriate economic analysis to justify such strategy. The fact that coal inventory continued to build after completion of building this coal inventory did not reflect on the soundness of the basic strategy, but related to other conditions that AEPCO did not anticipate.

5. **AEPCO coal inventories have reached unacceptable levels.** *(Recommendation #2)*

AEPCO coal inventories at a level of approximately 75 days would be appropriate to deal with the increased stockpile strategy as discussed earlier, but levels in the range of 137 days, as of the end of 2009, are not acceptable. AEPCO must develop a strategy to deal with this situation.

6. **Gas-supply management is generally effective, but continued attention to performance measurement is warranted.** *(Recommendation #3)*

Judging from the materials Liberty chose to examine on a test basis and the information learned through interviews, Liberty determined that AEPCO has sufficient and not excessive resources (*e.g.*, power-purchase contracts, generating units, fuel-purchase arrangements). Liberty also observed effective management practices and mechanisms for managing gas supply. AEPCO reports[13] that, in 2006 and 2007, it did a performance assessment of power trading activities in those years. During that period, the Manager of Power Trading and Scheduling did not identify any problems in the trading program. The performance assessments were discontinued in mid-2007 because they required considerable work to gather the data and generate the report.

AEPCO also reports[14] that it uses the ACES Power Marketing member web site to review current daily gas prices, and calls ACES Power Marketing when necessary for real-time gas prices. AEPCO also monitors its purchase prices against average ICE prices for that day. These efforts are appropriate, but gas supply management involves more than just daily gas prices.

7. **Fuel oils management is appropriate.**

AEPCO has little reason to maintain any substantial amount of fuel oil in inventory; therefore, it does not. The fuel oil that it might use as back-up fuel for generation is a standard product that is widely available in the quantities that it might use. Liberty sees no reason to conduct fuel oils management any differently.

D. Recommendations

1. **Formalize a process for examining the causes of differences between physical and book inventory, and take corrective action, as appropriate.** *(Conclusion #2)*

AEPCO should form an "Inventory Team," headed by the Apache Station Manager, to understand the variations between physically measured values of coal inventory and book values. It is important to attack this problem aggressively, and formalize the Inventory Team through the following steps:

- Develop a specific membership list for the Team, representing all appropriate functions within AEPCO
- Develop a specific charter for the Team, directing it to focus on improved inventory management, including all possible causes of inventory variation, with responsibility for reporting directly to the Chief Operating Officer with specific recommendations and costs associated with corrective action
- Develop a requirement for established meetings
- Develop a requirement for publishing minutes of meetings.

2. Take immediate action to develop a plan for reducing the coal inventory level at the Apache Station. *(Conclusion #5)*

AEPCO must take immediate action to develop a plan for reduction of coal inventory level at the Apache Station. The plan must include both physical activities, as well as economic considerations, and consider all dimensions of possible action, including consideration of the following:

- Variability of load forecast levels
- Quantity flexibility options in coal contracts
- Coal resale possibilities
- Overall coal inventory storage costs
- Re-evaluation of minimum inventory targets
- Re-evaluation of maximum inventory targets.

3. Explore performance measurement for AEPCO's traders. *(Conclusion #6)*

The *Gas Hedging* chapter of this report includes a recommendation that AEPCO begin to assess its performance in forward-market purchasing. Assessment for those purchases can be as simple as plotting the hedged price against the (unhedged) market price, although more quantitative assessments, such as measuring the reduction in volatility, are possible, and are probably well within the capabilities of AEPCO's helpers at ACES Power Marketing.

For the portion (about 25 percent) of gas requirements that AEPCO buys on shorter notice, AEPCO could develop a performance-scoring system by comparing the marginal cost of buying the gas and generating the power to the cost of buying power from the grid. The same system could also be used to assess the traders' effectiveness in realizing opportunities for short-term power sales. The performance metric in both cases would be the value created for AEPCO's traders' buy/sell/generate decisions.

The primary objective of measuring performance would be to improve. Careful assessment of how well a job has been done is the first step toward doing it better. As AEPCO and the traders get more comfortable with a performance-measurement system, it might be used to set goals for the trading function, or in the determination of compensation for the traders.

V. Gas Hedging

A. Background

This chapter addresses the following subjects regarding AEPCO's natural gas hedging:

- Strategy
- Goals
- Procedures, practices, and controls
- Performance measurement.

B. Findings

1. Historical Approach

AEPCO's[15] Resource Planning group takes load forecasts from the member co-ops and assembles them into a forecast of requirements for power. Running those forecasts through a dispatch-simulation computer model (PROMOD) then produces a forecast of power to be: (a) generated by each of AEPCO's generating units, and (b) purchased under each of AEPCO's long-term power-purchase contracts. The Resource Planning group generates forecasts that cover five-year periods, and then updates them a number of times during the year as part of AEPCO's budgeting and business-planning processes.

The generation forecasts also produce forecasts of requirements for generating fuels. Fuel prices and forward power prices within AEPCO's power-coordination area comprise inputs to the forecasting process, whose outputs include possible economy power purchases and sales, as well as quantities of fuel required, if power purchases or sales are indicated by relative price levels. This process supports the forecasting of fuel requirements by month for the next five years.

Since 2007, AEPCO has combined this forecast with gas-purchase level experience to hedge the price of the natural gas that it expects to use for power generation. AEPCO's early hedging activity focused on forward purchases of gas. Each calendar quarter, AEPCO would commit to purchase gas at an agreed price during each of the succeeding [redacted]

AEPCO's requirements for gas in the winter are much smaller than those in the summer. The Cooperative uses its storage contract [redacted]

AEPCO modified its hedging program, beginning with 2010 needs, taking advantage of its experience to date and conversations with consultants. AEPCO's Board approved these changes in June 2009. [redacted]

[redacted]

AEPCO reports that it generally finds prices in the market to be the best during [redacted]

To summarize, AEPCO lists the objective of its hedging program as [redacted]

2. Changes for 2010

Until now, AEPCO has used [redacted]

In the summer of 2009, after study with ACES Power Marketing and another consultant, AEPCO decided to [redacted]

[redacted]

[redacted]

3. Organization and Staffing[18]

Hedging falls under the responsibility of AEPCO's Manager of Power Scheduling and Trading, and his deputy, the Manager of Power Trading Services. These two individuals execute all purchases of natural gas and electric power that will occur after the next month. AEPCO has two Term Trader/Schedulers who buy gas and buy and sell power, and who schedule both gas and power, for the next day up to the rest of the month. A group of real-time Traders buy or sell, and schedule, power for the next hour.

The Manager of Power Scheduling and Trading has taken some training in physical and financial hedging. He relies extensively, however, on consulting services and advice from ACES Power Marketing. ACES Power Marketing assists AEPCO with various aspects of its trading and hedging activities, and provides daily reports on market conditions, advice on particular strategies, and certain execution and execution-support services. ACES Power Marketing's on-site representative manages entry of AEPCO's trades into the transaction-tracking system, and assists in approving supplier invoices for payment.

ACES Power Marketing also assists with administrative aspects of AEPCO's hedging program. ACES Power Marketing assists with the negotiation of all contracts, conducts all credit analysis for existing and potential trading counter-parties, and monitors AEPCO's credit exposures with respect to its counter-parties. ACES Power Marketing also assists AEPCO in administering its authority matrix for entering into agreements and transactions.

4. Transaction Tracking

AEPCO uses deal tickets to record natural-gas and term power transactions entered into by its traders. The real-time power traders enter their transactions on MS Excel™ spreadsheets. ACES Power Marketing's on-site representative gets the deal tickets for entry into the transaction-tracking system. The real-time traders' spreadsheets upload directly into the system.

ACES Power Marketing uses the Allegro transaction-tracking software. Each of ACES Power

Marketing's clients, both owners and customers, has a data base for its transactions. ACES Power Marketing's on-site representative ensures that all of AEPCO's transactions are entered into the system. She also uses the data in the system in approving supplier invoices for payment.[19]

5. Policies and Procedures[20]

An AEPCO Transaction Authority Matrix specifies which officers can approve commitments, and which commitments must go to AEPCO's Board of Directors for consideration. Separate limits apply to the amount of money committed and to the term (length) of commitments. AEPCO's Board of Directors has approved the Transaction Authority Matrix.

AEPCO also has documented policies and procedures for natural gas trading (Natural Gas Trading Authority Practices) and for power trading (Electric Power and Transmission Trading Practices). Subjects covered in those policies and procedures include the following:

- Who has authority to execute transactions
- The commodities and products that can be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations
- Other relevant factors associated with due diligence in authorizing transactions to be executed.

AEPCO Trading Sanctions define the procedures for addressing non-compliance with electric power and transmission and natural gas trading practices. These sanctions address the consequences of non-compliance. The Trading Sanctions also include general guidelines for determining appropriate disciplinary action, to ensure disciplined and consistent enforcement of the policies and procedures. The ACES Power Marketing on-site representative has responsibility for monitoring compliance with the trading practices limits and for reporting all non-compliance incidents to appropriate AEPCO staff and senior officers. Violations are reported to the violator's supervisor, and to that person's supervisor. AEPCO updates the Natural Gas Trading Authority Practices and Electric Power and Transmission Trading Practices as necessary. Their most recent versions bear a date of March 29, 2010.

C. Conclusions

1. AEPCO's objective for its hedging program is clear, but the Cooperative does not conduct structured measurements of effectiveness in meeting that objective. *(Recommendation #1)*

AEPCO's objective for its hedging program is [redacted] Liberty understands that the member cooperatives, through their representatives to AEPCO's Board of Directors, understand and support this objective.

While the objective is clear, Liberty did not find any evidence of effort by anyone to assess whether the objective was being met. Illustrations of the effect of hedging programs on price stability and price levels were contained in the materials prepared by ACES Power Marketing for AEPCO when it was considering whether to engage in hedging, but Liberty found no assessment of program results after AEPCO had decided to engage in hedging. This area needs attention.

2. AEPCO has adopted effective hedging strategies, and uses appropriate instruments to effectuate them.

[redacted]

[redacted]

3. Hedging personnel are adequately qualified.

The qualifications of AEPCO's employee, the Manager of Power Scheduling and Trading, who conducts hedging activities, typify what Liberty has seen at other utility organizations. Such individuals have often, as in this case, learned their trade primarily by practicing doing it. The AEPCO incumbent has also attended some short courses on physical and financial hedging. Often the principal benefit of such courses is to learn the terminology of trading and hedging.

AEPCO's other asset in this area is its relationship with ACES Power Marketing. With its 17 full members and 30-odd clients, ACES Power Marketing has a sufficiently solid and sophisticated clientele that it can attract and retain highly-qualified people, and support expensive and sophisticated systems. In its hedging activities to date, AEPCO has relied extensively on ACES Power Marketing's expertise in designing the program, and on its sophisticated capabilities and tools in managing it. AEPCO's members and customers should feel confident that its hedging program "is in good hands."

4. AEPCO's transaction-tracking capabilities and systems are first-rate, but have not been audited regularly. *(Recommendation #2)*

AEPCO's principal asset in this area is its relationship with ACES Power Marketing. The transaction-tracking software used is the industry standard, and the controls on this activity exhibit the expertise that ACES Power Marketing brings to the relationship.

As a routine matter, Liberty believes that controls on trading should be periodically examined by Internal Audit. We have no reason to expect that Internal Audit would take issue with any of the processes or flows. However, because trading and hedging expose an entity to large losses, they should be examined periodically.

6. AEPCO applies appropriate risk-management policies and procedures.

AEPCO has trading authority policies and procedures, which also cover hedging, for both electric power and natural gas. These policies and procedures cover all important areas, and reflect expertise in their construction. Instruments and processes are well covered and tightly prescribed.

D. Recommendations

1. Assess hedging program results. *(Conclusion #1)*

At a minimum, AEPCO should conduct annual assessments to determine whether the hedging program is meeting its stated objective: [redacted] Such an assessment can be as simple as plotting market prices versus hedged prices, and looking at the resulting graph.

Many utilities also use assessments of their hedging program to try to improve performance. Such an effort can require more sophisticated analytical techniques and capabilities, but any such effort would be well within ACES Power Marketing's capabilities. AEPCO should discuss the subject of program assessment with ACES Power Marketing, and select an analytical approach it finds comfortable. Results should be discussed with AEPCO's management and Board, along with analytically-supported recommendations for adjustment if appropriate.

2. Provide for periodic Internal Audit review processes and systems for tracking of transactions at AEPCO. *(Conclusion #4)*

Liberty sees no deficiencies in the structure of the control processes that AEPCO has in place. Nevertheless, good practice indicates that Internal Audit examine those processes to assure AEPCO's management and members that the processes are sound.

VI. Power Transactions

A. Background

AEPCO owns the Apache station, whose generating units have a net capacity of about 558 MW. AEPCO relies predominantly on its own generation to supply members' loads, supplemented by market power purchases. Its purchases fall into three principal categories:

- Long-term contracts from various sources to supplement AEPCO's requirements for capacity and for energy
- Short-term purchases from regional power markets, when AEPCO is able to buy on a real-time (hourly) basis at a delivered price lower than its marginal cost to generate with its more expensive units or to take from its purchase contracts
- Shorter-term purchases of market power that may be acquired to replace AEPCO generation during maintenance outages or at peak load times.

AEPCO has also made long-term sales of capacity and energy that were in excess of its members needs in the past. Particularly notable among these arrangements is a 20-year, 100 MW contract with Salt River Project ("SRP"). This SRP contract expires on December 31, 2010.

B. Findings

1. AEPCO Power Purchases

a. Power Purchase Summary

The next table shows AEPCO's total power purchases.[21] The Cooperative's firm purchases are for generating capacity, as well as for related energy when it is economic as compared to AEPCO's own generation or other market alternatives. Short-term purchases are made on an hourly basis, for one to three days, or for 15-30 days or more to provide energy during a maintenance outage for the Cooperative's own generating units. Total power purchases have ranged from about $35 to $49 million annually during the four-year period from 2006 through 2009. [redacted]

[redacted]

2. Firm Purchase Contracts

The next table[22] provides more detailed information on AEPCO's contracted firm power purchases during the four-year period from 2006 through 2009. [redacted]

[redacted]

[redacted]

The other firm purchased power contracts shown in the table resulted from AEPCO market-power contract solicitations performed starting in 2001. The solicitation processes are discussed further below.

[redacted]

3. Estimating Power Requirements

AEPCO develops plans for power resources using standard software packages accepted in the electric industry for these purposes. The Cooperative uses PROMOD software to model load requirements and power supply resources for budgets, for FPPAC forecasts, and for financial forecasts of up to five years. AEPCO also uses PROMOD for day-ahead, weekend, and maintenance outage scheduling of power resources. AEPCO uses another widely accepted product (Strategist power planning software) for long-term and resource expansion planning.

Load forecasts provide a foundation around which AEPCO forms power resource plans. Each AEPCO member prepares its own load forecast, with some assistance and coordination from AEPCO. New load forecasts are prepared every three years as part of a forecasting cycle designed to meet RUS requirements. These forecasts are updated annually in the years between establishing new planning baselines. An AEPCO manager uses the forecasts from the individual members, and factors in an econometric forecast. The University of Arizona prepares the latter. Twenty-year load forecasts are prepared for each member and approved by the member boards for each three-year cycle. The AEPCO Board of Directors approves the aggregate load forecasts for resource planning purposes.

The customers of the six primary members are mostly residential, with some small commercial customers but very few industrial customers. On the other hand, resource planning for the system requirements has changed drastically in recent years as AEPCO's largest all-requirements members have become partial-requirements members. Traditionally, all six of AEPCO's distribution cooperative members were all-requirements customers. First Mohave, then Sulphur Springs, the largest and second largest members, switched to partial requirements. Currently Trico, the third largest member, is in the process of becoming a partial requirements member. Partial requirements members are allocated a slice of AEPCO's power supply resources in accordance with their June 2001 load requirements as a percentage of the AEPCO total. The partial-requirements members are responsible for arranging their own capacity and energy requirements above the allocated levels. Partial requirements members may schedule and purchase energy from AEPCO in any amount up to their allocated limit.

They may schedule and purchase AEPCO power and sell part or all of it in the marketplace, if they so choose. The partial requirements members schedule energy supply through AEPCO, but only to their limits. They purchase the remainder from the power markets. [redacted]

4. AEPCO Power Solicitations

AEPCO has conducted several competitions for power supply resources since 2001. In August 2001, AEPCO issued a Solicitation for Proposals seeking baseload resources and May-to-September peaking resources for the years 2003 through 2010. The RUS has required competitive solicitations for new generating resources. During the preceding several years, generating capacity in the Southwest region had become overbuilt, resulting in significant excess generating capacity, which AEPCO believed would make purchased-power contracts less expensive. However, 2001 turned out to be a year of turmoil in regional power markets, causing

AEPCO to terminate the process. During this time period, Mohave, AEPCO's largest member, became a partial requirements customer. The California and Southwest power markets became dysfunctional during this time period. The Enron meltdown occurred in November 2001, causing further turmoil in the national and regional power markets.

AEPCO re-bid its solicitation in November 2002. Prior to this second solicitation, Sulphur Springs, AEPCO's second-largest member, had given notice that it would become a partial requirements customer. AEPCO's need for acquiring future base load power resources thus became substantially reduced.[25] The solicitation requested proposals for only peaking resources for May through September for the years 2003 through 2007. [redacted]

AEPCO's power supply resource modeling and planning identified a need for additional power supply resources for 2008 and beyond. In 2003, a solicitation for proposals requested baseload, medium-term, and peaking options. The requested starting date for contracts was 2008; a minimum of three years was requested, and AEPCO noted that the years 2008 through 2014 were to be of primary interest. AEPCO was interested in a diversity of suppliers, and considered transmission constraints also an important factor. All bidders were merchant power entities that had available capacity for sale in a market that continued to be over-supplied. AEPCO evaluated the proposals against each other, and compared them with the all-in costs of a new LM – 6000 gas turbine. The proposals were found to be significantly less expensive. [redacted]

In 2005 and 2006, AEPCO identified the need for additional baseload and peaking power supply resources. The Southwest Public Power Resources group ("SPPR") had been formed by this time, with AEPCO as a member. The SPPR includes municipal utilities, cooperatives such as Sulphur Springs, tribal power authorities, electric districts, and irrigation districts. Starting in 2006, SPPR has performed four joint solicitations for those of its members that elected to participate in each. The group initially estimated its long-term power supply needs as falling in the range of 1,300 MW. That amount has fallen substantially in recent years. AEPCO participated in the initial SPPR power supply solicitation in 2006. That solicitation focused on the shorter-term requirements of the group. In April 2007, six of the SPPR participants signed peaking contracts with selected bidders. [redacted]

In 2008, the SPPR issued a solicitation for bids for long-term power resources. The resulting proposals consisted mostly of bids for power supply from the development of new generating resources, which were generally unattractive to the tax-exempt public power group. No contracts resulted from this solicitation. The economic downturn starting in 2008 also significantly reduced the estimated power resource needs of the SPPR group. Another SPPR group solicitation for proposals for 500 MW of long-term power resources was issued in the summer of 2009, and an agreement was reached with a power supplier for a joint contract. However, with the continuing economic downturn, the SPPR group believed that the resource needs of the group participants had been reduced to far below the 500 MW requested. The solicitation was re-bid in early 2010, and the SPPR group has recently shortlisted three bidders for 220 to 280 MW starting in 2015 for contracts with a 25-year term. [redacted]

5. Off-System Contract Sales

[redacted] AEPCO is allocating the generating capacity from the Mesa and SRP contracts as they expire to its six 2001 all-requirements members. These power-sales contracts were signed quite some time ago, when AEPCO had excess power supply resources that were available. The Cooperative's resource modeling and planning indicate that it does not have long-term resources available for sale currently or in the future.[30] As result, AEPCO has not attempted to extend its contracts with SRP or to offer term contract sales in regional power markets. In fact, the Cooperative says that it does not normally make power sales beyond two days in duration, and that it relies primarily on real-time hourly sales when selling any excess resources.[31]

6. Trading

a. Day-ahead Scheduling and Trading

AEPCO's Power Trading desk prepares a schedule of its upcoming resource commitments on a daily basis. The day-ahead schedule seeks to meet most economically AEPCO's system requirements for the next day (for the next 2 or 3 weekend and holiday days each Friday). AEPCO uses the PROMOD dispatch modeling system to aid in determining its scheduling for the next day, week, or month. However, almost all scheduling takes place on a day-ahead or weekend basis. The day-ahead schedulers focus on this form of scheduling.

The day-ahead scheduler must first determine the electric loads that are expected during the following 24-hour period. In addition to the load forecasts included in the PROMOD model, the day-ahead schedulers review the hourly load history of recent days, in order to determine load levels for each hour at the temperatures experienced on each day. This recent load information gives the scheduler a best "read" as to actual loads that will occur for AEPCO at specific temperature levels.

AEPCO faces some complicating factors that make the determination of the level of power resources to schedule more difficult. Three of AEPCO's members provide pre-schedules that AEPCO must consider in making its day-ahead schedule. SRP may schedule from zero to the full 100 MW under its purchase contract. [redacted] Such potentially wide swings in pre-scheduling levels means that the scheduler has to make a best estimate of the SRP, Mohave and Sulphur Springs pre-schedules in order to complete the AEPCO schedule and provide it to the ICE between 5:15 and 6:45 AM. The AEPCO schedulers note that Mohave and Sulphur Springs tend to pre-schedule toward the maximum end of their range, as they cannot schedule additional resources on short notice. If these partial requirements members pre-schedule more power resources than they actually need, they may sell the excess in the power markets, if they so choose.[32]

On the power supply resource side, the scheduler checks with Apache to determine any updates for minor maintenance or problems that may cause any of AEPCO's generating units at Apache to be partially or fully unavailable during the following 24-hour period. The scheduler also communicates with the real-time traders to compare information and determine if any market-affecting resource shortfalls or major market outages have occurred. The scheduler then uses daily gas price and power market forecasts from ACES, as well as ICE market information, to determine the prices for components of AEPCO's power resource "stack" for the next day. The next table[33] shows a roughly estimated economic dispatch stack for AEPCO for July 20, 2010. The lowest cost resources are at the bottom of the stack; the pricing of each resource increases from the bottom to the top of the stack in ascending order. AEPCO will acquire assets in ascending order until the projected electric load for each hour is met.

AEPCO Rough Economic Dispatch Stack, July 20, 2010

Power Supply Resource	***Size (MW)***	***Marginal Cost per MWH***
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

The WAPA power purchases and the two Apache coal units will be scheduled first, as the generally least expensive power resources. On this particularly hot summer day with high air-conditioning loads, the scheduler bought 50 MW of "super peak" power to supplement AEPCO's other resources during the hottest hours (1 PM through 8 PM). On a high peak day, buying power on a real-time, hourly basis for these hours may be difficult to execute or very expensive, causing the scheduler to buy 50 MW for the super peak hours that were available one day in advance for a reasonable price.

On more normal days that are not near system peaks, decisions are made each day in scheduling the resources in the stack above the coal units. The AEPCO schedulers usually make decisions from among four resource options to fill out the top of the resource stack on most days. [redacted] According to AEPCO, market purchases may be more attractive than any of the gas-fired options, or may be placed in the middle, or even could be the most expensive option, if demand in the California and Southwest markets is high.[34] The resources at the very top of the stack are the most expensive, and rarely used, except in emergency situations or to provide required spinning reserve on peak days.

The scheduler then executes the day-ahead plan by making the power purchases and sales required to roughly meet the AEPCO load, and including these transactions in the day-ahead schedule, which is submitted to the ICE by 6:45 AM on the morning before the first hourly transaction at midnight, beginning the next 24-hour period.

7. Real-time Trading and Economic Dispatch

The results of the day-ahead schedule also go to AEPCO's real-time desk to manage the economic dispatch on an hourly basis. AEPCO has a team of real-time traders; one or two are on duty at all times. The real-time traders enter into hourly transactions for purchases and sales, if they are economic compared with AEPCO's power supply resource stack. The real-time desk constantly monitors the system loads, the resources operating to meet the loads, and looks ahead to determine changes in load, resources and potential opportunities in the upcoming hours. For each hour, the energy marketer assesses the dispatch order and compares to the costs of market resources (from ICE real-time market information) available for purchase with AEPCO's incremental generating costs, and will make hourly purchases from the market when economically advantageous. The real-time trader "shops the market" to fill in requirements in upcoming hours. AEPCO's real-time traders usually fill these needs with two-hour power purchases. Another option is to buy strips of several hours of power from the same source. However, since the market currently tends to have ample hourly availability, waiting for better pricing for purchases many times can be more economic than buying several hours or up to a whole day in advance.

The real-time traders have several counterparties that they have confidence can provide the resource timing, volume, and price required to meet AEPCO needs. In other words, the traders may have specific "go-to" counterparties that they know can deliver the timing, volume and price required upon short notice. The real-time traders note that there are only a handful of sources where 50 MW, 100 MW, or even 150 MW may be purchased quickly if AEPCO's biggest unit goes off-line unexpectedly.[35] AEPCO real-time traders may also be required to make real-time purchases or sales if the SRP, Mohave or Sulphur Springs pre-schedules have changed after the day-ahead schedule was submitted to ICE by the day-ahead scheduler.

8. Term Trading

AEPCO has historically made most of its power purchases that are not real-time or day-ahead trades for two or three days, when scheduling power supply requirements for a weekend or holiday. Liberty reviewed AEPCO's complete listing of power purchases and sales that were of greater than one day in duration but less than the long-term contracts that were described above. These purchases and sales of more than one day may be considered "term trading" for AEPCO.

Liberty reviewed the transaction listings from September 2005 until April 2010. As AEPCO has described, the vast majority of the transactions were for two-day purchases to cover weekends, as well as a small number of three and four-day purchases to cover holiday weekends. AEPCO notes that most, if not all of the transactions were the results of pre-scheduling for two days at a time. AEPCO pre-schedules on Thursday for Friday and Saturday, and pre-schedules on Friday for Sunday, Monday and holidays. These trades are normally conducted on ICE software. AEPCO usually contacts multiple counterparties from its established credit list and requests verbal bids for this weekend power. Depending upon the available credit with counterparties, volume, price and receipt point limitations, AEPCO may purchase from one or two suppliers for these weekend needs.[36]

The remaining AEPCO term transactions during this time period were identified and discussed with AEPCO to determine the particular need that was filled by these purchases. Some of the purchases were for 15 to 60 days in duration. Most of the term purchases were arranged to plan for maintenance outages or major equipment overhauls at AEPCO's Apache generating complex. AEPCO notes that "planned major overhaul outages are normally covered by purchasing some portion of power months ahead of the outage." AEPCO normally buys 50 percent to 75 percent of the power needed during the overhaul. AEPCO did not buy any power for these purposes in 2009 because of indications that market prices would be lower, and that AEPCO would consequently have reduced takes from SRP, Mohave and Sulphur Springs. The reduction in energy taken from these entities allows AEPCO to use more of its own generation to cover outages.[37]

The following paragraphs provide examples of the AEPCO term purchases, which were not numerous. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

9. ACES Services

ACES provides services to its owners, who are mostly generation and transmission cooperatives. AEPCO is a member and an owner of 6.25 percent of ACES. AEPCO relies on ACES for a number of services related to power and gas markets, energy trading and risk management. ACES maintains one full-time employee at the AEPCO offices to perform many of its service functions.

ACES' most important services provided to AEPCO relate to risk management. ACES provides an independent monitor function for all of AEPCO's gas and power transactions and trading operations. ACES oversees the middle and back-office functions of AEPCO's trading operations. AEPCO's schedulers/term traders have printouts from the ICE system that includes the details of their term transactions. The schedulers then fill out an AEPCO deal ticket and timestamp the ticket. Later, an ACES employee checks the transaction information and enters the deal information into the Allegro transaction system operated by ACES for all of its clients. ACES' Allegro system maintains the transaction records in its system separate from AEPCO, providing a risk management function. ACES also checks and enters AEPCO deal tickets for transmission transactions.

ACES also monitors and separately records AEPCO's real-time transactions. Real-time trades, including the real-time transaction details and the transaction tags, are captured in AEPCO's Minnesota Consulting Group ("MCG") software as they are made. The real-time traders also record their transactions in a separate MS Excel™ spreadsheet for each 24-hour period. AEPCO's nighttime traders check the transactions in the spreadsheet against the transactions in the MCG software to ensure that they are consistent internally. The spreadsheet is then e-mailed to ACES; it includes 24 hours of trading information. ACES checks the transactions, and enters them into its Allegro system. ACES will also follow up on specific transactions with the traders to ensure that they are correctly recorded.

Another function performed by ACES is that of counterparty credit reviews. The ACES home office maintains financial analyses of numerous trading counterparties, and updates them on an ongoing basis. ACES provides a "Trading Restrictions Report" to AEPCO and each of the traders daily. This report provides credit limits for each potential trading counterparty based on the credit standing of each.

ACES provides a significant amount of market information and analysis to AEPCO. For instance, ACES provides a "Power Report" that includes forward price curves that estimate future power pricing. Forward capacity curves are also provided. ACES prepares a "Daily Report" of market information for the ICE markets (Palo Verde, Four Corners, Mead, and California SP – 15). ACES provides a "Previous Day Recap" that summarizes the previous day's market activity. ACES provides an "Energy Price Outlook" that is a weekly update of national energy markets. ACES also provides daily e-mail energy market updates which are overviews of all U.S. energy markets.

ACES also provides other services to AEPCO that aid the trading operations. ACES performs mark-to-market analyses that value positions held by AEPCO for financial statement purposes. ACES also negotiates the standard ISDA contracts for AEPCO that are signed with each counterparty and used in each transaction. ACES' consulting arm is available to AEPCO on an ad hoc basis.

Finally, ACES provides scheduling for Anza, which is located in California. ACES has the software packages that are needed to interface with the California ISO because it has a number of clients in California. Because AEPCO can only wheel a portion of Anza's requirements to the member, ACES schedules supplemental power for Anza in California.[39]

10. AEPCO Trading Practices

AEPCO established and has regularly updated its "Electric Power and Transmission Practices" since at least 2004. The most recent update of these practices is dated March 29, 2010. The Trading Practices establish definitions and guidelines for AEPCO's trading operations, as summarized below.

The Trading Practices define:

- Who has authority to execute transactions
- The commodities and products that may be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume (as defined in exhibit A to the Trading Practices)
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations

- Other relevant factors associated with due diligence in authorizing transactions to be executed.[40]

The associated power trading Authority Matrix, most recently revised May 1, 2008, sets maximum transaction limits for five levels of employees (trader to CEO) regarding total trade dollars, total megawatt-hours, on-peak and off-peak and total megawatt capacity, term of the transaction, and lead-time for each transaction.

AEPCO also has a "Trading Sanctions" policy dated May 25, 2007, as well as a code of employee conduct. The Trading Sanctions define the procedures by which violations of the trading practices described above will be addressed. The Trading Sanctions assist in ensuring compliance with the trading practices and facilitate specific risk management practices. The ACES trading control specialist is responsible for monitoring compliance with the trading practices limits and reporting all non-compliance incidents to the appropriate AEPCO staff and the Risk Management Committee.[41]

11. FPPAC Internal Audit Review

AEPCO internal auditing performed an audit of the AEPCO "fuel bank" for the entire calendar years of 2007 and 2008. The audit was initiated in March 2009, and concluded with a report that is dated June 30, 2009. The AEPCO fuel adjustment mechanism had been re-instated as of September 1, 2005. A previous version of fuel adjustment mechanism was discontinued in 2001 with the restructuring of AEPCO. Previous to the internal audit, the Cooperative says that the only other audits of the fuel mechanism since September 1, 2005 were performed by outside auditors as part of financial statement audits.

The primary observation of AEPCO's internal audit was that several errors were identified in the Fuel Adjustor Mechanism ("FAM"), a spreadsheet maintained by the AEPCO financial services department for the period of January 2007 through December 2008. The errors caused the revenue of AEPCO to be overstated by a net $833,035 over the two-year period. On May 5, 2009 the AEPCO accounting department processed an adjustment journal entry for the same amount with a posting date of December 31, 2008. The AEPCO independent auditor's report and financial statements audit for 2008 included this adjustment.

The internal audit report enumerated numerous errors and 15 observations that were made by the audit, which each required a management response. The report enumerated errors in coal expense, legal expense, gas fuel, purchased power, wheeling expenses and non-class A sales for resale. The revenue of AEPCO is overstated by $98,659 in 2007 and again by $734,376 in 2008. The errors in the FAM that required correction by the accounting adjustments were caused by a combination of several factors, according to the audit report:

- Missing transactions in the KOB1 report generated by AEPCO's SAP accounting software, most likely because internal orders were not assigned to that report. The KOB1 report is the primary source of data used by the AEPCO financial services department to prepare the FAM

- Journal entries posted by the AEPCO accounting department for the month of December 2008, after the financial services department had already processed the KOB1 report for that month and without their knowledge
- Data entry errors in the FAM
- Errors in formulas of the FAM.

These errors were not identified by AEPCO until the internal audit report, because full reconciliations of the entries in the FAM versus the AEPCO general ledger had not been performed. Internal Audit recommended that the financial services department reconcile the year-to-date total amounts of several components of member fuel and purchase costs against the corresponding general ledger in order to identify any errors on a monthly basis, and to have them corrected before the FAM report is filed with the Arizona Corporation Commission.

The following is an example of one of the 15 observations in the internal audit report, and the management response:

> *The reconciliation of the GL records against FAM showed that several legal expenses for the period of January to October 2007 were not deducted in this report, causing the Member Fuel and Purchased Costs amount to be overstated by $43,550 for the year of 2007.*

The corresponding management response by AEPCO to this observation was as follows:

> *The process of calculating and reconciling the FAM has been updated to include cross-checking of the account balances derived from the KOB1 report with additional resource documentation provided by the purchase power and accounting departments. These source records include energy accounting documents and purchase power and transmission reports. In addition, as part of the FAM calculation, the senior financial analyst now completes a spot check comparison to individual GL balances related to coal and legal expenses in SAP.*
>
> *Financial services and accounting personnel have developed a standardized KOB1 report format which includes additional fields required to provide a complete record of information needed by both departments. The standard format ensures that both departments use the same parameters for gathering data and reporting purposes.*
>
> *Management and staff have also worked to improve communication and information flow between financial services and accounting personnel. Accounting staff notify the senior financial analyst by e-mail of unusual transactions affecting the accounts related to the FAM calculation. In addition, financial services and accounting personnel have increased our knowledge and understanding of how transactions within SAP affect the calculation of the FAM.*
>
> *These process changes were effective July 2009.*

The foregoing response or portions of it were used in the management responses for 14 of the 15 observations made in the audit report.

C. Conclusions

1. AEPCO has reasonably effective practices and operations for scheduling and dispatching power supply resources, but can suffer from not receiving timely information from some large members. *(Recommendation #1)*

Liberty's review of AEPCO's scheduling, real-time dispatch, and trading functions determined that the Cooperative effectively manages and operates these key functions. Operations take place under clear lines of responsibility, established operating routines, and a qualified work force. AEPCO effectively schedules and dispatches its own plants and long-term contracts, while regularly taking advantage of hourly market opportunities to buy economic purchased power to displace its own generation and purchase contracts. Both the day-ahead and real-time operations effectively use market information in their decision-making. AEPCO also has performed (in 2006) a year-long trading and transaction performance scoring method; however, it was determined that administering the program did not add sufficient value.

AEPCO does have difficulty in scheduling the resource requirements of its large member customers. Three of AEPCO's members provide pre-schedules that must be factored into AEPCO's daily day-ahead schedule. AEPCO says that the pre-scheduling information is not received in time to accurately schedule AEPCO's total needs. Since Salt River Project, Mohave and Sulphur Springs have very wide minimum and maximum take levels from AEPCO, such potentially wide swings in pre-scheduling levels means that the inability to "read the minds" of these members could result in daily over-supply or under-supply situations. The AEPCO scheduler has to make their "best estimate" of the SRP, Mohave and Sulphur Springs pre-schedules in order to complete the AEPCO schedule and provide it to ICE between 5:15 and 6:45 AM.

2. AEPCO's power trading operations have established effective processes and methods for arranging economic term purchases of power.

AEPCO has consistently expressed to Liberty that it has arranged "term purchases" (more than one day but less than one year) for two purposes: a) to purchase blocks of power needed for weekend days; and b) to arrange power for power plant maintenance and overhaul outages. Liberty's review of all of the AEPCO "term trades" from September 2005 to early 2010 confirmed that these are the types of trades that were arranged during the period. AEPCO primarily has arranged power trades on an hourly, real-time basis, and also under its long-term contracts. Liberty concludes that AEPCO effectively uses market power information to analyze the opportunities in the power markets to make economic purchases on day-ahead, real-time and term bases.

3. AEPCO's processes for soliciting long-term power resources have been thorough and effective in not over-committing AEPCO to either owned power resources or long-term contracts.

AEPCO has solicited proposals for power supply resources several times since 2001. Since 2006, AEPCO has been part of the SPPR buying group for power supply resources. [redacted] These processes have taken advantage of the overbuilt power supply markets in the Southwest region to the benefit of AEPCO members. The solicitation and evaluation processes demonstrate that the purchase contracts were superior options at that time to either building more generating capacity or buying through other available purchase contracts.

AEPCO's decision to join and participate in SPPR power supply solicitations since 2006 greatly increases its buying leverage and reduces asset ownership risk. Eighty-nine percent of AEPCO's future member load will be for partial requirements customers; therefore, the future need for additional power supply resources will be small. The SPPR provides a good mechanism to leverage AEPCO's smaller needs through an association of other public power entities.

4. **AEPCO's internal audit reports show an insufficient attention to detail regarding the FAM that has only recently been resolved. AEPCO also lacks written processes and procedures for calculating and reconciling FAM information and reports.** *(Recommendation #2)*

The lack of close attention to detail and the failure to reconcile accounts for the FPPAC are significant problems that require attention to assure continued confidence in the accuracy of fuel recovery. AEPCO has made significant and appropriate changes in its processes regarding the fuel filings. These changes should minimize or eliminate the errors experienced in 2007 and 2008. AEPCO's internal audit department has reviewed each quarterly FAM process since the discovery of the errors, and should continue to do so. The Commission must have a sound basis for confidence in the FAM information, which should make verification that processes have improved sufficiently a high priority for AEPCO and its internal auditors.

D. Recommendations

1. **Require partial requirements members and SRP to make timely submissions of pre-scheduling power requirements to AEPCO.** *(Conclusion #1)*

For Mohave, Sulphur Springs, SRP, or other partial requirements members to not provide their daily power requirements pre-schedule to AEPCO on a timely basis could have significant consequences for other members. AEPCO should immediately demand that pre-scheduling information be provided by a specific time that allows adequate time for AEPCO to include these requirements in its scheduling. AEPCO should not take responsibility for the consequences of a partial member's inattention or inappropriate action regarding scheduling. AEPCO should also undertake an analysis of the degree of past economic harm resulting from untimely submission, in order to determine whether the magnitude of harm is sufficient to warrant adjustments among members to address any such harm.

2. **Provide proof of the effectiveness of the new FAM processes to the ACC. Complete written processes and procedures for FAM calculations as soon as possible. Increase the frequency and depth of internal audits conducted at AEPCO, with more detailed focus on the fundamentals of fuel and energy procurement and management.** *(Conclusion #4)*

AEPCO's plans to document the processes and procedures for the FAM filings should be completed as soon as possible. AEPCO's current plan to complete these procedures by mid-2011 is not sufficiently prompt, they should be significantly accelerated to ensure that the proper processes are fully documented and not subject to the availability or specific knowledge of individual employees. AEPCO should then demonstrate to the Commission that its changes do in fact address all causes of its 2007 and 2008 filing errors and that it is taking efforts to verify their sufficiency.

Fuel bank audits as described to Liberty have not been conducted on a frequent enough basis, and have not been of great depth, given the high costs and risks associated with fuel and purchased power. Internal Audit should take direct and primary responsibility for establishing the frequency and scope of a more intensive fuel and energy audit program. If necessary, Internal Audit should have exclusive responsibility for identifying the sources of any outside assistance required to conduct them. Internal Audit is a comparatively small group that may not have sufficiently broad experience with fuels and energy operations to examine it in proper detail.

VIII. Engineering Analysis/Plant Operations

A. Background

Liberty conducted an engineering analysis of AEPCO's assets, focusing on the generating units, which form the core of those assets. Much of Liberty's work focused on the Apache Plant ("Apache"). Liberty examined station performance, operations, maintenance, and capital improvements. Liberty reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages and conducted a review designed to determine the "used & useful" nature of rate-base assets. Liberty's review included a physical inspection of the Apache Plant and interviews with the personnel responsible for managing key functions at the plant.

This report presents the results of Liberty's review, categorized into the following subjects:

- Station performance
- Outages
- Maintenance
- Capital additions and rate base
- Facility review

B. Findings

1. Organization

All of AEPCO's senior managers are employees of AEPCO. Otherwise, nearly all staff are Sierra employees, with most located at the plant. Several individuals from Sierra's financial, safety, and environmental functions are also located at the plant.

The general organization structure is somewhat "cleaner" than that of SWTC,[42] where there is more intermingling of employees on the organization chart. Liberty saw no evidence that this hybrid structure impedes overall effectiveness in any way. In practice, Liberty observed that AEPCO operates as a single organization, regardless of the role of Sierra in employing most personnel. There may be two organizations on paper, but Liberty found only one in practice. Accordingly, Liberty found no reason for criticism of the organization's design, functioning, and effectiveness.

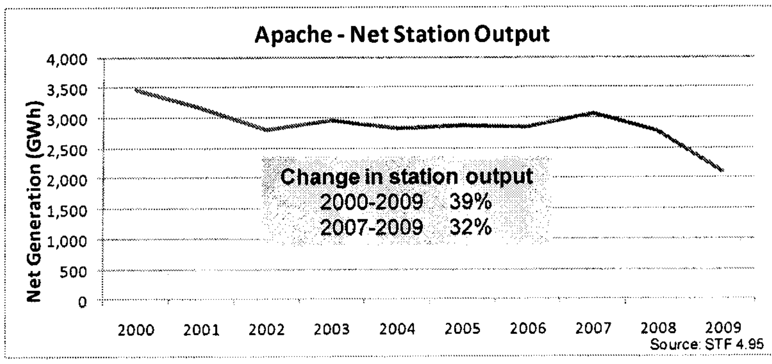
2. Generating Units

The bulk of the generation at Apache comes from Steam Units 2 and 3, which are 175 MW base load coal-fired units. Steam Unit 1, a gas-fired boiler, operates in combined-cycle with Gas Turbine 1 to provide a net 85 MW of peaking capacity. The remaining three gas turbines produce 129 MW of peaking capacity.

Gas Turbine 4 is relatively new, but the other units are aging, with the two base load units over 30 years old and Steam Unit 1 over 40 years old.

3. Station Performance

Liberty evaluated Apache performance, specifically as measured by availability, capacity factor, and unit heat rate. In 2009, Apache suffered a precipitous drop in output. Station management believes such performance was an anomaly; unfortunately, there are indications that more troubling forces are at work.

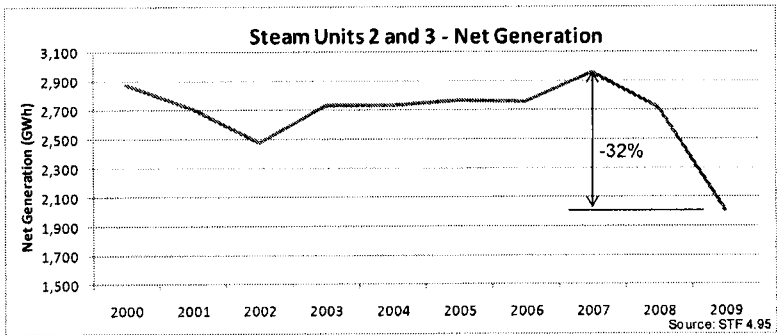


In any event, net station output is down nearly 40 percent, between 2000 and 2009, as shown on the accompanying chart.[43] At the same time, Steam Units 2 and 3, both of which performed poorly in 2009, now account for well over 95 percent of the station output. If these trends continue, and there are indeed reasons to believe they might, the future of this station could be in jeopardy.

a. Steam Units 2 and 3

The data and supporting analysis suggest that a transition is taking place. Specifically, the two flagship units, ST2 and 3, are evolving from base load units to, at best, intermediate units. In 2009, this was prompted by higher dispatch costs and a lesser level of economic competitiveness. At the same time, availability was well below expectations, dealing a double blow to station performance.

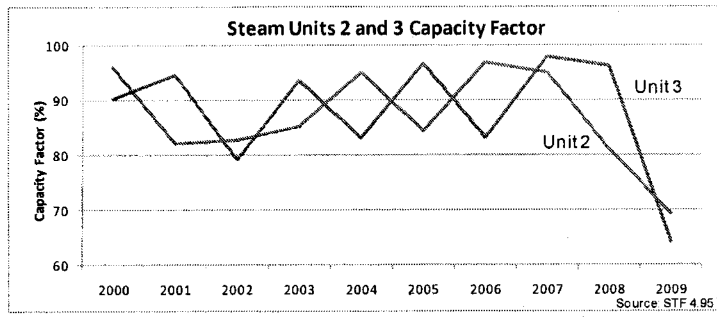
Steam Units 2 and 3



The base load coal-fired units are the key producers at Apache Station. It is from these two units that the great majority of the station's output will come. For many years, their performance was excellent, but a sharp drop was experienced in 2009. In analyzing the drop, one must emphasize that at least two major forces were at work. First, availability dropped sharply and outages were experienced on a previously unheard of frequency. Second, when available, the units were dispatched at rates well below their historic levels.

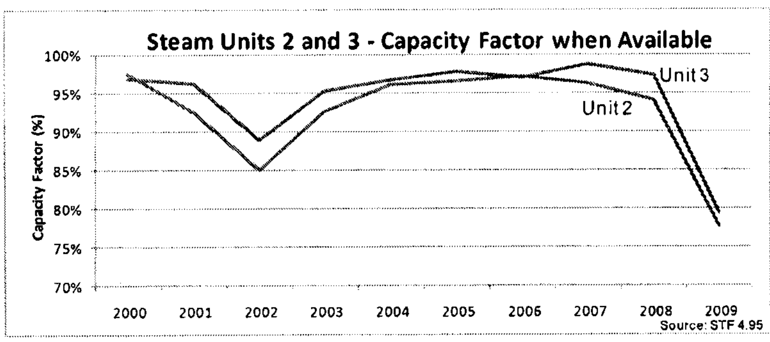
The accompanying chart illustrates the sharp drop in output in 2009. After rather consistent performance for many years, there was a 26 percent drop from 2008, and 32 percent versus 2007.

The drop resulted from reduced performance of both units, as shown on the following chart of capacity factors. The magnitude of the 2009 problems is clear when one considers that the capacity factor for Unit 2 was more than 10 points lower than it had ever been in the last ten years, while Unit 3 was 15 points lower.



Other measures of performance in 2009 traced the same pattern, with large drops in availability and increases in heat rate. Discussions with management indicate an internal belief that this was simply a string of bad luck. While that may be true, such a result should be reached only when no other logical reason can be found. It would appear, however, that this is the initial conclusion reached by the cooperative, and there does not appear to be any analysis supporting such a conclusion.

The two factors (availability and the economics of dispatch) resulting in such low generation in 2009 may in fact be related. It appears that the units were run back regularly during 2009, and operated below full power. Consider the following chart which shows the capacity factor for the two units only when they were available. This only occurred once before in the last ten years, in 2002, and then to a lesser extent. It would appear that the units lost 15-20 percent of their output in 2009 due to less frequent dispatch.



The major reason for this phenomenon seems to be a loss of competitiveness due to AEPCO's new coal contract. As a direct result of its higher dispatch costs, the station is being displaced by other, less expensive generators. In addition to day-to-day dispatch decisions, AEPCO's agreement with the Salt River Project for a 100 MW contract purchase from Apache has lost its effect, presumably because SRP can obtain the energy more economically elsewhere. Importantly, at the present time, the competitiveness issue will be present going forward, and the SRP contract expires at the end of 2010. On the surface, then, unless some actions are developed to increase sales, the low capacity factors at Apache will be continuing, and perhaps worsening.

The second issue of importance in 2009 was the number of outages, which was well beyond what could have been reasonably expected. An analysis of outages will be presented in the next section. For now, however, the question to be asked is whether there is a relationship between the increased cycling to which the units were subjected and the increased number of outages. It will be noted that the units have run at an average 96.7 percent when available over the prior five years (2004-2008). It can be assumed that this meant little cycling of the units. It is not unreasonable to question the degree to which these 30+ year old units might suffer when subjected to this new mode of operation. This is simply one possible root cause for the recent outages that should be considered in AEPCO's analysis of station performance.

The key observation here is that there are forces at work that are impairing Apache's flagship assets. Further, the inability to run the units at near full capacity may be having a higher cost than simply the lost revenue. If so, this suggests that management can afford more forceful actions to increase output. One option suggested by Liberty is to seek a shared savings arrangement with the mines and railroad to lower the dispatch costs for what is now the lost generation. To the extent that dispatch costs are lowered, AEPCO will be able to purchase more coal to the benefit of its suppliers as well.

Although it might be too soon to tell if 2009 was simply an unusual year for ST2 and 3, the early experience in 2010 may provide some indication. The availability data is likely misleading, because the first five months of the year include months favored for planned outages. In fact, there was only one forced outage in the period. Any conclusions drawn from the availability data would support an improving trend.

ST2 and 3 Performance

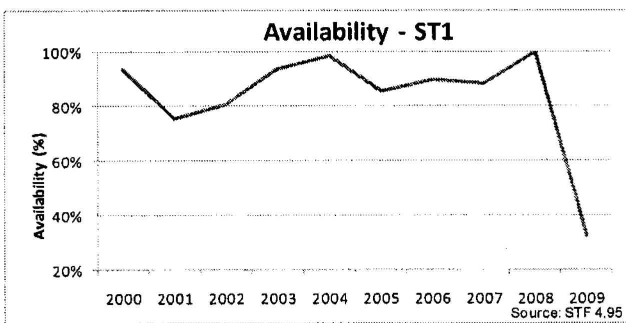
	ST2		ST3	
	2009	2010 thru May	2009	2010 thru May
Availability	89.5	72.0	80.7	93.4
Capacity Factor	69.3	50.3	63.4	76.3
CF while available	77.4%	69.9%	78.6%	81.7%

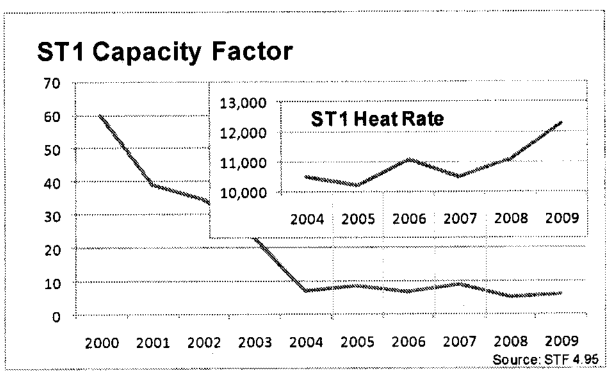
Source: STF 4.59 and 5.20

The capacity factor situation, or more precisely the dispatch issue, shows no improvement in 2010 and supports the notion that this is a long-term problem.

b. Steam Unit 1 and Gas Turbine 1

These units (referred to as "CC1") have operated in a combined cycle mode. Their role has changed considerably in recent years. CC1 operated at a 60 percent capacity factor in 2000, that rate declined to the mid-single digits by 2004, and has remained there since. On the surface, there arises a real question as to the viability of an old steam unit like ST1, particularly recognizing its substantial declines in reliability. ST1 experienced boiler-tube leaks in 2009, producing an availability factor of only 32 percent. ST1 has been down for re-tubing in 2010, thus producing an availability of essentially zero through May of this year. Meanwhile, ST1's overall efficiency has deteriorated sharply through the years. Management has attributed this to several factors:[44]





- The primary reason given is the decline in capacity factor.
- A second reason is the shift in 2004 to two-shift operation; *i.e.*, taking the unit off line at night and starting up in the morning.
- A lesser and temporary reason is the prolonged loss of a feedwater heater.

The accompanying chart shows the decline in capacity factor since 2000. The insert shows that heat rate has deteriorated considerably since 2004, when the capacity factor stabilized below 10 percent. This suggests that the capacity factor was not responsible for all, or perhaps any, of the loss of efficiency since 2004, which amounted to 17 percent.

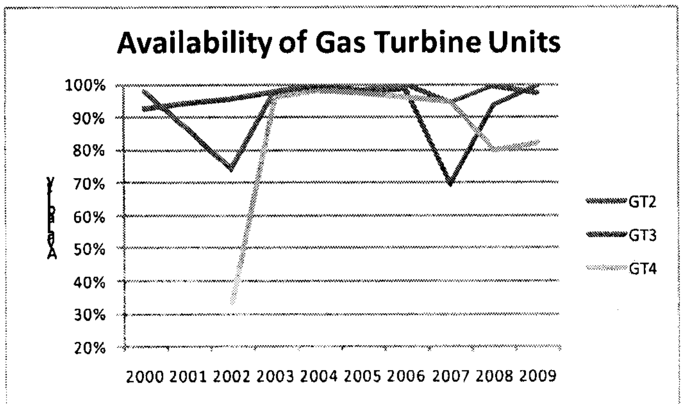
Factors such as these raise the question of the appropriateness of continued operation of and investment in CC1. Management has asked that question as well, commissioning a study completed April 5, 2010.[45] The study compared continued operation through 2020 versus placing the unit in "long term standby." This latter option considered two beginning dates for standby: 2011 and 2015. Major conclusions reached by that study include:

- "The continued use of CC1 for reserve and seasonal peaking capacity will still be, by a substantial margin, the most economic alternative of those evaluated for the members."
- Other than the serious boiler tube leak situation in 2009, "CC1 is in good condition. The steam turbine was overhauled in 2009 and the gas turbine in early 2010." With the boiler repairs underway in 2010, "CC1 is expected to operate on a seasonal basis for the remainder of this decade without further overhauls."

Other factors important in evaluating the future role of CC1 are the station's unique role and the nature of the AEPCO system. AEPCO has indicated that "the limited ability to import replacement power on the SWTC system" can lead to very high replacement costs and involuntary curtailments, should CC1 or similar capability not remain available. This limitation raises the value of the unit to AEPCO, although management did not explicitly address these factors in the study.

c. *Gas Turbines 2, 3, and 4*

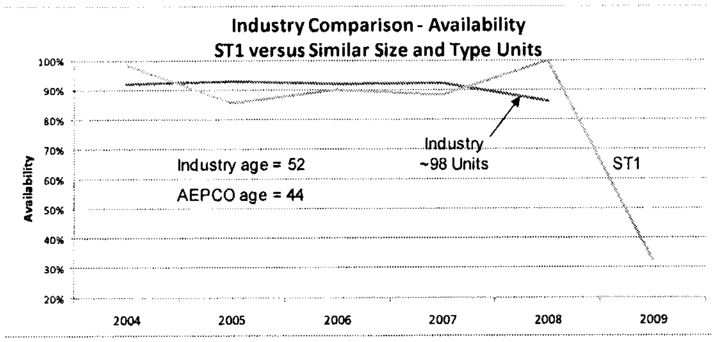
These three gas turbines function as peaking units. Availability of all of the units has generally been above 90 percent, with an occasional year that is much lower. Heat rates for all three units have varied widely through the years. Given the limited role of the units as capacity resources and their infrequent operation, performance deviations observed to date do not evidence significant problems, nor raise concerns like those applicable to the future of the steam units.

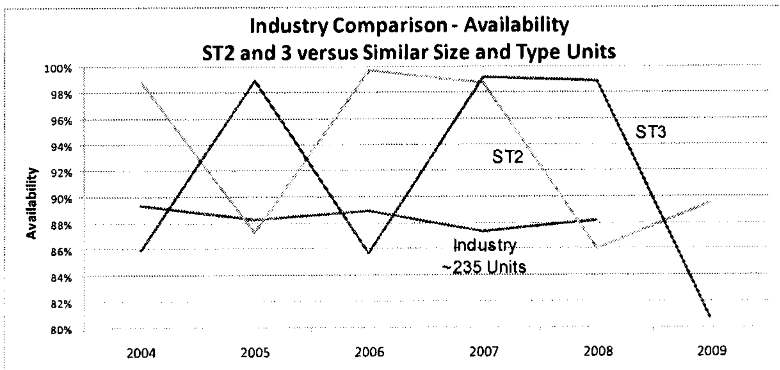


d. *Industry Comparisons*

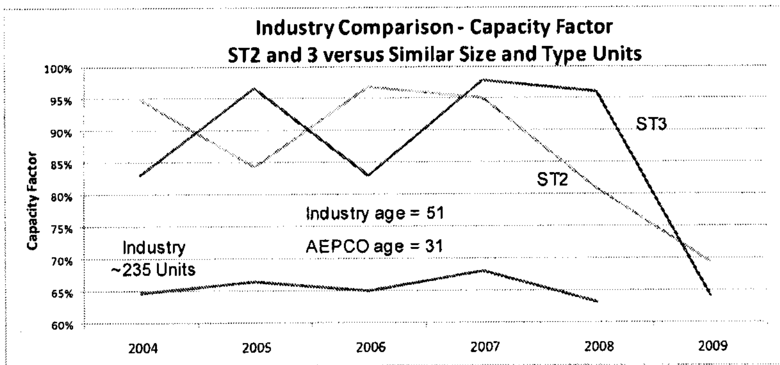
AEPCO's internal performance data indicates general deterioration; however, comparing AEPCO performance to industry data produces a different view. AEPCO units have generally performed well when compared with similar size and type units operated by others. This comparison does not negate the significance of the questions raised by AEPCO's problems in the past year or two; they continue to have real significance for the future of the station. An industry comparison does, however, show that these units have been relatively good performers for a fairly long historical perspective.

The adjacent chart illustrates ST1 availability versus similar units as reported in GADS.[46] ST1 availability was slightly below industry experience since 2004, until dropping precipitously in 2009. Note that the nearly 100 units in the data base are on average 8 years older than ST1. AEPCO therefore, has not compared well by this measure.





ST 2 and 3 compare much better to their industry counterparts, although they are substantially younger than the industry average. The industry plants' average age exceeds 50 years; therefore, they would not generally be expected to be playing a significant, high-performance role for their operators.



Despite the sharp drop in capacity factor last year, these two units are still generating at levels typical of the industry. Availability, on the other hand, is considerably higher at Apache. The units about equal the industry average during outage years, and far exceed them in non-outage years.

Making comparisons with others requires recognition that there exist differences in: (a) the roles assigned to the generating units, and hence their owners' expectations, and (b) the age of the units. AEPCO intends ST2 and 3 to operate as base load units. The data clearly indicates that such units are very frequently employed as intermediate units by others who operate similar units. The AEPCO economic data above suggests that ST2 and 3 may indeed be evolving to intermediate status. If so, its comparisons to industry data may look quite different in future years. Note also that the industry comparison units are 20 years older than Apache ST2 and ST3, which also affects any comparisons of data involving them.

The availability of AEPCO's gas turbines as compared with the industry shows mixed results. Unit 1 has had problems, but Unit 2 has consistently had availability in excess of 95 percent. Other than one particularly low year, GT3 availability has also been well above industry results.

Unit 4 has dropped to very low availabilities in the last two years. The engine on the latter unit was upgraded in 2009.

4. Outages

Unit outages, as the preceding data suggests, ran above normal in 2009. On a broader basis and over a longer term perspective, it does not appear that AEPCO has focused considerable, structured attention on the analysis of outage trends or their root causes. Liberty's data requests yielded a great deal of raw data but not analysis of what that data means, what trends exist, what patterns might suggest about operating or maintenance practices, or what interest may exist for delving further into outage causes.

On a more targeted basis, AEPCO has prepared technical analyses of some equipment problems. This work appears to be thoughtful and of high quality.[47] The recommendations from these analyses are limited and it is not clear what actions, if any, management has taken as a result of the study and thought put into this work. AEPCO also uses outside vendors and engineers to assist in consideration of equipment issues; this application of supplemental talent and experience is sound.

a. Planned Outages

The steam units have undergone five major, planned outages in the last few years. The accompanying table shows that all five of them ran over the planned duration (by an average of 9.6 days or 30 percent). This degree of overrun is problematic. Reported industry data suggests that outage extensions on these types of units is atypical.

Steam Units - Planned Major Outages Schedule Performance				
Unit	Year	Planned Duration (Days)	Actual Duration (Days)	Overage (%)
ST1	2006	18	35	94%
	2009	43	57	33%
ST2	2008	44	49	11%
ST3	2006	30	38	27%
	2009	27	31	15%
	Total	162	210	30%

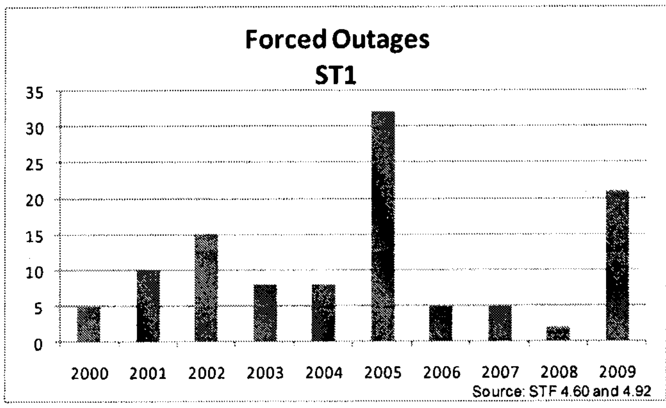
AEPCO has not applied significant levels of formal and structured outage planning, but this does not mean that planning practices are nonexistent. To the contrary, it appears that a great deal of work goes into planning outages. AEPCO provided examples of such work to Liberty.[48] AEPCO points out that, in lieu of a "written outage plan," it conducts detailed roundtable discussions to address outage scope, budgeting issues, resource allocation, and other needed actions.[49] The need for structure and formality is somewhat a function of size and complexity. AEPCO clearly does not have the same needs as, for example, a large station with planned outages involving thousands of work activities and severe cost penalties for outage extensions. But it is also clear that Apache has challenges that suggest that the other end of the spectrum is not appropriate either.

Steam Units - Planned Major Outages Cost Performance				
Unit	Year	Budget (Thousands)	Actual (Thousands)	Overage (%)
ST1	2006	275	221	-20%
	2009	2,500	3,511	40%
ST2	2008	7,091	7,995	13%
ST3	2006	5,312	5,653	6%
	2009	6,325	5,668	-10%
	Total	21,503	23,048	7%

Cost performance during planned major outages has also been a problem, although to a lesser extent than schedule. Some outages came in under budget but, on a cumulative basis, there has been a 7 percent overrun. Apache includes a 10 percent contingency in the budget, which is not unusual or inappropriate. The plant does not include any contingency on schedule which, for straightforward work scope, is typical.

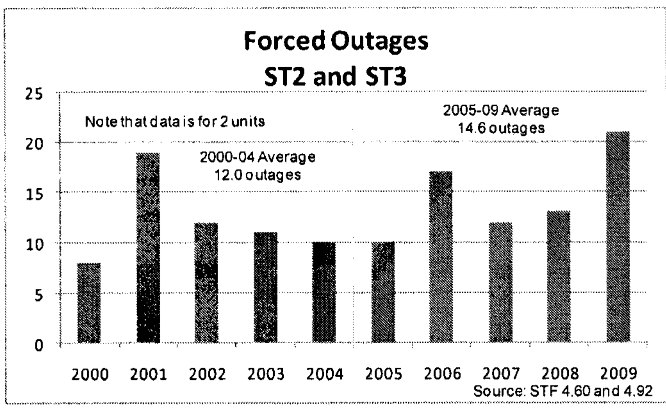
b. Forced Outages and Reductions of Output

AEPCO tracks the forced loss of generation in its data by: (a) forced outages, and (b) de-ratings, in which an event requires the plant to run at reduced output while addressing the event. Where de-rates are considered, AEPCO generally uses an equivalent outage duration, which corresponds to the fraction of capacity lost. For example, if the unit is forced to run at 50 percent of capacity for ten hours, the equivalent duration is 5 hours.

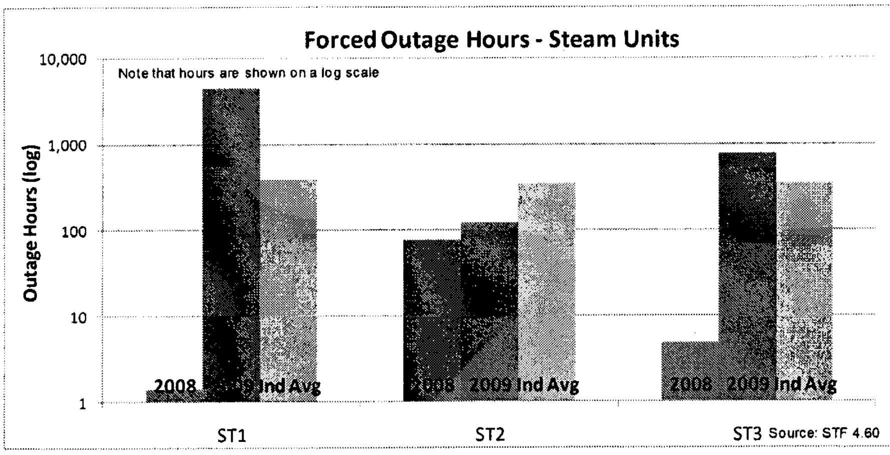


In evaluating reliability based on the number of forced outages per year, ST1 demonstrates weaker results than other similarly sized and type units have experienced. The accompanying chart shows sporadic results, ranging from 2 outages in 2008 to 31 in 2005. Typical industry performance for such units is about 2 forced outages per year. Moreover, Apache 1 is about 8 years younger than the average unit. ST1 forced outages thus run well above industry experience. The same remains true even after excluding the two very bad years (2005 and 2009) from the data.

Station management characterized these high rates as out of the ordinary, and there is a basis for such a characterization, especially for ST1. The accompanying chart for ST2 and 3 shows, however, that a "single aberrant year" does not tell the full story. The number of annual outages is growing with time. The average number of outages in the last years is 22 percent greater than the corresponding number for the prior five years. The average number of outages for similar size and type units is about 8 forced outages per unit, which would equate to 16 for the two units compared at Apache. Moreover, the peer units are about 20 years older than are ST2 and ST3. Notwithstanding the 2009 performance, it can be concluded that the Apache units are superior to their older peers but are trending towards industry levels as they age. It is this apparent trend, while the units are still young compared to their peers, that should give rise to sufficient concern to warrant management study.



Examining reliability as measured by total lost unit hours due to forced outages causes the Apache units to compare well with the industry for 2008, but not as well in 2009 (note the scale on the accompanying chart is logarithmic). ST1 was off for more than half the year. With the exception of ST3 in 2009, the coal units performed better than the industry average, which should be expected given that the average industry age is 20 years greater for these units.



Lost generation due to maintenance and operating issues, excluding that cause by unit outages, are characterized as de-ratings. Such events can be relatively frequent at Apache. The bottom line effect in terms of lost generation, however, has generally been small, both on an absolute basis and on a basis relative to the industry. The accompanying table shows the annual average number of de-ratings and the associated lost hours. The large number of hours on ST1 is due almost entirely to a single circulating water pump issue in 2008 that resulted in an extended de-rating of about 15 percent.

Average Annual Derates (2008-09)		
	Events	Equiv Hours
ST1	7	268
ST2	42	53
ST3	22	55

c. *Outage Causes*

Liberty conducted a detailed analysis of outage causes for the three steam units in 2008 and 2009. In addition, Liberty examined the outage data back to 2000 in a search for broad trends. For these analyses, we summarized the large number of outage codes into 17 summary codes that are a simpler and more effective characterization of unit issues. The results of the 2008-2009 analysis are shown in the next table. The major causes of outages in this two year period are typical:

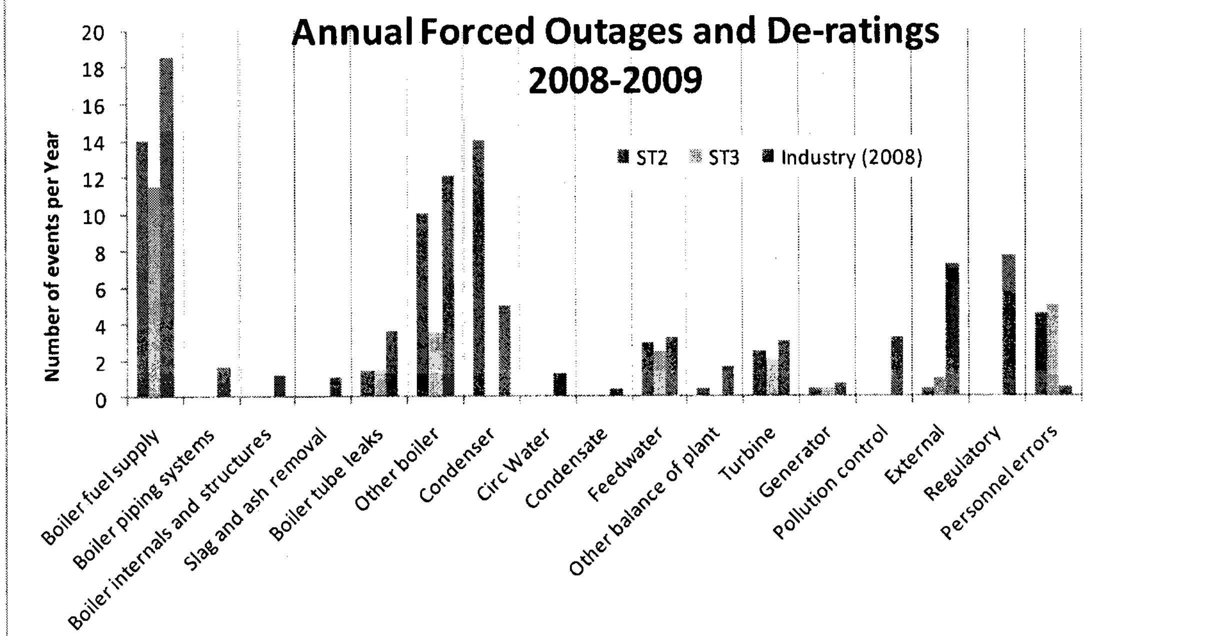
- Boiler tube leaks, especially on ST1
- Fuel supply (a broken gas regulator on ST1 and multiple mill-related de-rates on the coal units)
- Turbine and generator issues
- Condenser de-rates on ST2 due to tube leaks.

The two-year analysis provides little in the way of insightful conclusions. There are the obvious concerns with so many boiler tube leaks on ST1. Management has addressed that issue. Boiler tube leaks and mill problems present continuing issues on the coal units, but they remain in line with industry expectations. The same applies to turbine and generator problems. The ST2 condenser leaks merit further analysis, as performance has been well below the industry and seems to be worsening, at least over the limited two-year period.

Outages and De-rates by Cause (2008-09)								
	Unit 1		Unit 2		Unit 3		Total by Cause	
	Number	Equiv Hours	Number	Equiv Hours	Number	Equiv Hours	Number	Equiv Hours
Boiler fuel supply	3	1240.95	28	87.13	23	25.70	54	1,353.78
Boiler piping systems								
Boiler internals and structures								
Slag and ash removal								
Boiler tube leaks	10	[redacted]	3	[redacted]	3	109.45	16	2,269.74
Other boiler	7	84.65	20	39.48	7	5.45	34	129.58
Condenser			28	52.07			28	52.07
Circ Water	3	420.53					3	420.53
Condensate								
Feedwater			6	5.71	5	54.04	11	59.75
Other balance of plant	4	4.46	1	0.37			5	4.83
Turbine	3	778.9	5	6.71	4	255.43	12	1,041.04
Generator	3	202.49	1	2.67	1	[redacted]	5	629.69
Pollution control	1	0.12					1	0.12
External			1	0.07	2	0.24	3	0.31
Regulatory								
Personnel errors	3	174.61	9	5.07	10	3.45	22	183.13
	37	4,960.58	102	305.70	55	878.29	194	6,144.57

Source: Analysis of STF 4.60 data

The following chart, which compares Units 2 and 3 against industry data, confirms the conclusion that not much out of the ordinary can be observed. Apart from the ST2 condenser issues, however, personnel errors stand out as a major deviation. This category, at the far right of the following chart, includes unit trips caused by operators, maintenance personnel, or contractors. Apache error rates fall well above industry expectations.



Source: Analysis of STF 4.60 data

Liberty examined outage data back to 2000, in an effort to determine the nature and consistency of personnel errors leading to unit trips. The following table provides the history.

Unit Trips Attributed to Personnel Errors

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total	Industry
ST1	2	3	4	1	1	9	0	0	0	2	22	0.5
ST2	1	1	1	3	2	1	1	3	1	3	17	3.5
ST3	1	2	0	2	3	1	0	3	3	3	18	3.5
Total	4	6	5	6	6	11	1	6	4	8	57	7.5

Source: STF 4.60 and 4.92. Industry data are from GADS 2004-2008 – value shown is 10 times the annual average.

The data suggests recent improvement in ST1, which might at least partly be due to the fact that the unit does not run very often (especially since 2004). The coal units, however, do not demonstrate an improving trend. Their pattern over a ten year period shows a frequency of unit trips of ST2 and ST3 from personnel errors that is five times the industry average.

It does not appear that structured analyses or corrective measures have been applied to address this specific issue. Management has, however, taken numerous steps to deal with the question of outages in general, including:[50]

- An outage analysis team meets after each unit trip to seek causes and corrective measures.
- Discussions on outage trips are held with operators and maintenance personnel in their respective pre-shift tailgate meetings.
- Managers, foremen, engineers and other key staff address outage causes in their morning staff meetings.
- There is ongoing personnel training, including a new General Physics web-based program.
- There is an ongoing process of revising procedures to incorporate lessons learned.

These measures are all positive; however, it appears that they have not been effective (at least to date) in mitigating unit trips attributed to personnel errors. The magnitude of this issue, and its impact on plant performance and economic effectiveness, indicates the need for added management attention, analysis, and corrective action.

d. Replacement Costs

Having discussed above the higher number of outages for the steam units in recent years, it becomes appropriate to consider the cost to AEPCO of those outages. AEPCO responses to data requests[51] estimated replacement power costs by pricing the power at the average for the month of each outage. Similarly, AEPCO priced the avoided fuel costs at its fuel costs for the subject month.

Added Power Costs from 2008-2009 Outages

	All Outages > 2 days			Forced Outages > 2 days		
	Outages	Days	Penalty ($1,000)	Outages	Days	Penalty ($1,000)
ST1	7	71.4	-57	7	71.4	-57
ST2	6	81.3	8,626	3	8.2	703
ST3	9	53.1	2,946	3	11.9	493
Total	22	205.8	11,515	13	91.5	1,139

Penalty = Replacement cost less fuel cost
Source: STF 4.63 and 10.13

Liberty has summarized the results for all outages in 2008-2009 that lasted two days or more. For the three steam units there were 22 such outages with total replacement costs less fuel costs of [redacted] million. However, when limiting the sample to forced outages only (totaling 13 in number), as Liberty believes is more appropriate for such an analysis, the amount drops markedly to [redacted] million.

A single ST2 planned outage starting in March 2008 accounts for 65 percent of the replacement costs less fuel costs. The reported replacement costs for that period were an uncharacteristically high $69/MWh.

5. Maintenance

In examining the maintenance program at Apache, Liberty sought to answer the following basic questions:

- Is an effective maintenance philosophy and strategy in place?
- Are Apache's maintenance practices managed effectively?
- Does the maintenance program adequately balance cost and reliability?

One should expect a well managed maintenance program to be clearly defined and documented in terms of its objectives, priorities, and the strategies that support them. Such formalities are essential in large, complex organizations, but less important in smaller operations, where personnel tend to be tied together more closely and knowledge of the power plant is very high among the team. The latter characterization surely applies to the Apache Station, allowing its management and staff to be effective with a significantly lesser degree of formality.

Liberty believes that an effective maintenance philosophy and strategy is indeed in place at Apache, but there is little documentation to support it. Interviews, consideration of the SAP maintenance management system, responses to relevant data requests, and observations at the plant all support this conclusion. Clearly articulated policies and strategies have a real benefit regardless of unit size. Nevertheless, Liberty found in Apache's programs no gaps that have a material effect on performance.

a. Maintenance Programs and Systems

The following description offers key characteristics associated with the Apache maintenance systems, as described by management:[52]

> *"A computer maintenance management software program (SAP) is used to schedule and monitor the entire maintenance process. Preventative equipment maintenance work orders all have detailed instructions that outline the various steps that a craft person needs to perform in order to complete the required work. This part of the program is continually monitored for such things as instruction accuracy, parts and tool requirements and schedule frequency." "Apache has three full time maintenance planners on staff, and it is their responsibility to monitor the maintenance program and plan and schedule all necessary work throughout the year."*

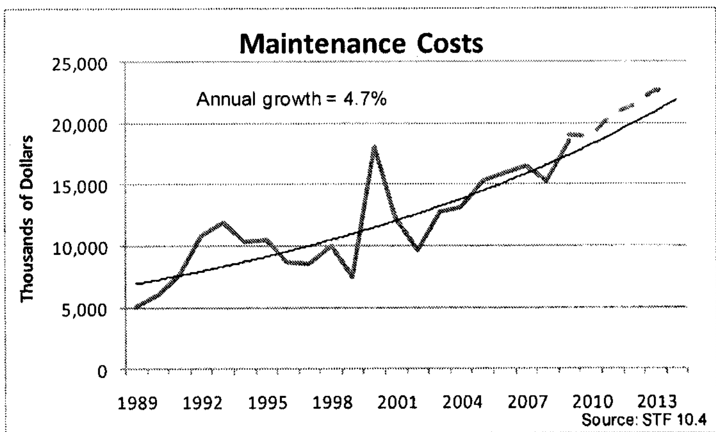
The SAP system offers a sound tool that supports the station in multiple ways. The areas benefitted include the overall maintenance management system including work orders, materials management, equipment histories and cost data. Liberty examined numerous sample reports submitted in response to data requests,[53] finding them all detailed and extensive. Liberty did not see any reports from the system that might be useful for management overview or overall performance monitoring. For example, there is no report on trends in maintenance backlog. One might reasonably conclude that the systems have value for getting the detailed work done and adequately support the planners and the workforce, but it is not clear they are being used to allow an appropriate perspective for management.

The scope of the management challenge is clear considering that there were 12,110 work orders created by the system in 2009. It is not clear, however, how that large effort is brought together for management reporting and analysis and how such reporting and analysis fits into the management process.

Apache also utilizes a Reliability Centered Maintenance program applicable to all rotating equipment. Staff reports that the program has been highly effective and cost beneficial, currently catching 90 percent of failures.

Management also reports that Apache enjoys a favorable balance between preventative and corrective maintenance, with 67 percent of work orders in the former category.[54]

b. *Costs*



There is nothing particularly revealing about total station maintenance costs. The spike (albeit small in an historical context) in 2009 would be expected, given the large number of outages and de-ratings. The growth going forward is not out of line with past growth, particularly because one might expect maintenance costs to grow faster with station age.

The root causes of the 2009 deterioration should be sought, and one obvious question goes to the adequacy of prior maintenance levels. Although that remains an appropriate question, nothing Liberty saw during the evaluation would lead to such a conclusion. Spending immediately before the 2000 spike seems to have been somewhat depressed for five or six, but if that contributed to future problems, they were more likely in that 2000 spike than in 2009. Liberty therefore has no basis to assume prior maintenance activities contributed to the 2009 performance issues.

6. Capital Additions

With age, investment needs grow, raising for all utility operators the inevitable question of "throwing good money after bad." With recent production trends at Apache, including a 40 percent decline in output since 2000, this question must be front and center. Liberty has examined this issue as it relates to this rate filing and the new plant placed in service. We can conclude that AEPCO's investments have been justified and appropriate. At the same time, it is critical to define the station's future mission as it will likely become increasingly difficult to judge the cost-effectiveness of station improvements.

a. *Recent Investments*

Liberty reviewed the major capital projects (estimated at >$500,000 each) that were placed in service since 2006. This sample includes 18 projects with an eventual installed cost of $27.1 million. A review of the data provides some key insights:

- Many of the projects involved environmental issues, in response to specific requirements or modifications or improvements to pollution-related equipment.
- There were no qualifying projects associated with ST1. The single large project involved steam turbine blade replacement in 2009, which amounted to $268,000. A large project is planned to re-tube the ST1 boiler in 2010.
- There was only one qualifying project associated with the gas turbines – engine upgrade for GT4 in 2009.

Projects >$500K - 2006-2009
(Thousands of Dollars)

Unit	Project	Estimate STF 10.1	Actual STF 4.61
ST2/3	Cooling tower upgrades	12,182	9,477
ST2	NOx reduction	3,236	2,894
GT4	Engine upgrade	2,324	2,516
ST3	Gas recirc fan replacement	2,135	2,047
ST3	Boiler cleaning upgrades	2,100	1,451
ST3	Stack liner coating	1,190	1,002
ST2	Stack liner coating	1,431	996
ST3	Stack liner coating (2009)	930	985
ST2/3	Ash line piping replacement	908	960
Station	New deep well 70	1,260	948
ST2/3	Coal handling upgrades	1,134	906
ST2/3	Mercury CEM	598	689
ST3	Bottom ash hopper reline	579	587
ST3	LP FW heater upgrade	600	444
ST2	Upper loop spray nozzle	522	357
ST3	Scrubber tower upgrade	535	351
Station	Deep well line replacement	707	258
ST2	Scrubber tower upgrade	525	242
	Totals	**32,896**	**27,110**

Source: STF 4.61 and 10.1

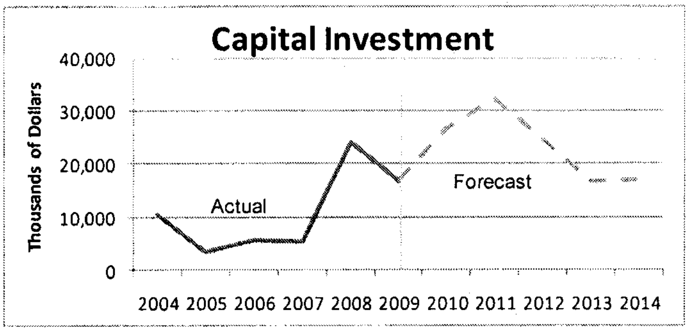
The listing of projects is typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable.

The content of the justifications is minimal compared to others Liberty has seen, including those prepared by SWTC for transmission projects. Some practices that might be questioned include limited presentation of reasonable options and the use of seemingly high replacement cost differentials in payback analyses.[55] On the positive side, the analyses are presented well, with all relevant information contained at a reasonable summary level and in an easy-to-understand construction. Liberty found that the analysis sheets provide ample information for the initial consideration of management and the board. Further, Liberty has no basis to question the diligence exercised by management or the board in questioning and testing the projects and their justifications.

In summary, Liberty finds that the major additions to rate base appear to be appropriate and justified on operational, economic, environmental and safety grounds.

b. *Future Investments*

Liberty has cautioned that the challenge associated with large investments in the future will be much greater as the role of the station changes, and AEPCO is likely to find justifications for major investments increasingly difficult. This issue is likely to surface sooner, rather than later, as suggested by the capital investment forecast for the next several years.



Source: STF 4.100

Note that actual and planned annual spending beginning in 2008 is more than double the levels of 2004-2007. However, Apache may not operate as the same type of station in the years ahead, compared to the characteristics of 2004. It would appear that, at least, the station will produce far less electricity and be somewhat less reliable. The appropriateness of a much higher and sustained level of capital spending is therefore a fair question, and one that management needs to consider seriously in the months ahead.

7. Facility Review

Liberty visited the Apache Station, and observed the steam units, the coal yard, and the warehouse and shops. The two coal units were in operation and ST1 was down for modifications. At the time of the visit, a coal train was being unloaded.

This review found the plant to be professionally staffed, with all of the personnel we met hospitable and helpful. The individuals supporting the site visit were expert in all facets of the plant and were able to fully answer all of our questions.

The facilities were generally clean by power plant standards and there was no real clutter throughout the plant. There appeared to be adequate provisions for maintenance activities, particularly including large, maintenance-friendly turbine floors.

The coal yard activities seemed efficient and the train unloading we witnessed proceeded with dispatch.

The supporting facilities, including the warehouse, weld shop and machine shop, seemed in excellent order. The machine shop is especially well outfitted in apparent response to the difficulty in finding local shops to provide timely support services. The warehouse operations are facilitated by SAP and the warehouse staff seemed comfortable with its use. Warehouse security seemed appropriate.

We visited the control room for ST2 and 3 and found it professionally staffed and orderly. Access to the plant is controlled by contract security, which appeared to be professional and capable.

In summary, our visit to the Apache Station yielded only positive comments about the facilities and staff at the station.

C. Conclusions

1. Technical performance, personnel and facilities are generally sound.

The management team was knowledgeable, engaged, open, and supportive of Liberty's evaluation. The organization appeared to have expertise and tools commensurate with the needs and challenges that AEPCO faces. With respect to factors relevant to this rate filing, Liberty's engineering analysis concludes that: (a) AEPCO's power plant operations are generally appropriate and typical of the industry, (b) AEPCO's investment in new and upgraded facilities has been appropriate for the demands placed on the cooperative, and (c) maintenance practices and spending appear to be consistent with the station's needs and good utility practice.

2. **Performance is generally sound from a technical perspective; while Liberty found no reason to call into question costs claimed in the current filing, AEPCO faces significant questions about the future of its units.** *(Recommendation #1)*

Liberty's review, as addressed in more detail in the following conclusions, found no major gaps in AEPCO performance. Liberty cautions, however, that a number of emerging issues may have a major impact on the station and its ability to serve the members in the future. A primary concern is the future role of steam units 2 and 3, the coal-fired units that currently produce more than 95 percent of the station's output. Operated in a base-load mode for about 30 years, these units now appear more likely to cycle, which would cause them to serve more as intermediate units. This change has resulted from a decline in the units' competitiveness due to a new coal contract, which in turn has reduced their dispatch, and contributed to the decline of the 100 MW sale to the Salt River Project. There is also a possibility that this new cycling of the units is having an impact on equipment, contributing to a significant drop in availability in 2009.

The dual effect of lower availability and less running time when available raises questions about the future role and economics of the station, as well as questions about the nature of future power supply for members. The answers to these questions will have a direct impact on decision-making at Apache and in power procurement. AEPCO should view the performance trends at Apache with significant concern. Major issues that do not appear to be the object of focused inquiry include:

- The continuing long term trend in declining station output which, if it continues, suggests a limited future for these units.
- The decline in reliability of the flagship units, ST2 and 3, which calls for an as-yet to be completed analysis of root cause. Maintenance and the effects of increased cycling of the units are two potential areas for study. It may well be that recent performance has simply resulted from a run of bad luck, but the data indicate that such a conclusion should not be accepted before suitable analysis.
- The increase in dispatch costs, as a result of the new coal contract, has resulted in ST2 and 3 being utilized much less than desired. It would appear that the units have become uneconomical as base load units.

It is not clear that these issues are getting the attention they deserve; they bear directly on the continuing viability of the station as an asset. Hostile forces are at work, and are well evidenced in the trend of performance. The key question at this time is whether 2009 conditions are anomalous or a warning of deterioration. There are real signs of the latter, as the issues facing ST2 and ST3 do not appear to be temporary.

3. Experience and recent management study confirm the continuing usefulness of CC1 and the gas turbine units.

Steam unit 1, a gas-fired boiler that operates in combined cycle with gas turbine 1, is a capacity resource. Its performance was also poor in 2009 and it has been out of service for the first part of 2010 for re-tubing of the boiler. AEPCO recently completed an analysis that justified further investment in ST1 (the boiler re-tube). This assumed that the recent improvements of the unit, including overhaul of both the steam and gas turbines, will likely assure reliable operation for at least the rest of the decade. Liberty does not have any reason to challenge this conclusion; however, it should be clear that this old unit brings risk with it. Prolonged outages, such as those experienced in 2009, could have a serious impact in the future. Note that AEPCO warns of potential involuntary curtailments in the years ahead due to limited import capability if this capacity is unavailable.

Management's April 5, 2010 study examined future options, concluding that continued use of CC1 for reserve and seasonal peaking capacity remained AEPCO's most economic alternative. The study's conclusions may seem surprising based on recent unit performance, but appear more credible from a longer-term perspective. Availability has been reasonable (although not up to average industry performance) for such units. If AEPCO can succeed in: (a) stabilizing availability at high levels going forward, and (b) holding maintenance costs at reasonable levels, it would appear that continued operation of the unit makes sense.

The three gas turbines have had good availability over time. AEPCO uses them as peaking units; any actual resulting deviations in performance give no reason to conclude that operating problems have arisen or that they will remain useful to AEPCO.

4. Apache has not suffered atypical losses of generation due to deratings.

Despite fairly frequent events that cause deratings, Apache has had only small levels of lost generation, both in absolute terms and by comparison with industry experience.

5. Maintenance has generally been effective, but a lack of formality and structure exists. *(Recommendation #2)*

Liberty's review of maintenance policies and practices found no reason to believe these activities are lacking. AEPCO employs good practices in preparing for and managing outages. The detailed systems used to plan, monitor, and execute work orders seem to be effective. On the other hand, summary level information, as might be expected for management to provide program oversight, does not appear to provide the perspectives that managers would usually require.

Consistent overruns in outage durations that AEPCO has experienced are not typical. AEPCO does not apply significant levels of formal and structured outage planning, nor does it need to, given the size of its fleet. However, results indicate a need for examining the creation of a somewhat more formal and structured approach.

Spending on maintenance has generally been consistent for many years, with occasional spikes, as might be expected. The only suggestion of potential under-spending might have been in the late 1990s, but this is far from conclusive. Further, there is no reason to believe that today's reliability issues are arising from maintenance activities so long ago.

6. Apache suffers a particularly high number of trips due to personnel errors. *(Recommendation #3)*

The number of coal unit trips due to personnel errors at Apache has consistently been about five times greater than is the case for similar units. Performance at ST1 has been even weaker. Actions taken by management on this specific problem have been limited and not effective. This problem deserves greater analysis and more aggressive action by management.

7. Forced outages have not imposed significant cost penalties on AEPCO.

The 13 forced outages of 2008 and 2009 combined have caused AEPCO to experience total replacement costs less fuel costs of [redacted] million. Fuel and purchased power expenses in these two years are in the range of $140 million. Thus, the penalty suffered by AEPCO due to the numerous outages in this period was moderate.

8. Past capital additions have been appropriately planned and executed.

AEPCO's recent investments in plant have been justified and appropriate. The review underlying this conclusion included all of the capital project justifications for large projects. Liberty found them to be in order and supportive of management's decision-making needs. Liberty found the listing of projects typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable.

The content of the justifications is minimal and Liberty found limited presentation of options and the use of high replacement cost differentials in payback analyses. Improvement in these areas could prove beneficial. However, Liberty found the analyses to be well-presented, in appropriately summarized and understandable format. The analysis sheets provide management and the board with sufficient information. Liberty found no reasons to question the diligence exercised by management or the board in questioning and testing projects.

In summary, past spending appears to have been appropriate; however, questions should be raised concerning future spending. Actual and forecasted spending from 2008 to 2014 is more than double the annual levels between 2004 and 2007. Considering the uncertainties on the future role of the station as discussed above, the appropriateness of a much higher and sustained level of capital investment in the future is not clear.

9. Liberty's on-site examination of Apache found station conditions to be appropriate.

Plant staff demonstrated sufficient breadth of expertise and was knowledgeable of the details of station conditions. The plant was in a clean and secure condition and exhibited sufficient provision for the conduct of maintenance activities. The train unloading Liberty witnessed proceeded without incident. Support facilities were well equipped. The control room was well staffed and orderly.

D. Recommendations

1. Conduct a study of the future role of Apache and how that role relates to member needs for future power supply. *(Conclusion #2)*

It does not appear that AEPCO has yet conducted the type of analysis needed to fully get on top of what seems to be a serious issue with the Steam Units 2 and 3. That analysis should be undertaken on an urgent basis and corrective actions, to the extent practical, implemented. The results of the recommended study should provide guidance for future decision-making, such as power procurement strategies and the appropriateness of future investments at the station. The causes and permanence of recent Apache performance can be debated; however, there is reason for management to take a hard look at the future role of the Apache assets. The historical role of the two key units as base load generation may be coming to an end.

AEPCO management has been aware of performance results and it has expressed concerns about their significance. What Liberty did not observe, however, was the performance of significant analysis to answer questions, such as:

- Why so many problems suddenly appearing in the same year
- Are there common root causes
- Are these isolated random events or an indicator of long-term decline?

Management should commence very soon an analysis of the future of the station and how any changes might influence continuing decision-making. Station output is down 40 percent since 2000, and continuing declines appear likely; therefore, there is an immediate need to answer these important questions.

Management should investigate options for improving the economics of ST2 and ST3 in order to improve capacity factor and station efficiency. Shared savings arrangements for incremental load with coal and transportation vendors are examples of the initiatives that AEPCO should consider.

2. Examine methods to create more structured and formal outage planning and management. *(Conclusion #5)*

Liberty agrees that sophisticated outage management systems and extensive pre-planning, which are easily justified in large utilities, will not necessarily be cost-effective at Apache. On the other hand, an approach with more structure and formality, tailored to Apache's size and needs, merits focused examination by AEPCO.

A helpful start in this regard may be a summary level "outage plan," prepared several weeks in advance of all planned outages. Basic outage parameters would be addressed, including major tasks, priorities, budgets, schedules, critical paths, resource requirements, shift and overtime plans, risk factors and risk mitigation strategies. The intent is to provide assurance that all such factors have been considered on a thoughtful basis and that management's expectations for the outage are clear.

3. Examine the root causes of trips resulting from personnel errors. *(Conclusion #6)*

Management should undertake a study to determine the root cause of personnel errors and to define actions to significantly reduce steam unit trips from this cause.

IX. FPPAC

A. Background

AEPCO has had a Purchased Power Fuel Adjustor Clause ("FPPAC") since 2005. AEPCO's filing in its current rate proceedings anticipated, but did not include a revised FPPAC and a Plan of Administration to support its execution. On May28, 2010, AEPCO filed in response to a data request drafts of a number of documents related to its proposed new FFPAC:

- Six-page Plan for Administration
- Five-page tariff schedule for PRMs
- Five-page tariff schedule for ARMs.

Liberty reviewed the continuing need for an FPPAC and the specific proposal that AEPCO has offered to amend it.

B. Findings

1. FPPAC Introduction

Decision No. 68071 (April 14, 2005) in Docket Nos. E-01773A-04-0528 and E-04110A-04-0527 addressed AEPCO's prior application for a general rate increase. Decision No. 68071 introduced AEPCO's FPPAC to track and to provide for the collection of the difference between: (a) actual fuel, purchased power, and wheeling costs, and (b) those established as base costs by the Decision No. 68071. The Decision set these base costs at 1.687 cents/kWh for ARMs and at 1.603 cents/kWh for PRMs. Demand charges associated with a certain power purchase agreement was the factor that differentiated these two base costs.

Decision No. 68071 attached a number of conditions to the approval of the FPPAC:

- Expiration in five years unless extended by the Commission
- Fuel and purchased power costs subject to prudence review at any time
- FPPAC calculations subject to review at any time
- Refund of FPPAC collections determined to be imprudent
- Filing of monthly reports with Staff detailing FPPAC calculations addressing the items proposed by Staff
- Monthly reports regarding fuel and power purchases and plant operations, containing the information proposed by Staff.

Decision No. 68071's approval of the FPPAC noted that fuel and purchased power comprised almost one-half of AEPCO's test year (2003) costs, and acknowledged AEPCO's assertion that volatility in such costs comprised a primary reason for the margin loss the cooperative suffered in 2003.

2. Current FPPAC Calculation

The adjustor rate was initially set at zero and was to remain at that level until October 1, 2006. At that date, and at each subsequent six-month interval, the adjustor would automatically change as required to recover the difference between actual and base costs. Decision No. 68594 (March 23, 2006) accelerated the first (October 1, 2006) reset date to April 1, 2006.

AEPCO must file one month before each October and April reset date a calculation of the new, proposed charge with a revised ARM tariff and PRM schedule. The calculation of the new charge consists of two parts, computed separately for ARM and PRM customers:

- A Power Cost component derived by: (a) adding the fuel, purchased power, and wheeling costs for the most recent 12 months, and (b) dividing this sum by kWh energy sales during the same 12 months
- A Bank Account component derived by: (a) calculating the total over or under recovered fuel, purchased power, and wheeling costs since clause inception, and (b) dividing this amount by the same kWh amount used to derive the Power Cost component.

The charge contained in the AEPCO filing becomes effective unless suspended by the Commission. Because the Decision established two different base costs (one for ARMs and another for PRMs), each ARM pays one adjustor rate, while each PRM pays a different adjustor rate.

3. 2008 FPPAC Review

Decision No. 70354 (May 16, 2008) addressed AEPCO's February 27, 2007 and February 29, 2008 requests to review (as contemplated in Decision No. 68071) the efficacy of the FPPAC. AEPCO pointed out that escalating fuel and purchased power costs were producing a bank balance that, after accounting for seasonal ebbs and flows, was growing too fast to recover past undercollected balances using the 12-month total kWh divisor in the FPPAC.

Decision No. 70354 noted that significant fuel and purchased power costs had caused the amount by which AEPCO had undercollected (the second, or "Bank Account" component of the FPPAC) to grow to $11.8 million by September 2007. It was undercollected by $4.9 million in January 2008 (the last month for which the Decision reported a balance). AEPCO proposed to alter this component by reducing the divisor from the most recent 12 months to the most recent 6 months of kWh energy sales. This change would have the practical effect of doubling the rate of recovery of an undercollected Bank Account balance.

The Commission observed (Decision No. 70354, paragraph 25) that, "AEPCO's proposed change to accelerate recovery will not change the inherent lagging tendency of the methodology. A completely different methodology may be needed to accomplish that, but that type of change is not an issue for the instant proceeding." Nevertheless, the Commission did determine that the change represented an appropriate interim means for accelerating recovery and thereby lessening the financial burden that even the reduced balance of $4.9 million was imposing on the Cooperative and its customers. The balance remained at about $4.4 million for ARM and PRM members combined, as reflected in AEPCO's calculation as of December 31, 2009 for use in resetting the adjustor rate on April 1, 2010. Natural gas prices have remained low, allowing the balance to drop. It has in recent months fallen into the $2 - $3 million range.[56]

Decision No. 70354 also discussed concerns by the PRMs about the failure of FFPAC calculations to consider differences in costs of energy supplied to them and to ARMs.

Specifically, one PRM observed that, although PRMs take primarily lower cost power from coal units, AEPCO was allocating to them higher natural gas fuel costs more associated with sales to ARMs. Staff believed that these issues could best be addressed in the next AEPCO rate filing (the one at issue in these proceedings). In this case, AEPCO and its ARM and PRM members have agreed to changes in the allocations of costs to differentiate energy costs associated with base resources and other resources.

4. Costs Included in the FPPAC

The costs that have been included in the FPPAC since inception include the cost of fuel and natural gas consumed in AEPCO generating stations, as recorded in RUS Accounts 501 and 547. The descriptions of these accounts follow:

501 Fuel.

A. *This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank, or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.*

B. *The cost of fuel shall be charged initially to Account 151, Fuel Stock, and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to Account 152, Fuel Stock Expenses Undistributed. In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.*

547 Fuel.

This account shall include the cost delivered at the station (See Account 151, Fuel Stock) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.

A different RUS Account (158) addresses the costs of SO_2 allowances. Therefore, AEPCO's FFPAC, in contrast to many others, recovers no costs of SO_2 allowance purchases or sales. AEPCO has generated sufficient numbers of allowances to avoid the need for purchases. AEPCO has made a moderate number of sales in the past. It has in recent years been banking them, however, given a desire to assure a reserve sufficient to support operations and low market prices for allowances. RUS considers these allowances to be security for its loans; therefore, RUS requires that the proceeds of sales of allowances be applied to loan balances.[57]

AEPCO's FFPAC also includes the costs recorded in RUS Account 555 (Purchased Power). The description of this account follows:

555 ***Purchased Power.***

A. *This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall also include, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, or capacity. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.*

The AEPCO FPPAC describes purchased power as including energy purchased on an economic dispatch basis, purchases made as a result of scheduled outages, and "all such" kinds of purchases made to substitute for AEPCO's own, higher cost energy. Another tariff clause includes purchases other than these, if recorded in RUS Account 555. Liberty asked about the intent of the language in these tariff provisions (lettered paragraphs B. and C. under the Power Cost Adjustor Rate section of the tariffs for ARMs and PRMs) because it seemed to imply that purchases for certain reasons (*e.g.*, as a result of forced, rather than scheduled outages) would not be recovered through the FPPAC. AEPCO advised that the language did not intend any exclusions, but rather to make clear that all forms of power purchases are included. The FPPAC tariff language does, however, exclude the demand and energy costs associated with sales for resale (presently including the City of Mesa and SRP).

The last cost element included in the FFPAC is wheeling (RUS Account 565). AEPCO excludes, however, the costs it pays to SWTC for network transmission service for the ARMs, because those costs are passed directly through to the ARMs.

5. FPPAC Change Proposed by AEPCO in Current Rate Proceedings

The new FPPAC that AEPCO proposes would continue to include the same categories of costs and it would continue to treat ARMs and PRMs differently. Its principal change would be to separate the FPPAC into Base Resource and Other Resources categories. Separate adjustor rates would be created for each of these two resource types. The definitions of the two resources categories are:

1. Base Resources:
    a. AEPCO Steam Turbine Units 2 and 3
    b. Economy purchases displacing these units
    c. Western Area Power Administration contract purchases by AEPCO
    d. Wheeling expenses associated with delivery of these resources
2. Other Resources:
    a. AEPCO Steam Turbine Unit 1 (including Gas Turbine 1) , Gas Turbines 2, 3 and 4.
    b. Contract purchases that serve the combined scheduled loads of Class A members (i.e., ARMs and PRMs)
    c. Other power purchased (except for those included above in item 1.b.)
    d. Power acquired by purchase or through resources to which a member has expressly agreed to participate

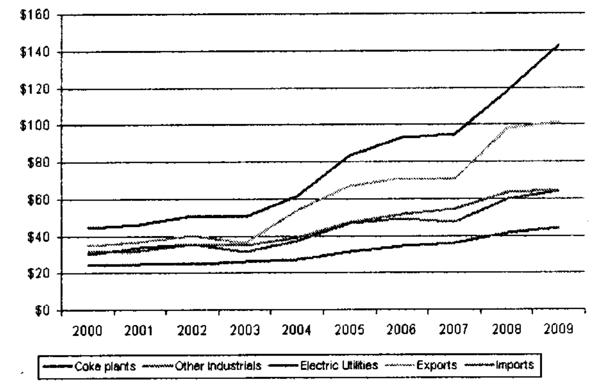
Each ARM and PRM would be charged (or credited as appropriate) for the kWh that it has received from each of the two resource types. Thus, for example, a PRM that secures its non-base requirements from the market, thus taking from AEPCO only its share of base resources, would be responsible for no energy costs associated with Other Resources.

For both ARMs and PRMs, the new FPPAC would follow a similar calculation process:

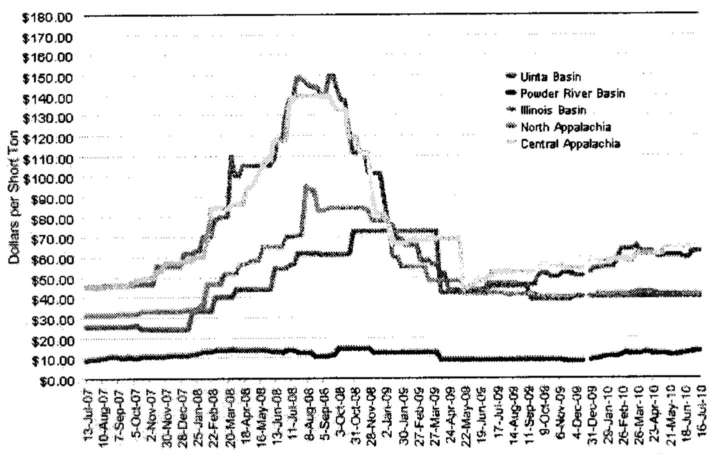
1. The decision in these proceedings will establish (separately for Base Resources and for Other Resources) a separate, unique base cost for each PRM and one common base cost for all ARMs (these factors are termed "power cost adjustor bases").
2. Each month, AEPCO will determine the amount of kWh that each member receives from Base Resources and from Other Resources.
3. Each month, AEPCO will determine a single overall cost per kWh for Base Resources for the month and a single overall cost per kWh for Other resources for the month.
4. AEPCO will determine each member's costs for the month (separately for Base Resources and for Other Resources) by multiplying the Base Resources and Other Resources receipts determined in Step 2 times the applicable rates for each resource type as determined in Step 4.
5. For purposes of calculating member costs, AEPCO will directly assign three categories of costs: (a) Southpoint and Griffith purchase and wheeling costs will be directly assigned to the ARMs (collectively) and to Trico, but not to the other PRMs, and (b) any future power purchase agreements joined into only by some members, and (c) costs and revenue credits associated with base resource transfers of power and energy among members and base resource economy sales to third parties.
6. AEPCO will then subtract from the costs determined for each member in Step 5 above the costs of the kWh receipts (from Step 2 above) at the base costs (from Step 1 above); this step produces separate determinations of each member's over- or undercollected Base Resources and Other Resources costs for the month.
7. AEPCO will enter each month's calculations of over- and undercollections in distinct "bank balancing accounts" for each member; each member will have a separate bank balancing account for Base Resources and for Other Resources.
8. Each member's two account balances will be set at zero upon the effective date of the new FPPAC; the FPPAC adjustor rates for all members will also begin at zero.
9. As is the case under the current FPPAC, AEPCO will calculate those adjustor rates twice per year (with filings to be made on each March 1 and September 1 for effectiveness, presumably remaining, as the current changes are, subject to Commission suspension).
10. AEPCO would make the first filing (to move the zero rate) on March 1, 2011, for effectiveness April 1, 2011.
11. The draft Plan for Administration calls for the same two-part adjustor rates, as does the current FFPAC; i.e., one part based on average monthly over- or undercollections (expressed as cents/kWh) across the preceding 12 months and the other based on recovering the bank balance (accumulated from inception of the new FPPAC) over six months. However, there would be separate two-part rates for Base Resource and Other Resource deliveries.

AEPCO will use its Billing Unit Model to itemize Base Resources and Other Resources sales (in both kWh and dollars) by member by month. This model will generate the detail required to support the various sales-amount and cost information necessary to support FPPAC calculations. AEPCO proposed to include in monthly compliance reports to the Commission the calculations of sales costs, and balances for each member. AEPCO anticipates, and Liberty concurs, that it will fall principally to the members to question the ability of the model to function correctly and to serve as the primary source for verifying correct application of all of the FPPAC requirements applicable to different member classes, to different resource types, and to individual member balances.[58]

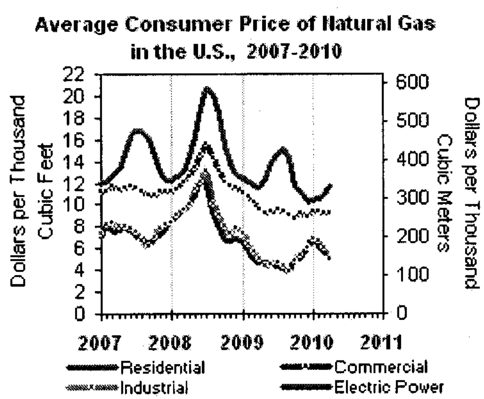
6. Fuel Price Volatility



The fuel and energy market volatility that drove the introduction of an FFPAC at AEPCO have not diminished. The following chart[59] from the U.S. Energy Information Administration shows the dramatic increases that electric utilities, among other coal users, have experienced in the very recent past. Increases in prices for coal from the Powder River Basin have been more moderate, but still significant. The sharp increases shown for the first part of 2009 have reversed, as the following chart demonstrates.[60] The scale of the second chart particularly masks the changes in Powder River Basin coal prices. The chart demonstrates that volatility has truly become a "two-way" street in the industry. Natural gas prices have also fluctuated greatly and fundamental, long-term changes in supply (Marcellus Shale[61] and imported LNG) have occurred. The following chart shows the dramatic recent changes in natural gas prices.[62]



A number of factors can be expected to continue affecting price certainty. Amid growing international demand for energy sources, world economic conditions remain very uncertain. The *Wall Street Journal*, for example, has just reported that China has surpassed the United States as the leading consumer of energy. Formerly an exporter of coal and oil, China is now aggressively engaged in locking up long-term sources of these fuels. Domestic markets for coal have already been affected by international demand, and this effect seems likely to continue. Natural gas has become much more competitive with coal, with utilities all across the country finding gas to be increasingly



displacing coal as a baseload generation source. Increasing renewable requirements have put new sources, such as wind, in what amounts to a "must run" location in the generation stack and the uncertain future of carbon reduction and capture also have significant potential to affect energy markets.

C. Conclusions

1. AEPCO's FFPAC has to date served to mitigate the effects of over and under collections of fuel and purchased power costs.

At the time of its adoption in 2005, the FPPAC responded effectively to the types of swings then characteristic and to be expected in AEPCO's energy markets. Some commissions had by then shown a preference for a shorter-term adjustment period (compared with the 12-month rolling average of AEPCO's adjustor), but the AEPCO approach was consistent with the range of current experience. The use of forecasted costs as the basis for adjustment clause calculation has also been increasing. Liberty did not, however, observe forecasting to be a strength of AEPCO. That observation supports reliance on historical data here. Other clauses also frequently include SO_2 allowance transaction net costs. The infrequency of AEPCO's allowance transactions and RUS requirements, however, also make the exclusion of their costs here appropriate.

Despite its successful history in recovering substantial differences between base and actual costs, however, changes in external forces and factors since the FPPAC's introduction have made it increasingly slow to respond to cost changes. The 2008 acceleration of recovery of undercollected balances helped materially.

2. Recent market dynamics suggest consideration of an FPPAC that will respond more quickly to cost changes, but AEPCO's circumstances require measured consideration of change. *(Recommendation #1)*

The Commission approved the acceleration of the FPPAC's "Bank Account" component in 2008 when undercollections totaled $4.9 million. The Commission recognized that this change would not eliminate the FPPAC's "lagging tendency," but deferred consideration of more fundamental change. The accuracy of the Commission's judgment is shown in the results following the acceleration. The balance dropped by about $0.5 million (10 percent) through the end of 2009. AEPCO advised that it has dropped much more substantially thereafter. These results appear to demonstrate that a continued fall in energy prices through 2009, and the sustaining of low prices through early 2010 (particularly for natural gas) has been a primary driver of the reduction in the undercollected balance. It is clear that, as the balance has been somewhat slow to decline in falling energy markets, so it would be slow to increase in rising markets. Nevertheless, recent experience and continuing global and national uncertainties make clear that the balance has the very real potential for reaching in the future the level that the Commission found to be of concern when it agreed to an accelerated balance amortization.

This concern has particular relevance for a cooperative generation enterprise. They tend to be significantly more thinly capitalized than their investor-owned utility counterparts. Entities such as AEPCO therefore have less ability to withstand significant undercollections of actual costs, even when their eventual recovery is highly likely. Cooperative G&Ts are also generally more thinly capitalized than the distribution cooperatives they serve. Thus, as between supplier and purchaser, the latter is, all else equal, better positioned to accommodate cost recovery deferrals.

These factors suggest a more current method of recovery at the AEPCO level, with its members then left to decide, each for itself, what method (*e.g.*, a correspondingly rapid recovery method) to use to address the financial changes that prompter payment to AEPCO would generate. Two countervailing factors apply. First, Liberty's cost-of-capital recommendations in the current AEPCO rate proceedings would strengthen AEPCO's financial position for the short term at least. Second, with the number of cooperatives that AEPCO serves, a sudden change that does not give them time to plan and adjust could be disruptive. A strength of AEPCO's rate changing process is the dialogue with members (the "customers" who have to accommodate changed energy costs in their own planning, budgeting, and pricing) that precedes formal requests to the Commission. While discussions about the FPPAC have clearly taken place, it does not appear that they have included any planning to address a more current recovery method. Certainly the changes proposed do not call for any such alteration.

3. **The changes that AEPCO has proposed to its FFPAC will serve to improve the alignment of cost causers and cost bearers, as between its all- and partial-requirements members.**

AEPCO has experience material migration from all-requirements service. Future planning for power-supply resources in the region has also changed in a way that gives AEPCO's members significant flexibility in how they pursue future opportunities. AEPCO's efforts to refine its methods for allocating costs among members is appropriate, and extending those methods to its FPPAC are sound. The success of these efforts will depend on AEPCO's ability to measure generation costs accurately on an hourly basis. Verifying its successful implementation will take diligence on the part of the members. Their stakes in accurate assignment and allocation of costs provide comfort that any "shakeout" issues that may arise will be promptly identified and corrected.

4. **AEPCO has not presented a specific method for closing out remaining balances under the current FPPAC and its proposed plan for administration, while generally sound, exhibits a lack of clarity in certain areas.** *(Recommendation #2)*

AEPCO's supplemental response to Staff Data Request No. 1.61 provided a proposed Plan for Administration for its proposed, changed FPPAC. That proposed plan observed the need to design a temporary surcharge for collecting the bank balances attributable to the prior FPPAC, but remaining as of the effective date of the new clause. AEPCO advised that it had yet to design this mechanism.[63] That mechanism should be defined and in place by the effective date of the new FPPAC.

In addition, Liberty's review of the AEPCO proposed plan for administration disclosed some areas that would benefit from clearer expression. Should the Commission decide that the FPPAC should remain, the plan for implementing it should be reviewed with Staff to assure its consistency with the Commission order and with the need for the plan to be complete and clear.

D. Recommendations

1. **Address through focused discussions with the Class A members a change that will produce more current FPPAC recovery.** *(Conclusion #2)*

AEPCO and the members should convene a series of discussions designed to produce a recovery mechanism that will provide for recovery or refund of under and over collections under the FFPCA within a period of from one to three months. These discussions need to consider the need for the members to have the time necessary to make adjustments they deem appropriate in pricing to their end-use members. AEPCO and the Class A members should strive to present to the Commission a proposal within six months of the effective date of the new FPPAC.

2. **Assuming that AEPCO's proposed FPPAC continuation and changes are found by the Commission to be generally appropriate, establish a temporary surcharge mechanism, and clarify the proposed plan for administering it.** *(Conclusion #4)*

The balances accumulated under the old FPPAC and therefore they should be collected in a manner that is consistent with the member expectations about recovery that existed at the time the deferrals were accruing. The most direct means for recovery would be to continue the Bank Account feature of the current clause, which should provide for recovery to be complete (subject to final reconciliation at the end of six months, if there is a material variation in Member usage) within six months and in accord with the charging principles applicable under the current clause.

The Staff and AEPCO should also conduct a joint vetting process to assure mutual comfort with the clarity, completeness, and precision of the Plan for Administration as proposed by AEPCO.

[1] Minson Direct Testimony
[2] AEPCO 2009 Final Report.
[3] http://www.nationalcoaltransportation.org/
[4] Source: response to DR No. STF 4.4.
[5] Source: Adger telephone interview of Walter Bray, May 28, 2010.
[6] Response to DR No. 4.23.
[7] Responses to DR Nos. 4.4 and 4.46.
[8] The contract was provided in response to DR No. 7.9.
[9] This material is from the response to DR No. STF 11.5.
[10] This material comes from DRs No. STF 4.35 and 4.58, plus Adger's (telephone) interviews of Walter Bray and Gary Grimm on May 28 and July 20, 2010.
[11] Gary Grimm, May 28 and July 20, 2010.
[12] Gary Grimm, May 28 and July 20, 2010.
[13] Response to DR No. 11.3.
[14] Response to DR No. 7.6.
[15] Most of this material came from Adger's interviews (by phone) of Walter Bray on May 28 and July 15, 2010, supplemented by information from the Company's responses to DRs No. STF 4.2 and 4.5.
[16] Response to DR No. STF 4.40
[17] Source: ACES PM briefing provided in response to DR No. STF 4.48. It appears that this briefing was presented some time in 2007.
[18] This information is from Adger's telephone interview of Walter Bray on July 15, 2010.
[19] Response to DR No. STF 11.7.
[20] Relevant materials were provided to Liberty in response to DRs No. STF 4.3 and 4.8.
[21] Response to Data Request STF 8.13.
[22] Ibid.
[23] Response to STF 5.2, AEPCO interview regarding power trading on May 18, 2010.
[24] AEPCO interview regarding power trading on May 18, 2010.
[25] Interview with AEPCO Vice President, Power Resources and Planning, July 20, 2010.
[26] Responses to Data Requests 8.10 and 8.11.
[27] Responses to Data Requests 4.70 and 4.71.
[28] Interviews with AEPCO Vice President Power Resources & Planning on May 18 and July 20, 2010; responses to Data Requests 4.70 and 4.71.
[29] Interviews with AEPCO Vice President Power Resources & Planning on May 18 and July 20, 2010.
[30] Ibid.
[31] Responses to Data Requests 1.59 and 8.12.
[32] Interview with AEPCO Power Trading Desk personnel, July 20, 2010.
[33] Ibid, response to Data Request 8.13.
[34] Interview with AEPCO Power Trading Desk personnel, July 20, 2010.
[35] Interview with AEPCO real-time trader, July 20, 2010.
[36] Response to Data Request 8.12.
[37] Response to Data Request 4.60.
[38] Interview with the Manager, Power Trading, July 20, 2010.
[39] Interviews with AEPCO Manager, Power Trading and Steve Zwilling and Jean Nitz of ACES, May 17 and 18 2010.
[40] Response to Data Request 4.8.
[41] Response to Data Request 4.14.
[42] STF 4.99
[43] The source for all performance data is STF 4.59
[44] STF 10.19
[45] STF 10.18
[46] Generator Availability Data System - NERC
[47] STF 10.17

[48] STF 10.14 and 10.15
[49] STF 10.14
[50] STF 10.16
[51] STF 4.63, 4.98 and 10.13
[52] STF 10.6
[53] STF 10.6, and 10.8 through 10.11
[54] STF 10.7
[55] Differentials of $[redacted]MWh are used. STF 10.13 data suggests that [redacted]MWh has been exceeded only a few times with values under [redacted]MWH much more frequent.
[56] Pierson, King Phone Interview July 7, 2010.
[57] Pierson, King Phone Interview July 7, 2010.
[58] Pierson, King Phone Interview July 7, 2010.
[59] http://www.eia.doe.gov/cneaf/coal/page/special/images/fig7.jpg
[60] http://www.eia.doe.gov/cneaf/coal/page/coalnews/images/weekly2/weekly2.jpg
[61] http://geology.com/articles/marcellus-shale.shtml
[62] http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html
[63] Telephone Interview with Pierson and King, July 7, 2010.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-09-0472

DIRECT

TESTIMONY

(PRUDENCE REVIEW)

OF

RICHARD MAZZINI

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 30, 2010

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EXHIBITS

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Richard Mazzini. I am an Executive Consultant associated with The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Mazzini, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I have been engaged as a consultant and utility manager in the electric utility industry since 1967. Until 1995, I was employed by Pennsylvania Power & Light Company in a variety of senior management positions. After entering the consulting business in 1995, I served in senior positions with Washington International Energy Group, Navigant Consulting and ABB. I have been an independent consultant since 2001. As a consultant, I have assisted utilities throughout the United States, Canada, the Caribbean and Europe and have worked on behalf of many utility regulatory authorities.

I have a B.E.E. degree from Villanova University and an M.S. degree in Nuclear Engineering from Columbia University. I am a Registered Professional Engineer in Pennsylvania and a member of the Institute of Electrical and Electronics Engineers and the American Nuclear Society.

Q. Have you prepared a more detailed summary of your background?

A. Yes; Exhibit RAM-1 provides it.

Q. What is the purpose of your testimony?

A. The testimony of John Antonuk examines the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), and also summarizes the review of AEPCO's facilities from an engineering perspective. Liberty prepared a report addressing the findings, conclusions, and recommendations of that examination. The report is attached to Mr.

Antonuk's testimony as Exhibit JEA-2. I directly performed the work reflected in the Engineering Analysis/Plant Operations section (Chapter VII) of that report. The purpose of my testimony is to support and respond to questions regarding that portion of Exhibit JEA-2.

Q. Can you please briefly summarize the portion of the report for which you are responsible?

A. I was responsible for directly performing the engineering analysis of APECO's assets, which focused on the generating units, which form the core of those assets. Much of my work concentrated on the units of the Apache Station. Liberty examined generating unit performance, operations, maintenance, and capital improvements. Liberty reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages and conducted a review designed to determine the "used & useful" nature of rate-base assets. Liberty's review included a physical inspection at Apache Station and interviews with the personnel responsible for managing key functions at the plant.

Q. Does that conclude your direct testimony?

A. Yes it does.

Richard Mazzini Resume

Areas of Specialization

Management and regulatory audits; utility operations, including nuclear and other power production; power marketing and risk management; strategic planning; organization analysis and competitive re-structuring; project management; cost management; and tariff design and management.

Relevant Experience

The Liberty Consulting Group

Public Service Commission of New York – A management audit of Con Edison. Project Manager for a 13-member Liberty consultant team.

Maine Public Utilities Commission – Review and analysis of proposed new transmission project, the Maine Power Reliability Project ("MPRP"). Lead Consultant for economic analysis.

Public Service Commission of Maryland – Consultant supervising the various auctions for procurement of power for Maryland's standard offer service ("SOS") customers and support for the PSC in their analysis of new approaches to SOS supply.

Management Audits

Public Service Commission of New York – An operational audit of Con Edison's reliability and emergency response planning and processes. Lead Consultant for corporate strategy and priorities, emergency planning and organization.

Federal Energy Regulatory Commission (FERC) – A review of the California ISO. Examined governance issues, operating procedures, transmission planning and analysis, organizational issues, interfaces with stakeholders and recommendations for the restructuring of the California market.

City of Seattle (Washington) – Review of the City's utility, commissioned by City Council and the Office of City Auditor, to analyze financial strategies, power market and risk management strategies and governance schemes. Lead Consultant for risk management.

St. Vincent Electricity Services, Ltd. – A management audit commissioned by the Board of Directors. Scope included generation, transmission, distribution, organizational assessment, safety, procurement and fuel.

New Jersey Bureau of Public Utilities – Evaluation of the gas supply and hedging programs of the four New Jersey gas distribution companies.

New York Power Authority – Consulting support for an internally sponsored audit of energy risk management functions.

Strategic Business Planning

Barbados Light & Power Company – Project Manager and Lead Consultant for a strategic planning initiative. Major areas of attention included new generation options, regulatory strategies, competitive threats, tariff design, new business opportunities, human resource issues, and planning processes.

Barbados Light & Power Company – Project Manager and Lead Consultant for the development of a model for the risk analysis of various new generation investments.

Electricité de France – Provided business planning and analysis services in the furtherance of the utility's wholesale and retail businesses. The work included research and analysis of potential gas partnerships, trading alliances and development of new retail markets throughout Europe.

SaskPower (Saskatchewan) – Project Manager and Lead Consultant for development of a strategic plan for the Power Production Business Unit. The project included asset valuation and optimization, transmission plans and strategies, efficiency improvement, market analysis and organizational options.

Omaha Public Power District – Project Manager and Lead Consultant for an extensive strategic business planning initiative. This multi-phase project spanned one year and included (1) asset evaluation, estimation of potential stranded costs and stranded cost mitigation strategies; (2) business growth strategies, including retail retention and expansion, new products and services, new utility businesses, wholesale marketing and bulk power trading; (3) corporate restructuring through the formation of four new business units; (4) organization design, including the creation of two new marketing organizations and a new trading floor; and (5) regulatory and legislative strategy development.

Omaha Public Power District – Project Manager and Lead Consultant for a follow-up analysis to the above project a year later to recommend added steps and course corrections. Provided new recommendations on organization design, customer service, stranded costs, energy marketing and trading initiatives, risk management, new business development, new products and services and strategic planning processes.

A Large Canadian Provincial Electric Utility – Strategic planning and business support in the analysis of future generation and transmission options associated with a major new generation construction project.

Tennessee Valley Public Power Association – Project Manager and Lead Consultant for development of a comprehensive new business strategy that reinvented the Association for a competitive environment. Key elements of the plan included a new expanded focus on government relations and the influencing of public policy, as well as the creation of four newly created business units and business endeavors.

City Council of Los Angeles (California) – Advice to the Council on the strategic plans of its municipal electric utility. Conduct of a workshop for the Council and staff on restructuring and competitive issues. Review of power marketing alliance strategies.

Riverside Public Utilities (California) – Analysis of the potential to sell all or part of the utility. Development of a new business vision and strategy. Analysis of outsourcing and alliance possibilities. Development of a power supply alliance, including design of the venture, development of RFP, evaluation of bidders, selection of finalist and negotiations. Organizational design and implementation. Planning and project management support for activities leading to open access.

Lower Colorado River Authority – Consulting support for strategic review and development of alliance strategies. Facilitation of management workshop to develop strategic responses to key issues and to examine options for strategic alliances.

ElectriCities of North Carolina – Business simulations and strategic planning for the North Carolina Power Agencies.

ElectriCities of North Carolina – Analysis of the Carolina P&L – Florida Progress merger with resulting strategies and negotiations on behalf of ElectriCities.

4–County Electric Cooperative – Strategic planning support for the Chief Executive Officer and Board of Directors. Designed and facilitated a planning workshop for the Board of Directors and key managers. Followed up with subsequent action plan for the Board.

Project and Cost Management

Omaha Public Power District ("OPPD") – Lead Consultant responsible for design and implementation of a cost management program for a major overhaul of the Fort Calhoun

Station. This $400 million project involved replacement of the two steam generators, pressurizer and reactor vessel head.

Power Marketing, Procurement and Risk Management

Public Service Commission of Maryland – Consultant supervising the various auctions for procurement of power for Maryland's SOS customers and support for the PSC in their analysis of new approaches to SOS supply.

Electricité de France – Supporting services for the implementation of a large trading and marketing alliance in Europe, including reporting and control processes and training workshops for employees.

SaskPower – Project Manager and Lead Consultant for the expansion of the bulk power marketing program and creation of an energy trading floor. Work included extensive recommendations on corporate structure, organization, trading and marketing strategies, trading floor characteristics, management controls, risk management strategies, training, alliance building and external interfaces.

Public Service Commission of Maryland – Provided consulting support to the PSC in the approval of the settlement agreement relating to SOS.

New Businesses

BGE Corporation (Constellation Nuclear Services) – Project Manager and Lead Consultant for the business analysis, planning, design and startup of a new subsidiary business for the client. The business, provision of nuclear related services to U.S. and international utilities, was successfully started in July 1999.

Electricité de France – Provided support in the planning, analysis, structure and negotiation of a large international energy trading and marketing alliance (EDF Trading, based in London).

Tennessee Valley Public Power Association – Project Manager and Lead Consultant for a survey and analysis of the Association's more than 150 member utilities. Produced an analysis with recommendations for the products and services that can best serve the members in a deregulated environment.

Municipal Electric Association (Ontario) – Project Manager and Lead Consultant for the development of a definitive business plan for a new power procurement business on behalf of the Association's more than 250 municipal electric utilities. Work included initial feasibility assessments followed by a complete actionable plan for the creation of the new organization, including structure, organization, staffing, financing, market analysis, contingency plans, product offerings and promotional strategies. The resulting new company became a reality in late 1997.

ENERconnect (Ontario) – Served as interim Vice President of Marketing and Customer Service for the startup of this new power procurement and services company. Project Manager and Lead Consultant for the development of a detailed operational plan for startup. Assisted in all aspects of startup including organizational design, business strategies, product design and development and support to executive management and the Board.

ABB Energy Solution Partners – Consulting support for ESP-sponsored projects, including customer and project research, project structure, energy supply options, alliances and preparation of proposals. Included regulatory research and discussions in Nevada, Michigan, New Jersey and New York.

Ambient Corporation – Consulting support for strategic and tactical business planning for this startup firm specializing in power line communications ("PLC"), including development of commercialization plan and supporting management processes, support of business plan, product and service development, regulatory strategies and financing documentation.

PacifiCorp – Customer research with two groups of large industrial and commercial customers. Designed and managed interactive workshops to obtain their input, served as subject matter expert for the sessions, produced and presented comprehensive analyses of the results with strategic insights for the client's marketing initiatives.

T&D Support

Alberta Electric System Operator – Analysis of transmission loss methodologies for the Alberta market.

A Large Canadian Provincial Electric Utility – Business planning support for the transmission business unit. Analysis of the business potential of new transmission opportunities. Analysis of U.S. transmission policies and their potential impact on a Canadian player in the U.S. markets.

Utility Management

Pennsylvania Power & Light Company – Served in a variety of management positions in a long career with the utility. Responsible for strategic business planning, rates, bulk power marketing, system operation, management of non-utility generation contracts, rate design, market research and contract negotiations with large customers. Key management roles in cost management, planning and scheduling for all Susquehanna nuclear station design, licensing, and startup activities including outage management.

Other Consulting Positions

Senior Vice President for ABB Energy Consulting, responsible for managing consulting engagements for a variety of U.S. and European energy firms.

Principal for Navigant Consulting, Inc., involved in numerous consulting engagements serving the electric utility industry in competitive initiatives.

Senior Vice President for the Washington International Energy Group, responsible for the firm's competitive positioning practice.

Education

M.S., Nuclear Engineering, Columbia University
B.E.E., cum laude, Villanova University

Registrations

Registered Professional Engineer – Pennsylvania

Memberships

Institute of Electrical and Electronics Engineers
American Nuclear Society

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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TESTIMONY

(PRUDENCE REVIEW)

OF

RANDALL VICKROY

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

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JULY 30, 2010

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INTRODUCTION

Q. State your name, position, and business address.

A. My name is Randall Vickroy. I am a senior consultant associated with The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Are you the same Randall Vickroy who has already provided direct testimony on cost of capital in this proceeding on July 2, 2010?

A. Yes, I am.

Q. Does that other testimony address your background insofar as it is relevant to the purposes of the following testimony?

A. Yes, it does.

Q. What is the purpose of this additional testimony in this proceeding?

A. The testimony of John Antonuk describes Liberty's examination of the prudence of Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "the Cooperative"), fuel, purchased power, and plant operations policies, activities, and costs. It's also a review of AEPCO's facilities from an engineering perspective. The findings, conclusions, and recommendations of that examination are attached to Mr. Antonuk's testimony as Exhibit JEA-2. I directly performed the work reflected in the Power Transactions portion (Chapter VII) of that report. The purpose of my testimony is to support and respond to questions regarding that portion of Exhibit JEA-2.

Q. Can you please briefly summarize the portion of the report for which you are responsible?

A. I was responsible for the direct performance of Liberty's review of APECO's power transactions. This review included examinations of: AEPCO's processes and models for forecasting power purchase requirements, its basis for soliciting long- and short-term purchases and sales and the effectiveness with which it has made and administered them, power purchase and sale costs, real-time trading and dispatch modeling and effectiveness.

Q. Does that conclude your testimony?

A. Yes.