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(Part 2 of 9)

EXHIBIT
admitted
S-28

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 57744.	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY OF JOHN ANTONUK
President, The Liberty Consulting Group

1. Introduction

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

A. My name is John Antonuk. I am the president of The Liberty Consulting Group. My business address is 65 Main Street, P. O. Box 1237, Quentin, PA 17083.

Q. Please describe your educational background and professional experience.

A. I graduated in 1973 from Dickinson College, earning a bachelors degree, with honors. I graduated in 1976 from the Dickinson School of Law, earning a juris doctor degree, with honors. I began my career in 1975 as an investigator for the litigation section of the Pennsylvania Attorney General's office. I then spent several years as assistant counsel to the Pennsylvania Public Utility Commission, for which I conducted administrative and civil litigation involving a wide variety of case types in the electricity, natural gas, telecommunications, water, and transportation industries. I also served in a number of capacities on a variety of matters involving commission administration and operations.

I then served as head of the service and facilities section of Pennsylvania Power & Light ("PP&L") Company's regulatory-affairs department. I left PP&L to begin consulting in the utility industry in 1982. I managed the litigation-services practice of Management Analysis Company, a consulting firm that specialized in the electric-utility industry.

I am one of the founders of Liberty, which I helped to establish 19 years ago. I have led or managed over 150 projects since I began consulting in the utility industries.

Q. Have you participated previously in state commission proceedings?

A. Yes. I have been engaged in many state utility regulatory proceedings in the electric, natural gas, and telecommunications industries in 25 years as a utility consultant. Much but not all of it has been on behalf of commissions or their staffs. I have served as a staff witness, an independent witness appearing on the commission's behalf, a contracted administrative law judge, a facilitator, an arbitrator, and a commission advisor.

Q. Please describe the business of The Liberty Consulting Group.

A. Liberty is a management-consulting firm that has been serving utility industry regulators and managers for 19 years. Liberty has performed over 250 utility engagements. Liberty's experience includes energy and telecommunications utilities across the country. Liberty has performed or is performing substantial engagements for utility regulatory authorities in two thirds of the states. Along with Arizona, these states are:

Arizona	Hawaii	Minnesota	New York	Tennessee
Arkansas	Idaho	Mississippi	North Dakota	Utah
Colorado	Illinois	Montana	Ohio	Vermont
Connecticut	Iowa	Nebraska	Oklahoma	Virginia
Delaware	Kentucky	New Hampshire	Oregon	Washington
District of Columbia	Maine	New Jersey	Pennsylvania	Wyoming
Georgia	Maryland	New Mexico	South Dakota	

Liberty's work in Arizona includes an examination of the recently proposed UniSource acquisition, a review of telecommunications matters involving Qwest, and the work at issue here, which relates to fuel and energy procurement and management by APS.

Q. What familiarity do you have with utility fuel and energy procurement matters?

A. For the Pennsylvania Public Utility Commission Staff, I managed proceedings arising from Commission Audit Bureau's first fuel audits. Later, as a consultant with Management Analysis Company I examined coal procurement for Central Illinois Public Service Company. Most recently, leading Liberty's practice for public service commissions, I have directed, managed, and participated in many examinations of fuel and energy procurement for regulators in Connecticut, Kentucky, New Hampshire, New Jersey, New York, Nova Scotia, Ohio, Pennsylvania, Tennessee, Virginia, and Wyoming.

Q. What is the purpose of your testimony?

A. My testimony addresses the results of Liberty's examination and evaluation of three inter-related subjects: (a) an audit of the procurement and management of fuel and energy by Arizona Public Service Company ("APS"), focusing on the 2005 months during which its Power Supply Adjustment mechanism ("PSA") applied, (b) the information and analysis that APS has offered to support recovery of fuel and energy expenses in this proceeding, and (c) potential adjustments to the PSA that will take advantage of lessons learned during its first year of operation and that will reflect likely conditions in the fuel and energy markets across the next several years.

2. Testimony Summary

Q. Provide an overall summary of the principal conclusions that you reach in this testimony.

A. Liberty's fuel and energy audit verified that APS handled fuel and energy procurement and management in a manner that produced appropriate costs during the April through December 2005 period. We did conclude, however, that APS should make a number of changes to improve management and operations on a going-forward basis.

Liberty's review of evidence from the rate case disclosed no reason to conclude that there have been any material changes in fuel and energy procurement and management performance through mid-2006, but that conclusion is more qualitative than quantitative, because Liberty has not performed the same audit activities for that period.

Liberty believes that it is appropriate to continue some form of a PSA-type mechanism, because fuel and energy volatility have returned to the marketplace in dramatic fashion. That volatility will likely continue for some time. Such volatility substantially diminishes the chance that rate-case decisions about fuel and energy expenses will bear a reasonably close relationship to costs experienced while rates apply, particularly given the dependence of APS on natural gas. Given a continuing justification for a PSA, it is appropriate to use costs for a 12-month period closely preceding the effectiveness of new rates to set the base rate portion of fuel and energy expense recovery. Calendar year 2006 costs, which APS witness Ewen has normalized in his testimony in these proceedings, serve this purpose. Normalization of 2006 costs for operational factors (such as unit outages) is also proper. APS witness Ewen took that approach. APS proposes his normalization as the basis for establishing the fuel and energy costs component of base rates.

We believe that the APS normalization requires a number of adjustments. First and most important, it relied upon late-2005 energy market prices, which have proven far to exceed what APS has had to pay in 2006. APS should adjust its calculations to use actual fuel and energy prices for the first half of 2006 and its current estimate of fuel and energy prices for the remainder of 2006. Second, the Ewen normalization of 2006 fuel and energy costs makes adjustments for exogenous (*i.e.*, not related to internal, operational factors such as unit outages or heat rates) events that happened mid-stream in 2006, or that will not happen until 2007. These factors include: (a) a later-than-expected 2006 rate increase for natural gas transportation, (b) a 2007 reduction in expensive capacity from SRP, and (c) the exclusion of a 75 MW sale to Tucson Electric Power. APS also erroneously included in utility revenue and expenses affiliate non-utility energy marketing and trading activity, which produced a net loss. Those non-utility revenues and expenses and the resulting loss should be excluded. This exclusion will reduce the increase in fuel and energy costs that APS has predicted. Actual net costs for the first half of 2007 also include about $3.7 million in margins from the optimization of an APS transmission capability. The Ewen normalized 2006 costs exclude those margins.

Liberty asked APS to recalculate its normalized 2006 fuel and energy expenses by correcting for the preceding factors, except for the $3.7 million in margins, which we discovered only recently. That recalculation supports a reduction of $111.6 million in fuel and energy expenses from those shown in the Ewen testimony workpapers. The "Net Retail Fuel Cost" shown in Workpaper PME_WP1 as $935,939,000 declines to $824,357,000 under the recalculation. This number includes the hedging-sharing method

proposed by APS. Eliminating that sharing method would drop the reduction slightly, to $111.4 million. Eliminating the sharing increases Net Retail Fuel Cost to $824,566,000. We also believe that fuel and energy costs should be reduced by a further $3,702,501 to reflect 2006 margins for PWCC non-utility transactions that involved an APS utility transmission asset.

Going forward, we believe that ways other than caps and collars can also provide the limits that the Commission seeks to place on fuel and energy cost adjustments. Caps and collars may prove difficult when current recovery of costs is most critical; *i.e.*, when market prices diverge most greatly from those that form the basis of base rates and the PSA. We believe that using forecasted fuel and energy prices (*e.g.*; those for calendar 2007) to set the PSA component for 2007 can serve the combined purposes of: (a) limiting the variation between recovery and cost to a level that maintains key financial ratios, (b) preserving Commission flexibility to set the duration of the amortization period for over- or under-collection balances, and (c) monitoring earnings to verify that variations in revenues and expenses in other areas do not offset variations between fuel and energy costs and recovery.

We also believe that the APS proposal to share an additional 10 percent of savings or losses from hedging activities is not appropriate. The APS hedging program does not operate on the basis of discretionary amounts or timing. It in fact discourages, as we believe it should, traders from timing hedges on the basis of expected future movements in market prices. Therefore, the current APS strategy and methods give no particular

reason to reward or to penalize. Sharing thus will provide no useful incentive under current operations. Most importantly, there should be no incentive to change strategy or methods so as to invite the introduction of speculation into the utility hedging program. Liberty believes it is not sound to promote utility efforts to out-guess the energy market. As this testimony will discuss later, however, we believe that a much more limited hedging sharing opportunity is appropriate because it will induce APS to seek economies without taking undue risk.

3. Fuel and Energy Audit

Q. Describe the scope of the fuel and energy audit.

A. Liberty responded to a Commission Staff request for proposals seeking an examination and analysis of the management and operations of fuel and purchased-power functions at APS, and the formulation of any appropriate recommendations. Liberty was awarded the engagement and proceeded to conduct an examination of: (a) organization structure, responsibilities, and staffing, (b) policies, procedures, systems, and tools, and (c) procurement approach, methods, and decisions. Liberty's examination addressed the following 12 work elements described in the RFP:

1. Identification of authorized decision makers up to the Board level for fuel and purchased-power procurement policy and transactions
2. The fuel and purchased-power costs in the PSA
3. Overall fuel and purchased-power procurement policy, goals, and strategies
4. Significant outages at plants other than Palo Verde for 2004 and 2005

5. Identification of any declines in non-nuclear plant performance
6. On-site inspections of fuel handling, quality control, inventory surveying methods and results, performance monitoring, and maintenance at generating stations
7. Review of the simulation models used to develop fuel and purchased-power volume requirements forecasts
8. Analysis of the models used by day-ahead traders to determine the correct dispatch of resources and other short-term decisions
9. Review of fuel and purchased-power contracts for reasonableness and for compliance with the terms and conditions
10. Review of hedging
11. Review of off-system sales
12. Review of audit reports on fuel and purchased-power procurement.

Q. Describe the work you performed in conducting this audit.

A. Liberty and the Commission's Staff began the audit by issuing a first set of data requests on February 3, 2006. Data requests eventually totaled more than 225. Liberty and Staff also conducted an extensive set of in-person interviews during the week of March 27, 2006. The audit team conducted on-site work observations and inspections at the West Phoenix and Redhawk gas-fired plants, and at the Cholla and the Four Corners coal-handling areas, to address operations issues. The team also directly observed work processes and conducted interviews at the coal lab at Four Corners, and at the combined utility and non-utility trading floor where dispatch, power sales and purchases, gas transportation management, and hedging transactions take place. This inspection included

the front office (where planning, simulation, and actual trading take place) and the middle and back offices (where accounting and controls related to energy transacting take place). Liberty and Staff followed these in-person sessions with many telephone interviews during the course of the audit, which produced a draft report early in May 2006.

Q. Please discuss APS's cooperation with the audit.

A. APS made timely and generally full responses to all requests, save one. The resources it assigned to the audit showed dedication to making people and data available, and to providing explanations and supplemental information when Liberty and Staff needed them. The exception was that APS declined to make members of the board of directors available for interviews. Liberty explained that such interviews were material in addressing the scope of the audit as defined by the RFP under which we conducted it. APS continued to object to making directors available. In Liberty's many examinations of director oversight of public utility management and operations, we have always gained such access previously.

Q. Please describe the consequences of failing to make that access available.

A. Liberty was ultimately able to gain sufficient information to conclude that there was no failure of information flow to the board. APS offered access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and on how they exercise that role. Liberty was able to conclude that the directors received sufficient regular reporting on fuel and energy matters. It would have been much better to discuss with the directors in person what information they consider important and how

they use it to oversee this important area of operations. In Liberty's prior engagements, speaking directly with directors formed an important process in concluding how well they serve in meeting public service responsibilities.

We have no reason to believe that there is a gap in senior oversight of fuel and energy matters. We did lose, however, an opportunity to firm up that conclusion with a typical and usual audit step. Given the lack of any observed problems of major consequence in APS fuel and energy procurement and management, there is not a substantial reason for concern about costs. However, board performance can sometimes form an important element of a public service commission's examination of utility management and operations. Liberty believes that, independently from its bearing on APS base or PSA rates, there should be a clear recognition by APS that the Commission's interests may warrant direct communication with directors. We understand the environment that now exists with respect to director statutory responsibilities and the exposures to suit that they face. Risks like these do call for discretion, but should not lead to a situation where directors become unwilling, when appropriate, to respond directly to questions directly posed by a utility regulatory body.

Q. Briefly summarize the APS generation portfolio that you considered in your audit.

A. APS is responsible for managing 10,400 MW of capacity at a number of generating stations, including Palo Verde. APS owns much generation jointly with others; APS therefore has responsibility for operating more capacity than it owns. Its ownership

during the audit totaled 6,415MW, which consists of the components listed in the following table.

Source	Megawatts	Percent
Natural Gas	3,411	53.2
Coal	1,835	28.6
Nuclear	1,164	18.1
Solar	5	0.1
Totals	6,415	100

The natural-gas fired units include:

- Ocotillo: two steam and two combustion-turbine units, totaling 340MW; owned and operated by APS, located in Tempe, Arizona;
- Redhawk: 1,060 MW; combined cycle units; owned and operated by APS since operation began in 2002; located west of Phoenix;
- Saguaro: two steam units and three combustion-turbine units totaling 395MW; owned and operated by APS; located north of Tucson, Arizona;
- Sundance: one simple-cycle gas-fired unit and 10 quick-start combustion turbines totaling 450MW; owned and operated by APS, which purchased the station in the spring of 2005; located in Coolidge, Arizona;
- West Phoenix: two combustion-turbine units and five combined-cycle units totaling 1,000MW; owned and operated by APS, located in southwest Phoenix;
- Yucca: four combustion-turbine units totaling 150MW; owned and operated by APS; located near Yuma, Arizona.

The coal-fired units include:

- Four Corners: 2,040MW total capability; 782MW share owned by APS, operated by APS; located in New Mexico; uses low-sulfur coal from the nearby Navajo mine;
- Cholla: 995MW total capability, 615MW owned by APS, operated by APS; located in Arizona; uses coal from the McKinley Mine in New Mexico;
- Navajo: 2,250MW, 14 percent share owned by APS; operated by Salt River Project; located in Arizona; uses coal from a Navajo and Hopi Indian Reservations mine at Black Mesa, Arizona.

The APS share of Palo Verde capacity comprises the nuclear element of its generation portfolio.

Q. What conclusions and recommendations do you reach as a result of audit work?

A. I summarize them below.

Organization and Staffing

Fuel and power procurement work groups have the necessary skills and experience, operate under adequate job descriptions, communicate effectively, have access to appropriate training, use generally adequate procedures and decision processes, document decisions sufficiently, operate under established procurement approval limits, and undergo regular internal auditing. There is a need, however, for improvements in procedures for fuel contract management and administration, and in procedures for accepting gas-supply offers.

Coal Management

With respect to coal, APS has effectively managed inventory levels and variance analysis, administered coal contracts, measured supplier performance, carried out sampling processes, automated its coal-sampling data systems, and made economical use of combustion by-products. However, APS still uses some inefficient manual processes for handling coal-weight information. In addition, it has reduced the Cholla inventory target, but has since been carrying amounts in excess of that lower mark. The APS practice is actually more appropriate than its target; therefore, the Company should change the target to reflect that practice.

Natural Gas Management

The historical APS approach to gas-supply management has been typical and effective. It now, however, faces substantially increased prices for pipeline transportation. Gas transportation for electricity generation is a matter of significant current debate, as providers seek to make large increases for customers whose volumes can swing substantially. APS does not currently have substantial options to address changes in its full-requirements arrangement for service from the El Paso Natural Gas pipeline.

APS should examine through a comprehensive, structured analysis its alternatives for reducing future pipeline-transportation costs. Examples of the alternatives include altering generating station facilities to reduce flow variations, participation in high-deliverability storage projects, and identification of other users who may have

complementary (and therefore mutually cost-reducing) usage patterns. APS should report the results of this analysis to the Commission within one year.

Fuel Contracts

APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective. APS applied an appropriate process in its recent solicitation of new long-term coal supplies for the Cholla Station. APS's two short-term coal supply agreements for the Cholla Station are also appropriate. APS uses a sound process to contract for gas commodity. APS's contracting process for fuel oils is appropriate.

Purchased Power

APS bases its marketing and trading activities on sound hedging policies and procedures, and conducts electricity sales and purchases consistently with least-cost dispatch guidelines. APS has produced economic transactions, and it trades with a diverse population of counterparties. The trading patterns observed during audit work showed no indication of favoritism to any counterparty, whether affiliated or not, with the exception of the since corrected and discontinued transmission optimization transactions of PWCC. This testimony addresses that exception later. APS is using appropriate tools and documentation to conduct electric power trading to achieve least-cost total dispatch.

APS's economic dispatch procedures and operations appear to have operated smoothly since the April 2005 integration of the former merchant generating assets. APS has been

meeting its requirements with appropriate short-term purchases, and the May 2005 RFP adds a long-term contract component.

APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale. The APS internal documentation separating the activities of regulated versus unregulated electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between these two business segments. Electric power purchase and sale data related to both regulated and unregulated APS activities is not delineated in some publicly available documents, specifically the FERC Form 1.

The principal negative finding in this area of fuel and energy management is that APS does not separate its utility and non-utility activities sufficiently. They operate in the same markets and with common counterparties, but they do so without physical separation. These factors create too great a risk of opportunity sharing between utility and non-utility traders, who are separate individuals. Locating the APS and non-utility trader next to each other on the trading floor fails to assure clear separation of their trading activities.

Verification that no such sharing has harmed utility customers is extremely difficult. APS should physically separate its utility and non-utility traders, unless it can demonstrate that non-utility trading, which has been at very large levels, will very soon diminish

substantially. APS also needs to complete promptly its efforts to assure that there is no non-utility co-opting of utility resources or opportunities.

Another concern was that PWCC, which conducts non-utility operations, made a number of transactions during 2005 to optimize a transmission corridor between delivery points at Borah Brady in Idaho and Four Corners. That corridor, however, represents a utility asset associated with an exchange agreement between APS and PacifiCorp. The two systems peak in different seasons; the difference allows PacifiCorp to make power available to APS in warmer months and APS to make power available to PacifiCorp in colder months. PWCC's non-utility use of this transmission capability generated positive margins of about $4.3 million from November 2005 through March 2006, and smaller margins in earlier months. APS discovered the non-utility use of the asset after non-utility operations made arrangements to use it and to retain the margins it produced. After this discovery in late 2005, APS was credited with the margins produced before November 2005. For transactions committed to earlier, but transpiring between November 2005 and March 2006, APS received credit before the fact for the $4.2 million in margins noted above.

This non-utility use of a utility asset was not appropriate and should not have occurred. APS did, however, discover the matter itself and make corrections. Moreover, the Company is now in the process of implementing internal procedures that will prevent a recurrence of this or similar use of utility resources or opportunities by affiliates. The occurrence of this situation shows the difficulties inherent in juxtaposing utility and non-

utility trading activities. It also underscores the need for robust internal monitoring and periodic commission review. We cannot address the sufficiency of the corrective measures now because they remain under implementation or in discussion with the Commission.

Off-System Sales

The audit found that the comparatively small margins that APS has recently produced for off-system sales result from the relatively "short" position it has in low-cost generation (*e.g.*, coal, nuclear, and hydro). The market price for bulk power in the Desert Southwest region is generally set by combined-cycle, gas-fired generation. Surplus operating capacity having low operating costs is the key to generating large positive margins on off-system sales. Some of APS' neighboring utilities, such as SRP, TEP and PNM, have this advantage. APS does not have excess coal and nuclear generation available for substantial portions of the year because its system load has grown past the company's coal and nuclear resources. APS therefore sells from (*i.e.*, at the cost of) plants with economic characteristics similar to those whose output sets the market-clearing price. Therefore, its sales opportunities and its margins from those opportunities are constrained.

Hedging

APS has designed and it operates a sound hedging program. The amounts of natural gas and purchased power that it hedges fall at the high end of the range of experience. The program has been successful in meeting its primary objective, which is to promote price

stability. It protects substantially against price increases, but will not operate to allow costs to fall when the market does. This lack of downward flexibility is not necessarily a problem; there exists a range of perspectives on the question. For example, the available market options that would allow APS to reduce costs if market prices fall either involve speculation or transaction costs that make their benefits dubious. There should, however, be a dialogue with stakeholders and with the Commission to make clear what goals the program should have and the extent to which it should produce hedged prices. This dialogue may not lead to a change in goals or hedge levels, but it will promote a common understanding of program operation and verify that it is meeting the needs and expectations of all customers.

Forecasting and Modeling

APS uses sufficiently accurate modeling to predict fuel and purchased-power volume and cost. APS has taken appropriate actions to ensure that it achieves least-cost total dispatch. APS uses outside reviews appropriately to improve management and operations. APS maintains adequate documentation to support regulatory oversight and review.

Plant Operations

The performance metrics of the base-loaded coal units demonstrate effective operation. The same is true for the gas units, but they have been adversely affected by the introduction of those units into the APS dispatch order in April 2005. APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing

with Redhawk #1 and #2 and West Phoenix #5 issues and the need for re-engineering them for intermediate dispatch operation. Capital and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements. APS times and layers its unit outage schedules effectively, and conducts scheduled outages within reasonable durations.

The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation. APS, however, should focus on optimizing the performance of the units as they complete the transition from early and merchant operation. APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement. The Company should improve its economic evaluations related to minimization of outage time.

Boiler leaks account for a conspicuously high percentage of net replacement power costs associated with some units. APS needs to evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3. In addition, there is a high level of operator and maintenance error at Four Corners Unit #3 and Navajo Unit #3. The Company should conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly identified and addressed. Also, the Company should determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. Moreover, because improving West Phoenix Unit #5 availability is important to the dispatch and keeping net

replacement power costs at minimum levels, APS should implement at this facility its policy requiring root-cause analysis when generation is lost.

The use of a 50/50 load forecast, coupled with fast growth and system constraints in the Phoenix Load Pocket, makes achievement of targeted reserves less certain. APS should analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket.

Financial Audit of PSA Costs

The APS accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate. Detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

There are a number of moderate improvements warranted, however. First, APS has yet to audit the PSA filing preparation. The PSA's newness and importance indicate that it become part of the next audit plan and APS's auditors should continue to address it thereafter periodically. Our audit found that APS documents its filing information well, but should adopt a formal written procedure addressing preparation of the monthly PSA filings. The audit did disclose one minor error. APS should correct an error that results in

a misclassification of costs among its three major types of generation. Total costs, however, are correct; the error involves apportioning those costs among generation types.

The audit's detailed review of the non-confidential PSA Over/Under values found them to be accurate, but APS should more transparently support them. The audit also disclosed that APS has not used consistent accounting methods for purposes of recording refunds associated with supplemental fuel charges. The audit did not find this inconsistency to have had a material impact on the PSA. APS should nevertheless more closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes.

Q. How would you assess the significance of these findings and conclusions?

A. We did not reach any conclusions that would indicate imprudently incurred fuel and purchased power costs for 2005. There was in 2005 an inappropriate use by non-utility operations of a utility transmission asset. APS has already corrected for that situation, however. Most of the changes recommended as a result of the audit seek to move APS in the direction of using best practices in terms of procedures and analytical methods. I would describe these changes as incremental improvements to overall management that is already effective in the areas we examined.

Some of the recommendations, however, may have significant future cost impact. One example is dealing effectively with the consideration of boiler replacements, operator

issues, and the remaining transitional issues associated with bringing a number of relatively new units into a utility (versus merchant-generator) environment. Another is the need to look closely at dealing with the large rate increases that the El Paso pipeline has been seeking at the FERC. Third is eliminating the common location of utility and non-utility trading personnel and activities, unless the remaining life of APS non-utility trading at high levels is definitively to be of very short duration. Finally, although we did not base the recommendations regarding the administration of the PSA on any finding that there is more than a very nominal mis-classification of costs, it is important that APS place strong emphasis on getting its accounting, auditing, and documentary support needs met as soon as possible.

Q. Did your audit find any basis for an adjustment in 2005 fuel and energy costs?

A. No. The standards we applied to such adjustments are imprudence, good utility practice, and reporting accuracy. The audit found no imprudence and no material variance from good utility practice (given the correction of the PWCC transmission optimization transactions). The inaccuracies found did not have a measurable impact on the fuel and energy revenues or costs material to PSA operation.

Q. Is there any other basis for an adjustment to 2005 fuel and energy costs?

A. A recommendation of the recent GDS report examining 2005 Palo Verde outages was that the Commission disallow amounts GDS found to have resulted from what it determined to be avoidable and imprudent outages. The audit did not address that subject.

Q. That report also recommended that the impact of those outages be considered in these base rate proceedings; have you done so?

A. We have not studied or formed an independent opinion on the reasonableness or prudence of the 2005 outages. We did however examine the Palo Verde performance that witness Ewen assumed in normalizing 2006 fuel and energy expenditures. His normalization did not rely upon actual 2005 performance of any generating unit, including Palo Verde. Instead it made adjustments intended to reflect normal operations with respect to characteristics such as outages. Therefore, it is not necessary to make any further adjustment to the Ewen normalization in order to remove the effects of below standard performance of Palo Verde or any other generating units during 2005.

Q. Did you examine 2006 fuel and energy costs?

A. We did not conduct detailed, transaction-based analysis of fuel and energy agreements and transactions. We also did not perform a detailed review of PSA filings, calculations, and support. Those types of analyses and reviews did serve, however, as material contributors to audit conclusions and recommendations focused primarily on 2005 activities and operations. The audit work, however, did support a conclusion that the organizations, systems, approaches, major contracts, strategies, activities, and priorities related to fuel and energy procurement and management continued into 2006.

In addition, we did determine that APS has accounted properly for the 2006 revenues and costs associated with the inappropriate non-utility use of an APS transmission asset discussed above.

Q. Can you reach any conclusions about APS performance in managing fuel and energy costs for 2006?

A. We believe that qualitatively it has continued to be effective through roughly the end of the first quarter, which is when audit field work ended. Moreover, most of the contracts, agreements, and hedging activities that we examined have continued in place for 2006. We have seen nothing that would suggest that 2006 conditions have deteriorated, or that performance has weakened. We consider 2006 conditions (with the specific exceptions discussed below regarding base rate adjustments) to be representative. We caution only that we do not represent our information and beliefs about 2006 conditions as constituting the kind of accounting or prudence review that we consider important for effective PSA administration, again as outlined below in this testimony. In any case, such a review in the middle of any target year (in this case, 2006) would be premature.

Q. Are you familiar with the questions raised by Mundell Amendment #1 in the recent proceedings addressing emergency relief for APS?

A. Yes; we conducted a review of them in the context of our audit and rate-case work.

Q. Please describe your efforts in connection with those questions?

A. We examined the transactions and parties with whom APS and non-utility operations made purchases and sales. We looked at transactions with common counterparties for any patterns that might suggest a failure of the utility traders to pursue utility opportunities. We looked at publicly available information dealing with off-system sales by other energy providers in the region.

These efforts supplemented the audit efforts that had already begun, which included assessing the organization, personnel, separation, modeling, dispatching, and trading floor operations involved in utility and non-utility off-system sales.

Q. What conclusions did you reach with respect to those questions?

A. We concluded that APS has acted to maximize off-system sales opportunities from the utility perspective. Our examination of transactions with common counterparties did not give any reason, with one exception (the PWCC transmission optimization transactions), to suspect that non-utility operations "co-opted" any utility opportunities, recognizing that such problems are difficult to detect in the absence of a very detailed, focused examination. We also found that the off-system sales and margins of APS were consistent with market prices and with the resources that APS had available for such use, after considering the relationship between its assets and its native usage.

We also found that other regional providers, in particular, appear to have a material advantage that APS does not. That advantage is the ability to provide, on more frequent occasions, low-cost base-load capacity for off-system sales at times when more expensive natural gas is setting the market price for such sales. The gap between provider costs and market-clearing prices provides for large margins on sales made at those times. APS by contrast frequently has only gas-fired generation available to make off-system sales. Thus, even if its units are competitive in costs to operate, its use of gas to sell in competition with others using gas reduces its margins substantially.

We caution that competitive sensitivities in the industry today place strong constraints on the data that is publicly available. Those constraints make only general analyses practicable to perform. At that level, it is clear that APS has, compared to others whose data we examined, much less ability to make its low-cost generation available at times when market prices are the most attractive from a seller's perspective.

4. Fuel and Energy Component of Base Rates

Q. Have you examined the base rate filing of APS in this proceeding?

A. Yes; on behalf of Staff we examined the fuel and energy aspects of the filing. In particular we focused on the testimony of APS witness Ewen, who used normalized, projected 2006 data to form the basis of the fuel and energy components of the APS request for an increase in base rates. We also examined the testimony of APS witness Richardson, who proposed a continuation of the PSA, but with changes.

Q. What did you conclude with respect to the normalized 2006 fuel and energy expenses discussed in the Ewen testimony?

A. We concluded that calendar-year 2006 serves appropriately as the period from which to establish the fuel and energy portion of base rates that APS would charge on a going-forward basis. We believe that normalizing 2006 data for plant operating characteristics (*e.g.*, outages, heat rates, capacity) is appropriate. We also believe that normalizing that data for factors such as customer growth, weather, and demand-side management is appropriate, particularly given the predominance of natural gas and purchased power as

the incremental energy sources that will serve as the primary sources for accommodating increased usage by APS retail customers.

We also believe that the Commission should rely on actual, recent data for market prices for fuel and energy, because they are so volatile. The November 2005 prices relied upon in the Ewen testimony to forecast 2006 fuel and energy costs have turned out not to bear a sufficiently close relationship to what APS has actually paid for them so far this year. Those late-2005 prices also do not comprise a good proxy for what APS is likely to pay for the remainder of 2006, based on end-of-June prices in the forward markets. We believe it appropriate in setting base rates to use: (a) actual costs for fuel and purchased power (and hedge prices and values) for the first half of 2006 and (b) current forward prices for these items for the remainder of 2006 rates.

We also believe that there should not be adjustments to base rate fuel and energy components for changes that will take place in contracts for fuel, transportation, capacity, or energy after 2006 ends. Moreover, changes that took place during 2006 should not be treated as though they began at other times. The actual costs under those contracts or agreements for the first half of 2006 and their currently estimated costs for the remainder of 2006 should form the basis of normalized 2006 costs. Like fluctuating market prices, they reflect the kinds of factors that we believe adjustment mechanisms appropriately address.

We also observed that APS erroneously included non-utility wholesale sales activity in its filing. The revenues and expenses associated with those activities (which lost money and therefore added to the net costs that APS assigned to retail customers) require exclusion from APS calculations of the rates at issue in this proceeding.

Finally, we do not agree with the APS proposal in this case to retain 10 percent of the margins (positive or negative) produced by its hedging program. As this testimony will address later, that program operates on a largely (and appropriately so) non-discretionary basis.

Q. Summarize the changes that you have asked APS to make to its normalization of 2006 fuel and energy expenses to bring the results closer to actual 2006 fuel and energy market prices.

A. They consist of the following:

1. Use the loads as APS has normalized them for customer growth, weather, auxiliary power, and demand-side management.
2. Continue to use the APS-normalized plant operating assumptions for forced outages, plant capacities, and maintenance.
3. Use actual natural gas and power prices through June.
4. Use forward natural gas prices as of June 30 to estimate costs for the second half of 2006.
5. Use actual realized hedge values through June.
6. Use forward prices as of June 30 to estimate values for the second half of 2006.

7. Use actual nuclear and coal fuel costs through June, 2006.
8. Use the APS 2006 long-range forecast projections of nuclear and coal fuel costs for the second half of 2006.
9. Do not change for purposes of the recalculation the APS-proposed 10 percent value sharing, which has been included in their original calculation.

Q. Earlier you testified that there were 2006 transactions involving non-utility use of an APS transmission asset; how were they treated in the Ewen testimony's normalization of 2006 costs?

A. They had no effect. After APS discovered the non-utility use of the asset, it secured corrections to pre-November 2005 accounting for margins and it made from the outset a correct assignment of margins for 2006. The 2006 margins for use of the asset were $3,702,501. APS believes that it is not appropriate to include these margins in its normalization because the utility no longer enters those transactions, and does not permit non-utility entry of such transactions because they involve a utility asset. APS does not permit utility entry of such transactions because they impose market risk, which subjects the utility to earning negative margins.

Q. Do you agree with that treatment?

A. We agree that the transactions do involve market risk and we agree that utilities should not take material market risk in making off-system sales. Therefore, we do not disagree with the forward-looking assumption that APS will not directly make such transactions and earn margins from them. However, we would continue to include the actual 2006

margins of some $3.7 million in normalized 2006 fuel and energy costs, while excluding them from 2007 projections of fuel and energy costs. We did not include a request to include these margins in the revised 2006 normalization that we asked APS to perform. We did not learn about the transmission optimization transactions until after we had made our request of APS. Therefore, we treat those margins distinctly, as this testimony will discuss later.

That said, however, a more difficult question is whether APS can in the future capture some portion of the margin without taking market risk. APS should aggressively explore arrangements allowing for use of the asset by PWCC or by a third party under a margin sharing approach. A fixed payment per year or a percentage of gross revenues might be options. APS has not yet examined whether such an arrangement would be economically attractive to a marketer or whether the Company can structure it consistently with FERC requirements and limitations. Should APS have success, it is not likely, however, to produce more than a marginal reduction in the costs recoverable through the PSA.

Q. You did not ask that APS recalculate normalized 2006 fuel and energy costs without the Company's proposed 10 percent sharing involving hedging activities; explain why.

A. We do not agree with the APS proposal. Our goal, however, with respect to the recalculation was to measure the net change in revenue requirements on as common a basis as possible with the Ewen testimony, which included the effects of the Company's proposed sharing. Maintaining the effects of the sharing facilitated a direct comparison

between the Company's approach and ours with respect to the normalization of key operations and market factors. With that direct comparison in hand, it is a fairly straightforward process to size the effects of the proposed sharing and to provide for their elimination, should the Commission determine it appropriate to do so.

Q. What changes did you ask APS to make to amend the Ewen testimony's 2006 normalization by eliminating contract changes?

A. We asked that the recalculation include, in addition to the market price factors listed above, the following changes:

1. Use actual Cholla coal transport rates for the first half of 2006.
2. Use the current projection of rates per ton on to calculate Cholla transport costs for the second half of the year.
3. Use an SRP T&C contract maximum capacity of 364MW through May and 372MW for June through December, use actual costs thereunder for the first half of 2006, and APS's best estimate for the remainder of the year.
4. Use Sundance capacity at 8 units (352MW) to reflect the 75MW agreement for sales to TEP through December 2006.
5. Include revenue from this TEP agreement in off-system revenue.
6. Use actual natural gas transport costs through June.
7. Use the best estimate of natural gas transport costs for the remainder of the year at current tariff rates, in order to account for the FERC rate case involving APS's pipeline transporter.

8. Recalculate capacity options needed to cover peak loads based on revised resources available (preceding SRP T&C and Sundance changes), and price them at June 30 market prices.

Q. What position did APS take with respect to your requested recalculation?

A. APS agreed to make the recalculation (without any concession as to its merits) and to provide the results by the end of July 2006.

Q. What did that recalculation show?

A. That recalculation showed net retail fuel cost of $824.4 million, for an average fuel cost of 2.8104¢/kwh. This amount represents a reduction of $111.6 million from the same measure as presented in Ewen testimony Workpaper PME_WP1. Adding the $3,702,501 in 2006 margins for transactions involving the transmission asset would further reduce the average fuel cost by 0.0138¢/kwh, to 2.7966¢/kwh.

Q. By how much would those numbers change with the elimination of the APS-proposed sharing mechanism?

A. The net retail fuel cost would increase nominally to $824.6 million and the average fuel cost would increase nominally to 2.8111¢/kwh. That cost would change to 2.7975¢/kwh after adjusting further for the 2006 margins on transactions involving PWCC's use of the APS transmission capability.

Q. What do you conclude about the fuel and energy portion of the APS claim for increased base rates in this proceeding?

A. It should be adjusted downward by $111.6 million (including the APS sharing proposal) or $111.4 million (excluding the APS sharing proposal) to reflect what we believe is a better approach to normalizing fuel and energy expenses in the context of an accompanying PSA. We also believe that it should be reduced by a further $3,702,501 to reflect 2006 margins for transactions involving the transmission asset. We believe that it should also be reduced further, as Mr. Dittmer's testimony discusses, to account for the removal of non fuel and energy costs associated with non-utility energy marketing and trading activity.

5. PSA Changes

Q. Did you ask that APS conduct any other calculations of fuel and energy expenses?

A. Yes. We asked that APS provide an estimate of 2007 expenses under similar assumptions.

Q. What was your purpose for this request?

A. We had two reasons. First, we do not consider 2007 circumstances irrelevant; we simply did not want them included in the 2006 normalization. We asked for the 2007 estimate to assess the impact of the 2007 changes that APS had included in its 2006 normalization. Second, we recommend the use of a forecasted year for setting the PSA rate in the future. We view calendar 2007 as an appropriate forecast period, given the timing of these

proceedings and the view that an annual PSA resetting is generally a sound approach. The 2007 estimate we requested shows the expected difference from 2006 costs (normalized as we would propose). That difference allows for a current estimate of the amount that the PSA would have to capture in current costs, should it change to operate on a prospective basis.

Q. Summarize the estimate that you have asked APS to prepare for its expected 2007 fuel and energy expenses.

A. It proceeds generally from the 2006 normalization that APS prepared, and includes the following specific items:

1. Normalize 2007 loads, for customer growth, weather, and DSM; reduce them for distributed generation resulting from new RES.
2. Base 2007 natural gas and power prices on forward prices as of June 30, 2006.
3. Calculate 2007 hedge values on the basis of June 30, 2006 forward prices, with 10 percent of the value excluded.
4. Price nuclear and coal fuel cost at APS 2006 long-range forecast projections for 2007.
5. Use the Cholla coal transport rate per ton expected to be in effect under the tariff for 2007.
6. Use an SRP T&C contract maximum capacity of 372MW through May; reduce it to 230MW in June.
7. Use a Sundance capacity of 440 MW to reflect all 10 units.
8. Use natural gas transport cost based on tariff rates currently in place for 2007.

9. Include renewable energy resource contracts currently in place (10MW geothermal, 6MW biomass, 77MW wind) at the market price.
10. Reflect that purchased-power contracts from the reliability RFP start in the summer of 2007.
11. Include capacity contracted for under the Reliability RFP of 400MW Gila River Combined Cycle gas plant toll (May through December) and 650MW call options (June through September) as of their effective dates.
12. Use the plant forced outage rates, plant capacities, and maintenance as normalized by APS for 2006.
13. Calculate capacity options needed to cover peak loads on the basis of resources available; price them at June 30, 2006 forward-market prices.

Q. What position did APS take with respect to your requested 2007 estimate?

A. APS agreed to make it (again without any concession as to its merits) and to provide the results by the end of July 2006.

Q. What did that estimate show?

A. That estimate produced a net retail fuel cost of $981.7 million, an increase of $45.8 million over the Ewen testimony workpapers' normalized 2006 fuel and energy costs. The 2007 estimate was also $157.4 million more than the 2006 estimate prepared to our specifications. The 2007 estimate produced an estimated average fuel cost of 3.2296 ¢/kwh.

Q. By how much would those numbers change with the elimination of the APS-proposed sharing mechanism?

A. The net retail fuel cost would drop to $975.0 million and the average cost would drop to 3.2074 ¢/kwh.

Q. What are the principal challenges in adopting an effective adjustment mechanism?

A. The specific challenges faced when implementing an adjustment mechanism with a sliding scale of rates whose intent is to minimize volatility include the following:

- Preserving opportunity for examining forward costs
- Maintaining incentives for good performance
- Reconciling actual costs to estimates
- Recognizing the time value of money
- Promoting rate continuity
- Balancing risks and rewards
- Maintaining APS financial benchmarks that promote the ability to secure financing at costs favorable for customers.

The PSA's brief history at APS also shows that the Commission considers it important to assure that the other factors that affect earnings, particularly customer growth, do not offset changes in fuel and energy costs. Ordinarily, those other factors are not as volatile as fuel and energy costs have been recently. However, with the extraordinarily strong growth that APS is experiencing, care needs to be taken to assure that full, current fuel

and energy-cost recovery does not produce returns in excess of those allowed because profitability is growing through other revenue and cost changes that affect base rates.

Q. What is the first principal feature of the design of a sound adjustment mechanism?

A. We believe that there should be Commission review of proposed charges before they become applicable. In one sense, the current PSA already does that, by basing PSA recovery on historical costs and by closely limiting changes in the PSA charge. That method can be effective, but in particularly volatile fuel markets can cause large deferrals of uncollected costs or recoveries far in excess of actual costs. The more volatile the market, the more difficult it becomes to match revenues and expenses on a fairly current basis when an historical period forms the basis of the charge.

Another approach would call for the filing, review, and approval of forecasts (*e.g.*, quarterly filings with annual approval) of costs and units of sale. Such forecasts would undergo inquiry by the Commission and other stakeholders. These forecasts, after review and approval, would determine whether a prospective adjustment to the PSA rate should be permitted.

Q. As compared with an historical-cost approach, what effect would the forecast approach have on the offsetting-costs criterion you just cited?

A. The historical approach, the 90 percent factor, and the collars on the current PSA make the current approach suitable for addressing the concern that APS will experience offsetting net revenue growth through increased usage. The forecasted approach would

not do so as it is generally used, but two specific changes would make it more effective in doing so.

First, the Commission can retain the flexibility to use the results of the fuel and energy revenue and expense forecasts to set whatever PSA rate it deems to be appropriate. It would not be bound to set the rate at a level that would produce an expected current balance for the year of zero. The Commission could combine the PSA-related forecast filings with some form of abbreviated financial review. This approach would provide assurances that changes in the PSA component are sufficient to maintain utility financial strength on the one hand, while not so large as to create a material over-earnings situation, on the other hand.

Second, the Commission could do as many other commissions have done. Specifically it need not set only the ensuing 12-months for the recovery of any deferred balances or of any expected, very-large changes in projected costs. It can change the recovery-period start times or lengths. This approach can be applied alone, or in combination with the financial review approach. This "amortization" approach is common in providing a rate path that provides for adequate recovery but along a more stable rate path.

The amortization technique, while effective in promoting rate stability, can become troublesome where third parties compete for utility customers. The reason is that changes in recovery periods can cause utility rates to be far under market rates, which will make it hard for marketers to compete. Alternatively, where a rate stabilization approach places

rates far above market, marketers get a price cushion that makes them look attractive even if they do not, by efficiency or other internal competence, have any edge that a fully and equally competitive marketplace would reward.

Q. What is the next principal feature of an effective PSA mechanism?

A. There should be clear provision for reconciliation of revenues and costs. These reconciliations should be provided for not less frequently than the period across which the adjustment applies (*e.g.*, quarterly or annually). They can be made more frequent, to the extent that variances exceed some predetermined level. APS should be subjected to clear filing requirements, addressing content and schedule, and identifying the information necessary to allow this reconciliation. There should also be a clearly scheduled opportunity to inquire into those filings, and for the Commission to consider and, if necessary, order any adjustments to any proposed APS reconciliation.

Q. What is the next principal feature of an effective PSA mechanism?

A. There should be an opportunity for an independent Commission review of prudence and reasonableness in all areas that drive the costs collected under the mechanism. These reviews should occur every two years or so, and they should be used to make justified, retroactive adjustments, even to reconciled costs/revenues, back to the end date of the last such independent review. The content of these reviews and the issues that they address should also be subject to examination and comment by the affected stakeholders, following which the Commission should make a determination of what, if any, costs

resulted from ineffective or imprudent utility performance, and of what, if any, adjustments should be made to future recoveries and over what period of time.

Q. Won't the forecast review, reconciliation, and performance evaluation aspects you have just discussed impose additional requirements on the Commission's staff?

A. Yes. The three activities will take expertise and they will take significant review time. We think that those time commitments are worth the results they will produce, in assuring that APS secures timely recovery of volatile fuel and energy costs, and in assuring customers that performance has been effective and that price changes are fair and accurate. That said, however, it will likely take time for the Commission to marshal the resources it will take to conduct these reviews. A number of utility regulatory commissions perform these functions almost entirely in-house, but they have generally had several decades to develop the resources it takes to do so. Others make limited use of outside consultants; *e.g.*, in conducting the performance evaluations at one or two-year intervals. Those reviews are generally at the direction of the regulators (in terms of contractor selection and work supervision), but at the expense of the utility.

Q. Should the Commission set advance restrictions on changes in the size of the adjustment factor?

A. A collar and recovery limits such as those imposed currently have particular merit when there are not regular methods for assuring that prospective changes are appropriate and that there is prompt reconciliation and regular review of prudence. The three techniques that we have proposed, however, can provide those methods, and assure that the

Commission has regular insight into and oversight of the mechanism. Given the protections provided by these three mechanisms, it is appropriate to consider removal of the collar and recovery limits. Recent experience has shown energy prices to be volatile. There is not a sound basis for projecting a reduction in that volatility. As upward market movement has put APS into a significant under-recovery position, so may future downward movements cause customers at least temporarily to overpay.

The financial circumstances in which APS and its parent found themselves prior to the emergency rate relief granted by the Commission underscore the potential seriousness of imbalances due to market price movements. We should expect that the existence of a reliable mechanism assuring reasonably prompt recovery of prudent and reasonable fuel and energy costs will remain a primary consideration for those who examine and rely upon creditworthiness of utilities. We further believe that measures should be taken to preclude delayed recovery from having material financial consequences (*e.g.*, through increased financing costs or restraints on access to financial resources). We also believe that the potential for downward market movements should be recognized. In a volatile market, delay in rate adjustment may also keep customer money in the utility's hands.

We value the concern about creating over-earnings situation. We believe that this concern can be addressed by consideration of financial condition at the annual forecast filings and proceedings, and by adjusting PSA recovery if necessary to prevent a problem. In order not to bog those proceedings down too much, the Commission could entertain them every other year.

Q. Do you propose to set a 2007 PSA rate on the basis of the APS estimate of 2007 fuel and energy costs under the assumptions you gave the Company?

A. No; we offer it as a current overall measure of the likely amount by which 2007 recovery by APS will under-run actual estimated costs under the assumptions that: (a) the Commission decides to set base rates on the basis of 2006 costs "re-normalized" as we propose, and (b) establishes a PSA rate of zero for 2007. It is also important to emphasize that this measure does not address how the Commission may choose to deal with current deferred fuel and energy costs (*i.e.*, how balances have changed since the end of 2005) and any changes through the remainder of 2006.

We do not consider a June 30, 2006 measure to be close enough in time to serve as a firm basis for setting a 2007 PSA rate. There will also have to be other adjustments to reflect changes that will occur in cost-driving factors that occur mid-year in 2007. Its value now is primarily to show that it is reasonable, based on current assumptions, to expect that 2007 increases will substantially offset 2006 decreases that result from our re-normalization for 2006.

Q. What then do you propose?

A. Should the Commission decide to alter the current 90/10 sharing approach based on historical costs, we would propose the use of a late-2006 estimate that applies then-current market price assumptions and accounts for mid-2007 changes that are reasonably certain to occur.

Q. What is your position on the APS proposal to exclude 10 percent of gains or losses from hedging from the calculation of both base fuel cost and the PSA?

A. We consider it too broad to serve as an incentive, but recommend a narrower incentive.

Q. How does the APS hedging strategy work?

A. The Company's hedging strategy focuses on stability in fuel costs. It accomplishes that objective by "locking in" the prices that it will pay for fuels and purchased power well in advance of when those fuels will be used. Prices are locked in through a variety of devices: long-term contracts with stable pricing provisions in the case of coal and nuclear fuel, and forward-purchase contracts, futures contracts and certain derivative contracts in the case of natural gas and purchased power.

In the case of natural gas and purchased power, the strategy is implemented by setting target proportions of the Company's requirements for which the price would be set at defined points in the future. Under the current strategy, those proportions are as follows:

- First 12 months of energy (natural gas and purchased power): 85 percent
- First 12 months of natural gas basis differential (difference in value between the pricing point in Louisiana where the NYMEX futures contract for natural gas settles, and pricing points in New Mexico and West Texas where the Company buys most of its gas): 50 percent
- Second 12 months of energy: 50-60 percent
- Third 12 months of energy: 30-40 percent.

The Company's traders are required to fix prices for these proportions of the Company's requirements for these fuels, using the devices listed above. The 36-month period covered by the strategy rolls forward quarterly; *i.e.*, each quarter, the traders increase the proportion of requirements hedged, from 30-40 percent to 50-60 percent for the months that move from the third 12 months into the second, and from 50-60 percent to 85 percent for the months that move from the second 12 months into the first.

Q. Why should the Company not share in profits and losses produced by that strategy?

A. The APS hedging strategy and its resulting program begin from the premise that the Company cannot realistically expect to "beat the market" over long periods of time. Thus, the program effectively limits the Company's ability to influence program results by limiting trader discretion. When the program generates large apparent profits, those profits result from post-commitment movements in market prices, not by superior Company performance. In fact, because the Company believes that its traders cannot consistently beat the market, it designs its hedging program to limit trader ability to try to do so. We share the view that inducing market-beating performance should be avoided in the case of trading activities of this type.

Q. In what area do you favor a balanced risk/reward provision?

A. We favor such a provision in the hedging area that the Company refers to as "optimization". When the Company transacts in the marketplace to generate hedges, it buys some "instruments" covering natural gas and some covering electric power. Typically, these instruments are NYMEX futures contracts for natural gas, and forward-

purchase contracts at Palo Verde for electric power. Natural gas and purchased power substitute for each other in the Company's incremental purchases of fuel because the generating equipment that the Company would operate to supply a marginal customer is gas-fired. To supply an incremental kWh of electricity to a customer, the Company could buy some gas and operate a gas-fired generating facility, or instead buy some power. Good practice is to make this decision after considering the relative prices of gas versus power delivered to APS's system. APS determines how much gas and how much power to buy after examining the relative prices of those commodities in forward markets.

Those price relationships change. When they do, the Company's traders can sell gas and buy power (or vice versa), to "optimize" the Company's hedge position, as long as the overall position stays at (or above) the target hedge level.

APS updates its estimates of its requirements for gas and purchased power weekly. These updated estimates consider factors such as revised load forecasts (updated semi-annually) and revisions to future prices for gas and power, scheduled outages for APS generating units, and operating characteristics of APS's generating units. APS traders can use the updated estimates to re-optimize the mix between gas and power purchases.

Available evidence suggests that the re-optimization process can make a notable difference. When the Ewen testimony normalization (which used November 2005 market prices) was prepared, the optimal balance between gas and purchased power in the Company's hedges was 88 percent gas and 12 percent purchased power. See Workpaper

PME_WP4. Since that time, power prices appear to have declined relative to gas prices, given that the balance of energy purchases has moved from gas to purchased power. The Company's responses to data requests submitted by Liberty (LCG-2-4) report that purchased-power volumes and costs in the first three months of 2006 were much higher than forecast under November 2005 market prices. Similarly, even though more than 90 percent of the Company's fuel and purchased-power expense for 2006 was hedged at the beginning of 2006, the Company's current estimate of that expense is $95.2 million. That sum is about 10 percent lower than what appears in the Ewen workpapers. This difference is the result of comparing system total fuel and purchased-power expense (after adjustment of hedge values to 100 percent) of $942,040,000 in PME_WP1 to $846,810,000 at p. 1 of APS10630.

This optimization (or re-optimization) process is an area where truly discretionary energy trading activities can add value. Updating the forecasts might be required for other aspects of the Company's operations, but re-balancing the hedge position between gas and purchased power might not. As suggested by recent experience, the benefits to customers of re-balancing can be significant. We consider it appropriate to provide a moderate level of sharing as an inducement to make sure that it happens. Good utility practice would suggest that it happen even without sharing, but we consider it very difficult to assess after the fact and through audit techniques how well such re-optimization took place.

Q. Does this complete your testimony?

A. Yes it does.

EXHIBIT
admitted
S-29

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 57744.	DOCKET NO. E-01345A-05-0816

SUR-REBUTTAL TESTIMONY OF JOHN ANTONUK
President, The Liberty Consulting Group

Q. What is the purpose of your sur-rebuttal testimony?

A. I wish to respond to certain points made by APS rebuttal witnesses Wheeler, Ewen, Robinson, and Rumolo about 2006 and 2007 fuel and energy costs and about the design of the PSA.

Q. What is your response to the APS rebuttal testimony that addresses the findings, conclusions, and recommendations of the fuel audit?

A. That testimony reflects general agreement with what the audit found, with the principal exception being that APS witnesses state that a number of recommended changes concern programs or activities that they believe APS is already undertaking. Accordingly, there is not a significant difference of opinion about what APS and we believe ought to be done to optimize fuel and energy procurement and management.

I observed no significant matter of disagreement that would affect either the base rates to be established in this proceeding or the design or implementation of the PSA. Generally, the best way to address audit findings is for the Company to prepare an implementation plan for each recommendation with which it agrees and a detailed explanation of its reasons when it concludes that particular recommendations should not or need not be implemented. Following such documentation, the Staff can then identify the best method for monitoring progress against the plan and resolving any differences of opinion about recommendations in dispute. Particularly given the Company's rebuttal testimony, we recommend that the Commission, as a result of this proceeding, should require the Company to prepare an implementation plan as outlined above.

Q. Please summarize your sur-rebuttal testimony addressing fuel and energy costs and the PSA.

A. This testimony addresses the reasons why the proposed base rate and PSA treatment of fuel and energy costs recommended in my direct testimony remains appropriate and why the Commission should not adopt the variations on that approach that the rebuttal testimony of APS witnesses Wheeler, Ewen, and Robinson recommends. I also address why the revised estimate of costs for 2007 (from the APS witness's rebuttal testimony) is not appropriate for two reasons: (a) volatility in fuel and energy markets and (b) the potential for error in what comprises an insufficiently tested estimate.

I clarify that the 2007 fuel and energy cost estimate that APS proposes to use is theirs -- not Liberty's or Staff's. I also clarify that the change between the 2007 estimate cited in my direct testimony and the one cited in the rebuttal testimony of these APS witnesses resulted not from an omission by Liberty or Staff but from an omission by APS. This second, significant error, addressed in my direct testimony, exemplifies the need for Commission scrutiny before it relies on a future-year estimate to set rates. That second error was the inclusion of non-utility revenues and expenses in the normalized APS fuel and energy 2006 data that Mr. Ewen used in his direct testimony to support APS's rate request.

I explain that the use of forecasted 2007 fuel and energy costs should be limited to the establishment of a forward-looking PSA rate element, and that such a forecast should be based on data that uses actual and forecasted cost and revenue information current

through at least the end of the third quarter of 2006. I state further that this data must be subject to Commission scrutiny prior to its use to set any rate element. I show through actual 2006 natural gas price information how volatility makes prediction of 2007 prices very uncertain, thus rendering estimates made as of mid-2006 unreliable. Consequently, the APS rebuttal testimony observations about whose approach will better match actual 2007 revenues and costs are speculative. I also show that APS witnesses are not correct in asserting that the Commission can consider the Company's 2007 fuel and energy expenses as reasonably fixed or certain or conclude that actual 2007 expenses will significantly exceed those of the normalized 2006 data on which we based our proposed base rate level.

I set forth the central procedural elements of the PSA approach that we recommend. Those elements include a September 30, 2006 forecast of 2007 fuel and energy expenses and an opportunity to scrutinize that estimate before next year. We believe that such an estimate can be provided by APS, and scrutinized in the current proceeding. I also set forth an alternate method, should the Commission be unable to complete those procedures before early 2007 (or whatever date the Commission establishes for the next resetting of those PSA elements that reflect current period, as opposed to deferred, costs). I recommend in that event that the Commission use our proposed normalization of 2006 costs (as opposed either to APS's normalized 2006 costs or its just-introduced proposal to use estimated 2007 costs) to set rates for 2007. I address why this alternate proposal, when combined with our means of reconciling actual 2007 costs through the PSA, will produce a reasonable level of certainty that APS will recover its prudent and reasonable

fuel and energy costs in a sufficiently timely manner. The implementation plan included in Witness Rumolo's testimony is not appropriate for adoption because it incorporates a number of problems identified in this testimony. Staff is continuing its review of the plan of administration proposed by APS, and will file comments and any alternate proposals regarding that plan of administration within approximately two weeks.

Q. Is it correct to describe your testimony as setting forth an opinion about the level of expected 2007 fuel and energy costs?

A. No, it is not. My testimony reported an APS-prepared projection of 2007 costs based on expectations as of June 30, 2006. My testimony did not endorse that estimate for any direct use in this proceeding. My testimony anticipated a late-2006 estimate (clarified in discovery to be one including actual data and assumptions current at the end of the first nine months of 2006) for use in developing an estimate of 2007 costs. The volatility in fuel and energy markets makes reliance on a mid-2006 estimate as troubling as reliance on the normalized 2006 data that witness Ewen addressed in his direct testimony.

In addition, we did not, as our testimony made clear, perform the detailed analysis of APS's estimate of 2007 costs that we performed for normalized 2006 costs. Therefore, we would not endorse the accuracy of the APS 2007 estimate discussed in my direct testimony. We offered it only for illustrative purposes, and would not recommend it as a basis for setting either a base or PSA rate element.

Q. How would your proposal address 2007 costs?

A. We would propose the use of a 2007 estimate that considers conditions as of the end of the third quarter of 2006. We also believe that such an estimate must be subject to review and scrutiny before it is used to set a PSA rate going forward. We recommend that this review take place in the current proceeding. If there is not time for such a review, then we would propose to use the 2006 normalized fuel and energy cost data described in our testimony, and to reconcile actual collections against actual expenses during 2007 for eventual refund or collection.

Q. Discuss the ability of the Commission to receive and consider a late-2006 estimate of APS's 2007 fuel and energy costs.

A. My direct testimony envisioned "... the use of a late-2006 estimate that applies then-current market price assumptions and accounts for mid-2007 changes that are reasonably certain to occur." (p. 42) Based on our experience, I believe that a proper evaluation of estimated 2007 fuel costs could be completed by the end of this year, if APS files updated estimates promptly after the end of the 2006 third-quarter. We believe that there is time and opportunity to consider that estimate in these proceedings, provided that there is an opportunity for the parties to examine, question, and if necessary provide testimony responding to it.

Q. Will your proposal produce increasing deferrals?

A. That answer is unknown, which makes the APS prediction that it will do so speculative. It may in fact produce over-collections before the reconciliation aspects of the PSA occur. What will eventually happen depends in significant part on the direction of fuel

and energy markets for 2007. The volatility in those markets is what led us to propose what we consider to be a reasonably certain basis both for managing the level of under- or over-recovered balances, and for assuring the financial community that there is a reasonable level of certainty regarding eventual recovery or refund.

Q. How would the approach suggested in Mr. Wheeler's Rebuttal Testimony relate to improving accuracy in "getting the base fuel rate right to begin with"?

A. Given the volatility in the marketplace, using a mid-2006 estimate of 2007 costs is not as sound as using the end-of-third-quarter estimate that we recommended. I therefore do not agree that the APS approach would necessarily improve the degree of correspondence between base rates to be set in this proceeding and actual 2007 experience. Nor do I agree that there is a basis at present in the record for concluding that our approach will leave APS with the deferral amount that the Company rebuttal witnesses posit.

Q. What did your testimony propose with respect to the retention of the 10 percent sharing mechanism that exists now in the PSA?

A. We anticipated its elimination, on the assumption that the Commission would use an earnings examination to determine whether the recovery of 100 percent of fuel and energy costs on a current basis would cause returns to vary too significantly from those finally used to set base rates in this proceeding. We do not oppose the use of an over-earnings mitigation method; we merely considered an earnings review to be a more direct tool.

Q. Do you agree with Mr. Wheeler that 2007 costs are already essentially "fixed" and well above the 2006 normalized costs your direct testimony cited?

A. No, I do not. In response to a data request in this proceeding (Data Request No. LCG-2-1), the Company provided us with its estimate of its Rate Year (2006) fuel and purchased-power costs using the future prices they expected on February 28, 2006. That estimate was $86.5 million, or 9 percent, lower than the estimate presented as part of the Company's filed rate-increase request, which used November 30, 2005 data and expectations. Total system costs, including fuel and purchased-power costs for off-system sales as well as for native load, were lower by $127.2 million, or 11.7 percent. That significant drop in just a few months shows that market changes can operate to change significantly the Company's expected 2007 costs.

There have been further significant market changes since last February. On top of those, the last few days have witnessed what can be described as a "collapse" in the prices of natural gas. The fluid energy markets of 2006 well demonstrate that there may be substantial changes in 2007 costs from those that the Company proposes to use. Given what has happened to prices during 2006, and the collapse of the last few days, 2007 costs may be below or above the Company's estimate using June 30, 2006 data. The difference may be substantial. An estimate based on September 30, 2006 conditions and expectations is a preferable approach because, while still uncertain, it will be closer in time to the start date of revised PSA rates.

Q. What is your view of the fuel and energy-cost influencing factors cited on page 6 of Mr. Ewen's Rebuttal Testimony?

A. They represent the kinds of factors that make fuel and energy costs variable. That variability is what makes them most appropriately addressable through a PSA or similar mechanism. Year 2007 costs estimated on the basis of June 2006 conditions are not what I would call "known and measurable."

Mr. Ewen's observation about ignoring them is inapt. We simply propose to treat them differently, and, moreover, in a manner that is soundly based and more responsive to concerns about their volatility than would be the case under the APS approach. That APS approach is to use a significantly premature estimate of 2007 costs, whose outputs moreover are largely unexamined and untested, as the basis for setting rates for the future. We differ in that we consider only two approaches appropriate. First would be to use a 2007 estimate that is both near-in-time to the start of 2007 and subjected to scrutiny not yet applied to Mr. Ewen's estimate. Second would be to use an historical base (that proposed for base rates in our testimony) that has undergone appropriate scrutiny. Under that second approach, the PSA would reconcile the virtually inevitable differences between estimated and actual 2007 costs.

Q. Explain in more detail why you consider it important to scrutinize estimates of 2007 fuel and energy costs before using them to set rates.

A. The first reason is that future fuel and energy prices can change very significantly over a short period of time. The second reason is that estimates are complex to perform, and

subject to both judgment and potential error. The potential for error is evident from Mr. Ewen's testimony, which incorporates a major change from the 2007 estimate provided to us. That change was made because APS apparently omitted an important cost component from the estimate that it prepared at our request for use in our Direct Testimony. The Company's original presentation of its Test Year fuel and purchased-power costs contained another large error. That presentation mistakenly included $849 million of revenue and $856 million of cost pertaining to the Company's unregulated power-trading operations. Possible error is an important reason why we do not consider any of the estimates of 2007 costs on the record now sufficiently tested for use to set either base rates or the PSA.

I also note that APS did not use a 2007 estimate as the basis for its rate-case filing. Had it done so, the parties would have had a greater opportunity to focus on its structure, components, and underlying details. Neither did APS provide in its rebuttal testimony an estimate more current than the one it had prepared for us based on June 30, 2006 conditions and expectations. Had it done so, the record would already include an estimate at least close to the vintage we have recommended. There has been no material opportunity for discovery regarding testimony presented in rebuttal. That lack makes Mr. Ewen's rebuttal testimony revisions to the APS estimate using June 30, 2006 data, while interesting, not sufficiently substantiated to form a basis for rate-setting. We do not recommend the use of such an estimate to establish rates, either through base or PSA components. Our testimony makes clear that we did not recommend such use, but that we did recommend the use of a properly scrutinized and more current estimate.

Again, we do not propose to ignore 2007 cost estimates. Instead, we simply request that they be accompanied by adequate substantiation. If supported before their application, we do not object to their use to set PSA rate elements, whether they serve to increase or decrease the collections, which, in any event, will be subject to timely reconciliation. If not, then we recommend against their use, in favor of reliance on a PSA balancing mechanism. In either case, the ability of APS to demonstrate to the financial community that it will recover all prudently incurred fuel and energy costs on a sufficiently timely basis will not come into substantial doubt.

Q. How did your testimony treat the crediting of the $3.7 million in transmission optimization margins?

A. We understood that APS had already credited the margins through the PSA and we did not ask for any change in historical PSA treatment. We were not asking for any additional benefits to customers from past transactions. Instead, from a base-rate perspective, we included them to make sure that 2006 costs reflected all 2006 transactions. This approach is consistent with our treatment of all 2006 versus 2007 costs.

If similar transactions do not occur in 2007, then the PSA mechanism will operate to make APS whole. Similarly, if APS finds a way in 2007 to do for the benefit of utility operations what it was inappropriately doing for non-utility operations, then the Company will still be made whole. Our approach is even-handed, and it induces APS to seek to maximize opportunities for utility customers, much as it had been doing for shareowners

in the recent past. Either way, it is not correct to conclude that APS will be deprived of any recovery of fuel and energy expenses.

Q. What is your response to Mr. Ewen's Rebuttal Testimony on page 13 addressing your inadvertent exclusion of capacity payments from 2007 fuel and energy cost estimates?

A. As a preliminary matter, I found his statement far too cryptic a way to address an omission that was not ours, but APS's. More significantly, it underscores the peril in using a largely untested estimate for setting an important rate element. We offered the APS estimate, as our testimony made clear, only to help gauge the overall magnitude of the effect of our PSA proposal as far as it was observable at a point in time that was then current. We did not offer it, nor should the Commission take it, as our view of 2007 costs or as a sound basis for setting APS base or PSA rates.

Q. What should the Commission do if there is not, as Mr. Ewen testifies, time to incorporate your proposed approach in time for a new PSA rate to be effective at the beginning of 2007?

A. We believe that there is time to set a new PSA adjustor, provided that the Company files complete estimates soon (its next testimony filing in this proceeding presents such an opportunity), so that the parties can begin their examination. However, under no circumstances do we recommend that the Commission use an untested (as Mr. Ewen's is) estimate of 2007 expenses. If an examination of a 2007 estimate based on conditions and estimates as of the end of the third quarter of 2006 is not feasible, then the Commission

should adopt our proposed means for normalizing 2006 data as the basis for setting rates, and make reconciliations to actual 2007 experience after the fact.

If the variance from that amount, which can be reported monthly, grows substantially, a mid-year reconciliation in 2007 can address any urgent financial consequences, should any arise.

Q. Discuss the degree to which your reason for proposing the use of estimated 2007 costs was to "mitigate" a "tremendous run-up" in 2007 deferrals resulting from your "conscious understatement of base fuel costs."

A. We did not understate base fuel costs, consciously or otherwise. The Ewen direct testimony to which we responded did not propose to use forecasted 2007 costs. Mr. Robinson's Rebuttal Testimony nevertheless criticizes our efforts for not proposing to use a 2007 estimate. The Ewen testimony normalized 2006 costs. We simply did the same, with our only changes being those necessary to do so on a basis that we considered to be more sound.

More significantly, the implication that some form of embarrassment about our views of normalized 2006 costs led us to use estimated costs trivializes what we sought to do. Our recommendation for PSA changes had nothing to do with the size of any actual or expected deferral. Its goal was to set forth a sound approach for tracking fuel and energy costs and customer collections in a manner that fairly considers and balances Company and customer needs and interests.

Q. Did you in fact recommend the items numbered as 2, 3, and 6 from the list beginning on page 9 of Mr. Robinson's rebuttal testimony?

A. No. His item 2 suggests that we recommended a 2007 PSA adjustor based on the forecast cited in our direct testimony. We clearly did not then and we do not now recommend any rate based on that forecast. Mr. Ewen's rebuttal testimony appears to reflect our position correctly, even though Mr. Robinson's does not. Moreover, Mr. Robinson continues to be cryptic, like Mr. Ewen, in failing to make clear that the numbers "corrected" by Mr. Ewen in the 2007 estimate address an omission from a forecast that APS prepared and supplied to us.

As to item 3, we made no recommendation respecting the treatment of the prior unrecovered balance. We merely observed that we found no reason to conclude that any amounts were imprudently incurred in 2005. We stated specifically that we had not undertaken the analysis and testing necessary to determine the same for 2006 expenditures. Therefore, it would not be correct to conclude that we have endorsed the recovery of any 2006 expenditures without their being subject to accuracy and prudence review. Moreover, we believe that the period of recovery for prudently incurred 2005 expenditures should be as determined after Commission review. We have not recommended that the recovery period should be within any specifically identified future period. The review of 2006 costs and the amortization of any deferred balances are among the matters we have recommended be treated in the late-2006 Commission PSA examination that we propose.

Item 6 states that we endorse a 90/10 sharing of certain future year costs. Our testimony did not include this recommendation. We recommended a very limited sharing of the benefits of optimizing hedge positions as two relationships change as actual experience replaces estimates: (a) natural gas versus purchased power prices and (b) changes in fuel and energy requirements.

Q. Mr. Robinson's rebuttal says that Staff's proposal would "obviously" understate 2007 fuel costs. Please respond.

A. First, the very basis for using a PSA or similar mechanism is that fuel costs are volatile and unpredictable. The fact that it is not at all obvious what future fuel and energy costs will be is a core reason for using a PSA. We proceed from the premise that there is no helpful level of certainty that 2007 fuel costs will be what APS forecasted them to be as of June 30, 2006. Look for example at what APS thought 2007 costs were going to be in February 2006. That estimation differs by more than $100 million from what the APS estimate as of June 30, 2006 showed them to be.

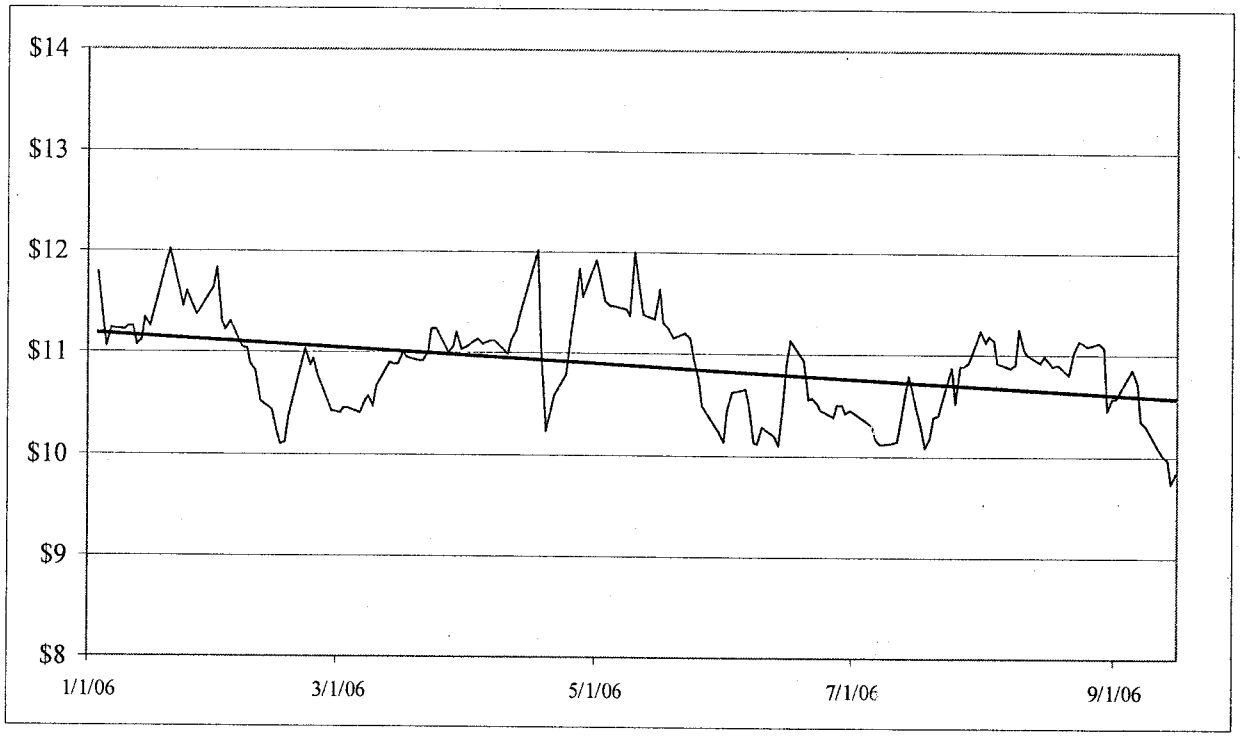
What we find to be "obvious" is that there remains all too much time for 2007 fuel and energy costs to change between a mid-year vantage point and the view that will be available when 2007 starts. Moreover, even after 2007 begins there will remain another 12 months for actual experience to turn what Mr. Robinson now calls obvious into what has a very good chance of widely missing the mark.

Our approach would be the same whether the change Mr. Robinson is suggesting starts the Company out "ahead of" or "behind" the potential deferral amount on which its rebuttal testimony focuses, because we take a long term view of the application of a PSA. We urge the Commission not to be swayed by Mr. Robinson's exaggeration and misstatement of our proposal's intent and methods to give APS a boost that may have no bearing on what it actually spends in 2007.

Q. What do energy market conditions illustrate with respect to the uncertainty you are discussing?

A. Take, for example, natural gas prices, which strongly drive APS energy costs at the margin. The following chart shows the danger in picking one's vantage point for an estimate of future prices and costs. The chart shows the strip prices for 2007 (*i.e.*, the average of the monthly forward prices for each of 2007's 12 months) at the close of each trading day through mid-September 2006. The trend line shows an overall decline through the year.

If we had used late January 2006 prices to estimate 2007 prices for natural gas (a primary source of volatility in APS fuel and energy costs), we could have priced gas at $12.01/MMBTU (the January 20, 2006 closing price). If we used, as APS suggests, June 30, 2006, we have a closing price of $10.45. If we use a more current date (September 15, 2006) we have a closing price for the 2007 strip of $9.84. The January 20 price exceeds the June 30 price by 22 percent. The June 30 price exceeds the September 15 price by over 6 percent, even though the time gap between them is only 2½ months.



Between Friday, September 15 (the last date that the preceding chart covers) and September 19, 2006, natural gas prices fell even more precipitously, reaching $8.03 per MMBtu. This drop was over 18 percent across two-trading days. The next two trading days produced another 5 percent drop to a price of $7.64 on September 21.

We do not contend that these will necessarily be the actual 2007 prices as that year unfolds; we do, however, contend that these changes show that what APS now says about 2007 isn't necessarily so, and that the most recent estimates practicably available should be used.

Q. Does that complete your Sur-Rebuttal Testimony?

A. Yes, it does.

EXHIBIT
admitted
S-30

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 57744.	DOCKET NO. E-01345A-05-0816

SUPPLEMENTAL TESTIMONY OF

JOHN ANTONUK
President, The Liberty Consulting Group

I. Introduction

Q. Mr. Antonuk, did you previously file testimony in these proceedings?

A. Yes, I filed Direct and Surebuttal Testimony addressing APS's fuel and purchased-power costs and the design of a revised PSA to recover those costs on a going-forward basis.

Q. What is the purpose of this supplemental testimony?

A. The purpose of this testimony is to address three matters, which are:

- To provide a proposed plan of administration that would implement Staff's proposed PSA mechanism, which my earlier testimony has discussed; this plan corrects a number of problems in the Rumolo rebuttal testimony's plan intended to implement Staff's proposed mechanism
- To provide the results of our review of the Company's forecast of its fuel and purchased-power costs in 2007 (based on data available as of September 29, 2006; hereafter termed the APS "Rejoinder Forecast") provided in the Rejoinder Testimony of Mr. Ewen
- To comment on the implementation of a 24-month rolling average approach to resetting a PSA rate.

Q. Was this testimony prepared by you or under your supervision?

A. Yes. In particular, I was actively involved in both the preparation and the supervision of the work on the development of the plan of administration for Staff's proposed PSA mechanism. Randall Vickroy, whose testimony accompanies mine, was the Liberty team member responsible for leading the detailed reviews underlying the portions of this

testimony that address the various estimates and forecasts of fuel and purchased power costs. That work took place under my supervision, but he is much more familiar with the details underlying those estimates. His testimony accompanies mine in order to permit those parties interested in those details to pursue them with the person who is most knowledgeable about them.

2. PSA Plan of Administration

Q. Have you prepared a proposed plan of administration for implementing staff's proposed PSA?

A. Yes. That Plan of Administration ("POA") is attached as Attachment JA-1 to this testimony.

Q. Please describe the POA's implementation of the PSA.

A. The POA addresses the three components that make up the Staff's proposed PSA rate:

- A "Forward Component" to recover or refund the difference between APS's estimated fuel and purchase power costs and those embedded in base rates
- An "Historical Component" to recover or refund the difference between collections under: (1) the Forward Component plus base rates, and (2) actual fuel and purchased power costs
- A "Transition Component" to recover or refund accrued balances remaining from the prior PSA and to allow for a mid-year PSA rate adjustment to address extreme fluctuations in the marketplace.

Q. Please describe the operation of the Forward Component.

A. Staff's proposed PSA mechanism will reset the PSA rate as of February 1 each year. The POA terms this 12-month period starting on February 1 as the "PSA Year." The Forward Component of the new PSA mechanism will provide for the recovery over the coming PSA Year of the difference between the amount of fuel and purchased-power costs embedded in base rates and the amount that APS forecasts that it will incur for fuel and purchased power (assuming forecasted sales for that same period) over the calendar year (January 1 through December 31). The forecasted year is based upon a calendar year instead of the PSA Year (the PSA Year is the 12-month period staring on February 1st).

Q. Why do you use different 12-month periods for the forecast year and the PSA Year?

A. Using forecasted costs and sales will provide for more current cost recovery, but requires care in assuring that the costs and sales forecasts used to set the Forward Component have been scrutinized. Providing an adequate period for Commission review necessarily creates some time gap between the timing of the forecast and the beginning of collections based on using that forecast. The following factors guided our decision to select a calendar year forecast and a February 1 PSA Year:

- Allowing a prior opportunity for interested-party comment on and Commission review of a forecast and the new Forward Component rate calculations that depend on it
- Keeping the "vintage" of the forecast as close as feasible to the effective date of the new Forward Component's inclusion in the PSA rate customers pay

- Recognizing that calendar years would provide the most recognizable and easily implemented basis for forecasting costs and sales
- Keeping the effective date of PSA rate changes consistent with a February 1 reset date.

Q. Won't the use of different periods frustrate the ability to reconcile charges based on forecasted costs with costs actually experienced by APS?

A. No. Let me first note that providing for such reconciliation is an essential element of our proposal. We have provided a feature (the Historical Component) that will produce such reconciliation. We designed its application to provide for regular reconciliation between: (a) actual revenues collected under the Forward Component plus base rates for a given period, and (b) actual costs for the same period, in order to avoid the mismatch postulated by the question.

Q. How will this Historical Component operate?

A. Beginning with the February 1, 2008 PSA Year, the PSA will include the Historical Component. Over the course of any given PSA Year, the Forward Component Tracking Account will track collections against actual costs. These accrued balances will then be refunded or collected over the coming PSA Year. For example, the Historical Component for the PSA Year beginning February 1, 2008 will refund/recover the balance of the Forward Component Tracking Account for the prior PSA Year, *i.e.*, the PSA Year beginning February 1, 2007.

1 **Q. Does your POA require that the first PSA Year begin on February 1, 2007?**

2 A. No. Staff's proposed PSA recognizes the possibility that the Commission decision on
3 whether to change the current PSA may not come in time for a new PSA Year to start on
4 this date. We allow for that possibility by creating a first PSA Year that may have a
5 duration of less than 12 months. We do so by fixing the first Year's end-date at January
6 31, 2008. This approach will allow the first PSA Year to start after February 1, 2007
7 without disrupting the normal cycle we anticipate for the future.

8

9 **Q. How does your plan address the timing of the filings that will be required to make**
10 **the Forward Component and the Historical Component operate effectively?**

11 A. We call for the filing of the Forward Component and the Historical Component
12 calculations to take place annually, each September 30. Using this date requires an
13 estimate of balances for the remaining five months of the PSA Year. For example, the
14 September 30, 2008 filing will include proposed calculations for the PSA Year starting
15 on February 1, 2009. The September 30, 2008 filing will use actual balances accrued for
16 the months of February through August (the first seven months of the PSA Year) and
17 estimates of those balances for the remaining five months.

18

19 The POA requires yearly filings on September 30th with a portion to be estimated so that
20 Staff and other interested parties can become familiar with and inquire about: (a) the
21 forecasts used to calculate the Forward Component that will be reset in February and (b)
22 the details underlying the calculation of the balances accruing in the Forward Component
23 Tracking Account.

Allowing early examination of these components, balances, and calculations is important to assuring that the Commission will have an opportunity for effective review before a changed PSA rate becomes effective. We recognize, however, that the earlier we mandate the APS filing, the more we require the use of estimated versus actual data. The longer that gap becomes, the greater becomes the potential for mismatching costs and collections. Therefore, the POA provides for a second APS filing by December 31. This filing will update the estimated balance calculations and recompute the resulting Historical Component calculation.

Q. The third PSA component that Staff proposes is the Transition Component. Please describe its operation.

A. When the new PSA begins operation sometime in early 2007, there will remain balances under the PSA that applies now (the "old PSA"). The recovery of some of those balances has already been addressed by the Commission; the recovery of others, I understand, has not. The Transition Component provides a means for incorporating those specific recovery elements already approved by the Commission and for recovering any other old PSA balances that the Commission may approve.

Please understand, however, that the Staff's proposal intends no changes in the amounts of recovery of any balances accruing under the old PSA. It just provides the vehicle for recovering those already addressed by the Commission and those that may be addressed in the future.

The Transition Component also allows an opportunity for the Commission to consider whether, after the adoption of the Forward Component for any year, any changes have occurred that cause the Component to not sufficiently reflect current APS fuel and purchased-power costs. We would not expect this aspect of the Transition Component to be used frequently, if ever. We incorporated it, however, because the volatility of energy markets gives any adjustment mechanism (whether it uses partly forward/partly historic or strictly historic costs) the potential for producing recovery that far exceeds or under-runs actual costs.

The POA also recognizes that the balance established for recovery under the Transition Component may (as is the case for the Historical Component) get over or under recovered during a PSA Year. This may happen, for example, because forecasted sales used to set the rate component to recover a fixed balance will almost certainly deviate from actual sales over that period. The Transition Component will use tracking accounts to keep track of the difference between collections and balances for Commission consideration of future reconciliation. The filing of the Transition Component balances and calculations also works similarly to and under the same deadlines as those applicable to the Historical Component.

Q. Does the Staff's PSA contemplate that each new PSA Year will bring fully contested rate hearings?

A. No. We certainly consider scrutiny and an opportunity for prior Commission modification of proposed PSA components rates to be important. However, we must remember that all of the components will be reconciled to actual costs. Moreover, periodic examinations of accounting accuracy and fuel and purchased-power prudence will remain as options for adjustments as well. We believe that those protections are substantial enough to allow for a much more streamlined review before the various PSA components become effective.

We would not propose this method if it involved on a yearly basis the kind of review and time given to fuel and purchased-power issues in this proceeding. That approach would defeat the purpose of providing for an efficient means for current recovery of costs, and later review of their accounting accuracy and prudence.

3. Rejoinder Forecast Review

Q. Please describe the knowledge that Liberty's team brought to its review of the Rejoinder Forecast.

A. We began with knowledge about APS's power plants, power-purchase contracts and fuel management arrangements for calendar 2005 and into early 2006. We gained that knowledge from our audit of APS's fuels management policies and practices. In addition, we have through our work in this docket already examined a number of other similar estimates. Specifically, we began our review of the Rejoinder Forecast by examining its relationship to three estimates already available to us. John Antonuk's earlier Direct and

Surebuttal testimonies address Liberty's analysis, review, and conclusions about those three sets of information, which we describe below.

First, we examined the normalized estimate of 2006 fuel and purchased-power costs that APS witness Ewen presented in this docket in January of this year (the APS "Direct Normalized 2006 Estimate"). ***Second***, we asked that APS prepare a revised estimate of its normalized 2006 fuel and purchased-power expenses ("the Renormalized 2006 Estimate"). That estimate annualized a number of significant cost factors (*e.g.*, numbers of customers) and it normalized other factors (*e.g.*, weather, generating station maintenance schedules). That APS estimate also used actual prices that the Company had paid for fuel (including fuel transportation) and purchased power during the first six months of 2006, and forward prices for fuel and purchased power for the last six months, as those prices had been observed and reported on June 30, 2006. We used the Renormalized 2006 Estimate to form Staff's recommendation for establishing the fuel and purchased-power component of base rates. ***Third***, we asked APS to prepare a fuel-cost estimate for 2007, using similar assumptions and adjustments ("the June Vintage 2007 Estimate"). The Direct Testimony of John Antonuk commented on the June Vintage 2007 estimate to illustrate the potential impact of the very different prices for natural gas and purchased power that were present in futures prices at that time.

Q. Describe how the basis of that APS June Vintage 2007 Estimate relates to the basis on which the Staff proposes to calculate PSA rates.

A. It materially differs in two ways. First, as the Direct and Surebuttal Testimony of John Antonuk stated, the PSA mechanism that we recommend should use the best available forecasts of fuel prices and fuel requirements. The very high level of volatility that has come to characterize fuel markets requires the use of a very recent forecast to set a PSA adjustment that is forward-looking. Specifically, a forecast used for setting a forward-looking PSA should have a vintage as near as possible to the time that a PSA rate adjustment becomes effective. Assuming the continued resetting of the PSA rate each February, the end of September of the prior year is, in our judgment, about as late as an estimate can be made, while still allowing the Commission an opportunity for review before use in resetting a PSA rate.

The June Vintage 2007 Estimate, while useful in providing a comparison of 2006 and 2007 fuel costs current at that time, is not sufficiently current to use to set a 2007 PSA rate under the mechanism proposed by Staff. Moreover, the June Vintage 2007 Estimate does not comprise the kind of forecast that should be used to set a PSA rate. At the time of John Antonuk's Direct Testimony, we sought an estimate of 2007 costs that would provide an "apples-to-apples" comparison to the APS numbers underlying our proposed base rate fuel and purchased-power element. Therefore, the 2007 data that APS used in making the June Vintage 2007 Estimate used annualizations and normalizations similar to those that we asked APS to use in the Renormalized 2006 Estimate that we sought for purposes of setting base rates.

Q. Why do you believe that annualization and normalization differ in their applicability to base rates, as opposed to an adjustment clause?

A. Using annualization and normalization is generally appropriate for setting base rates, which will apply across an indefinite future period. When rates apply for a multi-year period, it is appropriate to adjust for factors that would make the use of any particular year's projections unrepresentative. For example, a unit with an 18-month outage cycle will have two outages across three years. If one of those outages occurs in the year used to set base rates, customers will in effect pay the costs of an outage every year. Certainly, an automatic recovery mechanism, such as the PSA, can correct for that mismatch; we believe, however, that good practice calls for setting base rates on the basis of properly normalized and annualized data. One exception to this general guideline, which we do not believe is material here, is that we did not normalize for contract changes that were expected to occur during or after 2006, because we felt that the PSA mechanism would provide an adequate means for testing those changes.

A PSA, however, should use forecasted costs for the single year for which it would apply, in order to avoid unnecessary complexity and to minimize the difference between the estimates used to set a PSA and actual costs. The fact that the June Vintage 2007 Estimate does not comprise a true forecast of 2007 costs forms a second reason why it would not serve well as a basis for a 2007 PSA rate.

Q. Your earlier testimony also noted the need for review of a forecast before its use to set PSA rates; have you had a chance to perform such a review of the APS Rejoinder Forecast?

A. Yes. We compared that forecast to the earlier sets of information I discussed above. We then asked APS to explain certain changes that we observed when making those comparisons. APS responded by performing a sequence of forecast runs ("cases"), with each one changing selected inputs one at a time. This sequential approach allowed us to isolate the effects of a number of significant cost changes that we had observed. We examined each of those cases, and then reviewed details of the results with APS. The purpose of these reviews was to assure ourselves that no evident errors had occurred, and that the Rejoinder Forecast displayed internal consistency.

We performed another important validation, which consisted of examining selected key elements of the underlying estimate data (*e.g.*, heat rates and fuel and transportation costs), in order to verify that those inputs either had not changed, or had changed in demonstrably valid ways, when compared with: (a) the inputs used in the other estimates we had reviewed earlier, and (b) the data we gathered during the audit.

Q. Please list and describe any important conceptual differences between APS's June Vintage 2007 Estimate and the Ewen Rejoinder Forecast.

A. The first important conceptual difference from the June Vintage 2007 Estimate is that APS's later data has included previously omitted option premium payments and large block purchases of power. Specifically, the June Vintage 2007 Estimate did not include

the Rejoinder Forecast's additional option premium payments of over $30 million and additional term purchases of about 1,800 gigawatt hours, which have a forecasted cost of an additional $107.8 million. These changes produced a shift in the forecasted operation of the APS system; *i.e.*, they replaced a portion of APS's generation from new combined-cycle plants (*i.e.* Redhawk) with purchases under term contracts and tolling agreements. The changes in the operation of the APS system also caused a decrease in off-system sales, which had the effect of lowering the total margins those sales produce.

A second important difference resulted from the effects of fuel market volatility. It demonstrates how quickly costs can change. Western U.S. energy markets experienced considerable declines in fuel and purchased-power prices following the end of June. The timing of the Renormalized 2006 Estimate and the June Vintage 2007 Estimate did not permit them to reflect those declines. The Rejoinder Forecast does, however, reflect changes in the market through September of 2006. We might have seen prices go in the other direction and they may do so as the remainder of this year unfolds. They may move substantially and in unpredictable directions during 2007 as well.

Other differences between the June Vintage 2007 Estimate and the Rejoinder Forecast include:

- The Rejoinder Forecast assumes that 2007 customer additions will occur gradually throughout the course of the year; the annualized data of the previous estimates used the anticipated number of customers at year end.

- The Rejoinder Forecast used the Company's planned maintenance schedule for 2007; the previous estimates normalized outage rates across a number of years (reflecting the fact that normalizing maintenance schedules produces unit outage rates that differ from year to year within each station's particular maintenance cycle).
- APS adjusted the forecast of supplemental sales under its contracts with PacifiCorp, in order to conform them to recent experience.

The June Vintage 2007 Estimate that APS prepared for us already included some differences in assumptions from those that the Company used in its earlier estimates. Those differences resulted largely from our requested changes associated with the Renormalized 2006 Estimate.

Q. Summarize your opinion about the propriety of the APS changes from the use of annualized and normalized data in earlier estimates to the use of forecasted data in the Rejoinder Estimate.

A. We concluded from our review that the changes observed in the Rejoinder Estimate appropriately reflect forecasted 2007 costs, as opposed to normalized 2007 costs. The changes to a true "forecast" give the Rejoinder Estimate a sound conceptual base for use in setting the forward component of the PSA rate for 2007 collection.

Q. Describe what you did to examine the support for and the propriety of the changes from the June Vintage 2007 Estimate to the Rejoinder Forecast.

A. We initially discussed these changes with Mr. Ewen in a conference call. Our objective was to understand why fuel and purchased-power costs changed from the June Vintage 2007 Estimate to the Rejoinder Estimate. Following our discussion, APS developed four intermediate forecast cases. Their addition gave us six altogether. One of those six was the June Vintage 2007 Estimate. Sequentially examining the four new cases allows for the isolation of the effects of each factor that had a significant impact on the cost changes between the June Vintage 2007 Estimate and the Rejoinder Forecast (the sixth case).

Q. List the biggest factors that caused a change in net retail fuel cost from the earlier estimate.

A. The table attached to this testimony provides a comparison among the six cases. The Renormalized 2006 Estimate, which the Antonuk Direct Testimony recommended as the basis for determining the fuel cost component of the Base Rate, is also included in the table for comparison.

Our comparison of the Rejoinder Forecast and the June Vintage 2007 Estimate showed a net retail fuel cost change from $981.7 million to $957.7 million; *i.e.*, the Rejoinder Forecast produced a decrease of about $24 million. This amount was noted in John Antonuk's Direct Testimony. As noted in that testimony, this amount retained the Company's proposal to retain 10 percent of the value of the fuel-cost hedges. The Rejoinder Forecast eliminated that sharing by including the fuel-cost hedges in at 100 percent. With 100 percent of the hedge values, the June Vintage 2007 Estimate was $975.0 million. The major factors that caused the fuel cost changes between these

estimates were added cumulatively from new Cases A to E, with Case E representing the estimate included in the Rejoinder Forecast. The differences in those cases consist of:

- Case A added contracted option premium payments of around $33.7 million.
- Case B changed the annualization of APS customer totals at year-end 2007 to the actual budget forecast for customers, thus decreasing load requirements.
- Case C decreased market prices for delivered natural gas by about $1.20 per Mcf and decreased power prices at Palo Verde by about $8.70 per megawatt hour on-peak and by about $9.45 per megawatt hour off-peak.
- Case D changed the modeling of the PacifiCorp Supplemental contract to more accurately reflect the company's historical experience.
- Case E included APS's 2007 plant maintenance forecast in place of a normalized maintenance schedule; Case E also included about 1,800 gigawatts of additional block purchases of power for 2007.

Q. Describe your analysis and conclusions regarding Case A.

A. Case A changed the June Vintage 2007 Estimate by including an additional amount of premiums related to APS's contracted options to buy power from off-system providers. These options form an integral part of APS' plans to meet native load requirements. APS had mistakenly omitted them from its June Vintage 2007 Estimate. The Company has identified six contracts that included capacity charges for gas tolling and peaking capacity options. APS contracted for 1,150 Megawatts of capacity for the June through September peak season and 500 megawatts for the October through December time period.

The total cost of option premiums was $33.7 million higher in Case A. The inclusion of the additional costs for generating capacity reservations increased retail fuel costs by a like amount. Two related changes offset this increase somewhat, producing a net increase of about $25 million in retail fuel costs:

- Increased net benefits from APS gas hedges offset about $6.5 million
- Additional off-system sales margins offset approximately another $2 million.

Our review produced no reason to question the propriety of this net change.

Q. Describe your analysis and conclusions regarding Case B.

A. Case B isolated the fuel-cost impacts of changing from the use of annualized customer totals as of the end of 2007 to a forecast of customer additions spread across the year. The decrease in customers during the year caused a reduction in native load sales of about 490 gigawatt hours, caused by the lower numbers of customers postulated, particularly in earlier months of 2007. The resulting reduction in load requirements lessened APS's need for generation and power purchases. This reduction decreased natural gas costs by about $12.5 million, purchased power by about $5.5 million, and coal costs slightly. The reduction in APS production requirements also freed up more Company generation for use in making economic off-system sales. Estimated margins from such sales accordingly increased by about $5 million.

In summary, a net reduction of about $23.5 million in fuel costs resulted from the change from annualized to forecasted customer numbers. Our review produced no reason to question the propriety of this net change.

Q. Describe you analysis and conclusions regarding Case C.

A. Case C examined the effects of the decrease in market prices from roughly the end of June 2006 (the time of the June Vintage 2007 Estimate) through the end of September (the vintage of the Rejoinder Forecast). Reductions across this quarter were substantial; they amounted for example to about $1.20 per Mcf in the delivered price of natural gas, which generally fires APS's marginal generating units. Gas is also the dominant source of marginal production throughout the Southwest region; therefore, this case also caused a decline in the forecasted market price of power at the Palo Verde delivery point. Estimates of on-peak electric pricing fell by about $8.70 per megawatt-hour; and off-peak pricing decreased by about $9.45 per megawatt-hour. Estimates of on-peak electric pricing fell by about $8.70 per megawatt-hour; and off-peak pricing decreased by about $9.45 per megawatt-hour.

Together, Case C's drops in natural-gas and purchased-power prices caused APS's fuel costs to decrease by about $85 million. Almost all of this forecasted reduction came from reduced costs of running the company's combined-cycle gas turbines. However, reduced production costs naturally caused a corresponding drop in the gains APS would realize from hedges. Those decreases in hedging gains totaled about $62 million. The drop in market prices also caused a decline of about $3 million in margins from off-system sales as electric pricing, unit margins, and off-system sales all declined. The net reduction in APS fuel costs from the decreases in market prices therefore amounted to $19.7 million. Our review produced no reason to question the propriety of this net change.

Q. Describe your analysis and conclusions regarding Case D.

A. The APS Rejoinder Estimate over-rode its model's forecast of the effects of the PacificCorp Supplemental Agreement. APS made this "manual" change because it considered the results to fall outside historical experience under that agreement. APS did not find any reason to believe that 2007 will bring results outside the range of its historical experience. This APS adjustment reduced the Company's native-load energy requirements by about 367 gigawatt-hours. This reduction produced a corresponding reduction in production and purchased-power requirements and related costs of about $14.5 million. This adjustment also had the effect of increasing off-system sales margins by about $3 million, because it increased the amount of system-generated power available for off-system sales.

The cumulative effect of the two impacts related to changes to the PacifiCorp agreement was to decrease fuel costs by about $17.5 million. We have some concern about manual over-rides to model outputs, but could find no independent reason for challenging the Company's justification for doing so here. Moreover, its relatively moderate cost reduction and the fact that it is reconcilable under the PSA led us to conclude that its acceptance is justifiable in these circumstances.

Q. Describe your analysis and conclusions regarding Case E.

A. Case E introduces two major changes that cause a shift in the sources of electricity forecasted by the APS dispatch model. Case E's first change applies actual (rather than

normalized) 2007 maintenance schedules for APS generating units. The actual plan for 2007 includes a longer (by 23 days) Palo Verde 3 refueling outage to accommodate a steam generator replacement. Second, Case E introduces a large volume of block power purchases in order to reflect more accurately the expected capacity plan for 2007. Specifically, Case E added block purchases totaling about 1,800 gigawatt hours to the contracted option capacity already in place.

The maintenance and purchase power changes combined to produce a shift from APS's new, combined-cycle gas generation units to: (a) gas tolling purchases made under the option contracts, and (b) block term purchases. However, while Case E produced a shift in generation sources, this shift caused only minimal changes in APS's net fuel costs. Many of the combined-cycle gas units in the desert Southwest region have production profiles and costs similar to those in the APS system. Replacing APS gas generation with outside gas generation therefore does not have a very large net fuel cost impact. Case E reduced natural gas costs because it reduced the use of APS's own generation. Resulting increases in purchased-power expenses and decreases in off-system margins offset all of this reduction.

Case E produced a net change of less than $1 million in increased costs due to this substitution of gas units. Accordingly, the 23 additional outage days at Palo Verde 3 (produced by substituting a single year's forecasted duration for a multi-year period's normalized duration) accounts for almost the full amount of the $11.7 million additional fuel expense resulting under Case E. After getting APS to re-categorize and clarify

several lines of its Case E run, we were able to conclude that no reason existed to question the propriety of this net change.

Q. Please summarize the overall changes in net retail fuel cost from the June Vintage 2007 Estimate to the Rejoinder Forecast.

A. The net retail fuel cost for the June Vintage 2007 Estimate was $981.7 million. The addition of capacity option premiums under six contracts added $25 million to fuel costs. The change to APS's actual plant maintenance schedule added about $11.7 million to fuel costs. The change from annualized customer levels to forecast customer levels caused a decrease of $23.5 million. The significant drop in market prices produced a decrease of $19.7 million. Finally, APS's change in estimating the impact of the PacificCorp Supplemental contract caused a reduction in fuel costs of $17.4 million. The net effect of these changes was a decrease of approximately $24 million, to $957.7 million.

Q. Describe what review you undertook to assure that base data between the estimates (*e.g.*, fuel and transportation costs, heat rates) did not change inappropriately.

A. Liberty had the same team members who conducted our fuels management audit examine all six estimates. We also examined background information that affected all six cases, such as coal costs and the costs of coal transportation. We also verified that estimates of forward prices for natural gas and purchased power were competitive.

1 **Q. Using coal costs as an example, please describe your efforts to validate changes in**
2 **underlying data.**
3 A. We cross-checked the coal and coal transportation price data underlying the September
4 2006 forecast of 2007 costs for consistency with data provided earlier for 2005 and 2006.
5 We looked at the data separately on the following bases: station by station, total delivered
6 price, coal price, and transportation price. We used ¢/MMBtu, and delivered tons of coal
7 as appropriate.
8
9 Our baseline data for 2005 and 2006 came from responses to data requests from both the
10 fuel management audit and this proceeding. We were able to conclude that the overall
11 price changes from year to year were what we expected to see, and fell within the yearly
12 price escalation ranges that we had already observed in earlier work. We examined Four
13 Corners and Cholla separately. The escalation in Four Corners 2007 prices was in accord
14 with the rates we had seen for previous years, for which we had tested 2005 and early
15 2006 escalation rates. We had also previously tested the propriety of 2005 and early 2006
16 at Cholla. The changes for 2007 are in line and we found them also to reflect a recent
17 transportation-rate settlement. We confirmed that fuel handling and adjustments remained
18 stable, and continued to form a very small portion of overall fuel and purchased-power
19 cost. We also verified that the overall escalation in coal costs for 2007 is in accord with
20 expectations, given the nature of APS's supply agreements.
21
22 **Q. What do you conclude about the propriety of using the newer estimate to set a PSA**
23 **rate for 2007?**

A. First, we consider the change from the use of annualized and normalized data to forecasted 2007 data to be appropriate. Second, we believe that the vintage (end of September 2006) of the Rejoinder Forecast appropriately balances the need for the use of current data and assumptions with the desire to continue with a PSA rate resetting in roughly the February 1, 2007 time frame.

Third, we do not seek to convey the impression that this forecast will necessarily predict what will actually happen in 2007. No estimate could, but this one, we conclude, is comprehensive and logically structured, consistent with reasonable expectations about system assets, and reflective of market price expectations current as of its vintage. Our fourth conclusion, therefore, is that our review adequately confirms the sufficiency of the Rejoinder Forecast for use in setting our proposed PSA Future Component for a PSA Year commencing at or near February 1, 2007.

4. Use of a 24-Month Rolling Average PSA

Q. What is your view of the use of a 24-month rolling average to set PSA rates?

A. The main advantage of a "rolling average" approach is that it would smooth out the cost discontinuities produced in very volatile energy markets. We consider volatility to be the main justification for an effective rate-adjustment mechanism. Therefore, we do consider that approach to be responsive to the issue of managing volatility. On the other hand, we think it can raise two major concerns. The PSA rate would change as we understand it each month to incorporate the rolling-average process. The first concern is that this approach could actually increase deferrals. Second, very frequent rate changes, even if

only moderate, can increase customer confusion and cause negative customer reactions. If that approach is adopted by the Commission, however, Staff's PSA could accommodate it with changes. Those changes would eliminate the Forward Component, and change the Historical Component Tracking Account to a 24-month balance, and require the monthly calculation of a PSA rate to recover that balance.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment JA-1 to Supplemental Testimony of John Antonuk
Comparison of Fuel Cost Cases

Parameter	Base	Case A	Case B	Case C	Case D	Case E
Prices						
- Palo Verde on-peak ($/Mwh)	74.38	74.38	74.38	65.69	65.69	65.69
- Palo Verde off-peak ($/Mwh)	55.00	55.00	55.00	45.56	45.56	45.56
- Delivered gas ($/MMBtu)	8.69	8.69	8.69	7.49	7.49	7.49
On-system prod. (Gwh)						
- Nuclear	8,811	8,811	8,811	8,811	8,811	8,578
- Coal	13,230	13,246	13,218	13,200	13,156	13,181
- Natural gas	8,811	8,794	8,426	8,294	8,021	7,139
- Purchased power	1,832	1,832	1,737	1,860	1,810	2,864
Total	32,684	32,684	32,193	32,166	31,799	31,762
Off-system prod. (Gwh)						
- Nuclear	0	0	0	0	0	0
- Coal	16	16	28	26	51	144
- Natural gas	1,826	1,826	1,865	1,773	1,841	98
- Purchased power	724	724	661	727	670	1,274
Total	2,566	2,566	2,554	2,527	2,562	1,515
Off-system avg. revenue ($/Mwh)	64.57	64.57	64.37	55.91	55.95	60.79
Off-system margins ($000)	23,879	23,999	29,030	25,834	28,690	5,749
PacifiCorp Supp. Rev. ($000)	22,549	22,548	22,549	19,689	7,258	7,258
Net Retail Fuel Cost ($000)	981,708	1,006,687	983,207	963,456	946,023	957,749
Base Fuel Rate (cents/kwh)	3.2296	3.3112	3.2824	3.2204	3.2016	3.2491

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on xxxxx, xx, 200x in Decision No. xxxxxxxx. This PSA replaces the Power Supply Adjustment mechanism approved in Decision No. 67744 ("the old PSA"). The PSA provides for the recovery of fuel and purchased power costs from January 1, 2007 onward.

The old PSA used historical, experienced costs to set a PSA rate, and then reconciled subsequent collections thereunder to actual costs, subject to a number of guidelines and limitations. By contrast, the PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This PSA also provides for a transition method for the refund or collection of balances accrued under the old PSA, prior to its replacement by this PSA. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

This POA describes the application of the PSA. It assumes that the old PSA continues to apply until the Commission decision regarding the adoption of this PSA during the first quarter of 2007.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) fuel and purchased power costs and those embedded in base rates.

2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The refund or recovery of balances arising under the provisions of the old PSA, prior to its replacement by this PSA.
    b. The opportunity to seek a mid-year change in the PSA rate in cases where variances between recovery of fuel and purchased power costs under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission first deem such an adjustment to be appropriate.
    c. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

The PSA Year begins on February 1 and ends on the ensuing January 31.[1] The first PSA Year in which the new PSA rate shall apply will begin on February 1, 2007 or such other date on which the Commission approves the adoption of this PSA. In any event, the first PSA Year will end on January 31, 2008. Succeeding PSA Years will begin on each February 1 thereafter.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a proposed calculation of the three components of the PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its fuel and purchased power costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecasted costs by the forecasted sales to produce the ¢/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PSA Year basis (*i.e.*; February to January), and its

[1] The Commission decision approving this PSA may come after February 1, 2007, in which case the first PSA Year will be less than 12 months.

balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the Forward Component Tracking Account balance and the Historical Component Tracking Account balance is divided by the forecasted kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[2]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[3]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

[2] For example, the September 30, 2007 filing would include actual balances for February through August of 2007 and estimated balances for September 2007 through January 2008.

[3] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

As of February 1, 2007, there will remain balances under the operation of the old PSA. This PSA does not make any change in the recoverability of such balances, but does apply the Transition Component as a method for recovering such balances as are already permitted for recovery under the old PSA and whose recovery the Commission may otherwise allow. The Transition Component will provide for the capturing and collection of those balances. APS will continue to make the filings required under the old PSA for so long as is necessary to recover and reconcile any balances arising thereunder, to the extent that such balances have not been transferred for recovery through the Transition Component of this PSA. Pre-2007 balances already approved for recovery (but not already recovered) under the old PSA will be rolled into the Transition Component upon this PSA's effective date. Any 2007 balances accruing under the old PSA before its replacement will be tracked during the first PSA Year, and their recovery shall be addressed in the calculation of the Transition Component applicable during the second PSA Year, which shall begin on February 1, 2008. The pre-2007 charges already approved for recovery under the old PSA consist of the following:[4]

1. February 1, 2006, adjustor rate of $0.004 per kWh to recover $110 million of 2005 costs;
2. May 1, 2006, surcharge of $0.000554 per kWh to recover $15 million of 2005 costs outside of 4 mil bandwidth that are not related to nuclear plant outages; and
3. May 1, 2006, interim adjustor rate of $0.007 per kWh to recover certain 2006 costs as described in Decision No. 68685.

APS shall file by December 31, 2006[5] a calculation of the ¢/kWh unit rate required to collect costs included in the preceding list over the same estimate of 2007 sales used to calculate the Forward Component. This calculation shall comprise the Transition Component for the first PSA Year's PSA rate.

The Transition Component will also be used if necessary to address the need for any other reconciliations that may be required or appropriate under the old PSA. Following review, the Commission will determine the amount to be collected and the period over which it will be collected. The amount permitted to be collected shall be included in the Transition Component Balance. The Transition Component will provide the PSA element for the collection of the approved Transition Component Balance over the time period established by the Commission.

The preceding uses of the Transition Component deal with the transition from the old PSA to this PSA. The Transition Component will also be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the

[4] Depending upon the Commission's resolution of APS' pending rate case, Docket No. E-01345A-05-0816, APS may also be allowed to recover certain prudently incurred fuel and purchased power costs incurred as a result of certain Palo Verde outages.

[5] Staff acknowledges that the 2006 information would have to be addressed in the context of the pending rate case, Docket No. E-01345A-05-0816.

Transition Component to address a significant imbalance between collections and costs under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate (¢/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.*, Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first billing cycle in February unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being current as of that date for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use

the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[6]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect on February 1, subject to true-up.

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

[6] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh effective on XXX, XXXX.

Forward Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The purpose of the Forward Component is to adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the prior calendar year's actual fuel and purchased power costs and the recovery of such costs under the combination of the base fuel rate of $0.0XXXXX per kWh and the Forward Component applicable for that prior calendar year.

Forward Component Tracking Account – An account that records on a monthly basis APS's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Old PSA – The Power Supply Adjustment mechanism approved in Decision No. 67744 to track changes in the APS cost of obtaining fuel and purchased power.

This PSA – The Power Supply Adjustment mechanism approved by the Commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PSA also provides for the transition from the prior PSA to this PSA, allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year – A consecutive 12-month period generally beginning each February 1.

PSA Year One – A period beginning on the date determined by the Commission in Decision No. xxxxx and ending on January 31, 2008.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are excluded.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component – An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for: (a) the transition between the prior PSA and current PSA, and (b) significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Calculations

a. Schedule 1. PSA Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component from Schedule 2, Line 8.
2. On Line 2, enter the Historical Component from Schedule 4, Line 5.
3. On Line 4, enter the Transition Component for the Commission approved prior PSA transition refund/collection balance from Schedule 6, Line 3.
4. On Line 5, enter the Transition Component for any Commission approved Mid-Period Transition refund/collection balance from Schedule 6, Line 6.
5. On Line 6, enter the Transition Component for any other Commission approved Transition adjustment refund/collection balance from Schedule 6, line 9.
6. On Line 7, enter the Tracking Account Transition Component for any Commission approved refund/collection Tracking Account balance from Schedule 6, Line 20.
7. On Line 8, enter the sum of Lines 4 through 7 to calculate total Transition Component.
8. On Line 9, enter the sum of Lines 1, 2, and 8 to calculate the total PSA Rate.
9. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

b. Schedule 2. PSA Forward Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (kWh), excluding the E-3, E-4, E-36 sales for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Fuel Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

c. Schedule 3. Forward Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Forward Component being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns ***h*** and ***i***. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns ***a*** and ***b***, respectively; the sum which equals the Total Native Load Energy Sales; column ***c***. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.
2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue in columns ***d*** and ***e***, respectively; the sum of column ***d*** minus ***e*** equals the monthly Net Native Load Power Supply Costs in column ***f***. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.
3. On Lines 1 to 12, calculate the PSA Retail Power Supply Costs, column ***g*** by dividing the Retail Energy Sales in column ***a*** by the Total Native Load Energy Sales in column ***c***, then multiply the product by the Net Native Load Power Supply Costs in column ***f***. Directly-assigned power supply costs and related energy sales from applicable special contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column ***a*** by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column ***h***.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column ***a***, the result which is entered in column ***i***.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column ***j*** by subtracting the Base Rate Power Supply Recovery and the Forward Component rate recovery from the PSA Retail Power Supply Costs, columns ***g*** and ***h***, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

d. Schedule 4. PSA Historical Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, L13, column *i*.
2. On Line 2, enter the Historical Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales without E-3, E-4 and E-36 MWh.
5. On Line 5, enter the Applicable Historical Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

e. Schedule 5. Historical Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Historical Component being tracked.

On Line 8, for January and Line 1 for February, enter the Historical Component balance as of February 1, 20XX. On Line 2, (Prior period PSA Historical Component Calculation From Schedule 4, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Historical Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Historical Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Historical Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Historical Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Reflect notes as appropriate.

f. Schedule 6. PSA Transition Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Prior PSA Transition Commission Approved (Refundable)/Collection Amount.
2. On Line 2, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
3. On Line 3, calculate the Prior PSA Transition Component (Refundable)/Collection Rate by dividing Line 1 by Line 2.
4. On Line 4, enter the PSA Mid-Period Transition Commission Approved (Refundable)/Collection Amount, if any.
5. On Line 5, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
6. On Line 6, calculate the Mid-Period Transition Component (Refundable)/Collection Rate by dividing Line 4 by Line 5.
7. On Line 7, enter Any Other Transition Commission Approved (Refundable)/Collection Amount, if any.
8. On Line 8, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
9. On Line 9, calculate the Any Other Transition Component (Refundable)/Collection Rate by dividing Line 7 by Line 8.
10. On Line 10, enter the sum of Lines 3, 6, and 9 to arrive at the total Transition Component (Non-Tracking Account Items).
11. On Line 11, enter the Prior PSA Transition Tracking Account Balance from Schedule 7a, Line 8.
12. On Line 12, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
13. On Line 13, calculate the Prior PSA Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 11 by Line 12.
14. On Line 14, enter the Mid-Period PSA Transition Tracking Account Balance from Schedule 7b, Line 8, if any.
15. On Line 15, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
16. On Line 16, calculate the Mid-Period Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 14 by Line 15.
17. On Line 17, enter Any Other PSA Transition Tracking Account Balance from Schedule 7X, Line 8, if any.
18. On Line 18, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
19. On Line 19, calculate the Any Other Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 17 by Line 18.
20. On Line 20, calculate the total Tracking Account Transition Component by adding Lines 13, 16, and 19.
21. On Line 21, calculate the total Transition Component by adding Lines 10 and 20.

Reflect notes as appropriate.

g. Schedule 7a. Transition Component Tracking Account "Old PSA"

Enter the appropriate: effective dates for the PSA ***Prior*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, Old PSA balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L1) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component, Old PSA

application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Transition Component Adjusted Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balanced produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 11.

Reflect notes as appropriate.

h. Schedule 7b. Mid-Point Transition Tracking Account

Enter the appropriate: effective dates for the PSA ***Mid-Point*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, PSA Mid-Point balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Transition Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 14.

Reflect notes as appropriate.

i. Schedule 7X. (Enter Description) Transition Tracking Account

Follow similar procedures discussed in g and h above, for any other Transition Tracking Accounts.

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PSA calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.
    h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.

3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

EXHIBIT
admitted
S-31

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

STAFF'S NOTICE OF FILING ERRATA

On November 20, 2006, Staff of the Arizona Corporation Commission ("Staff") filed the Supplemental Testimonies of John Antonuk and Randall Vickroy and the Power Supply Adjustment Plan of Administration, in the above-referenced matter. At that time, Staff inadvertently omitted the schedules referenced in the Plan.

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Staff hereby files Schedules to the Power Supply Adjustment Plan of Administration.

RESPECTFULLY SUBMITTED this 27th day of November, 2006.

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
Arizona Corporation Commission
1200 West Washington Street
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Original and 17 copies of the foregoing filed this 27th day of November, 2006 with:

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective February 1, 20XX
($.000000/kWh)

Line No.	PSA Rate Calculation		Current February 1, 20XX [1]	Proposed February 1, 20XX	Increase/(Decrease) $.000000/kWh	Increase/(Decrease) %
1	Forward Component - FC (Sch. 2, L8)		$ -	$ -	$ -	0.00%
2	Historic Component -HC (Sch. 4, L5) [2]		$ -	$ -	$ -	0.00%
3	Transition Component (Refund)/Collection					
4	Prior PSA Transition Component	(Sch.6,L3) [3]	$ -	$ -	$ -	0.00%
5	Mid-Period Transition Component	(Sch.6,L6) [4]	-		-	0.00%
6	Other (*Enter Description*) Transition Component	(Sch.6,L9) [5]	-		-	0.00%
7	Tracking Account(s) Transition Component	(Sch.6,L20) [6]				
8	Transition Component (L4 + L5 + L6 + L7)	(Sch.6,L21)	$ -	$ -	$ -	0.00%
9	PSA Rate (L1+ L2 + L8)		$ -	$ -	$ -	0.00%
				-		

Notes:

[1] No Current Info. Provided in 1st new PSA filing methodology: Prior PSA methodology in effect 1st to last Billing Cycle February 2006 through January 2007, respectively.

[2] An Historic Component is not anticipated in the 1st year under the new PSA methodology since the HC is to true up related to respective prior period PSA activity.

[3] Outstanding balances related to application under prior PSA methodology are accounted for here: Commission approved Docket No. XXXXXXXXXX

[4] Provides for Mid-Period Corrections when necessary; Commission approved Docket No. XXXXXXXXXX

[5] Provides for Other changes when necessary; Commission approved Docket No. XXXXXXXXXX

[6] Tracks (Refund)/Collection Balances applicable to each sub-category Transition Component; See Schedule 6 for Commission approved Docket Nos. and detail.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Forward Component Calculation Effective February 1, 20XX
($ in thousands Forward Component in $.000000/kWh)

Line No.	PSA Forward Component - Calculation	Current February 1, 20XX [1]	Proposed February 1, 20XX	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Projected Fuel and Purchased Power Costs	$ -	$ -	$ -	0.00%
2	Projected Off-System Sales Revenue	-	-	-	0.00%
3	PSA Adjustments to Fuel and Purchased Power Costs [2]	-	-	-	0.00%
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ -	$ -	$ -	0.00%
5	Projected Native Load Sales, excluding E-3, E-4, E-36 (kWhs)	-	-	-	0.00%
6	Projected Average Net Fuel Cost $/kWh (L4 / L5)	$ -	$ -		
7	Authorized Base Fuel Rate $/kWh	$ -	$ -		
8	Forward Component $/kWh (L6 - L7)	$ -	$ -		

Notes:

[1] No Current Info. Provided in 1st PSA-2 filing: PSA-1 in effect during 1st to last Billing Cycle February 2006 through January 2007, respectively.

[2] Includes costs associated with E-36, ISFSI and mark-to-market accounting adjustments.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Forward Component Tracking Account - (PSA Prior Forward Component in effect from Jan 1 to Dec 31, 20XX)

($ in thousands)

Line No.	20XX Cycle Billing Month	(a) PSA Retail [1] Energy Sales (MWh)	(b) Wholesale Native Load [2] Energy Sales (MWh)	(c) Total Native Load Energy Sales (MWh) (a + b)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs (d - e)	(g) PSA Retail Power Supply Costs (a/c * f)	(h) Base Rate Power Supply Recovery (a * 0.0XXXXX)	(i) Forward Component [6] Recovery (a * 0.0XXXXX)	(j) (Over)/Under Collections (g - h - i)	(k) Interest [5] (i * rate/12)	(l) Tracking [7] Account Balance (j +k +l)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest Rate [5]		4.38%										

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule E-36 were excluded from the PSA Calculations.
[2] Includes traditional sales-for-resale and PacifiCorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 XXXXXX, ISFSI and mark-to-market accounting adjustments.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
[6] Forward Component Effective Feb 1, xxxxx to Jan 31, xxxx 0.00000 - Feb 1, XXXX to Jan 31, xxxx 0.00000
[7] Tracking Account Balance Line 13 carried to Schedule 4, Line 1.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historic Component Calculation Effective February 1, 20XX
($ in thousands Historic Component in $/kWh)

Line No.	PSA Historic Component Calculation	Current February 1, 20XX[1]	Proposed February 1, 20XX	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance (From Schedule 3, L13, Cl i)[2,3]	$ -	$ -	$ -	0.00%
2	Historic Component Tracking Account Balance (From Schedule 5, L8)[4,5]	-	-	-	0.00%
				-	0.00%
				$ -	0.00%
3	Total Historic Amount to be (Refunded)/Collected Balance (L1+L2)[6]	$ -	$ -	-	0.00%
4	Projected Energy Sales without E-3, E-4 and E-36 (MWh)	-	-		
5	Applicable Historic Component for February 1, XXXX ($/kWh) (L3 / L4)	$ -	$ -		

Notes:

[1] No Current Info. Provided in 1st New PSA filing: Prior PSA in effect during 1st to last Billing Cycle February 2006 through January 2007, respectively.

[2] Current Forward Component Tracking Account Balance as of December 31, XXXX.

[3] Includes interest for January.

[4] Current Historic Component Tracking Account Balance as of January 31, XXXX.

[5] Because the actual amount of revenue to be received in December and January from application of the prior Applicable Historic Component is not available at the time of filing, Schedule 5 will reflect as necessary estimates for those periods as well as true-up calculations for the prior period estimates, See Schedule 5 for more detail.

[6] Beginning Balance as of February 1, XXXX. - to be carried forward to subsequent period PSA, Historic Component Tracking Account Balance, Schedule 5, L1.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historic Component Tracking Account - Prior PSA Historic Component In Effect Feb 1, 20XX through Jan. 31, 20XX
($ in thousands)

Line No.		20XX Actual Data												Estimated Data	
		January	February	March	April	May	June	July	August	September	October	November	December	20XX January
1	HC Beginning Balance as of Feb. 1, XXXX 1 and thereafter:		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from December - January Estimate [2]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	HC Adjusted Beginning Balance (L1+ L2)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Historic Component ($/kWh) 3		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
5	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [4]	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable HC (L4 x L5) [5]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [6]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	HC Ending Balance as of Jan 31, XXXX 1; (L3 -L6 +L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

[1] Beginning Balance as of February 1, XXXX - carried forward from prior period PSA, Historic Component Calculation Schedule 4, L4.

[2] True-up is the result of using estimated revenue for December January since actual amount was not available at the time of prior period PSA filing.

[3] Historic Component, Prior Period PSA, Sch. 4, L6.

[4] Sales amounts are for energy billed beginning with the first billing cycle of February 20XX.

[5] Difference between Line 4 times Line 5 and Line 6 are due to billing adjustments.

[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Calculation Effective XXX XX, 20XX
($ in thousands Transition Component (s) in $/kWh)

Line No.		Current Effective Dates	Proposed Effective Dates	Increase/(Decrease) $ Values	Increase/(Decrease) %
	PSA Transition Component Calculation (Non-Tracking Account Items)				
1	Prior PSA Transition - Approved (Refundable)/Collection Amount [1]	$ -	$ -	$ -	0.00%
2	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX	-	-	-	0.00%
3	**Prior PSA Transition Component (Refundable)/Collection (L1 / L2)**	$ -	$ -	$ -	0.00%
4	Mid-Period Transition - Approved (Refundable)/Collection Amount [2]	$ -	$ -	$ -	0.00%
5	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX	-	-	-	0.00%
6	**Mid-Period Transition Component (Refundable)/Collection Rate (L4 / L5)**	$ -	$ -	$ -	0.00%
7	Other (***Enter Description***) Transition - Approved (Refundable)/Collection Amount [3]	$ -	$ -	$ -	0.00%
8	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX	-	-	-	0.00%
9	Other (Enter Descriptions) Transition Component (Refundable)/Collection (L7 / L8)	$ -	$ -	$ -	0.00%
10	Total Transition Component (Non-Tracking Account Items (L3 + L6 + L9)	$ -	$ -	$ -	%

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Calculation Effective XXX XX, 20XX
($ in thousands Transition Component (s) in $/kWh)

Line No.		Current Effective Dates	Proposed Effective Dates	Increase/(Decrease) $ Values	%
	PSA Transition Component Calculation (Tracking Account Items)				
11	Prior PSA Transition Tracking Account Balance - (Refundable)/Collection [4]		$ -		
12	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX		-		
13	**Prior PSA TA Transition Component (Refundable)/Collection (L11 / L12)**		$ -		
14	Mid-Period Transition Tracking Account Balance - (Refundable)/Collection [5]		$ -		
15	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX		-		
16	**Mid-Period TA Transition Component (Refundable)/Collection Rate (L14 / L15)**		$ -		
17	Other (***Enter Description***) Transition Tracking Account Balance - (Refundable)/Collection Amount [6]		$ -		
18	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX		-		
19	Other (Enter Descriptions) TA Transition Component (Refundable)/Collection (L17 / L18)		$ -		
20	Total Tracking Account (s) Transition Component (L13 + L16 + L19)		$ -		
21	Total Transition Component (L10 + L20)		$ -		

Notes:
[1] Commission Docket No. XXXXXXXXXX
[2] Commission Docket No. XXXXXXXXXX
[3] Commission Docket No. XXXXXXXXXX
[4] Source, Schedule 7a, Line 8
[5] Source, Schedule 7X, Line 8
[6] Source, Schedule 7X, Line 8

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7a
Prior PSA Transition Tracking Account - Prior PSA Transition Component In Effect Feb 1, 20XX through Jan. 31, 20XX
($ in thousands)

Line No.		20XX Actual Data											Estimated Data	
		January	February	March	April	May	June	July	August	September	October	November	20XX December	20XX January
1	Prior PSA Transition TA Beginning Balance as of Feb. 1, XXXX[1]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from December - January Estimate [2]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Adjusted PSA Transition TA Beginning Balance (L1+ L2)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Prior PSA Transition TA Transition Component ($/kWh) [3]		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
5	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [4]	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable TA Transition Component (L4 x L5) [5]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [6]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Prior PSA Transition TA Ending Balance as of Jan 31, XXXX; (L3 -L6 +L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

[1] Beginning Balance as of February 1, XXXX - carried forward from Prior PSA Transition Amount as Approved and entered on Prior PSA Schedule 6, L1.

[2] True-up is the result of using estimated revenue for December January since actual amount was not available at the time of prior period PSA.

[3] Prior PSA Transition Component, Prior PSA Sch. 6, L3

[4] Sales amounts are for energy billed beginning with the first billing cycle of February 20XX.

[5] Difference between Line 4 times Line 5 and Line 6 are due to billing adjustments.

[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7b
Mid-Period Transition Tracking Account - Prior Mid-Period Transition Component in Effect Feb. 1, 20XX through Jan. 31, 20XX
($ in thousands)

Line No.		20XX Actual Data											Estimated Data	
		January	February	March	April	May	June	July	August	September	October	November	20XX December	20XX January
1	Mid-Period Transition TA Beginning Balance as of Feb. 1, XXXX [1]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from December - January Estimate [2]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Adjusted Mid-Period Transition TA Beginning Balance (L1+ L2)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Mid-Period Transition TA Transition Component ($/kWh) [3]		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
5	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [4]	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Mid-Period TA Transition Component (L4 x L5) [5]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [6]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Mid-Period Transition TA Ending Balance as of Jan 31, XXXX [1]: (L3 -L6 +L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1. Beginning Balance as of February 1, XXXX. - carried forward from Mid-Period Transition Amount as Approved and entered on Prior PSA Schedule 6, L4.
2. True-up is the result of using estimated revenue for December January since actual amount was not available at the time of prior period PSA-2 filing.
3. Mid-Period Transition Component, Prior Period PSA-2, Sch. 6, L6
4. Sales amounts are for energy billed beginning with the first billing cycle of February 20XX.
5. Difference between Line 4 times Line 5 and Line 6 are due to billing adjustments.
6. Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

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IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827 **NOTICE OF FILING REPORT**

Arizona Corporation Commission ("Staff") hereby files its report regarding its inquiry into Arizona Public Service Company's fuel and purchased power procurement and costs. The attached report is a public version with confidential information redacted. A confidential version of this report will be provided under seal to the commissioners, their assistants, the assigned administrative law judge, APS, and any parties who have signed protective agreements with APS in this matter. Because of the length of the report, Staff intends to serve the parties electronically. Staff will be happy to provide a hard copy of the report upon request.

RESPECTFULLY SUBMITTED this 1st day of September, 2006.

Janet E. Wagner

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Legal Counsel
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Arizona Corporation Commission
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Final Audit Report
APS Fuel and Purchased Power
Procurement and Costs
Non-Confidential Version

(Redacted Information Shaded)

Presented to:

Arizona Corporation Commission
Utilities Division

Presented by:

The Liberty Consulting Group

August 31, 2006

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I. Introduction

A. Project Scope and Objectives

The Staff of the Arizona Corporation Commission ("ACC") issued a November 16, 2005 RFP seeking an audit of the fuel and purchased power procurement practices and costs of Arizona Public Service Company. The RFP sought an examination and analysis of the management and operations of the utility's fuel and purchased power functions and the formulation of any appropriate recommendations. The RFP asked that the audit address:

- Organization structure, responsibilities, and staffing
- Policies, procedures, systems, and tools
- Procurement approach, methods, and decisions.

The RFP identified a series of work elements within these broad areas. The Liberty Consulting Group ("Liberty") responded to this RFP with a December 9, 2005 proposal to perform the audit. The ACC selected Liberty to perform the audit. The following report describes the examination and analyses that Liberty undertook, the findings and conclusions it has reached, and the recommendations that Liberty considers appropriate for addressing those conclusions.

B. Company Background

Arizona Public Service Company ("APS" or "the Company") is an electric utility based in Phoenix, Arizona. APS operates as the largest subsidiary of Pinnacle West Capital Corporation ("PWCC"), a holding company with over $11 billion in assets and $3 billion in annual revenues. APS utility operations generated 75 percent of consolidated PWCC operating revenues in 2005 -- up by 3 percent from 2004. Over the past three years, the operating revenues of the other two PWCC business lines (non-utility marketing/trading and real estate) have declined moderately. A factor in the non-utility marketing/trading sector's contraction has been the placement of former merchant units into the APS utility generation mix, as the Company has moved back (albeit under a changed paradigm) in the direction of vertically integrating utility electricity services. PWCC does not view marketing/trading as a longer-term business priority in light of marketplace changes in Arizona particularly and in the region generally. The following table shows the relative contribution of APS to consolidated operating revenues.

Table I.1 PWCC Operating Revenues

	2005	2004	2003	2002	2001
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	$ 2,237,145	$ 2,035,247	$ 1,978,075	$ 1,890,391	$ 1,984,305
Marketing and trading segment (a)	351,558	400,628	391,196	286,879	469,784
Real estate segment (a)	338,031	350,315	361,604	201,081	168,908
Other revenues	61,221	42,816	27,929	26,899	11,771
Total operating revenues	$ 2,987,955	$ 2,829,006	$ 2,758,804	$ 2,405,250	$ 2,634,768

APS has averaged a 3.8 percent increase in customers for the past three years. In 2004, APS was serving approximately 990,000 customers in 11 of Arizona's 15 counties. Customer numbers surpassed 1,000,000 in 2005, during which APS experienced load growth of 9.3 percent. Strong

growth is not a recent phenomenon at APS. The Company has been the second-fastest growing utility in the United States since 1999. APS projects that annual growth rates will remain at 2.8 percent for customer numbers and will run at 3.8 percent for total usage. PWCC's most recent annual report illustrates APS's dramatic growth in customers and in usage per customer. Fuel costs have risen strongly as well. The following tables summarize these areas of growth.

Figure I.2 APS Annual Customer Growth and Electricity Use

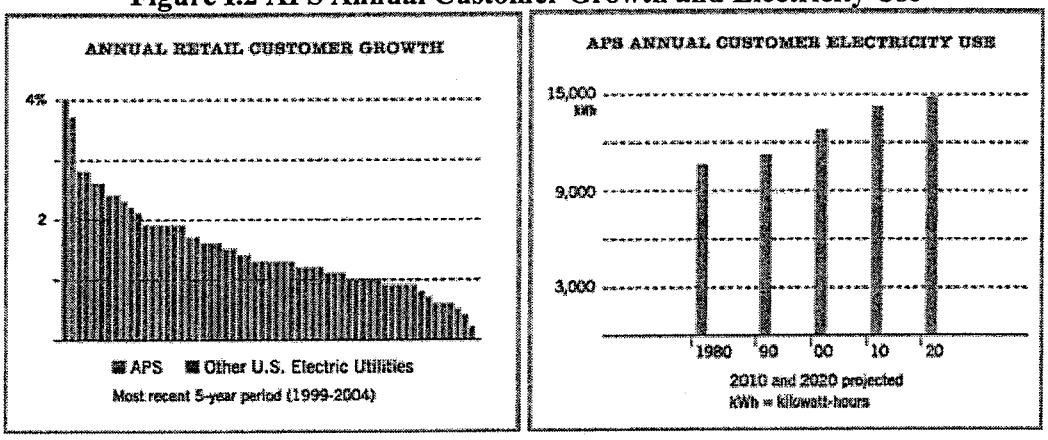


Figure I.3 Fuel Cost Increases

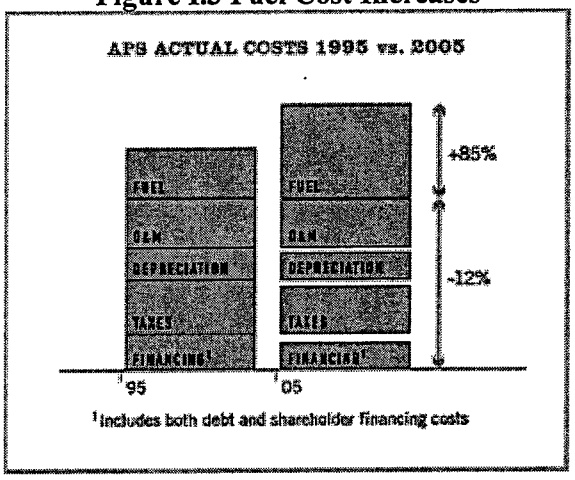


Table I.4 APS
Annual Fuel Expense

Year	Fuel Expense
2005	$595 million
2004	$567 million
2003	$517 million

The nature of APS fuel contracting (particularly long-term coal contracts and nuclear fuel arrangements) also produces a very substantial forward commitment. Take-or-pay commitments in its coal contracts through 2024 total $1 billion, and have a present value of $600 million.

New APS rates became effective April 1, 2005, following a settlement agreement. The resulting total revenue requirement increase was $75.5 million. The settlement agreement also provided for the transfer of four APS-affiliate owned gas-fired generation units (totaling 1,780MW) into the APS rate base. The approved settlement agreement implemented a Power Supply Adjustor ("PSA") that provides for fuel (including nuclear fuel) and purchased power cost recovery.

APS is responsible for managing 10,400 MV of capacity at 11 generating stations, including Palo Verde. The following table lists the fossil stations, which formed the principal focus of this audit.

Table I.5 APS Generating Stations and Fuel Type

Station Name	Fuel Type	Station Name	Fuel Type
Four Corners	Coal	Redhawk	Natural Gas
Cholla	Coal	Sundance	Natural Gas
Navajo	Coal	Saguaro	Natural Gas
Douglas	Oil	West Phoenix	Natural Gas
Ocotillo	Natural Gas	Yucca	Natural Gas

APS jointly owns much of its generation with others; APS has responsibility for operation of more capacity than it owns. Its ownership totals 6,415MW, which consists of the following components and percentages of total ownership:

- Palo Verde Nuclear Generating Station ("Palo Verde"): 1,164MW (18.1 percent of total)
- Natural gas: 3,411MW (53.2 percent)
- Coal: 1,835MW (28.6 percent)
- Solar: the remaining 5MW (0.1 percent).

A brief description of the major units follows:

- Four Corners: five coal-fired units
  - 2,040MW total capability
  - 782MW share owned by APS
  - Owned by six southwest utilities
  - Operated by APS
  - Located on the Navajo Indian Reservation west of Farmington, New Mexico
  - Uses low-sulfur coal from the nearby Navajo mine
- Cholla: four coal-fired units
  - 995MW total capability
  - Three units (with a total capability of 615MW) owned by APS
  - Fourth unit (with a capability of 380MW) owned by PacifiCorp
  - Operated by APS
  - Subject to a seasonal exchange agreement under which APS receives power during its summer peak and provides power during PacifiCorp's winter peak
  - Uses coal from the McKinley Mine in New Mexico
- Navajo: three coal-fired units
  - Each unit has a 750MW capability
  - Owned by partnership of five utilities and the U. S. Bureau of Reclamation

  - APS share is 14 percent
  - Operated by Salt River Project
  - Located on the Navajo Indian Reservation near Page, Arizona
  - Supplied by a Navajo and Hopi Indian Reservations mine at Black Mesa, Arizona
- Redhawk: two gas-fired, combined cycle units
  - Each with a capability of 530MW
  - Owned and operated by APS
  - Began operating in mid-2002
  - Located near the Palo Verde Nuclear Generating Station west of Phoenix
- West Phoenix: seven gas-fired units
  - Two combustion turbine units and five combined-cycle units
  - Owned and operated by APS
  - 1,000MW combined capability
  - Located in southwest Phoenix
- Ocotillo: four units
  - Two steam and two combustion turbine units
  - Combined capability of 340MW
  - Operated and owned by APS
  - Located in Tempe, Arizona
- Sundance: one simple-cycle gas-fired unit
  - 10 quick-start combustion turbines with a combined 450MW total capability
  - Located in Coolidge, Arizona
  - Owned and operated by APS
- Saguaro: five gas-fired units
  - Two steam units and three combustion turbine units; 395MW total capability
  - Located north of Tucson, Arizona
  - Owned and operated by APS
- Douglas: one oil-fired unit
  - Combustion turbine peaking unit with a capability of 16MW
  - Located in Douglas, Arizona
  - Owned and operated by APS
- Yucca: four gas-fired units
  - Combustion turbine units with a combined capability of 150MW
  - Located near Yuma, Arizona
  - Owned and operated by APS
  - Also includes an Imperial Irrigation District combustion turbine and steam unit
- Solar
  - Total capacity of all solar plants is about 5MW.

C. Audit Work Summary

The audit of APS fuel and purchased power procurement practices and costs began with the issuance of a first set of Liberty and Staff data requests on February 3, 2006. Liberty and Staff submitted nine sets of data requests consisting of 226 questions. Company responses were generally timely and responsive. The APS team assigned to assist in coordinating

communications with Liberty and the Staff acted constructively to resolve uncertainties, assure complete answers, and support logistics needs. The Liberty team conducted initial interviews during the week of March 27, 2006. APS was responsive to requested interview subjects and topics, with one exception. Liberty found interviewees direct and forthcoming in responding to questions, and seemingly mindful of the importance of Commission access to and understanding of fuel and energy management at APS.

The exception to access to personnel involved the members of the board of directors. APS declined to make them available for interviews. APS did offer access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and how they exercise that role. Liberty's standard audit practice, however, is to discuss with directors in person what information they consider important and how they use it to oversee important areas of operations. Liberty could not address the directors' role in the manner planned. Liberty did ultimately gain sufficient information to conclude that there was no failure of information flow to the board, but believes that there should be future acceptance by APS of the propriety of direct communication with directors.

Liberty's team also conducted on-site work observations and inspections at the West Phoenix and Redhawk Plants to address operations issues. Liberty did the same at the Cholla and the Four Corners Generating Station coal handling areas, in order to observe and discuss coal-handling operations with station personnel. Liberty also directly observed work processes at the Four Corners coal lab, and discussed operations with lab personnel. Liberty examined operations and questioned APS personnel on the trading floor where dispatch, power sales and purchases, gas transportation management, and hedging transactions take place. This location includes PWCC's non-utility trading operations. This inspection included the front office (where actual trading takes place) and the middle and back offices (where accounting and controls related to energy transacting take place). Liberty also conducted phone interviews with APS employees to discuss follow-up questions arising from fieldwork, data gathering and analysis.

D. Report Structure

The following list summarizes the structure of this audit report:

- *Chapter One*: Introduction
- *Chapter Two*: Goals, Strategies, Organization, Policies, and Procedures
- *Chapter Three*: Fuel Management
- *Chapter Four*: Fuel Contracts
- *Chapter Five*: Hedging and Risk Management
- *Chapter Six*: Forecasting and Modeling
- *Chapter Seven*: Plant Operations
- *Chapter Eight*: Purchased Power and Off-system Sales
- *Chapter Nine*: Nuclear Fuel
- *Chapter Ten*: Financial Audit of PSA Costs.

Chapters Two through Ten address the work elements specified by the RFP. Each of those chapters sets forth a description of the scope it addresses. It then describes the factual information and observations (*Findings*) applicable to each area or issue examined. Each chapter then proceeds to set forth the conclusions reached by Liberty from those facts and about Company performance in each material performance area. Those conclusions specify where Liberty considered performance already to be effective and those areas where Liberty identified opportunities for performance improvement. The conclusions would also have expressed any Liberty opinions that performance failed to meet the standards of good utility practice, prudence, and reasonableness.

This audit report provides a recommendation specifically identifying what actions APS should take to address the issue underlying each conclusion that identified an opportunity for improvement. The report cross-references each recommendation to its underlying conclusion. Liberty has also assigned to each recommendation a ranking of between "1" (representing those that should be implemented with greatest dispatch) and "3" (representing those whose completion has the relatively lowest implementation priority). The following summary lists all of the audit's conclusions and recommendations, and provides the cross referencing and recommendation rankings.

E. Conclusions and Recommendations Summary

Chapter II. Organization, Staffing, and Controls

Conclusions:

1. Personnel in the fuel and power procurement have solid analytical skills and sound experience appropriate to meeting objectives and responsibilities.

2. Job descriptions for personnel in fuel and power procurement are current, and adequately address current responsibilities.

3. Communication within and among the fuel and power procurement organizations and upper levels of management is satisfactory.

4. The fuel and power procurement organizations have a satisfactory program for training and cross training of individuals within their departments.

5. APS maintains an appropriate decision matrix, or chart of approval authorities.

6. The program for employee training and compliance monitoring under the Code of Conduct is satisfactory.

7. The fuel and power procurement organizations have satisfactory procedures for many of the specific functional areas within these organizations, but Fuel Procurement does not have sufficient procedures for fuel contract management and administration. (*Recommendation #1*)

8. Documentation of fuel and power procurement and supply management activities is satisfactory.

9. The APS Audit Services group conducts regular and appropriate internal audits of fuel and power procurement functions.

10. The Company's procedures for accepting offers of gas supply are not sufficiently formal. *(Recommendation #2)*

11. Senior executive management has routinely provided to the board of directors substantial information about fuel, energy, and plant operations performance.

12. Available summaries of the board members' backgrounds show sufficient experience in matters relevant to utility fuel and energy management; however, Liberty was not able to determine through interviews with them what specific knowledge and experience they bring to bear or what values, criteria, performance indicators, and critical decision/judgment points they apply. *(Recommendation #3)*

13. The board's risk management role as defined in written policies and procedures is sound and the risk management program produces effective performance and status reports.

Recommendations:

1. Develop a complete set of procedures related to the management and administration of coal contracts. (*Conclusion #7; Priority 3*)

2. Audit and revise procedures for acceptance of offers for gas supply. *(Conclusion #10; Priority 3)*

3. Secure an understanding with APS that Commission auditing includes access to members of the board of directors. *(Conclusion #12; Priority 3)*

Chapter III. Fuel Management

Conclusions:

1. APS has effectively administered coal contracts.

2. Manual processes in handling coal weight information are not efficient. (*Recommendation #1*)

3. APS procedures for taking samples of coal at the Four Corners Station are sound.

4. APS has undertaken an appropriate program to automate the coal-sample analysis data-management process at the Four Corners laboratory; the program should be in place imminently.

5. The Fuel Procurement Department has an effective process for monitoring supplier performance; the performance of these suppliers has been satisfactory.

6. The Fuels Department appropriately manages coal inventory, but its recent reduction in the inventory target for Regular Coal at the Cholla Station has been too large. *(Recommendation #2*

7. APS has taken appropriate action in response to recent variances between coal inventory book values and the results of physical inventory surveys.

8. APS has appropriately sought beneficial uses and sales of coal combustion by-products.

9. APS has appropriately sought alternative means for disposal of coal combustion by-products at Four Corners when faced with significantly increased disposal costs from BHP.

10. APS's historical approach to gas supply management is typical, but current circumstances constrain its ability to address changes from full-requirements service from the pipeline. *(Recommendation #3)*

11. APS's pursuit of additional pipelines is appropriate.

12. APS's approach to buying fuel oils is reasonable.

Recommendations:

1. Streamline the procedures for handling of information on coal weights. *(Conclusion #2; Priority 3*)

2. Revise the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply. *(Conclusion #6; Priority 3)*

3. Conduct a comprehensive analysis of gas purchasing and management under ELP's revised rate structure, and report to the Commission. *(Conclusion #10; Priority 1)*

Chapter IV. Fuel Contracts

Conclusions:

1. APS applied an appropriate process for the procurement of new long-term coal supplies for the Cholla Station.

2. APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective.

3. APS's two short-term coal supply agreements for the Cholla Station are appropriate.

4. APS uses a sound process to contract for gas commodity.

5. The Company's efforts to develop alternatives to ELP have been appropriate.

6. APS's contracting process for fuel oils is appropriate.

Recommendations:

None.

Chapter V. Hedging and Risk Management

Conclusions:

1. APS has designed and it operates a sound hedging program.
2. The Company's program has been successful in meeting its primary objective.
3. The Company's hedging program will, however, prevent costs from falling. *(Recommendation #1)*
4. The segregation of utility and non-utility activities is not as complete as it should be. *(Recommendation #2)*

Recommendations:

1. Engage stakeholders in a discussion of hedging program objectives. *(Conclusion #3; Priority 2)*
2. Report to the Commission on the future plans for non-utility activities. *(Conclusion #4; Priority 1)*

Chapter VI. Forecasting and Modeling

Conclusions:

1. APS uses sufficiently accurate modeling to predict fuel and purchased power volume and cost.
2. APS has taken appropriate actions to ensure that it achieves least-cost total dispatch.
3. APS uses outside reviews appropriately to improve management and operations.
4. APS maintains adequate documentation to support regulatory oversight and review.

Recommendations:

None.

Chapter VII. Plant Operations

Conclusions:

1. The performance metrics of the base-loaded coal units demonstrate effective operation.
2. The performance metrics of the large gas units also demonstrate effective operation; however, performance metrics of these units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.

3. The performance metrics of the less efficient gas units also demonstrate effective operation; however, performance metrics of the large gas units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.

4. The capital expenditure and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements.

5. APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement. (*Recommendation #1*)

6. The use of a 50/50 load forecast, coupled with the fast growth of the Phoenix Load Pocket, and system constraints of the Phoenix Load Pocket, makes achievement of targeted reserves less certain. (*Recommendation #2*)

7. The timing and layering of APS unit outage schedules follows industry practice, and is effective.

8. Major, scheduled outages at the base-load coal plants have had an appropriate length; however, outages at some of these plants from boiler leaks account for a conspicuously high percentage of net replacement power costs associated with these units. *(Recommendation #3)*

9. The level of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3 is high. *(Recommendation #4)*

10. Improving West Phoenix Unit #5 availability is important to the dispatch and keeping net replacement power costs at minimum levels. (*Recommendation #5*)

11. APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing with Redhawk #1 and #2 and West Phoenix #5 issues involving the units and the need for re-engineering them for intermediate dispatch operation.

12. The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation.

Recommendations:

1. Prepare and execute an action plan that will improve economic evaluations related to minimization of outage time. *(Conclusion #5; Priority 1)*

2. Analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket. *(Conclusion #6; Priority 2)*

3. Evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3 in light of current high net replacement power costs. *(Conclusion #8; Priority 3)*

4. Conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly identified and addressed; determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. *(Conclusion #9; Priority 2)*

5. Implement for West Phoenix #5 the requirement for root cause analysis when generation is lost. *(Conclusion #10; Priority 3)*

Chapter VIII. Purchased Power and Off-System Sales

Conclusions:

1. The trading activities of APS M&T are based on sound hedging policies and procedures, and ensure that the procurement and sale of electric power is conducted in a manner that will meet least-cost dispatch guidelines.

2. APS effectively utilizes its portfolio of generating resources and power purchases to optimize value in the marketplace.

3. APS has developed the necessary documentation and tools to ensure that electric power trading can be conducted in accordance with the goal of achievement of the least-cost total dispatch.

4. APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale.

5. The APS internal documentation separating the activities of utility versus non-utility electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between this information. *(Recommendation #1)*

6. The APS and non-utility trading operations are not sufficiently physically segregated. *(Recommendation #1)*

7. PWCC made some inappropriate commitments to trades using utility assets in 2005; but APS has eliminated them, transferred their margins to the utility accounts of APS, and begun changes to prevent the future use of utility assets by affiliates. *(Recommendation #2)*

8. The primary reason that sales for resale have produced smaller margins than those of neighboring utilities is APS's lower proportional levels of excess coal and nuclear generation.

Recommendations:

1. Clearly segregate utility and non-utility trading in all operations and reporting to ensure that utility trading is conducted to maximize utility opportunities. *(Conclusions #5 and #6; Priority 1)*

2. Complete the process of preventing future affiliate use of utility assets and examine means for continuing transmission optimization transactions through some form of sharing mechanism. *(Conclusion #7; Priority 1)*

Chapter IX. Nuclear Fuel

Conclusions:

1. APS conducts nuclear fuel procurement and management through an effective organization.

2. APS has developed and used effective procedures for procuring nuclear fuel.

3. APS uses an appropriate basis to account for its nuclear fuel costs for ratemaking purposes.

Recommendations:

None.

Chapter X. Financial Audit of PSA Costs

Conclusions:

1. APS's accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing.

2. APS audits, however, have yet to address PSA filing preparation. *(Recommendation #1)*

3. APS documents its filing information well, but lacks a formal written procedure addressing preparation of the monthly PSA filings. *(Recommendation #2)*

4. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate.

5. Despite their general accuracy, including the total costs of generation, APS over- or under-stated individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation. *(Recommendation #3)*

6. Liberty's detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

7. Liberty's detail review of the non-confidential PSA Over/Under values found them to be accurate, but they should be more transparently supported. *(Recommendation #4)*

8. A review of APS handling of supplemental fuel charges and refunds indicates that supplemental charges and refunds have been accounted for in the PSA when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA. *(Recommendation #5)*

Recommendations:

1. Conduct periodic internal audits of the PSA filings to verify the soundness, completeness, and accuracy of the activities that produce them, with the first such audit to be conducted as part of the next audit plan. (*Conclusion #2; Priority 2*)

2. Develop a written policy and procedure for the preparation of the confidential PSA filings. (*Conclusion #3; Priority 2*)

3. Correct PSA reporting methods to assure more accurate classification and reporting of coal, oil, and gas generation information. *(Conclusion #5; Priority 2)*

4. Revise the PSA confidential filing format to provide a sufficient level of detail to support the calculation of the components contained within PSA non-confidential filings. *(Conclusion #7; Priority 1)*

5. Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes. *(Conclusion #8; Priority 2)*

II. Organization, Staffing and Controls

A. Scope

This chapter addresses the following topics related to the goals, strategies, organization, policies and procedures that guide APS fuel and energy procurement and portfolio management:

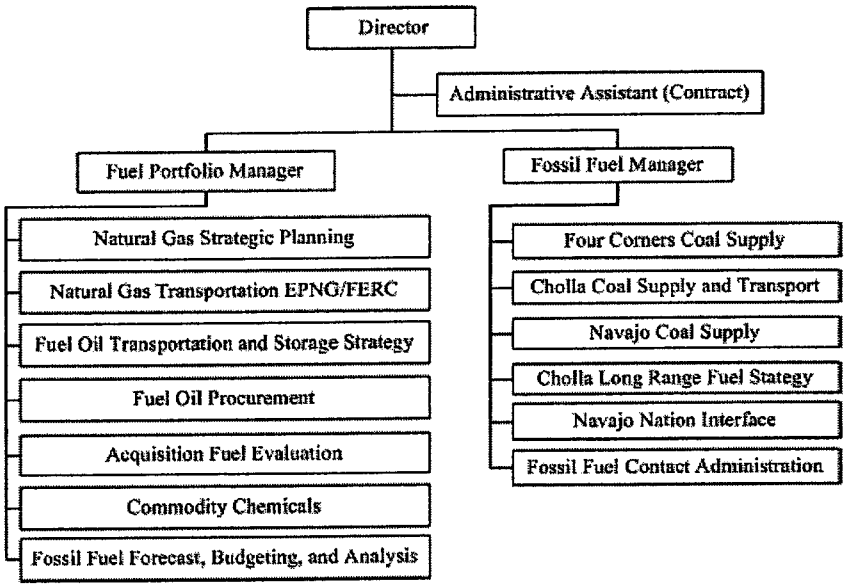
- Organization structure
- Staffing
- Approval authorities
- Goals, strategies, policies and procedures
- Documentation requirements
- Auditing.

B. Findings

1. Fuel Procurement and Management Organization

The Fuel Procurement Group, headed by the Director, Fuel Procurement, secures fuel for power generation at APS. The Fuel Procurement Group reports directly to the Vice President, Fossil Generation, who in turn reports directly to the President and CEO of APS. This group manages all aspects of fossil fuel management, including budgeting and analysis, fuel and transportation procurement, chemical procurement, waste product management, and contract administration. The group, however, does not procure natural gas. While it does secure the transportation services for natural gas, APS Marketing and Trading procures the natural gas commodity. The following chart depicts the organizational structure and the functions for which each Manager is responsible.

Figure II.1 APS Fuel Procurement Group Organization



The Fuel Procurement Group contains three senior personnel:

- The Director
- Two managers reporting to the Director: the Fossil Fuel Manager and the Fuel Portfolio Manager
- Three individuals reporting to the Fossil Fuel Manager
- Four individuals reporting to the Fuel Portfolio Manager.

The Director, Fuel Procurement has responsibility for meeting fossil generation requirements at lowest possible cost by directing the:

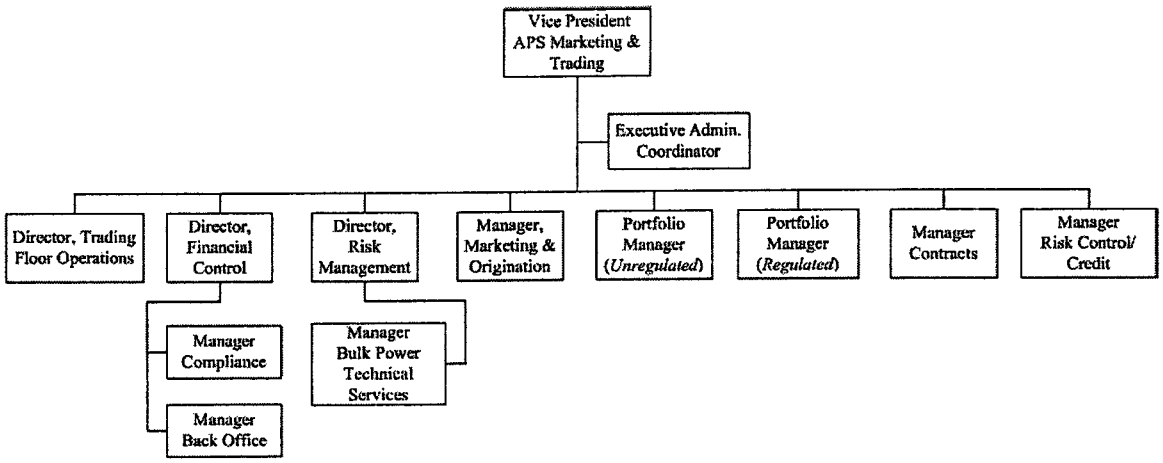
- Design, development, and implementation of comprehensive fuel strategies
- Acquisition of fuels, water, and lime
- Associated contract administration
- Development, evaluation, and implementation of cost and performance metrics.

The Fossil Fuel Procurement Manager is responsible for implementing the fossil-fuel strategic plan, and for negotiation, procurement, and administration of all fossil contracts, including the arrangement of coal-transportation requirements. The Fuel Portfolio Manager is responsible for managing design, development, and implementation of comprehensive corporate strategies to optimize use of the Generation Business Unit asset portfolio. He is responsible for acquisition of natural gas transportation services, fuel oil procurement, transportation and storage, commodity chemicals, and fossil fuel forecasting, budgeting and analysis.

2. Electric Power and Natural Gas Procurement and Trading Organization

The Vice President, APS M&T heads the department, and reports to APS's CFO. Two directors and eight managers report to this Vice President. The following figure shows this organization.

Figure II.2 APS M&T Organization



The APS Marketing & Trading ("APS M&T") Department is responsible for:

- Economic dispatch of generating units on the APS system

- Procurement of wholesale purchased power and natural gas for APS native load needs
- Marketing of surplus APS generation and natural gas
- Risk management and control activities for electric power and natural gas transactions.
- Performance of certain financial control operations that support trading and hedging activities (often referred to as the "mid-office" and "back-office" activities).

The APS M&T's Portfolio Manager (Regulated) has responsibility for:

- Procuring term supplies of wholesale purchased power for the utility
- Procuring natural gas for the utility
- Marketing surplus APS generation and natural gas
- Using all available trading and hedging tools, such as futures, options, swaps, and derivatives to carry out the APS hedging program.

The Portfolio Manager (Regulated) works closely with M&T's Director of Risk Management to determine physical and financial risk exposures, and to manage these risks.

The Director, Trading Floor Operations within M&T is responsible for real time electricity and natural gas trading, resource commitment, and bulk power scheduling. He coordinates all electricity and natural procurements having durations up to 30 days, including portfolio integrity, risk management and business development. He maintains close relationships with the Portfolio Manager, the Director, Fuel Procurement, and the Generation Group, in order to coordinate market conditions and system needs with fuel contract status and power plant operations.

3. Performance Measurement

An overall APS program for performance management guides measurement of employee performance in Fuel Procurement and in APS M&T. This program includes annual performance evaluations conducted by immediate supervisors of employees. Part of the evaluation process includes establishment for the next year of goals related to measurable objectives for fuel and power procurement management and operations. Reviews conducted at the end of each year between employees and managers affect decisions about salary changes.

The Vice President, Fossil closely monitors the performance of both fuel procurement and power generation activities through a number of regular meetings and reports. He conducts monthly, individual meetings with each person who reports directly to him. In addition, he meets every two weeks with representatives from each of the power generating stations. The Vice President's direct reports include the following twelve persons:

- Director, Fossil Fuel Procurement
- Director, Generation Engineering
- Director, New Generation
- Plant Managers (there are 8 of them)
- Manager, Technical Services.

The Vice President Fossil regularly monitors a number of monthly reports addressing fuel and power generation; they include:

- Fuel inventory and deliveries – actual compared to planned
- Fuel expense by station – actual versus budget and variances
- Fuel variance explanations
- Estimated coal and oil prices for power plant dispatch (which the Vice President approves)
- Detailed fuel variance analysis by station
- Heat rate target versus actual for the month and for 12 months for each generating unit
- Non-commodity and secondary fuel expenses.

The President and CEO of APS follows a similar pattern of meetings and reports to monitor the performance of fuel and power generation activities. He meets monthly in individual sessions with each individual reporting directly to him. He also holds monthly staff meetings with all officers. He monitors generating unit availability, gas and energy prices, and hedge positions on a daily basis. He regularly monitors fuel, power and station activities compared to budgeted performance.

The President and CEO cited recent, major activities related to assessing, negotiating, and executing new coal supply agreements for the Cholla Generating Station as an example of the types of special, non-recurring issues typical of those that he personally follows closely. He cited as another example the accompanying new rail transportation agreements, which APS found necessary to review because mining operations at the McKinley Mine wind down earlier than originally anticipated. He reviewed the final agreements prior to their execution, but they were signed by the appropriate Company official as specified by the corporate policy addressing authorization limits.

The President and CEO cited a number of the types of issues about which he advised the Board of Directors, mentioning plans, progress, and the final contract status of the new coal supply, and associated rail transportation, to the Cholla Station. Liberty found documentation in Board of Director minutes confirming review and discussion of these activities, as the change in coal supply for the Cholla Station progressed from initial plans to final coal and rail contracts.

4. Training

APS does not use a formalized training program or training manual for employees in the fuel and power procurement function. APS does, however, operate a number of specific ongoing training programs, and conducts a variety of less formal cross-training activities:

- All employees must take standard corporate safety training classes that include Emergency Evacuation, Hazard Communication and Defensive Driving
- All employees receive Ethics and Standards of Business training provided by the company; this online training concerns the Company Ethics Policy and Standards of Business Practices, and is explained in detail in the corporate booklet entitled *Do The Right Thing*

- APS M&T personnel have been participating since December 2005 in live training sessions on the *Market Behavior Rules* of the Federal Energy Regulatory Commission ("FERC"); the sessions will continue through March 2006
- Other training programs for generating station personnel address various skills, specific power plant operational areas, simulator training and safety-related training.

Fuel Procurement personnel must take specific courses addressing ACC and FERC Code-of-Conduct requirements. This training provides a brief description and explanation of the actual codes and the Company policies and procedures to ensure that the employees of the PWCC family of companies comply with the requirements of the two commissions.

Fuel Procurement personnel receive encouragement to attend selected seminars or training courses related to their specific areas of fuel purchasing, transportation, or management. The department also routinely works on cross training, and has incorporated requirements into performance evaluations. Examples include:

- The Director, Fuel Procurement recently served on a temporary, one-year job rotation assignment with APS M&T operations on the trading floor
- The Fossil Fuel Manager served on temporary assignment to the Ocotillo Station last summer
- The Director and the Managers who report to him have handled the chemical procurement function.

APS uses an eight-step, organized succession management process to develop a succession plan for positions within the Company. These eight steps are:

- Position profile creation
- Initial identification of candidates
- Candidate profiles creation
- Calibration review
- Position profiles and candidate profiles entry into succession management data base
- Development plan discussion
- Periodic reviews
- Reports.

Such a plan exists for the Director, Fuel Procurement position. APS has currently identified three candidates for this position. These individuals have been rated against the profile created for this position and the necessary developmental needs and plans for each of these individuals have been documented.

5. Job Descriptions

Job descriptions for employees in the fuel and power procurement functions are current, and adequately reflect the responsibilities of the positions for which they have been written. These

job descriptions provide the starting point for defining job responsibilities against which individual performance is measured in the performance evaluation process.

6. Staffing

The vice presidents, directors, and managers in the fuel and power procurement functions have adequate background and experience for the positions that they occupy. The Director, Fuel Procurement has been with APS for 25 years, and has been in the fuels organization for over 9 years. The Fossil Fuel Manager has been with APS for 21 years, and has been in the fuels organization for approximately 10 years. The Fuel Portfolio Manager has been with APS for 16 years, and has been in the fuels organization for 7 years. The Vice President, Fossil Generation, to which the Director reports, has been with APS for 42 years, having held a number of positions of increasing responsibility related to management and operations of APS generating stations.

The Vice President, APS Marketing & Trading has been with APS for 26 years. He progressed through a variety of power plant positions, became an electrical engineer while working at APS, and was named the Director of Bulk Power Marketing and Resource Operations in 1996.

The Director, Trading Floor Operations has been with APS for 28 years, and has been in the Bulk Power Marketing Department for 10 years. The Portfolio Manager has been with APS for 18 years, and has been in APS fuel and gas trading areas for 14 years. He has served as APS's Director of Generation Fuel Procurement, and has held his current position for two years.

The level of background and experience for senior employees in both fuel and power procurement positions typifies that of lower levels in the organizations as well. The relevant APS organizations are staffed by mature, experienced individuals. This strength shows that a long-range emphasis on candidate identification and personal development has served to ensure continuation of the appropriate level of experience.

7. Approval Authorities

Several corporate policies related to decision-making control the approval of procurement activities within the fuel and power procurement organizations. Corporate Policy #51 addresses delegation of authority. It provides for delegation of authority as necessary to accommodate the business needs of the Company, while maintaining adequate control. It specifies that the Controller oversee the delegation of authority and the authorization levels necessary to execute various procurement and work authorizations.

APS has supported this delegation of authority policy with a formal system of controls within the MLIS computer system. These controls establish commitment levels for each level of management. A *Decision Matrix* includes the name of the employee, and the following designations for which the individual has authority:

- Business Entity
- Account Type
- Document Type
- Authorization Limit.

Liberty's test examination of a number of fuel-supply procurements found that the proper level of management executed the necessary agreement. Liberty also examined the degree of involvement of senior management and the board of directors on major procurement decisions. Liberty found that top executive management and the board, were timely informed of initial plans of action, recommendations for new suppliers, and the associated transportation agreements for a new coal supply to the Cholla Station, which involved a large and important set of procurement actions for the Company.

8. Goals and Strategies

APS groups involved in fuel and energy procurement operate under business plans, or what APS terms "Initiatives." The corporate business plan incorporates specific success indicators or targets (such as production costs in cents/kWh) for the current year and for five years into the future. These success indicators include the following categories:

- Safety
- Reliability & Operations
- Customer Satisfaction
- Growth
- Workforce
- Environment
- Financial Leadership.

The *Generation Business Plan* is similar in nature, and includes its own specific success indicators or goals for the current year: These goals include the categories of:

- Safety
- Reliability and Efficiency
- Production Cost
- Environmental.

The Fuel Procurement organization develops initiatives for each year. The 2005 initiatives, for example, addressed fuel supply issues for each of the large generating stations, fuel portfolio initiatives, and administrative initiatives. The initiatives for 2005 for the Cholla Station included several specific actions related to the need to develop new coal supply and transportation agreements, recognizing the wind-down of coal mining operations at the McKinley mine, which has supplied this station for many years.

Initiatives for 2006 fall into the same overall action categories as the 2005 initiatives, but included new station-specific and new fuel portfolio items. One of the important new items identified for the Four Corners Station was the longer-term need to assess optimum ash disposal methods. The BHP ash hauling costs passed on to APS will likely increase significantly in a few years, because it will become necessary to use a new ash disposal area much farther from the station.

9. Policies and Procedures

APS does not have procedures for procurement of coal. Throughout the operation of its two major coal-fired stations, Cholla and Four Corners, the Company has had "life of plant" coal supply agreements. The narrow scope of buying requirements (although the volume is large) has led APS to consider coal procurement procedures to be unnecessary. APS also does not have procedures for coal contract management and administration, but it does have a set of flow charts addressing some required activities for Cholla and Four Corners. These flow charts, however, do not include many significant coal contract management and administration processes.

For example, the Cholla charts contain no indication of timing of any of the process steps. Further, APS has not addressed any steps in the processes for coal sampling, analysis, or data handling. The documentation also fails to address important elements in the creation of the Cholla *Coal Receiving Report*:

- Whether and how station personnel should obtain independent data on the weight of coal
- What specific scales should be used
- What process should be followed to secure coal-weight data from the scales (automatically printed or written down by someone)
- How weight data gets to the proper place for further steps in receiving report creation.

The Cholla charts also do not make a clear conversion from tons to BTU. Utilities buying coal seek energy, or heat content, not just tons. Liberty is accustomed to observing clarity in how a utility converts to, reports, and analyzes BTU content.

APS M&T uses a number of policies and procedures to manage natural gas and purchased power procurement for system native load requirements. An overall APS hedge policy provides an overview of the philosophy, strategy development, target setting, methods, and controls supporting the management of the electric power and natural gas commodity risks associated with load-serving obligations. A more detailed *System Hedge Plan* provides specific actions, targets, plans, and metrics. The document sets forth the main elements of the hedge plan in terms of target hedge levels by specified dates, the elements of current system risk, and the overall term of hedges. APS also operates under detailed corporate *Energy Risk Management Guidelines*. This comprehensive document contains an extensive discussion of energy risk-management philosophy, objectives, processes, and controls.

APS also has documented methods for handling the affiliate aspects of energy and fuel procurement. Its Cost Allocation Manual ("CAM") bears on fuel and energy management. APS has developed procedures that address cost allocations, and are contained in *ACC Code of Conduct Policy No. 1* of the *Policies and Procedures*. This eight-page set of procedures, entitled *Affiliate Accounting Policies*, provides overall guidelines and standards to ensure compliance with regulatory requirements related to competitive electric affiliate relationships. This document does not contain detailed cost allocation procedures, but instead provides overall policy guidance on accounting for affiliate transactions involving APS.

APS code-of-conduct procedures reside in several documents, starting with Company policies and procedures that implement the ACC Decision No. 62416. These procedures contain a set of nine specific policies that relate specifically to dealings with affiliates:

- Policy 1: Affiliate Accounting Policies
- Policy 2: Access to Information
- Policy 3: Compliance
- Policy 4: Contracting for Personnel Services Between APS and Its Competitive Retail Electric Affiliates
- Policy 5: ESP Contacts and Requests for Service
- Policy 6: Joint Promotion, Sales, and Advertising with a Competitive Retail Electric Affiliate
- Policy 7: Physical Separation of Entities
- Policy 8: Shared Officers and Directors
- Policy 9: Training Policy.

The Company's *Energy Risk Management Guidelines* ("ERMG") also set standards for the ethical conduct of employees in fuel and power procurement functions. APS updates at least annually these detailed procedures outlining compliance and enforcement requirements. The ERMG also incorporates the FERC's *Market Behavior* rules, which form part of APS's FERC-approved *Market Based Rate Tariff*, and provide descriptions of risk policies and related procedures. The APS training program addresses employee understanding of and compliance with code-of-conduct procedures.

10. Documentation Requirements

Effective fuel management depends upon two general categories of documentation:

- *Procurement*: information documenting the scope and nature of activities to secure fuel, transportation, storage, and related requirements. Typically, this data reflects whether fuel was procured through an organized process, and through a competitive bidding process that produces delivery to the generating stations at costs (consistent with quality and reliability objectives) that will produce the lowest cost of electricity at the bus-bar.
- *Administration*: fuel-delivery data that must be monitored on an ongoing basis to manage effectively the existing fuel contracts. Information in this category includes fuel quantity, quality and schedule data. Associated with this information will be the concurrent power plant performance data that reflects the efficiency of power generation when the fuels currently being procured and delivered are burned for the generation of electricity.

APS has occupied for many years an uncommon position for a coal-burning utility. The Cholla and the Four Corners Stations have operated under long-term coal contracts referred to as "life-of-plant" contracts. This position has made APS a much less frequent market participant (at least for large-volume purchases or transportation) than is typical of many other utilities. Four Corners is essentially a mine-mouth plant. An adjacent mine delivers its coal from the mine via conveyor belt. APS anticipates that that this coal supply will last well into the future. Thus, there has not

been need or significant opportunity to procure large, new supplies of coal for Four Corners. Without this need, there has been a corresponding lack of need for procurement documentation.

Similarly, APS originally had a very long-term arrangement for the supply of coal to Cholla from the McKinley Mine, located only 117 miles away. The Cholla Station was designed to burn coal from this mine. A difference from Four Corners, however, is that supplies from the McKinley Mine are now projected not to last as long as originally anticipated. APS therefore began in 2004 the process of soliciting new coal supply sources for Cholla.

The recent emergence of a need for alternate supply at Cholla brought new challenges to APS. The Company did not develop or use written procedures for that procurement. APS, however, did follow a structured, disciplined process for procurement of new Cholla supply. This process produced substantial documentation, which Liberty examined. The *Fuel and Purchased Power Contracts* chapter of this report provides a discussion this procurement's decision process. Liberty's review of the documentation showed:

- Issuance of requests for proposals to a substantial number of potential coal suppliers
- Economic analysis of incoming bids
- Consideration of the impacts of the potential new coal supplies on the Cholla Station
- Coordination of coal price information with requests for new rail rates from the railroad
- Timely information to management about the status of the procurement process.

Documentation for fuel oil and natural gas purchases reflects the very different procurement processes that characterize the purchasing of those fuels. In both cases, common industry practice is to establish formal relationships with a large number of suppliers, and then to place orders for specific quantities in response to established suppliers' offers of supply. An order for gas might be for an amount sufficient to operate a generating unit for a month, or for a few hours. An order for fuel oil might be for one load of a tanker truck.

In this market environment, industry practice is to enter standard form contracts with suppliers, and then to place orders for discrete quantities under those contracts. The form contracts cover ordering procedures, fuel quality, and commercial issues, such as warranties and billing and payment terms. Orders often take place through telephone calls, followed by purchase orders, in the case of fuel oil. For gas, an APS gas trader selects offers from an electronic trading platform, or by telephone contact with offerors. In the case of gas, the supplier sends confirmations by via facsimile or e-mail to confirm the order. APS checks those confirmations against prices and quantities entered into the Company's transaction-tracking system by APS's trader.

The second category of important fuel management documentation addresses the implementation and administration of fuel contracts that result from the procurement process. The APS Fuel Procurement organization monitors the activities related to management of existing fuel contracts through a number of documents specifically designed for this purpose. These documents form the basis of information routed to senior management of APS on a monthly basis. Primary documents used regularly for management of fuel contracts include the following:

- *Daily Coal Shipments*: This information, which coal-handling personnel at the stations provide, serves as a primary tool to ensure vendor compliance with quantity, quality and

schedule requirements. It contains coal quality data, coal weight information, rail shipment designations, and summary monthly information.

- *Monthly Cholla Coal Inventory*: This information lists actual and target inventory information for each of the various coal types maintained in Cholla inventory. Information arrives electronically from the station; Fuel Procurement personnel maintain it on spreadsheets as a tool in contract management.
- *Cholla Coal Receipts*: This information details the monthly coal receipts by vendor, and comprises the tool for measurement of contract compliance.
- *Monthly Coal Fuel Variance Analysis*: APS Fuel Procurement personnel prepare this report for each fuel type; it provides annual year-to-date fuel costs and budgets, along with details of all of the components of the costs for each station. For example, the seven components of the Cholla costs, listed in terms of cents/kWh, comprise:
    - Regular sulfur coal
    - Low sulfur coal
    - Accruals
    - Inventory adjustments
    - Secondary fuels
    - Heat rate efficiency/Fuel handling
    - Other variances.
- *Monthly Total Coal Plant Fuel Costs*: This data, presented in both tabular and graphical form, provides actual and budget fuel cost information, by month, for all plants and for each station individually, with data listed in both total dollars and cents/kWh.
- *Monthly Fuel Variance Analysis, Gas/Oil*: This report is similar to the report for coal.
- *Monthly PNW Gas Transportation*: This data provides monthly and year-to-date gas transportation information.
- *Daily PNW Gas Burns for the Month*: This data provides daily burns of gas, in MMBtu, for the PNW system, in both tabular and graphical format.
- *Monthly Oil Inventory*: This report lists the diesel and residual fuel inventories at each station that uses these fuels. The data includes fuel receipt and burn information required to determine inventories.

11. Auditing

The internal auditing function within APS Audit Services has conducted internal audits of fuel procurement, power procurement and price-risk management. In the last three years ending in late 2005, the group has conducted 25 such audits. Each audit report includes:

- An executive summary addressing:
    - Objective
    - Conclusion
    - Recognized Strengths
    - Improvement Opportunities & Management Response
    - Status
- A detailed report describing:
    - Background

- Work Performed
- Scope
- Issue
- Management Response
- Observation.

Audit Services defines an audit *issue* as an identified deficiency with respect to regulatory requirements, corporate policies and procedures, or EHS Management Practices reviewed during an audit. Audit Services requires a *Management Response* to all *issues.* Observations are behaviors/practices recognized by the auditor(s) during the audit. Observations are made to increase the overall effectiveness of the programs and to highlight good management practices. Audit Services does not generally require a management response for observations.

A number of the internal audits addressed BHP coal-contract price-escalation issues. These audits have [redacted] Their conduct has strengthened the coal-contract administration process. Their objectives have been to determine whether:

- BHP properly escalated the price of Four Corners Power Plant coal
- Appropriate contract and administrative controls were in place to ensure compliance with the fuel agreement.

Another internal audit addressed coal accounting at the Cholla Station. It examined the processes and procedures for handling coal and calculating fuel expense and coal inventory at the station. This audit addressed the issue of [redacted] Fuel Procurement personnel informed Liberty that [redacted] This same audit also addressed coal inventory adjustments. It [redacted]

Several audits addressed natural gas issues. Two addressed price index reporting, after the FERC established new requirements for this activity in 2003. Additionally, an industry-standards group issued a "Best Practices" guide for this activity. The auditors concluded that APS's policies and procedures in this area [redacted].

Liberty's examination of these internal audits across the past three years demonstrated attention to important components of the fuel and power procurement operations and risk management. The audits took place with acceptable frequency, addressed issues adequately, did [redacted], identified [redacted], and produced timely and appropriate responses from APS management. Liberty understands that Audit Services intends to continue to conduct them on a regular basis.

12. Board of Director General Oversight of Fuels and Energy

The parent and APS boards have common membership. Their meetings are technically distinct, but often held on the same day. The parent classifies nine of its twelve directors as independent

under New York Stock Exchange ("NYSE") and *Director Independence Standards* adopted by the parent board. The board has the following standing committees:

- Audit: assists the Board in monitoring financial statement integrity, independent auditor qualifications and independence, performance of the internal audit function and independent auditors, and compliance with legal and regulatory requirements. (Met six times in 2004 and six times in 2005).
- Human Resources: reviews compensation strategy; approves compensation and benefits policies, approves CEO compensation goals and objectives, assesses CEO performance, sets CEO compensation, recommends persons to the full Board for election or appointment as officers, and makes director compensation recommendations to the full Board. (Met three times in 2004 and five times in 2005).
- Finance and Operating: reviews historical and projected financial performance, follows issues affecting financial condition, recommends approval of short-term investments and borrowing guidelines, reviews financing plan, recommends approval of issuance and redemption of securities, credit facilities, and other types of credit support, recommends approval of the general parameters applicable to long-term debt and equity security issuance, and recommends dividend and other distribution actions to the Board. (Met four times in 2004 and four times in 2005).
- Corporate Governance: develops corporate governance policies, practices, and guidelines, recommends to the full Board criteria for selecting new directors, identifies and evaluates individuals for Board membership, recommends director nominees to the Board, and recommends committee assignments to the Board. (Met four times in 2004).

The following table summarizes the assignments of the current members of the parent board.

Figure II.3 Board of Directors and Committee Membership

Director	Independent	Tenure	Age	Committees				Subsidiary Boards				
				Audit	HR	Corp. Gove	Fin. & Ops	APS	PWEC	APSES	SunCor	El Dorado
Basha	Y	1999	68	M	M	M		X	X			
Davis	N	2001	59				M	X				
Gallagher	Y	1999	61				C	X	X		X	X
Grant	Y	1985	67	M	M	M		X	X		X	
Herberger	Y	1992	63		C	M	M	X	X			X
Hesse	Y	1991	63	C		M	M	X	X			
Jamieson	Y	1991	62	M	M	M		X	X			
Lopez	Y	1995	60	M	M	M		X	X		X	
Munro	Y	2000	57	M		C	M	X	X			
Nordstrom	Y	2000	56	M		M	M	X	X			
Post	N	1997	55				M	X	X	X	X	X
Stewart	N	2001	62				M	X	X	X		

The following summaries from recent proxy statements describe the directors' backgrounds:

- Basha, Edward N. Jr.: Chairman of the Board of Bashas' supermarket chain since 1968 and an Arizona civic leader.
- Davis, Jack E.: Pinnacle West COO and President and APS President and CEO; formerly in various APS executive positions (including generation and transmission) since 1993.
- Gallagher, Michael L.: Chairman Emeritus of the Phoenix law firm of Gallagher & Kennedy, P.A.
- Grant, Pamela: Civic leader, former president and CEO of Goldwater's Department Stores, and former president of TableScapes, Inc. (party supply rentals)
- Herberger, Roy A, Jr.: Former President and now President Emeritus of Thunderbird, The Garvin School of International Management
- Hesse, Martha: Former President of Hesse Gas Company former Sr. VP of First Chicago Corporation (financial services), and former Chairman of the Federal Energy Regulatory Commission
- Jamieson, William S. Jr.: President of Micah Institute of Asheville, North Carolina and former President for the Institute of Servant Leadership
- Lopez, Humberto S.: President of Tucson-based HSL Properties, Inc. (real estate development and investment)
- Munro, Kathryn L.: Principal and former Chairman of BridgeWest, LLC (investment company) former CEO of Bank of America's Southwest Banking Group
- Nordstrom, Bruce J.: CPA and President of Nordstrom and Associates, PC, Flagstaff, AZ
- Post, William J.: Pinnacle West Chairman and CEO, and Chairman of subsidiaries, APS, PWEC, APSES, SunCor, and El Dorado; in executive positions at APS since 1982.
- Stewart, William L.: Retired (2003) CEO of affiliate PWEC and former President, Generation, of APS

The board met nine times during 2004 and nine times during 2005. Senior APS executive management routinely reported the following information during 2005 and early 2006 meetings:

- Year-to-date Generation and APS M&T performance
- Comparisons of actual versus budgeted performance for coal, nuclear, capacity, and availability.

The meeting minutes also disclose that management discussed the following types of subjects at various points during the year:

- Update on a proposed pipeline project
- Status of rate proceedings and fuel/energy cost recovery
- RFPs for securing energy from the marketplace
- Status of negotiations on new Cholla coal and rail transportation agreements and options
- Review of gas and oil market prices with outside auditor
- Sale of natural gas storage development project
- Summary of generation shortfalls, Arizona merchant generation, renewables, new generation technologies, and overall generation options

- Review of recent rate changes for McKinley mine coal transportation
- Fuel and purchased power hedging, comparison of hedged prices with market prices, and forecasts for oil and natural gas demand growth.

13. Board Risk Management Role

PWCC's board of directors has the responsibility for approving the overall risk profile and for establishing an infrastructure to support it. Specifically, its duties include:

- Approving the risk policy
- Approving overall business strategies for risk management and control
- Reviewing those strategies periodically
- Approving overall risk limits.

The PWCC Energy Risk Management Guidelines state that the board of directors has delegated risk management and monitoring responsibility to the PWCC Energy Risk Management Committee ("ERMC"), which consists of:

- PWCC and APS CFO and Executive Vice President (Committee Chair)
- PWCC Vice President and General Counsel
- APS Vice President – Planning
- PWCC Audit Services Director
- APS Directory of Energy Risk Management
- APS Vice President and Controller
- APS Director of Tax Services
- APS M&T Vice President
- APS Executive Vice President of Generation
- APS Vice President and Treasurer.

The Risk Management Guidelines assign specific responsibilities to the EMRC:

Monthly

- Review the PWCC risk position
- Oversee Energy Risk Management Group ("ERMG") enforcement activities
- Review and approve summaries of limit violations
- Take appropriate corrective actions to respond to violations
- Review and approve the addition of products not on the Approved Products List
- Review aggregate and individual credit exposure information

Annual

- Determine risk capital to be allocated to APS M&T and APSES
- Establish and maintain risk tolerance limits
- Present reports to the PWCC board of director's Finance and Operating Committee on significant exposures and risks

- Present reports to the PWCC board of director's Audit Committee on APS M&T and APSES controls and systems

As Needed

- Approve counterparty credit limit structures
- Approve portfolio-level trading limits
- Approve new products and trading instruments
- Monitor risk management staffing adequacy and clarity of authority and responsibility for risk management
- Approve changes to the Risk Management Guidelines
- Review non-standard transactions and hedging plans.

C. Conclusions

1. Personnel in the fuel and power procurement have solid analytical skills and sound experience appropriate to meeting objectives and responsibilities.

Fuel and power procurement personnel have sufficient experience in the essential activities of fuel planning, procurement, and management. Liberty's review of work products created within the department during this audit indicated that the capabilities of all of the individuals in the fuel and power procurement organizations are strong and consistently applied. Interviews with personnel verified the existence of the proper skills to perform the tasks assigned. Liberty's observations about the capabilities of APS personnel also demonstrated the ability to grow into larger roles, if development is appropriately supported.

2. Job descriptions for personnel in fuel and power procurement are current, and adequately address current responsibilities.

The job descriptions related to the activities performed by employees in the fuel and power procurement functions are current, and reflect the present responsibilities of positions to which they apply. APS appropriately uses job descriptions as the frame of reference for the assessment of job responsibility performance in personnel evaluations.

3. Communication within and among the fuel and power procurement organizations and upper levels of management is satisfactory.

Personnel within the fuel and power procurement organizations displayed a good understanding of the overall mission of their departments, of current activities and challenges, and of key strategic and tactical issues within the organization. Common understandings reflect good communication within the organization and management attention to the importance of involving all personnel in the activities of the organization.

Communication with upper levels of management takes place effectively through a regular process of staff meetings and formal written reports prepared for the Vice President, Fossil, as well as the President and CEO of APS.

4. The fuel and power procurement organizations have a satisfactory program for training and cross training of individuals within their departments.

The fuel and purchased power organizations do not have formal training or cross-training programs documented through a manual or plan. These organizations have taken a less formal, but effective approach to training and cross training. They recognize training as an ongoing process, and accomplish it effectively through a combination of on-the-job cross training, various industry seminars, conferences, and internal programs.

APS maintains thorough succession plans for senior positions within the organization; they specifically identify individuals capable of filling senior positions.

5. APS maintains an appropriate decision matrix, or chart of approval authorities.

APS maintains several procedures related to decision-making and delegation of authority, and an appropriate decision matrix, or chart of approval authorities, that specifies the magnitude of commitments that can be made by various levels of management.

6. The program for employee training and compliance monitoring under the Code of Conduct is satisfactory.

APS has developed and communicated adequate procedures governing ethical behavior of employees. APS employees receive annual training on these Standards of Conduct, and attendees sign a statement certifying that they have received this training,

7. The fuel and power procurement organizations have satisfactory procedures for many of the specific functional areas within these organizations, but Fuel Procurement does not have sufficient procedures for fuel contract management and administration. (*Recommendation #1*)

A number of appropriate guidance documents and procedures address the fuel and power procurement organizations. The documentation starts with business plans and initiatives for each year. APS has detailed procedures for dealing with affiliates and code of conduct guidelines. The *System Hedge Plan* and suitably detailed and comprehensive *Energy Risk Management Guidelines* address natural gas and power procurement.

APS follows ASTM procedures in its weighing, sampling and analysis of coal, and in calibration of its coal scales. However, in the area of coal contract management and administration, the Fuel Procurement organization operates only under an incomplete set of flow charts.

8. Documentation of fuel and power procurement and supply management activities is satisfactory.

The business plans and initiatives are central to overall documentation of APS strategies and plans for fuel and power procurement and management. They are well prepared, comprehensive, and available to the right personnel. They contain sufficient detail to provide meaningful documentation of strategies and plans. The fuel and power procurement organizations also use a number of other reports and records to manage the fuel supply process and include appropriate reports necessary to monitor and manage supplier contract compliance and the essential fuel needs of the utility. Upper levels of management are also kept up to date on fuel and power procurement activities through regular weekly and monthly reports.

APS's purchase-order process for fuel oil and its transaction-confirmation process for natural gas are typical for purchases of these fuels. These processes include adequate documentation creation and maintenance, and documentation retrieval ability.

9. The APS Audit Services group conducts regular and appropriate internal audits of fuel and power procurement functions.

APS Audit Services has actively conducted internal audits of fuel procurement, power procurement, and price-risk management. In the last three years ending in late 2005, 25 specific audits have been conducted. Audit Services did

10. The Company's procedures for accepting offers of gas supply are not sufficiently formal. *(Recommendation #2)*

The Company buys most of its gas monthly during the week prior to when deliveries would begin. Gas is bought in two ways: (1) accepting pre-approved suppliers' offers posted on an electronic trading platform, and (2) telephone contacts with suppliers. The APS staff person in charge of this activity estimates that about 75 percent of the gas is bought electronically, with the rest bought over the phone.

The parties set the prices to be paid for the gas when the supply offers are accepted. The Portfolio Manager (Regulated), a gas futures trader, and the physical gas trader generally confer prior to accepting each offer. The Portfolio Manager (Regulated) reported that he spot-checks the prices that APS pays against other offers and against price-reporting services.

Liberty's did not observe sufficient formality in the process for overseeing these transactions. At current price levels, this process produces expenditures of $30 to $40 million per month. Expenditures of that magnitude warrant greater structure in assuring that price determination and acceptance always occur as intended.

11. Senior executive management has routinely provided to the board of directors substantial information about fuel, energy, and plant operations performance.

Management provided baseline operating and budget variance information to the board. In addition, at various times during the past year, management advised the board about important milestone events, including major new contracts, coal transportation issues, development of alternative natural gas transportation sources, hedging effectiveness, and cost deferrals.

12. Available summaries of the board members' backgrounds show sufficient experience in matters relevant to utility fuel and energy management; however, Liberty was not able to determine through interviews with them what specific knowledge and experience they bring to bear or what values, criteria, performance indicators, and critical decision/judgment points they apply. *(Recommendation #3)*

The board on paper demonstrates a sound blend of experience level, industry knowledge, relevance to fuel and energy matters, local knowledge, and executive and other leadership ability. The only source Liberty had for confirming the details of that experience and its effective

application in overseeing APS fuel and energy management, however, were the board minutes and the impressions of senior management about what the board does.

Liberty ultimately gained sufficient information to conclude that there was no failure of information flow to the board. APS offered access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and on how they exercise that role. Directors received sufficient regular reporting on fuel and energy matters. It would have been better to discuss with the directors in person what information they consider important and how they use it to oversee this important area of operations. Speaking directly with directors has formed an important process in reviewing how they meet public service responsibilities in Liberty's prior engagements.

Liberty has no reason to believe that there is a gap in senior oversight of fuel and energy matters, but could not corroborate that conclusion through direct discussion with directors. There is not a substantial reason for concern about costs. However, board performance can sometimes form a very important element of a public service commission's examination of utility management and operations. Liberty believes that there should be a clear recognition by APS that the Commission's interests may warrant direct communication with directors in the future.

13. The board's risk management role as defined in written policies and procedures is sound and the risk management program produces effective performance and status reports.

Liberty found the PWCC program generally to be a strong one, and specifically that it meets the needs of APS. If carried out as described, the board's role in that program is appropriate. However, board and board committee minutes do not communicate much that leads to understanding specifically how members use information they get, and make decisions and judgments that are important. The minutes are not out of the range one would expect at a company like PWCC or APS. Minutes, however, generally do not provide a particularly good source for securing much more than a listing of subjects addressed, management representatives who discussed them, and formal votes taken.

D. Recommendations

1. Develop a complete set of procedures related to the management and administration of coal contracts. (*Conclusion #7*)

The Fuel Procurement organization should develop procedures that detail the steps associated with management and administration of its coal contracts. Such procedures are an important tool to document the current institutional memory of how these activities are performed, especially in view of the aging nature of the workforce and the need to capture the lessons learned from the many years of experience that individuals have with fuel management processes.

2. Audit and revise procedures for acceptance of offers for gas supply. *(Conclusion #10)*

APS uses a comparatively unstructured process to make commitments resulting in very large expenditures. Audit Services should review the effectiveness of and the controls associated with the process, and work with APS M&T to revise procedures as necessary.

3. Secure an understanding with APS that Commission auditing includes access to members of the board of directors. *(Conclusion #12)*

Liberty did gain an understanding about what information the board got and about what senior management thinks the board does with that information. Liberty did not see any gaps in that information, nor did Liberty develop concern from the perceptions of management about what the board did with the information (assuming those perceptions to be correct). That information and those perceptions are not, however, sufficient to assess board effectiveness, any more than an assessment of the effectiveness of an employee or an organization can be meaningfully assessed by looking only at: (a) information flowing to it from persons reporting to it, and (b) what persons reporting to it think that their superiors do with that information.

APS should agree that future Commission audits may include access to members of the board of directors.

III. Fuel Management

A. Scope

This chapter of Liberty's report addresses the following topics related to APS's management of its fuel supplies:

- Contract administration responsibility
- Receipt inspections
- Information monitored
- Historical supplier performance
- Disputes and backcharges
- Inventory practices
- Ash disposal.

B. Background

1. Contract Administration Responsibility

Responsibility for overall direction of fuel contract administration rests with the Fuel Procurement department's director, who assigns and coordinates these activities to support the department goals. Each of the two managers reporting to the director also has responsibilities related to fuel contract administration. The Generation Fuel Portfolio Manager has administration responsibilities for fuel oil and natural gas transportation contracts. The Fossil Fuel Manager has responsibility for administration of the coal contracts. APS M&T manages natural gas commodity contracts.

Two Supply Chain Managers ("SCMs") and one Materials and Supply Analyst report to the Fossil Fuel Manager. One of the Supply Chain Managers handles coal supply scheduling and monitoring activities for the Four Corners Station. The other handles these functions for the Cholla Station. The Supply Chain Managers have responsibility for ongoing monitoring of delivered coal quality and quantities and for compliance with the other terms and conditions of the contracts. They establish the initial delivery schedules for each coal contract, in order to pace deliveries of the contracts' annual delivery targets. They update those delivery schedules each month for the balance of the year in order to account for deliveries to date and the balance of the annual contract commitments to be met by each coal supplier. They use regularly updated spreadsheets to support the scheduling process.

One of the Supply Chain Managers spends about one week per month at the Four Corners Station, performing coal-contract administration responsibilities. The BHP coal contract is complex, particularly with respect to price adjustments. The contract provides essentially for [redacted] activities that require close monitoring. This Supply Chain Manager serves as the Fuel Procurement Department interface between BHP personnel and the two APS auditors working at the BHP site. Administration of this coal contract requires what amounts to an ongoing audit process that must examine each element of supplier requests for pass-through to APS of [redacted] costs. One of the APS auditors at the BHP site works for APS

Audit Services; the second works for the APS Engineering Department. The latter has an office at the BHP Mine, and has been monitoring BHP costs for APS on a real time basis for approximately ten years.

The Cholla coal supply agreement is not as complex as the BHP contract for Four Corners. The Cholla contract uses a [redacted] pricing mechanism. Consequently, the Supply Chain Manager responsible for Cholla contract administration focuses more on coal scheduling and logistic operations, and communication with the mine and the BNSF, as necessary to keep coal flowing smoothly between the mine and the station. He travels to the Cholla Station regularly, but does not need to spend as much time at the station as does the SCM responsible for Four Corners. Each Supply Chain Manager has almost daily contact with fuel handling personnel at the Four Corners and Cholla stations.

The Materials and Supply Analyst assists each of the two Supply Chain Managers in handling invoices, serving as the interface between the Accounting Department and Fuel Procurement. He performs all reconciliations related to invoicing, and ensures receipt of appropriate input and approval from the two Supply Chain Managers and the Manager of the Department. This Analyst also assists in the preparation of statistical information that reports monthly fuel delivery and budget information.

APS secures data on actual supplier performance from coal receipts that APS coal handlers process at each station. Plant personnel feed the data from these receipts into the APS computer system. The contracts establish the coal quality parameters against which deliveries are measured each month. Monthly weighted averages generally establish the performance measurement bases. Coal-sample analysis information collected within the computer system at the Four Corners Laboratory is uploaded into the APS computer system, and subsequently monitored by the Supply Chain Managers through various computerized reports on coal quality.

2. Receipt Inspections and Information Monitored

Coal Weights

Certified scales measure all weights for coal delivered to the Cholla and Four Corners generating stations, whether it arrives by rail or by conveyor belt. Contract provisions, however, determine whose scales take the weights used for determining compliance with delivery requirements. Certified mine scales take the contract-compliance weights for shipments to the Cholla Station. The primary Cholla suppliers, the McKinley and Lee Ranch mines, use a weigh-bin type of scale. APS also weighs the coal as it is received at the Cholla Station in order to verify the weights provided by the mines. The station's belt scales perform this function, but are not certified. Typically, weigh-bin certified scales are accurate to within 0.2 percent, while belt scales have a lesser accuracy factor of 0.5 percent.

Certified belt scales at the station measure the weights of coal delivered to the Four Corners Station. BHP maintains and certifies these scales, as the contract requires, to ASTM standards. The two belt scales used for this purpose, designated the 2A and 2B Scales, each have full-load capability of 1,200 tons of coal per hour. Calibration of these scales takes place every six months, in the presence of representatives from the scale manufacturer, BHP, APS, and the Navajo Nation. APS has installed its own separate weigh bin system at Four Corners. APS uses

that system for scale calibrations. Calibrated weights are used to calibrate the weigh-bin load cells; the State of New Mexico certifies these weights every five years.

In no case does APS feed coal weights electronically into the APS computer system directly from the scales themselves. Some other utilities have processes for automatically transmitting coal weights in the form of electronic signals from scales directly into a computerized fuel management system. Such direct feed avoids duplication in data handling of coal weight information and it reduces a source of possible error in coal weight information. A series of manual steps in coal-weight data entry and transfer creates multiple sources of error or compromise. These manual steps include reading and interpreting electronic data information, entering it by pencil on paper coal-receipt logs, or, alternatively, reading paper printouts from scales and transferring this weight information onto coal receipt logs with pencil and paper.

The mine prepares a "Manifest" or "Bill of Lading" for each train delivering coal to Cholla. This document states the amount of coal loaded into each rail car and the total weight of the train. The BNSF also provides a "switchlist" verifying the cars delivered to the station for each train. Utility Equipment Operators at Cholla record the weight of coal fed to one of Cholla's four operating units, or to one of the plant stockpiles to be reclaimed later. Coal weights are manually recorded in unloading report forms, scale reports are printed, these reports are attached to the train manifest, and they are hand carried each day to the Cholla Accounting Department. There, a station accountant enters this data into spreadsheets that track coal by unit, and by inventory stockpile. Another station accountant then crosschecks the data. The accountant then uses these spreadsheets to key the data into the APS computer system. This process includes multiple handling of the same piece of coal weight data from the time of coal unloading until the data is finally in the APS computer system.

Belt scales weigh Cholla coal at various points, as it proceeds through the station's fuel unloading system. APS then compares the Cholla scale weights with those on the mine's manifest, in order to verify that the proper amount of coal has been received and unloaded. APS investigates any apparent discrepancies. The Cholla Accounting Department manages this weight comparison activity. They tally a running variance between the plant's scales and the supplier's scales, and use this variance as an adjustment factor to determine the quantity of coal burned when coal is reclaimed from inventory from one of Cholla's stockpiles for burning in the operating units.

An October 2003 APS Audit Services internal audit report [redacted]

At the Four Corners Station a representative of APS and the BHP Navajo Coal Company read, every 24 hours, the digital electronic scale display in the coal sample tower building, record the coal weights from both the 2A and 2B belt scales, and sign the "Coal Delivery Log Sheet Daily Report." This multi-part document then gets hand carried to the shift supervisor, the operations manager, the station accounting clerk, and the fuel laboratory. An accounting clerk at the station uses this document to enter daily coal tonnages into the APS computer system.

Liberty's examination of processes used to track coal weight information found routine performance of appropriate comparisons to contract requirements, in order to verify vendor compliance. Liberty also found effective APS communication with vendors on coal-weight related issues.

Coal Samples and Sample Analysis

Personnel at the Cholla and Four Corners generating stations visually inspect all coal received, in order to ensure that it exhibits no contamination from extraneous materials such as wood, metal, rocks, and other miscellaneous debris. APS fuel contracts contain provisions for rejection of coal if such contamination is found. In the last five years, only one Cholla shipment, from a Colorado supplier, had to be rejected.

APS samples all coal delivered to Cholla and Four Corners to verify that the quality of coal delivered falls within contract specifications. As with weights, the contracts specify whose samples must be used for these determinations. Samples taken at the mines by the vendors form the basis for analyses of Cholla coal shipments. Cholla personnel have conducted structured studies to confirm the accuracy of vendor-taken coal samples and analyses. The first study, covering a six-month period, statistically compared: (a) coal-sample analyses from the McKinley mine, (b) APS analyses conducted on a split of the mine sample, (c) a sample taken from the Cholla coal mills, and (d) station emission monitoring data. APS took the emission monitoring data 24 to 30 hours after the mine samples were taken, in order to allow for the normal transportation delay in the flow of coal from the mine to the station. These studies showed a close correlation between samples taken at all locations, and confirmed to the satisfaction of APS that coal samples and analyses received from the McKinley typified the actual quality of coal received by APS.

APS subsequently conducted a similar study on coal samples and analyses taken at the Lee Ranch mine. This study also demonstrated a close correlation between samples taken at all locations, and confirmed that APS could have confidence in the validity of sampling and analyses results received from the mine.

APS takes samples at the Four Corners Station from the flowing stream of coal as received from the BHP conveyors at the station. APS takes one coal sample for approximately every 2,000 ton lot of coal received, using ASTM-certified coal sampling equipment. APS maintains two identical coal samplers. Each sampler operates in an automatic mode, and is computer controlled to collect representative samples. Coal is initially collected in 40-pound "milk cans" and then riffled down to produce two identical 2.2-pound samples, which are sealed in clear plastic bags. The bags are identified with sample numbers that include the date, sampler number, and sample sequence taken. One bag goes directly to the Four Corners lab for analysis and a second split of

the sample is double bagged and retained in the sample tower building for storage as a referee sample. Liberty found the sample collection area and equipment to be clean and well maintained.

APS conducts all its coal sample analysis work at the APS Four Corners lab. Liberty's inspection of the laboratory found it to be well equipped and operated in a satisfactory manner. In similar utility coal analysis laboratories around the country, the outputs from sample analysis equipment are automatically fed into a computerized, laboratory data-management system, or directly into utility fuel-management systems. That approach minimizes opportunities for incorrect entry of sample analysis results into computer systems and the need for redundant handling of sample analysis information. APS has plans to manage sample analysis information in this manner; however, the current data management system is antiquated, and includes a number of manual steps in data recording, data crosschecking, data entry into a lab computer system, and eventual data entry into the main APS computer system. Testing of the new data management system is currently underway; APS personnel at the lab reported that full operation of the system should occur within approximately one month.

APS has engaged the services of an outside firm to provide an independent assessment of its coal sampling and coal analysis operations. Reports provided by this firm for both 2004 and 2005 indicate that the Four Corners laboratory continues to produce sound coal-sample analysis. This report also evaluated the APS sample collection system at the Four Corners Station, finding that it continues to produce sound results. The outside assessment found that the mechanical sampling system and the results of coal sample analysis from the laboratory met ASTM standards. This report also found the laboratory equipment and instrumentation to be in good condition, properly calibrated, and standardized. Laboratory personnel exhibited sound training and understanding of the importance of their responsibilities.

Liberty's examination verified that the personnel in the Fuel Procurement organization enforce contractual provisions related to coal quality. Data examined by Liberty showed that only two shipments to Cholla during 2005 and none in 2006 failed to meet Btu content specifications -- by a slight amount in each case. The lengthy history of good coal-quality performance from the McKinley mine made it unnecessary for APS to take corrective action. No 2005 or early 2006 deliveries to the Four Corners Station fell outside specifications.

Information Monitored

APS monitoring of coal quantity and quality information occurs in a number of places, including the Fuel Procurement organization, the generating stations, and the Four Corners Laboratory. Information on coal quality and quantity eventually drives payment amounts to coal suppliers. The Fossil Fuel Procurement Manager uses vendor-payment and cash-flow outputs from the APS computer system to monitor those payments. He is also responsible for the routine preparation of reports on fuel costs, quality, and quantity received by type, by supplier, by generating station, and for the APS system as a whole. The Fuel Procurement organization uses these fuel data reports, and provides a number of them to more senior management within APS. The Fuel Procurement Manager also has responsibility for verifying all invoices for fuel procurement and for quality-based adjustments to invoices, in order to ensure that they are in accordance with contract provisions and agreements.

3. Historical Supplier Performance

The two Supply Chain Managers and the Materials and Supply Analyst in the Fossil Fuel Management organization spend substantial time monitoring the performance of coal suppliers. The current coal contracts and purchase orders form the basis for this monitoring process. Responsibilities for monitoring this information are clear, and the information is available as necessary for this monitoring process. The information comes from reports generated by the APS computer system. The primary information monitored includes:

- Compliance of the suppliers with established delivery schedules
- Coal quantities specified by the contracts
- Coal qualities specified by the contracts.

Force Majeure and Contract Disputes

Force majeure provisions, while common, can produce physical or price disruption in utility fuel supply. Responding effectively to vendor claims is an important element in assuring reliable, economical supply. During 2005 and 2006 to date, APS did not face any counterparty claims of force majeure; therefore, APS experienced no situations requiring response in this period.

Disagreements with vendors are also inevitable over time. Managing them effectively is important in assuring effective long-term relationships with valued suppliers and in preventing transitory problems or disputes from having significant cost or reliability consequences.

There are no open or unresolved contractual issues involving coal supply for the Cholla Station. There is currently one open contractual issue involving Four Corners Station supply. It involves a [redacted].

There have been no non-performance disputes within the last five years. During the period from 2005 through 2006 to date, APS has not terminated any coal contracts due to non-performance. APS did, however, terminate the 2005 [redacted] The main agreement providing coal to Cholla is The Coal Supply Agreement of 2005. It is an extension of the P&M Amended & Restated Coal Supply Agreement of 2004, which the parties extended to add additional years of commitment in 2008 and 2009 as McKinley Mine's final reserves are identified. This extension replaced the need for the 2005 [redacted].

Coal Quality

The quality of coal delivered, as compared with specifications comprises a primary indicator of supplier performance. During the last five years, there has only been one instance where APS has rejected coal from a supplier. That case did not involve a regular coal supplier, but a Colorado supplier undergoing test performance. Given the very large quantities of coal delivered to APS on an annual basis (4.4 million tons to Cholla and 8.6 million tons to Four Corners), the dearth of non-compliant deliveries reflects strong supplier performance. APS's sourcing arrangements for

coal, the absence of any adverse trends in supplier performance, and APS's attentiveness to supplier-performance issues give reasonable confidence that positive supplier performance will continue into the future.

4. Inventory Practices

Inventory Management

Cholla Station's October 2003 target was to maintain 35 days of coal in inventory The actual inventory level of 96 days far exceeded the target. An APS Audit Services review noted that [redacted] APS has since reduced the amount of targets and actual inventory at Cholla. The following table illustrates the Cholla coal inventory situation, measured in days of coal in inventory, as of January 2006:

Table III.1 Recent Cholla Inventory

Type of Coal	Target	Actual
Regular Sulfur	25 Days	26 Days
Alternative	25 Days	33 Days
Low Sulfur	30 Days	20 Days

The following chart displays the projected Cholla coal inventory, measured in tons of coal, for 2006. The chart illustrates the APS plan to manage coal inventory during 2006, and reflects the expected buildup of coal over the summer to meet increased demands for coal-fired generation during the summer months.

Table III.2 Projected Cholla Inventory

ENTIRE FOLLOWING TABLE IS CONFIDENTIAL

[redacted]

ENTIRE PRECEDING TABLE IS CONFIDENTIAL

The McKinley Mine produces Cholla's "Regular-Sulfur" coal, which any of the four units can burn. There are two types of "Alternative" coal. Alternative #1 coal (from Lee Ranch) has a higher ash and sulfur content than does McKinley coal. APS uses Alternative #2 coal (Spring Creek coal from the Powder River Basin) to address a precipitator issue. The Spring Creek coal has high sodium content. Over extended periods of time, the Unit #3 & #4 precipitators would become fouled as a result of sodium depletion in the precipitators. APS has found blending small quantities of the high-sodium Spring Creek coal with McKinley coal to be effective in combating precipitator fouling.

The McKinley Mine also produces "Low-Sulfur" coal for Cholla. Units #2 and #3 have a common emission requirement, but only Unit #2 has a scrubber. APS therefore holds the McKinley low-sulfur coal in reserve to supply Unit #3 when not operating in conjunction with Unit #2. With both units operating, the scrubbed emissions from Unit #2 and the unscrubbed emissions from Unit #3 combined still meet the state emission limit of less than 0.8 #SO_2/MMBtu. The APS long-range plan to [redacted] Unit #3 [redacted] would [redacted]

Space limitations constrain APS's ability to separate completely the different coal types inventoried there. APS maintains a separate low-sulfur coal pile. It does not strictly do so for the other coals, however. It maintains those coals in what essentially amounts to a single large pile, although APS can distinguish one coal from another by observing coal color and by using physical landmarks as references. This approach, however, does cause the coals to tend to commingle. The commingling presents operational challenges for coal yard personnel.

Four Corners presents an inventory situation that differs significantly. The Four Corners inventorying responsibility falls not to APS, but instead to the coal supplier. BHP must maintain adequate inventory to meet station needs. BHP maintains that inventory at the mine and at the BHP coal processing facility, which is located at the power plant. BHP must maintain sixty days of equivalent supply, which is approximately 1,200,000 tons of coal for Units #4 and #5. It must maintain at least 100,000 tons of that amount at the plant's blend piles. All of the coal is defined as usable, although coal in the pits and field stockpiles must be transported and processed at the BHP fuel handling facility at the power plant.

BHP has proven over the years to be reliable in meeting these requirements. Inventory data indicates that in 2005 and 2006 to date the minimum of 100,000 tons has always been maintained at the plant. The BHP mine lies approximately 15 miles south of the plant. BHP strip-mines from seven veins of coal, and transports to the plant via the mine's railroad. BHP maintains three locomotives and spare rail cars to ensure reliability. The railroad has no record of shutdown for operational reasons. It was shut down only once, many years ago, for five days due to regulatory reasons. Alternate truck transportation provides a backup source of delivery.

BHP crushes coal at a facility adjacent to the plant, and stacks it out in one of ten piles for reclaim and delivery to APS. Each reclaim pile, which contains approximately 28,000 tons of coal, can supply one day of operation of the Four Corners Station. Conveyors deliver coal to either one of two APS surge bins on a 24/7 basis. Coal can be conveyed to any one of the five units from the surge bins.

Inventory Measurement

Physical measurement of coal in inventory comprises an important component of electric utility fuel management. A utility should take inventory measurements on a regular basis to control effectively coal going into and from inventory. Uncertainty in inventory levels affects calculated efficiency of the generating station. Calculated efficiency needs to be accurate, for example, to assure proper location of the station in the economic dispatch order.

Typically, coal burning electric utilities undertake yearly comparisons of physical measurements and book amounts of coal in inventory at each generating station. Consistent trends in the variance calculated from such comparisons may indicate the existence of several problems; *e.g.*, measurements of coal going into inventory, measurements of coal leaving inventory, problems with the survey process, or problems preparing the coal pile for the inventory measurement. It is important to identify any existing problem source and to correct it.

Two primary methods can address variances between the book value of coal inventory and the physical inventory measurement. The "percent-of-pile" method calculates the variance amount as a percentage of the amount of coal in book value inventory. The "percent-of-burn" method calculates the variance amount as a percentage of the amount of coal burned by the generating station. The APS inventory surveys have used the percent-of-pile method.

In accordance with the agreement with PacifiCorp, the owner of Cholla Unit #4, a volumetric survey of the coal piles at Cholla is performed annually utilizing Global Positioning System ("GPS") survey techniques. The same contractor has performed the volumetric survey for the past several years. The surveys have generated a "base topography" of each of the piles from 32 base elevation points located around the piles. The surveys have then determined each pile's volume by taking several hundred GPS coordinates as the pile is traversed. The surveys have included annual analyses of coal-pile density and quality. Wet densities of the coal piles are measured at various depths and locations using a nuclear density gauge equipped with a depth probe. The survey contractor then has quantified the number of tons of coal in each pile by utilizing the volume information and the most recent density information. Cholla's "Regular" pile and the two "Alternative" piles are treated as one aggregate pile for the purpose of comparing and adjusting survey results. The physically separate "Low Sulfur" pile is treated separately.

Current procedures require an adjustment when a comparison of the GPS survey tons and the book inventory tons results in a deviation of greater than +/-5 percent. In that case, the book inventory tonnage is adjusted to the GPS survey tonnage prior to the end of the calendar year in which the survey is performed. The 2004 comparison of the aggregated piles produced a deviation of 5.367 percent, with the book inventory being the greater. Discussions with PacifiCorp led to agreement on a deferral of the required adjustment until the next GPS survey in 2005. This following survey showed much greater deviations: approximately 12 percent for the aggregated pile and 9 percent for the low sulfur pile. Again, book inventory was higher. An adjustment to the book inventory took place in December 2005. The following table summarizes the results of the 2004 and 2005 GPS surveys.

Table III.3 Cholla Power Plant – Coal Pile Survey Results 2004

	Regular + Alternative Pile Area				L/S Pile	
	P&M + Alt 2A Regular	Lee Ranch Alt 1A	Spring Creek Alt 2	Total Reg. + Alternative Coal Pile	Low Sulfur Coal	Total
Book Inventory - October 29	509,070	-	28,202	537,273	177,519	714,791
Coalpile Tons per GPS Survey	503,165	-	15,765	518,930	174,715	693,645
- Less Capitalized Base	(10,941)	-	-	(10,491)	(3,347)	(13,838)
Adjusted GPS Survey Quantity	492,674	-	15,765	508,439	171,368	679,807
Difference (Tons)	16,396	-	12,437	28,834	6,151	34,984
Difference (%) - 2004 Survey	3.22%	na	44.10%	5.37%	3.47%	4.89%

Table III.4 Cholla Power Plant – Coal Pile Survey Results 2005

	Regular + Alternative Pile Area				L/S Pile	
	P&M + Alt 2A Regular	Lee Ranch Alt 1A	Spring Creek Alt 2	Total Reg. + Alternative Coal Pile	Low Sulfur Coal	Total
Book Inventory - December 12	268,952	41,849	58,579	369,380	79,877	449,256
Coalpile Tons per GPS Survey	237,112	47,258	51,238	335,608	75,901	411,509
- Less Capitalized Base	(10,491)	-	-	(10,491)	(3,347)	(13,838)
Adjusted GPS Survey Quantity	226,621	47,258	51,238	325,117	72,554	397,671
Difference (Tons)	42,331	(5,409)	7,341	44,263	7,323	51,585
Difference (%) - 2005 Survey	15.74%	12.925	12.53%	11.983%	9.17%	11.48%

The results of these two surveys show the difficulty of accurately accounting for the three different coals maintained in the aggregated pile. The 2004 variance between book inventory and survey inventory for the Spring Creek coal pile was over 44 percent. This extraordinarily high variance did not likely result from scale calibration errors, but more likely from difficulty in determining the boundaries separating the Spring Creek "Alternative" coal. The survey results also show that book inventory values always exceed survey inventory values. Cholla either was burning more coal than the scales were measuring, or not as much coal was being received as the scales were measuring.

Cholla station management decided to conduct a further examination after observing the results of the 2005 survey. Operations and accounting personnel examined data from 2005 and 2006 to date. The 2005 data did not reveal any explanations; however, the 2006 data indicated a lack of sufficient correlation between weights of coal coming to the station and coal going into the units, indicating a potential need for scale adjustments. APS made adjustments; thereafter it has seen a nearly exact correlation between the weights of coal to the station and coal to the units.

Station management also decided to conduct quarterly GPS surveys in 2006 to confirm that it has addressed the inventory variance issue fully. The surveys require a nominal cost of $4,000. APS will continue to conduct the density portion of the survey, which costs $15,000, only annually.

5. Coal Combustion By-Products

The Cholla and Four Corners Stations generate a number of different coal combustion by-products: fly ash, bottom ash, and scrubber sludge. APS sells the material having commercial value, and disposes of the rest in landfills.

Cholla Station

APS stores fly ash collected dry in fly ash silos at the station. A contractor then ships approximately 90 percent of this material offsite in bottom dump trailers or in railcars. The remainder consists of the slurry collected in wet scrubbers and of fly ash that the contractor rejects (*i.e.*, does not ship). APS pumps this remainder to the Cholla Fly Ash Pond for disposal. APS collects bottom ash in the bottom of the boilers, grinds it, and pumps it as slurry to the Cholla Bottom Ash Pond. APS sells approximately [redacted] of the Cholla bottom ash. Non-marketable bottom ash remains in the pond. The table below shows the quantities of Cholla ash handled in 2005, the tons of ash sold, and the revenues received from these sales.

Table III.5 Cholla Power Plant: Ash Disposal Figures, 2005

Material	Disposed		Sold	
	Tons	Cost	Tons	Cost
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash				

APS plans no changes in storage methods for the next 12 months, but eventual changes at Cholla Unit #1 will alter the ash handling process. A fabric filter baghouse will replace the current mechanical dust collectors and the wet particulate scrubber. Scheduled for startup in December 2007, the baghouse will allow collection and storage of additional dry fly ash for potential sale.

Four Corners Units 1, 2, and 3

APS removes all fly ash and SO_2 scrubber sludge from the flue gas by wet Venturi scrubbers, and decants it to about 40 percent solids in thickeners at the station. Pumps then move the fly ash and SO_2 sludge mixture from the thickeners to the Units 1-3 fly ash disposal ponds, which are located about one and one-half miles to the west of the plant site.

The fly ash removal process occurs on a continuous basis. After pumping the fly ash and SO_2 sludge mixture to the disposal ponds, APS completely decants it of all water through simple particle settlement in the disposal ponds. The decanted water flows by gravity to a lined holding pond for re-use in the station. The fly ash disposal pond and water-holding pond are constructed with bottom ash, and lined with local clay and an HDPR liner to prevent seepage. Full fly ash disposal ponds are capped and reclaimed.

APS removes bottom ash from Units 1-3 boilers by water sluicing, and pumps it to hydrobin silos for decanting. Decanted bottom ash is loaded daily into belly dump trucks by gravity, through a discharge valve at the bottom of the hydrobins. The trucks transport the wet bottom ash about one and one-half miles to the west of the plant to the Unit 1-3 fly ash disposal pond. These ponds are located at mine areas where the coal has already been extracted. The bottom ash is used continuously for the construction of the dikes for future Unit 1-3 fly ash disposal ponds.

The table below shows the quantities of ash handled from the Four Corners Units 1, 2, & 3.

Table III.6 Four Corners Units 1, 2, & 3: Ash Figures

	2005		Jan 2006	
Item	**Tons**	**Cost**	**Tons**	**Cost**
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash Disposed				
Item	**Tons**	**Revenue**	**Tons**	**Cost**
Cenosphere Material Sold	[redacted]	[redacted]	[redacted]	[redacted]

Four Corners Units #4 & #5

APS removes fly ash from the Unit #4 and #5 baghouses, sells what it can to [redacted] as a concrete additive, and disposes of the remainder. All fly ash is handled with pneumatic transfer lines and transfer silos. No fly ash is stored for longer than one day. All fly ash from these units is hauled by truck from the on-site transfer silos to the BHP coal mine for back-fill into the mine pits where coal has already been extracted. In preparation for hauling, mixing pug mills co-mix the fly ash with expended scrubber slurry and SO_2 sludge from the scrubber thickeners. APS removes bottom ash from the boilers by water sluicing, and then pumps it to hydrobin silos for decanting. Each day, the decanted bottom ash is disposed of by the same methods used for the other Four Corners units.

The table below shows the quantities of ash handled from the Four Corners Units 4 & 5.

Table III.7 Four Corners Units 4 & 5: Ash Figures

	2005		Jan 2006	
Item	**Tons**	**Cost**	**Tons**	**Cost**
Bottom Ash	[redacted]	[redacted]	[redacted]	[redacted]
Fly Ash Disposed				
Item	**Tons**	**Revenue**	**Tons**	**Revenue**
Fly Ash Sold	[redacted]	[redacted]	[redacted]	[redacted]

APS plans no changes in the next 12 months in Four Corners fly ash or bottom ash storage and disposal. However, future changes are planned. The preceding tables show that Four Corners ash disposal costs are currently about $[redacted], some of which is offset by ash sales. APS anticipates that after 2008, costs will increase to over $[redacted] per year, because BHP will begin hauling the waste to mined-out areas considerably farther from the Four Corners Station.

APS has studied a number of alternatives that may save costs over the long-term. APS conducted detailed economic evaluations of a number of alternatives, using a net present value approach:

- [redacted]

[redacted]

6. Natural Gas and Fuel Oil Use

The table below shows APS energy sources in 2005 and those projected for 2006. The proportion of requirements estimated to be met by natural gas will increase, because the Company projects gas-fired units as the primary source (supplemented by power purchases) for serving new load.

Table III.8 Sources of Energy

Source	2006 Estimated	
	GWh	%
Nuclear fuel	8,942	27.7
Coal	13,241	41.0
Natural gas	6,581	20.4
Hydro/Solar	41	0.1
Purchased power	3,465	10.7

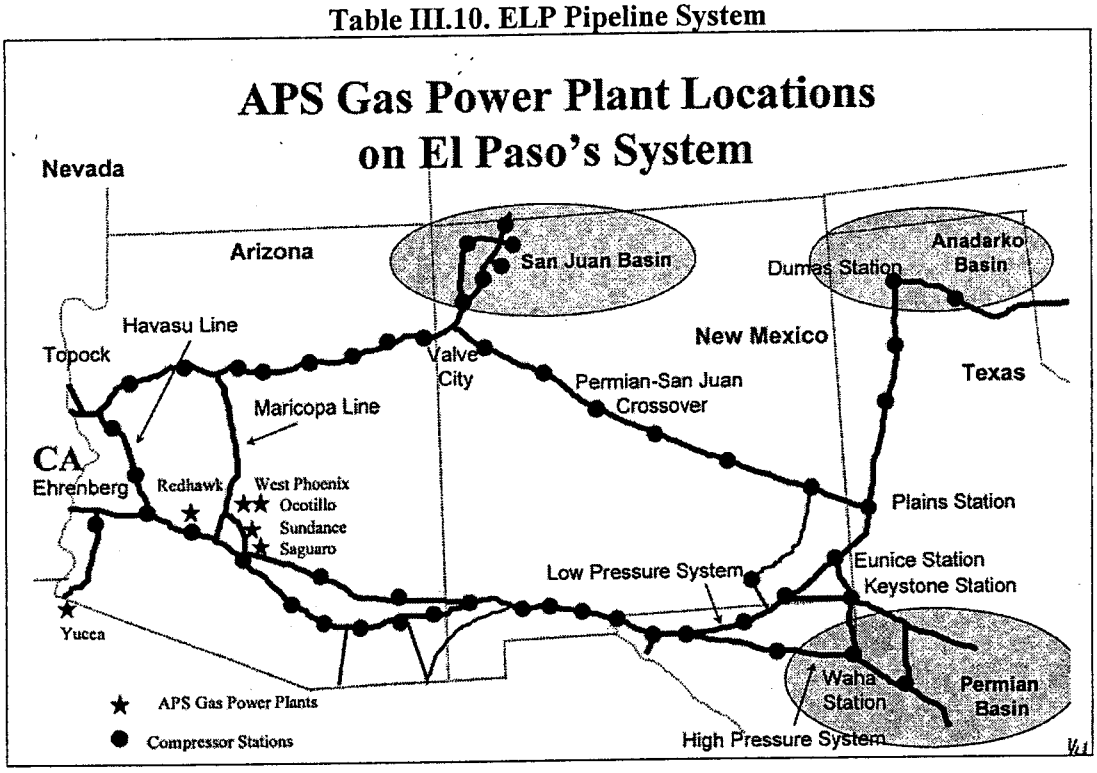
Gas has been a relatively more expensive fuel for APS; therefore, its contribution to total costs exceeds its contribution to total electricity production. The table below presents estimated 2006 expenditures for each fuel, including transportation and handling.

Table III.9 Energy Cost by Source

Source	2006 Estimated	
	$	%
Nuclear fuel	44,574	4.5
Coal	232,094	23.2
Natural gas	430,443	43.0
Hydro/Solar	0	0
Purchased power	294,285	29.4

At present, APS's only source of natural gas transportation is the ELP pipeline system, which the following diagram illustrates.

Table III.10. ELP Pipeline System



The map shows ELP system connections to three producing areas: the San Juan Basin, the Permian Basin, and the Anadarko Basin. For reasons of proximity and price, APS buys its gas from the San Juan and Permian Basins. About 70 percent of the Company's gas comes from the San Juan Basin. The prices are relatively lower there; transportation constraints prevent APS from buying more natural gas from this basin. The Company is trying to improve its access to the San Juan Basin, which a subsequent chapter of this report addresses.

APS also uses small amounts of fuel oil in some generating facilities. The Ocotillo, West Phoenix, and Yucca units can burn natural gas or No. 2 fuel oil (diesel fuel). Saguaro is also dual-fired, but uses residual fuel oil. APS burns gas for air-quality reasons, but maintains sufficient fuel oil inventories to provide two to three days of back-up in case the gas supply is interrupted. The Douglas unit, a diesel-powered reciprocating engine, runs only in the summer. Cholla uses a mixture of diesel and jet fuel for start-up. Palo Verde uses diesel for emergency back-up generators. The following table shows the oil burn in 2005 and projection for 2006 for those plants that make some use of oil. Palo Verde handles its own fuel oil inventories and usage, and does not report fuel use to APS's General Fuel Portfolio Management department.

Table III.11 Fuel Oil Use (MMBtu)

Station	2005 Actual	2006 Estimated
Cholla	[redacted]	[redacted]
Douglas	779	3,282
Yucca	2,581	2,527

7. Gas Purchasing Methods

APS M&T buys gas initially in the form of futures contracts. A futures contract provides the right to receive a fixed quantity of gas, delivered to a defined delivery point, at an agreed time in the future. APS buys primarily the standard contract that is traded on the New York Mercantile Exchange ("NYMEX"), which provides for 10,000 MMBtu, delivered uniformly over the month specified in the contract to the Henry Hub, a market center in Louisiana. APS also buys contracts to cover the difference in price between the Henry Hub and the market centers where it actually takes physical delivery of most of its gas: Blanco in the San Juan Basin and Waha Station in the Permian Basin. Purchasing these location differential contracts provides what are called "basis" hedges. These futures and basis purchases form an integral part of the Company's hedging strategy, which is addressed in detail in a later chapter of this report.

During "Bid Week", the Company sells the futures contracts that it holds for the month that is about to start (the "prompt" month"). "Bid Week" is the name given to the week before the start of a calendar month. During that week, gas suppliers and gas buyers agree on gas sales/purchases for the following month. Trading on the NYMEX in the "prompt" month futures contract also closes during this period. APS also liquidates its basis hedges during this period. APS uses the proceeds of that process to adjust gas purchase prices it has paid to reflect the difference between the value of the gas at the Henry Hub and that at the market centers on ELP.

After selling its futures contracts and basis hedges, APS buys physical gas at the ELP market centers. The combined effect of these transactions (futures contract purchases, futures contract sales, basis hedge purchases, basis hedge sales, and physical gas purchases basis) fixes the price of the gas for system use at the price of the futures contracts as of the time they are purchased. When the futures contract is sold and the physical gas is bought at the same time, the prices in those two transactions offset each other. The net effect of all of the transactions is that the price of the physical gas received is the price paid for the futures contract when it was bought.

APS purchases of physical gas during Bid Week call for uniform delivery over the course of the next month, just as futures contracts do. The Company's need for gas varies daily, however. This variability is a principal cause of a frequent need either to sell gas into the secondary market or to buy additional gas from that market, in order to match supply to requirements.

8. 2005 Gas Quantities Bought

APS determines the amounts of gas to be purchased by forecasting generation. APS uses a computer model to forecast generation and requirements for fuel and purchased power. APS prepares these forecasts for a seven-year horizon. The simulation model selects the optimum economic combination of power plant operation and power purchases, using power plant

operating characteristics, actual fuel prices as far into the future as they can be determined, and forecast prices for periods beyond that.

The current strategy calls for gas acquisition to start [redacted] months in advance of the time that it is to be used. APS buys additional quantities as the delivery month approaches, until it has secured [redacted] percent of the anticipated quantity a full [redacted] months before the gas will be delivered. Target hedge levels apply to total energy to be bought, including both natural gas and purchased power. The hedges are generally about [redacted] to [redacted] percent gas, and [redacted] to [redacted] percent purchased power.

The following table shows 2005 budgeted and actual quantities of gas. The comparison shows strong overall correlation, but substantial monthly variability.

Table III.12 Forecast and Actual 2005 Gas Quantities

Month	Quantities Forecast	Quantities Used	Difference (% of forecast)
January	2,284,491	3,014,126	31.9
February	1,558,868	2,026,985	30.0
March	2,020,670	508,648	-74.8
April	2,168,036	3,480,511	60.5
May	3,975,882	5,568,442	40.1
June	5,519,733	5,748,773	4.1
July	7,351,188	7,665,043	4.3
August	7,792,391	6,787,717	-12.9
September	4,903,711	4,471,149	-8.8
October	3,809,537	5,007,104	31.4
November	3,467,319	2,969,108	-14.4
December	3,906,243	3,400,514	-12.9
Total	48,758,069	50,648,120	3.9

(MMBtu)

9. Dispatch and Measurement

After converting futures contracts to physical gas, APS M&T arranges delivery by the pipeline. The group nominates daily quantities from receipt points in the producing areas to delivery points at the generating facilities that the Company intends to run. Operation of each generating unit is determined on a day-to-day basis, depending on load conditions. The acquired gas is delivered ratably over the course of the month. On each day, any gas that is flowing under an agreement to purchase, but is not required to serve that day's load, is sold into secondary markets. Conversely, if additional gas is required, it is bought in secondary markets.

The pipeline company provides measurements at entry into and exit from the pipeline. Measurements at the receipt (inlet) points are compared by the APS M&T's back office to the invoices received from gas suppliers. The gas suppliers usually accept the pipeline's measurements. The pipeline calibrates most of its meters monthly. A representative from APS's Fuel Procurement department witnesses the calibrations at the delivery end. That person has a copy of ELP's *Metering Standards Guide*, and reviews ELP's invoices.

For quantities delivered, three sets of measurements are taken and compared:

- ELP's meter readings at its delivery points
- Meters on each gas-fired generating unit
- Measurement of each unit's electrical output.

The latter measurement is used in APS's transaction-tracking system (TranZ) to "back into" an estimate of the gas delivered to each unit, using its heat rate.

The Company's Generation Business Services department collects the three measurements into a monthly Fuel Reconciliation report. The Generation Engineering department, Fuel Procurement, and APS M&T's back office review this report. If any group has a concern, it addresses it with the other two, and then, if necessary, with ELP for resolution.

10. Fuel Oil Use

Diesel oil and jet fuel are readily available from numerous suppliers near APS's oil-using stations. APS enters into spot agreements with local suppliers to provide and transport required fuel oil supplies. Each generating station has sufficient storage to cover its requirements for two or three days. Inventory levels are reported daily to the Commodity Lead in General Fuel Portfolio Management. That person tracks usage, deliveries, and inventories, and then orders additional supplies when inventory at a particular plant is too low. Orders are placed with vendors having ongoing purchase orders on file with APS's Disbursement Accounting department. Prices are usually surveyed for a couple of days before the order is placed.

An oil products pipeline delivers to the West Phoenix plant site, where APS owns storage. An oil vendor operates that storage. Other plants receive supplies via tanker truck, except for Saguaro. That plant is the only one that uses residual fuel oil, which it receives by rail car.

C. Conclusions

1. APS has effectively administered coal contracts.

Responsibilities for fuel contract administration are well defined, appropriate systems are in place to administer fuel contracts, and the necessary data for this administration is available and properly used.

2. Manual processes in handling coal weight information are not efficient. (*Recommendation #1*)

Liberty found the processes for handling coal weight information to be inefficient, because they rely on multiple, repetitive data handling steps that could be better automated. There are no instances where coal weights are electronically fed into the APS computer system directly from the scales themselves. Similar inefficiencies exist at the Four Corners Station.

Electronic transfer of information at the Cholla Station directly from coal scales into the APS computer system could eliminate the following steps:

- One reading of an electronic digital meter

- Three different manual entries of the same information either onto paper, or into computers
- One scale printout of coal weight information
- One cross-check and comparison of printout information with manually read and written information
- Two instances where information is hand carried from one point in the process to another.

Because of the multiple and manual handling of coal weight information, there also are opportunities for entry of incorrect information. Because of these possibilities, APS has introduced steps of cross-checking in order to confirm that the weight information is correct. With more automated processes, these steps of cross-checking could be eliminated.

3. APS procedures for taking samples of coal at the Four Corners Station are sound.

APS uses appropriate ASTM coal sampling techniques and equipment. Coal samples are collected by an automated and computer controlled system. Samples are appropriately bagged and marked, referee samples are collected and stored, and samples are regularly transported to the coal laboratory a short distance away from the sample tower building. The sample collection area and sample collection equipment were clean and properly maintained. APS has engaged an independent firm to audit the entire coal sample collection and sample analysis process on an annual basis. The reports from these annual inspections have indicated that these systems continue to produce quality results.

4. APS has undertaken an appropriate program to automate the coal-sample analysis data-management process at the Four Corners laboratory; the program should be in place imminently.

The current coal-sample analysis data management process at the Four Corners laboratory is fairly antiquated. Data from the sample analysis equipment is manually recorded, and subsequently input into a stand-alone lab computer system. From this computer system, the data is printed out, and then re-entered into the APS computer system. In similar utility coal analysis laboratories around the country, the outputs from sample analysis equipment are either automatically fed into a computerized laboratory data management system that can communicate directly with utility fuel management systems, or are fed directly into utility fuel management systems. Thus, many current utility systems are highly efficient, and there is little opportunity for incorrect entry of sample analysis results into computer systems, or the need for redundant handling of sample analysis information. APS has plans to manage sample analysis information in this more efficient and more automated manner, and is currently testing a new data management system. APS personnel at the lab reported that full operation of the system should occur within approximately one month.

5. The Fuel Procurement Department has an effective process for monitoring supplier performance; the performance of these suppliers has been satisfactory.

Liberty found that the Fuel Procurement Department has been effective in managing the fuel procurement process and the material aspects of supplier performance. The responsibilities for

monitoring this performance are clear, the monitoring systems are in place, and the data necessary for this activity is both accurate and available.

6. **The Fuels Department appropriately manages coal inventory, but its recent reduction in the inventory target for Regular Coal at the Cholla Station has been too large.** *(Recommendation #2)*

The Fuel Procurement Department recently lowered its Cholla Station coal inventory targets, and the amount of coal carried in inventory. A reduction was appropriate, but APS has set the Regular-Coal target at too low a level. APS has actually consistently managed Cholla Regular Coal inventories at levels exceeding the revised target. This lowered target calls for a 25-day supply, or about 212,500 tons. APS has appropriately been holding inventories at higher levels, given past supply-chain disruptions and the unpredictability it will face regarding coal deliveries over the next several years. Mine concerns will continue and perhaps escalate as the McKinley Mine winds down operations and the Lee Ranch Mine ramps up production. APS has projected inventory levels of Regular Coal at close to the current, 25-day target for the first three months of 2006, but projects that balances for the remainder of 2006 for Regular Coal will be approximately 90,000 tons greater than its target level of 212,500 tons.

7. **APS has taken appropriate action in response to recent variances between coal inventory book values and the results of physical inventory surveys.**

APS has an appropriate program for conducting annual physical surveys of the coal in inventory at the Cholla Station and for adjusting book inventory values annually if the variance between book values and physical survey results is greater than +/-5 percent. The results of the 2004 and 2005 physical coal inventory surveys indicated in both cases that the book inventory value exceeded the results of the physical survey. In 2005, the Analysis of inventory variance data was 12 percent for the aggregated coal piles and 9 percent for the low sulfur coal pile.

Cholla Station management conducted a thorough study to determine the cause or causes of such variances, and has taken appropriate action to make slight adjustments to some of the station's coal scales.

8. **APS has appropriately sought beneficial uses and sales of coal combustion by-products.**

Where possible, APS has used ash in the construction of its own dikes for ash disposal ponds. Ash is used on haul roads where possible, to provide improved road stability. APS has an ongoing program to sell some ash for use in cement production. In 2005, a total of approximately $[redacted] in revenues were received from sales of coal combustion by-products from Cholla and Four Corners.

9. **APS has appropriately sought alternative means for disposal of coal combustion by-products at Four Corners when faced with significantly increased disposal costs from BHP.**

Upon learning that the Four Corners disposal costs were going to [redacted] APS evaluated a number of alternative projects with the potential to [redacted]

The projects were appropriately .

10. APS's historical approach to gas supply management is typical, but current circumstances constrain its ability to address changes from full-requirements service from the pipeline. *(Recommendation #3)*

Electricity generators tend to be different from other customers for gas pipelines' transportation services in at least two important respects:

- Generators use relatively large quantities of gas over relatively brief periods. Those periods occur at different times of the day: morning and evening peaks, and perhaps during the day between peaks, but not at night.
- Generators are relatively less sensitive to the cost of the pipeline services that they require, because (a) they may not have access to other sources of reliable electric energy when they need it to serve their loads, and (b) facilities modifications required for changing their patterns of use may be difficult or expensive to install.

With large amounts of gas flowing to California year-round, ELP has been able to accommodate APS's specialized requirements without difficulty. ELP's full-requirements service allowed APS's requirements to be served without distinguishing between APS's varying rates of take, and other customers' more-uniform off-takes. Now, more of ELP's load has shifted to its east-of-California markets. In addition, ELP's other customers are interested in shifting costs away from themselves. In these circumstances, the FERC's interest in unbundled services and pricing has brought changes to ELP's rates that will result in enormous increases in ELP's charges to APS. Indications are that using the pipeline in the same way will increase APS's bills for pipeline services from about $ per year to about $ per year. Unless APS finds ways to use less of ELP's newly-specialized services for electricity generators, it has little option but to pay the extra costs.

The first way to use less of the expensive services is to evaluate whether facilities additions or other usage changes might result in lower requirements for the specialized services. Liberty recommends that the Company analyze facilities additions and other changes that would have the desired effect, and present a report to the Commission.

11. APS's pursuit of additional pipelines is appropriate.

The other possibility for reducing APS's requirement for ELP's services is additional pipelines. Shifting part of APS's load to other pipelines may help directly, but perhaps also indirectly. Competitive alternatives may counteract ELP's tendency to shift costs to services that APS

requires. Opportunities presented by additional pipelines should be part of the analysis that the Company presents to the Commission.

12. APS's approach to buying fuel oils is reasonable.

Procedures are appropriate and well documented. Processes appear to be working smoothly.

D. Recommendations

1. Streamline the procedures for handling of information on coal weights. (*Conclusion #2*)

A potentially attractive solution to this inefficiency in handling of coal weight information would be to modify the electronic outputs of coal scales, and procure the necessary interface equipment in order that these signals can be fed directly into the APS computer system. This enhancement would eliminate the multiple, redundant, and inefficient processes now used at Four Corners and Cholla. APS must evaluate the electronic outputs of each of its coal scale systems and determine the steps necessary to feed (if possible) this electronic information directly into the APS computer system. There will clearly be costs associated with such modifications, and the appropriate cost/benefit studies must be conducted. It is, however, Liberty's belief that the long-term benefits of such new processes will outweigh the short-term costs.

2. Revise the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply. *(Conclusion #6)*

Revision of the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply will acknowledge what APS is in effect already doing, and doing appropriately. The Company is addressing through inventory management the need to provide for the uncertainty of coal deliveries over the next several years. This change would increase the APS target for Regular Coal from 212,500 tons of coal to 297,500 tons of coal. This target should be maintained until 2009, at which time it will be appropriate to reconsider a downward revision of the target.

3. Conduct a comprehensive analysis of gas purchasing and management under ELP's revised rate structure, and report to the Commission. *(Conclusion #10)*

The very large increase in the prospective cost of ELP's gas transportation services warrants a thorough study of possibilities for reducing that cost. The list of possibilities includes, in addition to others that APS may identify:

- Addition or alteration of facilities at APS's generating stations that would have the effect of reducing the variations in flow required to operate APS's gas-fired generating units
- Participation in high-deliverability storage projects, in Arizona or elsewhere
- Identify gas users with complementary use patterns that might share pipeline capacity with APS.

Liberty recommends that the Company provide a report to the Commission on its investigations. As some alternatives are continuing to evolve, and the Company should have ample time to identify and evaluate others, Liberty recommends that the target date for completion of this report be set at one year.

IV. Fuel Contracts

A. Scope

This chapter of Liberty's report addresses the following topics related to Arizona Public Service Company's (APS) coal contracts:

- Procurement Processes
- Contract Summaries
- Renegotiation of Contracts.

Liberty's review of natural gas purchasing included an examination of gas-purchasing process descriptions and interviews of key personnel. Liberty examined a sample of contract files, and observed purchasing, sale, and scheduling operations on the trading floor. Liberty's fuel-oil purchasing review included examining purchasing process descriptions and procurement data and interviews of key personnel. The evaluation criteria included the following:

- Reasonableness of the procurement processes in the context of the markets in which they are conducted
- Reasonableness of market interaction levels and costs to ensure least-cost dispatch
- Reasonableness of supplier qualification processes
- Accuracy and completeness of fuel supply contract files.

B. Findings

1. New Cholla Supply Sources: 2005

The APS contracting position is not typical for electric utilities that burn large amounts of coal for power generation. The existing APS long-term contracts for its two major generating stations that burn coal have caused it not to be a routine, large participant in the supply market. More recently, however, APS has faced a need for more significant purchasing activity. In the past two years or so, APS has been acting to obtain new long-term coal supplies for the Cholla Station. Cholla was originally designed and built to burn coal from the McKinley Mine in New Mexico. This mine has been the predominant source of station supply since the 1960s, when the station began operation. More recent projections for the life of the McKinley Mine indicate that mineable coal reserves will not last as long as initially anticipated.

APS secured a 2004 amendment and restatement of the contract for supply from McKinley, and amended the contract again in 2005. These changes added commitment years of 2008 and 2009 as the McKinley Mine identifies its final coal reserves. At the same time that APS was amending the McKinley contract to cover final commitments from the mine, APS also began the process of procuring coal supplies that would support Cholla Station operation after the McKinley supply ended. APS issued a solicitation that produced eight proposals from four suppliers. The responders, listed below, offered a variety of sources, tonnages, and pricing provisions:

- Arch Coal – Black Thunder Mine in Wyoming – three different proposals
- Kennecott Energy – Spring Creek Mine in Montana
- Kennecott Energy – Jacobs Ranch Mine in Wyoming

- Oxbow Carbon & Minerals LLC – Elk Creek Mine in Colorado
- Peabody – North Antelope/Rochelle Mine in Wyoming
- Peabody – Lee Ranch & El Segundo Mines in New Mexico.

All of the new sources of supply identified in response to this 2005 solicitation offered coal with quality characteristics different from those of McKinley Mine coal. APS understood that selection of a new source would require station modifications at Cholla. APS analyzed this need by evaluating the necessary modifications, which differed for each potential source. This analysis estimated the capital and operating costs of the required modifications, and addressed the consequences of burning differing combinations of the various coals proposed. The evaluations also modeled BNSF rail transportation rates, in order to place the alternatives on a comparable coal-cost basis; *i.e.*, at the plant rather than at the mine.

APS finally compared the proposals on a net present value analysis in order to produce final rankings that considered more than the delivered cost of coal, but rather, the more relevant total cost to produce electrical energy. The comparison included:

- Each offeror's cost of coal
- Associated costs of transportation
- Required capital costs
- Estimated recurring O&M costs
- Costs of any unit derates
- Increases in auxiliary power.

APS decided that procuring 100 percent of its Cholla requirements from the Lee Ranch and El Segundo Mines of Peabody would be the best available options. APS estimated that coal from these mines would produce the lowest delivered cost ($[redacted]/MMBtu, in [redacted] dollars, as compared to $[redacted]MMBtu for McKinley coal). APS also determined that this coal would produce the smallest net present value cost over the life of the contract after adding in all of the associated, incremental capital and operating costs. APS and Peabody agreed on December 20, 2005 to a long-term relationship for the Cholla Station. The agreement includes a base price, in [redacted] dollars, of $[redacted]/ton, and will run from [redacted] through [redacted].

2. 2005 Short-Term Purchases from Peabody and Kennecott

APS made two additional short-term coal purchases in 2005. APS purchased 550,000 tons of Lee Ranch coal from Peabody and 50,000 tons of Spring Creek coal from Kennecott. APS made these purchases on a sole-source basis; it did not use a solicitation process.

APS made the Lee Ranch purchase to deal with supply constraints from McKinley. APS's 2005 projected requirements for Cholla were [redacted] tons of coal. APS received notice that the McKinley Mine would not be able to deliver more than [redacted] tons during 2005. APS had to address a potential [redacted] shortfall. APS requested a proposal from Peabody for Lee Ranch Mines to supply the added tonnage. Peabody proposed in April 2005 a price of $[redacted] per ton for 550,000 tons of [redacted] Btu/lb coal from Lee Ranch. APS found this price to be sufficiently

competitive, given that Peabody's bid (at roughly the same time) for supply of the same coal on a long-term basis to the Cholla Station was $[redacted]/ton, in [redacted] dollars. Subsequently, APS and Peabody signed a short-term coal supply agreement with a term from May 10, 2005 to December 31, 2006, for provision of 550,000 tons of coal from Lee Ranch to Cholla.

APS did not use a solicitation for Kennecot's Spring Creek coal because of its unique nature and significance to Cholla Station operation. The coal's high sodium content makes it beneficial in solving precipitator-fouling problems when blended with other coal for use at Cholla Units #3 and #4. Over long periods of operation, the Cholla Units #3 and #4 precipitators become fouled due to sodium depletion in the precipitators. When relatively small amounts of the Spring Creek coal are used in these units, the high sodium content of the coal enhances precipitator operation and APS is able to achieve extended periods of operation without taking the units off line. APS has not found another coal that contains such high levels of sodium.

APS already had a January 1, 2004, open-ended purchase agreement with Kennecott for unspecified quantities of coal to be delivered in the future, at prices to be determined on agreement between the parties. APS used this "Master Agreement" for the purchase of the 50,000 tons of coal from Kennecott. In the fourth quarter of 2004, APS requested that Kennecott prepare a proposal for delivery of 50,000 tons of Spring Creek coal for delivery to Cholla during the first quarter of 2005. Kennecott proposed a price of $[redacted] per ton for 50,000 tons of [redacted] Btu/lb coal in December 2004. Cholla's inventory of Spring Creek coal was then at only 15,000 tons. Because of its regular contact with the market for this coal, APS believed that this was a fair price for the coal required. After the fact, the APS assessment of the market proved was corroborated. A few months later the Kennecott bid for supply of this same coal on a long-term basis to the Cholla Station was $[redacted]/ton, in 2008 dollars. APS confirmed the purchase with an agreement letter signed by the Director Fuel Procurement. Approval of a commitment of this nature was within the Director's established authority limits.

3. Summary of Current Coal Contract Portfolio Summaries

Current Cholla Supplies

A contract with P&M Coal Company provides for primary supply to Cholla Station. This contract is an amended and restated agreement dated January 1, 2004. The agreement runs through December 31, 2006, and provides for the wind-down at McKinley Mine as it reaches the end of its operations. The following table summarizes total contract tonnages. The contract also allows for up to [redacted] tons of low-sulfur coal each year, if available. The following table shows the Contract Base Pricing.

Table IV.1 P&M Contract for Cholla Coal Supply

2004	Tons	2005-2007	Tons	2008-2009	Tons
TOTAL	[redacted]	*TOTAL*	[redacted]	*TOTAL*	[redacted]
Tier 1	[redacted]	Tier 1	[redacted]		
Tier 2	[redacted]	Tier 2	[redacted]		
Tier 3	[redacted]	Tier 3	[redacted]		

Table IV.2 P&M Contract Base Pricing

Year	$/Ton
2004 – 2007 - Tier 1	
2004 – 2007 - Tier 2	
2004 only– Tier 3 (first tons)	
2004 only– Tier 3 (second tons)	
2005 – 2007 Tier 3	
2008	
2009	

The Base Prices escalate annually, based on two indices combined: . The price also adjusts monthly for Btu content, based on monthly weighted averages around a target Btu content of Btu per pound. The contract also provides for price adjustment if the ash content exceeds percent in more than three trainloads per year, and a price adjustment for sulfur if the sulfur content of the coal is above #SO_2/MMBtu in more than trainloads per year. Payment for the coal is based on weights and samples taken at the mine. The contract also contains other standard provisions typically found in coal supply agreements. The agreement is typical of agreements of this type.

In addition to this contract, APS also has the two, previously discussed short-term contracts for the 2005-2006 time period:

- 550,000 tons of coal from the Peabody Lee Ranch Mine
- 50,000 tons of coal from the Kennecott Spring Creek Mine.

Future Cholla Supplies

This long-term contract runs from January 1, 2006 through December 21, 2024. Its term and deliveries are integrated with the existing McKinley Mine supply. The tonnages under the new agreement increase annually as McKinley operations wind down. Coal will come from the Peabody Lee Ranch and El Segundo Mines in New Mexico. The following table summarizes the contract tonnages.

Table IV.3 Peabody Cholla Contract Deliveries

Year	Yearly Tons
2006	
2007	
2008	
2009	
2010 – 2024	

The Base Price under this coal supply agreement is $[redacted] in [redacted] dollars, with quarterly adjustments under seven different indices that relate to coal production operations. There are price re-openers in the years [redacted], callable by either party, upon which prices are to be renegotiated. The price also adjusts for Btu content on a monthly weighted average basis around a Btu target of [redacted] Btu/pound. The following table shows required coal quality measured on monthly weighted-average basis.

Table IV.4 Coal Quality

Monthly As Received Quality		Rejection Limits
Moisture	[redacted]	[redacted]
Ash	[redacted]	[redacted]
Btu	[redacted]	[redacted]
SO_2	[redacted]	[redacted]
Mercury	[redacted]	[redacted]

Payment for the coal is to be based on weights and samples taken at the mine. The contract also contains other standard provisions typically found in coal supply agreements. The agreement is typical of contracts of this type.

Four Corners Coal

Four Corners supply comes from a surface mine located adjacent to the station. This mine has been supplying station coal since initial operation in the early 1960s. The original, August 18, 1960 coal supply agreement covered Units 1, 2, and 3. A September 1, 1966 Fuel Agreement Number 2 covered Units 4 and 5. Both agreements, with BHP Navajo Coal Company, were recently renegotiated, dated August 31, 2003. Their new terms run from January 1, 2005 through July 6, 2016. These mirror agreements give APS extension rights for a term of not more than 15 and not less than 5 years. Pricing under any contract extension will be by negotiation.

Delivery quantities are to be not more than [redacted] tons/day (or in excess of [redacted] per hour) of [redacted] Btu coal. BHP's contractual obligations are to maintain sixty days of equivalent supply, which amounts to approximately 1,200,000 tons for Units 4 and 5. At least 100,000 tons of that amount must be maintained at the blend piles at the plant. Monthly average contract qualities are:

Table IV.5 Monthly Average Contract Qualities

Monthly As Received Quality		Rejection Limits
Moisture	[redacted]	[redacted]
Ash	[redacted]	[redacted]
Btu	[redacted]	[redacted]
Sulfur	[redacted]	[redacted]
Volatile		[redacted]
Alkali as Na2O[1]		[redacted]

The contract price is the sum of the following [redacted] components, specified in cents/MMBtu: [redacted]

4. Renegotiation of Coal Contracts

Between 2005 and April 2006, APS renegotiated three of its coal supply agreements. The following sections summarize them.

Cholla Coal Supply

The P&M Amended & Restated Coal Supply Agreement of 2005 is an extension of the P&M Amended & Restated Coal Supply Agreement of 2004. The contract was extended to add additional commitment years of 2008 and 2009, as McKinley Mine's reserves are identified. The contract pricing for the years 2005 and 2006 did not change as a result of this extension.

Four Corners Coal Supply – Agreements #1 and #2

The Restated and Amended Four Corners Fuel Agreement #1 extends the Four Corners Units 1,2,3 Restated Coal Supply Agreement of January 20, 1992. The original agreement required extension or expiration. The Restated and Amended Four Corners Fuel Agreement #2 is an extension of the Four Corners Unit 4 & 5 Restated Coal Supply Agreement of January 20, 1992. The original agreement also required an extension or expiration of the agreement.

The key provisions achieved through renegotiation of the Four Corners agreements were the [redacted].

5. Natural Gas Commodity Procurement

Natural gas fuels over 50 percent of APS's generating capacity. That capacity runs primarily in the warmer months, however. Gas therefore provides only about 20 percent of the energy that APS uses to provide electricity to its customers. However, natural gas is a relatively expensive fuel in the APS mix. Therefore, it represents over 40 percent of the Company's 2006 budget for fuel and purchased power, even after giving effect to the considerable hedges acquired to limit price, and after considering FAS 133 mark-to-market reversals.

The El Paso Natural Gas Company ("ELP") pipeline system is the only significant APS option for delivering gas to its generating facilities. A 1996 rate settlement fixed APS's obligation for ELP's costs through December 31, 2005. However, the FERC altered the full requirements provision of the 1996 settlement effective September 2003. Since 2003, APS has been working with ELP and other pipeline customers to determine APS's cost responsibility after the end of that settlement, and under ELP's current rate case filed June 30, 2005 at FERC.

APS does not use bid solicitations or requests for proposals to buy physical gas because of the liquid nature of the market centers where it buys its gas. APS's gas traders select offers through an online trading system (the InterContinental Exchange, or "ICE") or through telephone contacts. APS transacts with suppliers with whom the Company has a master gas-purchase agreement in place, and from that list limits transactions to those who remain within the individual credit limits determined by APS.

The traders initially buy in month-long blocks for delivery at a uniform rate over the course of the delivery month. APS uses fixed and index pricing in comparable proportions for these purchases. APS makes most of these agreements to purchase during "Bid Week," which consists of the few days before the end of each month when buyers and sellers in the market generally agree on transactions for the following month. APS does make some purchases with delivery periods exceeding one month. These longer agreements, however, provide for re-pricing at the beginning of each new month.

Within a given delivery month, APS may make supplemental, shorter-term (*i.e.*, "intra-month") purchase or sales, in order to keep its supplies in line with its needs. APS uses the same ICE-or-telephone process for intra-month purchases and sales. A typical intra-month gas purchase would include a several-day purchase or sale to respond to a change in electric load from forecasts. A typical intra-month gas sale would consist of a gas sale when an accessible supply of inexpensive power comes on the market. These sales take advantage of greater economy in buying power and selling gas, versus burning it in the operation of a generating unit. APS continually optimizes the "value" of its gas portfolio by examining and responding in the marketplace to changing natural gas prices relative to electricity prices and available opportunities.

APS uses industry-standard form contracts to buy physical gas. Recent agreements use the North American Energy Standards Board ("NAESB") Standard form 6.3.1, dated April 19, 2002. That form consists of a base contract for purchases and for sales of natural gas. It contains general terms and conditions for purchases and sales and a standard form "Exhibit A", which is used to confirm specific transactions. Such confirmations operate as an industry-standard means of verifying for both parties the existence of a "deal" and of those principal terms (*e.g.*, price, firmness, quantity, delivery point) not addressable in the standard form contracts. APS requires a fully executed form contract to be on file for each authorized counter-party.

Before the NAESB contract, APS used a Gas Industry Standards Board ("GISB") form or a Master Agreement for Purchase/Sale. APS may still use an older agreement for a counter-party with whom it does not trade much, if the older form can address current transactions adequately. For counter-parties with whom it is actively trading, APS uses the current form agreement.

The principal criterion for qualifying potential suppliers to supply gas to APS is credit standing. APS qualifies prospective suppliers under a credit analysis process that applies both quantitative and qualitative factors. APS uses a proprietary *Credit Review Model* to analyze various credit factors. Quantitative factors include financial leverage, liquidity, capital structure, and performance analysis. Qualitative factors include product diversity, risk-management capability, regulatory environment, and growth prospects. APS grants an unsecured credit line to those suppliers for whom the credit analysis reveals "investment-grade" credit. Non-investment-grade suppliers must post collateral or secure APS manager approval in order to transact with APS.

APS keeps its vendor list current with the use of its TranZ deal-capture system. Credit reviews of all fuel vendors occur at least annually, and more frequently when deemed necessary. The deal-capture system prevents transactions with unauthorized vendors or with vendors over their credit limits with APS. The ICE electronic trading platform provides for coding credit limits for specific counter-parties. The APS "middle office", the Energy Risk Management department, has responsibility for keeping that coding current every day. The following tables list the Company's top 10 counter-parties for gas purchases and sales in 2005.

Table IV.6 Top Ten Counter-parties for Gas Purchases, 2005

Company	Quantity Purchased
[redacted]	[redacted]

Table IV.7 Top Ten Counter-parties for Gas Sales, 2005

Company	Quantity Sold
[redacted]	[redacted]

APS "enabled" (qualified for purchasing) eight new suppliers in 2005, and started buying from one of them (IPC (USA), Inc.). Six new suppliers were enabled in 2004. As of the end of March, APS had added no new suppliers in the first quarter of 2006.

6. Gas Transportation

APS currently transports gas only through the ELP pipeline system. APS's bills from ELP, totaling $[redacted] per year, have been essentially the same for about a decade, due to the 1996 ELP settlement. The period of that settlement expired at the end of 2005. APS took full-requirements service from ELP until the fall of 2003. The full requirements relationship gave APS considerable flexibility in receipt and delivery points. APS could vary quantities for delivery to its power plants in response to variations in its electric load.

In September 2003 the FERC required ELP to convert its full-requirements contracts to the more-typical contract-demand-type service agreements. APS experienced no change in its cost responsibility under that conversion, but lost its receipt/delivery points and delivery-quantity flexibility. Since that change, APS has had monthly contract demand levels developed from its use patterns in a test year.

At the end of June 2005, ELP filed a rate case at the FERC, for new rates to go into effect after the end of the settlement period (*i.e.,* the start of 2006). Full implementation of the new rates has been deferred several times, but the majority of new tariffs for services are now in place. The case still remains open and settlement discussions continue as well. The new services that APS would take under the ELP proposal now have hourly flow provisions and penalties for violating those provisions. The new services also have hourly and daily balancing provisions, whereas the full-requirements service only required APS to balance monthly. Balancing is the requirement to put the same quantity into the pipeline that a customer takes out. When only monthly balancing was required, APS could spread its efforts to adjust quantities bought and injected into the pipeline to equal quantities withdrawn over an entire month. With daily or hourly balancing, APS has to find a way to vary the quantities that it is buying and injecting into the pipeline to match the quantities that it is withdrawing on a daily or hourly basis.

APS estimates that the combined effect of these changes could raise APS's ELP costs from the old $[redacted] to [redacted] per year. The APS 2006 budget for fuel and purchased power shows estimated charges for gas transportation of $[redacted] million. APS transports gas through ELP under nine firm gas-transportation contracts and two interruptible contracts. APS has been considering its options in response to the conversions and the new rates. APS had not by the end of the first quarter of 2006 executed any of the firm contracts. Three of the firm contracts had previously been executed: two associated with the Sundance power plant purchase, and one associated with a recent expansion of ELP's system.

Storage is one potential option for addressing the new ELP pricing structure. Pinnacle West Energy Corporation ("PWEC"), APS's former merchant-energy affiliate, sought to develop a high-deliverability storage project in an underground salt deposit near Luke Air Force Base on the west side of Phoenix. High-deliverability storage can accommodate the large changes in flow rates that characterize combustion turbine operation. Such a facility would assist materially in meeting ELP's new balancing requirements economically. ELP acquired the project from PWEC; however, legislation enacted in 2004 prevented further development.

APS is pursuing new pipeline options. In December 2005, APS signed a precedent agreement with Transwestern Pipeline Company ("TRW") to take capacity on a new pipeline project

connecting the San Juan Basin to the Phoenix area. The applicants expect to file for FERC approval this summer. TRW's target in-service date is April 30, 2008. That project could serve Redhawk and Sundance generating stations. It would apply balancing requirements much less stringent than those of ELP's new services.

APS is also addressing options with the [redacted] APS hopes to [redacted]

7. Fuel Oils

APS uses very small quantities of fuel oils. Most of the reported use in 2005 was for start-up fuel at the Cholla generating station, which is coal-fired. APS used smaller quantities in the summer at the Douglas and Saguaro generating stations. APS does not use bid solicitations or requests for proposals to buy fuel oils or oil transportation. There are a number of suppliers near each power plant. APS places an order to an authorized supplier when additional supplies are required, after surveying market prices for several days.

APS uses its own contract for oil purchases. The Company has contracts for the purchase and sale of No. 2 diesel fuel and No. 6 residual fuel. The contracts set forth general terms and conditions; *e.g.*, title transfer, transportation and balancing and the exercise of options, billing and payment, events of default and remedies. APS generally buys fuel oils on a delivered basis; therefore, it includes the cost of transportation in the agreed price. APS styles these contracts as master purchase and sale agreements, with oral transactions under them to be followed by facsimile confirmations specifying transaction-specific terms. Each contract attaches a sample form "Exhibit A" to be used for the confirmations. Exhibit A provides for specification of price, quantity, delivery point, period of delivery, and any other transaction specific terms.

C. Conclusions

1. APS applied an appropriate process for the procurement of new long-term coal supplies for the Cholla Station.

In February 2005, the Fuel Procurement organization issued an RFP for new coal supplies for the Cholla Station, with deliveries to begin in 2008. The RFP was necessary because the current coal supply from the P&M McKinley Mine was predicted to end in 2009. The RFP was sent to the major coal suppliers in New Mexico, Colorado, Wyoming and Montana capable of responding with the volumes of coal required. APS also requested that BNSF provide an offer for coal transportation services for the Cholla Station from the anticipated supply regions. APS conducted a thorough analysis of bids received for coal supply and for transportation, and integrated these bids into an economic analysis. This analysis determined the lowest overall cost to produce electrical energy from the various coals proposed, when all of the new capital and operating costs at the Cholla Station were considered. The process used by APS was reasonable, considering: the timing of the need for coal, the extent of the modifications required at the Cholla Station, the potential coal suppliers contacted, the analytical process used to determine the

optimum combination of coal supply and plant modifications, and the provisions of the finalized coal supply agreement.

2. APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective.

The coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are as follows:

Cholla:

- The P&M Amended & Restated Coal Supply Agreement of 2005
- The Peabody Agreement dated 12/21/2005

Four Corners:

- The Restated and Amended Four Corners Fuel Agreement
- The Restated and Amended Four Corners Fuel Agreement #2.

These coal supply agreements are typical of the vintage of coal supply agreements that they represent and have been negotiated, or renegotiated, in an appropriate manner. The agreements provide a reasonable balance between the needs of both Buyer and Seller, and contain the types of protective provisions that one would expect to find in coal supply agreements of this nature.

3. APS's two short-term coal supply agreements for the Cholla Station are appropriate.

APS currently has two short-term agreements for supply of coal to the Cholla Station (the 550,000 ton agreement with Peabody for coal from Lee Ranch, and the 50,000 ton agreement with Kennecott for coal from Spring Creek). Each agreement was required for short-term supply situations at the Cholla Station, and was appropriately entered into considering the unusual supply constraints that APS was facing at the time. The terms and conditions of each of these agreements are also appropriate.

4. APS uses a sound process to contract for gas commodity.

APS gas purchase amounts approach $500 million annually; therefore, the contracting process for gas deserves major attention. APS provides the requisite level of attention. The procurement process with a new counter-party begins when an APS trader fills out a "vetting" form requesting authorization to trade. Credit and other analyses follow, culminating in a signed contract if both parties agree. Trading is generally not authorized until all documents are in place.

APS also administers its contracting process effectively. APS has knowledgeable and capable staff people managing the contracting process. Contract files are orderly and complete. APS M&T's Compliance function actively monitors compliance with relevant guidelines and procedures, and the "middle office" actively monitors credit and other risks.

5. The Company's efforts to develop alternatives to ELP have been appropriate.

The industry generally faces a significant problem in: (a) developing gas transportation and ancillary services, such as balancing, for electric power generation (particularly combustion turbines), and (b) pricing them fairly. The Commission's Staff has addressed this aspect of the

problem in its *Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project*, filed in Docket No. E-01345A-05-0895 on March 2, 2006. (See especially p. 8.) The very substantial differences between ELP's services and pricing in this area and those for the TRW's proposed Phoenix Project show that the issues are perhaps more about cost incidence and bargaining leverage than they are about physical aspects of providing the services.

The ELP situation compounds the problem, given difficulties with its California markets. Those problems have given, and will continue to give, ELP a tendency to shift costs to its east-of-California markets whenever possible. ELP's rate proceedings at the FERC offer a forum for seeking protection from this tendency, but when parties (including most everybody but APS) present the FERC with a settlement, it is difficult to expect that the FERC will overturn it.

In those circumstances, APS has little alternative beyond paying the higher costs or trying to reduce its reliance on ELP. It is particularly difficult to use dramatically less of the types of services at issue, because APS is increasingly using its gas-fired generation as load continues to grow at a very fast rate. APS effectively must work as best it can with ELP in the short run, while aggressively pursuing its options for the longer term.

APS (and its affiliates) have been aggressive about developing options for the longer term. APS spent considerable effort on the Silver Canyon Pipeline Project in 2003 and 2004. The Commission approved the Company's application to participate in this project in Decision No. 67239, issued September 15, 2004. TRW's Phoenix Project has involved a similar effort, which the Company addressed with the Commission in its application filed in Docket No. E-01345A-05-0895 on December 16, 2005. The Company's efforts with the [redacted] have the potential for yielding additional diversification. TRW's Phoenix Project and a connection to [redacted] would provide sufficient access to other pipelines to carry over [redacted] percent of APS's maximum daily gas consumption.

High-deliverability gas storage is especially valuable to the operation of combustion turbines because of its ability to accommodate the large changes in flows. Continuing to address that option therefore has substantial merit as well.

6. APS's contracting process for fuel oils is appropriate.

APS's processes for managing its requirements for fuel oils are appropriate to the level of that activity. As discussed in the chapter on fuels management, APS's procedures in this area are sound and well administered.

D. Recommendations

Liberty has no recommendations in this area of examination.

V. Hedging and Risk Management

A. Scope

Liberty examined the goals, strategy, procedures and practices of the Company's hedging program. The principal questions addressed by our review were the following:

- What are the objectives of the Company's hedging program?
- Are they clearly defined?
- What strategies and instruments (futures, options, etc.) are used in pursuit of the Company's objectives?
- What are the qualifications of Company personnel involved in hedging activities?
- Are the Company's transaction-tracking capabilities adequate to the task of controlling and managing the Company's hedging program?
- What policies and procedures are used for managing the risks associated with the Company's hedging program?

B. Findings

The Company's hedging program was formed in 1996, in response to early signs of instability in power markets in other parts of the United States. APS was also experiencing increased exposure to price instability, as its requirements for natural gas and purchased power to supply its own markets were increasing. By 2003, the Company had established formal guidelines for the level of hedge protection for those requirements. Those guidelines provided for coverage extending out [redacted]. Today, the Company formulates its *System Hedge Strategy* annually. APS M&T recommends a strategy, including specific targets, and senior management reviews and approves it. The target hedge levels reflect an identified percentage of the Company's anticipated consumption of natural gas and purchased power. APS does not use separate limits for each, but sets the targets as a percentage of the expected or forecasted total of natural gas purchases and purchased power combined.

APS M&T manages the hedging program. The group uses weekly forecasts of volumetric exposure to natural gas and purchased power. APS M&T places hedges to fix the prices of the targeted percentages of gas and power expected to be required over the next [redacted]. The *System Hedge Strategy* and the *Target Hedge Levels* control the timing and magnitude of hedge positions. The Company's Energy Risk Management department monitors the hedge position relative to the targeted hedge levels, and prepares a monthly compliance report for the Company's Energy Risk Management Committee.

1. Goals and Objectives

The primary objective of APS's hedging activity has always been to increase stability in the rates that the Company charges its customers for electricity service. Attaining that stability has produced a hedging program aimed at managing the volatility of natural gas and purchased-power prices toward stability, as well. APS M&T tries to enter hedge positions at the lowest prices available, and correspondingly seeks to buy natural gas and power at the lowest prices available. APS M&T also works to lower fuel costs by optimizing the energy source used to

serve system load and off-system sales. APS does not time or size its hedge positions with the goal of lowering costs, however, but of reducing volatility in fuel costs.

The Company does not use quantitative measures of price stability in setting objectives for its hedging program. Such measures might include a focus on limiting volatility to a certain percentage, or instituting price stability measures only when volatility exceeds a specified percentage. The current *System Hedge Strategy* focuses instead on fixing the price of defined proportions of the Company's requirements for natural gas and purchased power in advance of estimated needs for them.

An outside expert reviewed the [redacted]. That review [redacted]:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted].

2. Hedging Strategies and Instruments

Company purchases of coal and nuclear fuel take place under long-term contracts that APS considers to have stable pricing provisions. These arrangements thus provide a natural, or physical, hedge for an estimated [redacted] of 2006 fuel and purchased-power expenses. APS therefore does not undertake any hedging involving those fuels. Its active hedging program addresses natural gas and purchases of electric power, which comprise the remaining principal

[1] Arizona Corporation Commission Decision Number 61225 (October 30, 1998). See pp. 28-29.

components of its primary energy mix. Those components account for the other [redacted] of estimated fuel and purchased-power expense for 2006. Combining the natural hedges associated with the pricing provisions in its contracts for coal and nuclear fuel and the hedges purchased for natural gas and power produces the following results:

- [redacted] percent of total energy requirements are hedged for 2006
- [redacted] percent are hedged for 2007.

The Company's hedging strategy has been to fix the prices of the natural gas and purchased power that it requires through the use of forward contracts, energy futures, and swaps. The definitions of these instruments are:

- *Forward contract:* A bilateral contract in which buyer and seller agree on delivery of a specified quantity to a specified point at a specified price (or pricing mechanism) at a specified date in the future.
- *Futures:* A contract to buy or sell a fixed quantity of a commodity, delivered to a specified location, at a specific time in the future. Futures contracts are standardized, to allow their trading on public exchanges, such as the New York Mercantile Exchange ("NYMEX"). The right to receive (or deliver) the amount of the commodity covered by the contract is traded; the price of the commodity actually delivered is set at the time that trading in the contract closes.
- *Swaps:* In general, swaps are bilateral contracts in which buyer and seller agree to exchange an asset or liability for a similar asset or liability for the purpose of lengthening or shortening maturities, raising or lowering interest rates, or maximizing revenue or minimizing financing costs. APS reports that its swaps are "NYMEX look-alikes", negotiated directly with individual counter-parties, rather than bought on the exchange.

APS generally purchases power at delivery locations on its transmission system, such as Palo Verde and Four Corners. The price of that power can be hedged (fixed) at those locations. APS makes most of its purchased-power hedges as forward-purchase contracts at the Palo Verde location. APS generally buys natural gas, however, at the San Juan and Permian Market Centers on the El Paso Natural Gas ("ELP") transmission system, in New Mexico and West Texas, respectively.

The NYMEX futures contract for natural gas settles at the Henry Hub, a market center in Louisiana. Prices can differ at the delivery locations more directly relevant to getting the gas to APS, however. Transportation cost differences and constraints are examples of the reasons for those differences, which the industry refers to as "basis." APS manages these potential differences by also hedging (in addition to its hedging of the differences in futures prices of the gas commodity at the Henry Hub) its exposure to location, or basis, differentials between the ELP market centers and the Henry Hub. Various financial institutions "make markets in" (*i.e.*, buy and sell) basis differentials between the Henry Hub and other market centers; APS M&T places its basis hedges with several of those institutions.

Beginning in 2003, the Company adopted formal guidelines setting the proportion of its requirements for gas and purchased power for which prices would be fixed. With escalating volatility in energy markets and an increasing proportion of its power-supply portfolio exposed

to those markets, APS increased those proportions in 2005. The proportion of APS's power supplies exposed to short-term energy markets increases because the growth in its load is generally accommodated with increased operation of its gas-fired generation, or increased purchases of short-term power.

Effective in late June 2005, the Company raised its hedge targets for its [redacted] ([redacted]) window as follows:

- [redacted] percent of forecast gas and purchased-power requirements will be hedged for the subsequent [redacted]
- [redacted] percent of forecast gas and purchased power will be hedged for forward [redacted]
- [redacted] percent of forecast gas and purchased power will be hedged for forward [redacted]
- Additionally, the Company will hedge [redacted] percent of its natural gas basis for the next [redacted].

The required hedge levels apply to total combined natural gas and power purchases. The lower percentages in the more-distant future periods recognize that volatility can be more pronounced in the near months. Futures prices for all periods tend to be affected when market-moving events, such as the hurricanes of 2005, occur. Prices farther into the future tend less to be affected by such events. The lower percentages for the fifth and subsequent quarters allow the Company's traders to wait for disturbances to subside before locking in prices for those periods.

The consultant that reviewed the Company's [redacted]

The [redacted] -percent target for the immediately ensuing [redacted] recognizes the uncertainty in the Company's load forecasts (and thus the uncertainty in its requirements for gas and purchased power). The Company re-estimates weekly its requirements for gas and purchased power for the next [redacted]. Inputs to the revised forecasts include not only revised load forecasts (updated semi-annually), but also updated future prices for gas and power, scheduled outages for APS generating units, and operating characteristics of APS's generating units, for example. APS also re-optimizes the mix between gas and power purchases with each update. Some trading of forward "positions" in gas and power may occur in response to shifts in the balance between them. The Company reports that the [redacted] percent hedged is typically [redacted] percent gas, and [redacted] percent purchased power, but this ratio can vary. Hedging at less than 100 percent prevents buying too much energy, with consequent extra costs.

APS does make minor adjustments in response to periodic re-optimization, but does not follow the practice of actively trading its hedges. In other words, once a hedge has been put in place, *i.e.*, once a forward contract, a futures contract or a swap has been bought, it is held to maturity,

rather than being bought or sold in response to changes in market prices. The hedging programs of other major natural gas users sometimes allow for "secondary" transactions, in which hedged positions are further traded in an effort to reduce costs. APS views this type of activity as speculation, in that entering such trades requires acting on expectations regarding market direction. The Company has consistently taken a strong position against speculation.

3. Qualifications of Company Personnel

APS M&T has an authorized complement of 70 people and an actual staffing level of 59. They conduct a number of activities other than those associated with the hedging program:

- Nomination of all gas pipeline capacity
- Dispatch of all generating plants and power-purchase contracts
- Arrangement of all off-system sales of electricity and any releases of unused gas transmission capacity
- Conduct of PWCC's remaining non-utility wholesale-market activities
- Monitoring compliance with certain risk-management guidelines
- Development and administration of the Company's natural-gas and purchased-power contracts
- Billing for any gas or power sales
- Payment authorization for natural gas and power purchases.

Most APS M&T personnel are long-time APS employees. Nearly all traders have long experience in power-plant operations. The Vice President, APS M&T was Supervisor of Generation Operations before transferring to Bulk Power Marketing. Most APS M&T employees joined the department (or a predecessor organization) when it was started. The exception is the department's Director of Risk Management, who has a background in trading and risk management in the petroleum industry. He entered power trading with another company, and joined APS M&T in 1999.

The Director of the Company's Energy Risk Management Department, which is organizationally outside of APS M&T, is also a long-time APS employee. He has been involved with APS's energy-trading and risk-management activity for almost the entire time that it has been in existence.

The Company complemented its internal energy trading experience when it initially set up the marketing and trading function. Specialists from the capital markets industry were brought in for that task. The guidelines, procedures, and other structures that those specialists developed remain still largely in place today. All aspects of APS's marketing and trading operation are highly structured, and have been so since the creation of the marketing and trading function.

APS's Vice President, Generation & Transmission (now President of the Company) originally established the marketing and trading operation. He supervised it until early 2003, when that role moved to the Chief Financial Officer ("CFO"). The CFO came to APS from a utility system in the Midwest, where he had started and managed a marketing and trading function.

4. Transaction-tracking Capabilities

The internally developed *TranZ* system tracks M&T activity. APS states that:

> *TRANZ ... provides customized functionality for transaction capture, confirmation, scheduling/operations, valuation, credit and market risk measurement, invoicing, and for reporting ... physical and financial electricity and natural gas transacting activities.*

The system includes the following components:

- *TranZSCHED*: trade capture and delivery system for power, both long-term and real-time transactions;
- *TranZGAS*: trade capture and delivery for natural gas;
- *TranZEVAL*: hourly dispatch module, based on operating-cost and heat-rate characteristics of generating units;
- *TranZVIEWER*: detailed historical data on realized results;
- *TranZMTM*: mark-to-market calculation derived from relevant deal terms in trade capture, and from market prices obtained and calculated according to procedures and stored in the database (TranZDATAMART);
- *TranZINVOICE*: preparation of invoices and data for reports to accounting and treasury departments, using verified values from VIEWER;
- *TranZVALIDATION*: Independent System Operator settlement validation program, which interfaces with the ISO to validate settlement figures based on trading activity recorded in SCHED.

TranZ categorizes the transactions it includes into a book structure, which provides for segregation by trading entity and by commodity. The entities include:

- *System*: APS's utility activities, including purchases and sales of gas and electricity (including jurisdictional off-system sales), and emissions allowances
- *Merchant*: (no longer reflect any activity) these books tracked transactions including sales of power and capacity from the Redhawk merchant plants and the Silverhawk plant, and purchases of fuel for those plants, prior to the change in status of the Redhawk units and the sale of the Silverhawk plant
- *Trading*: APS's non-utility wholesale transactions, including supplying power to retail affiliate APSES, and supplying power under several contracts entered into during the Merchant Period (between the 1999 and 2003 rate cases); most of this activity is in three contracts, with Citizens/UniSource, Tohono Oodham and the City of Williams, AZ.
- *Retail*: transactions supporting Texas and California electricity and natural gas retailing.

Traders primarily conclude transactions: on an electronic trading platform or by phone (on a recorded line). APS uses the Intercontinental Exchange ("ICE") trading platform. Each trader enters transactions on a trade ticket or deal log as they are concluded, and those transactions are entered into TranZ by the end of each day. APS's "middle office" compares each trader's

transactions to confirmations for the same transactions that are returned by each counterparty, generally via facsimile or e-mail.

5. Policies and Procedures

APS has extensively documented policies and procedures governing its hedging activity. Principal documents include the following:

- *PWCC Energy Risk Management Guidelines*: This document describes the Company's philosophy and objectives for its energy risk management program, and describes the organization and processes that govern the program. These guidelines are updated annually, and each APS M&T and APSES employee must annually confirm reading them, and agreeing to comply with them.
- *Energy Risk Management Procedures*: This document describes the procedures used by the Company's Energy Risk Management ("ERM") department to identify, measure, monitor and report on the major risks that the Company faces in conducting energy trading activities. ERM is independent of APS M&T, and provides a monthly report to the Company's Energy Risk Management Committee.
- *Energy Risk Management Model Documentation*: This document describes the computer models and data used to quantify and manage market and credit risks incurred in conducting energy-trading activities. It was prepared, and is updated annually by the Company's ERM department.
- *Price Data System Users Guide*: A contractor developed the Price Data System ("PDS") for APS, to automate the process of gathering (and validating) data required for the computations involved in assessing the Company's exposure to market risks. The PDS gathers raw price data, refines it and loads it into the TranZDATAMART. This guide (manual) assists users in operating the system.
- *Counterparty Credit Review Preparation Guide*: A users' guide for evaluating counter-party credit. The ERM department developed and annually updates this guide.

The Company also actively administers its policies and procedures. APS M&T has an internal compliance-management function, which reports to a System Hedge Oversight Committee. That committee is composed of the parent company CFO, APS M&T's Vice President, the Director of Risk Management, and the Portfolio Manager (Regulated). Its functions are to review the status of the Company's hedge positions, to consider and discuss general market conditions, and to review potential modifications of the System Hedge Strategy if warranted.

The Company's ERM department resides organizationally outside APS M&T. It reports to a different officer. ERM provides the "middle office" function for the Company's trading activity, and monitors counter-party (credit) risk and market risk. The industry uses the term "middle office" to refer to the energy-trading organization whose responsibility is to assure that trading activity is entered into the organization's transaction-tracking system in a timely manner, and to verify trades with counter-parties. ERM provides monthly compliance reports to the parent company's Energy Risk Management Committee. The committee considers the overall risk position, ERM's monthly compliance report, and the nature, status, and remedy for any policy or procedure violations or exceptions. The committee is composed of the following:

- The parent company's Executive Vice President and Chief Financial Officer

- The parent's Vice President, General Counsel and Secretary
- APS's Vice President, Planning
- The parent company's Audit Services Director
- APS's Director, ERM
- APS's Vice President and Controller
- APS's Director, Tax Services
- The Vice President, APS M&T
- The Executive Vice President, APS Generation
- APS's Vice President/Treasurer.

6. Utility and Non-Utility Activities

APS M&T provides products and services in two distinct businesses:

- Buying (and hedging) the utility company's short- to medium-term requirements for natural gas and purchased power, optimizing the utility's contracted gas transportation capacity, and conducting the utility's off-system sales of electric power.
- Wholesale trading in support of PWCC's remaining merchant activities, including optimizing some gas transportation capacity acquired during the *Merchant Period.*

The non-utility trading business is substantial. The following table presents some comparisons between the utility and non-utility wholesale businesses.

Table V.1 Comparative Utility/Non-Utility Statistics ($MM)

	2004		2005	
	Utility	Other	Utility	Other
Operating revenues	2,035	401	2,237	352
Fuel/Purchased power expense	567	321	595	293
Total assets	8,674	746	9,732	1,070

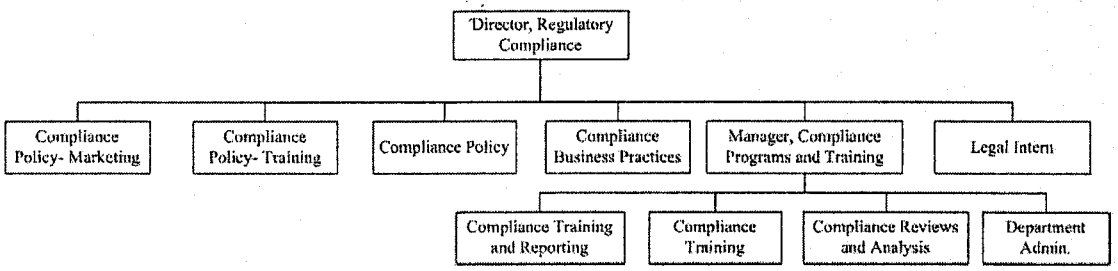
Using the same entity to conduct both businesses when a utility is involved creates special risks. The natures of the two businesses are different. Nevertheless, many activities to conduct them (*e.g.*, buying and selling power, hedging natural gas prices, selling natural gas transportation capacity into secondary markets) are the same. Moreover, many of the counter-parties with whom these transactions are conducted are also the same. Finally, the presence of an adjustment clause at the utility may create an incentive to move individual transactions between the two businesses. Higher-margin transactions could be moved to the wholesale trading business, where the parent company and its stockholders will realize all of the benefits of those transactions, and lower-margin ones to the utility, where the PSA mechanism mitigates impacts to stockholders.

The Company has addressed these risks. First, in response to an audit by the FERC's Office of Market Oversight and Investigations,[2] the Company organized an internal compliance function.

[2] The report from this audit was approved by the FERC in "Order Approving Audit Report and Directing Compliance Actions", issued December 16, 2004, in U. S. Federal Energy Regulatory Commission Docket No. PA04-11-000, *Arizona Public Service Company.*

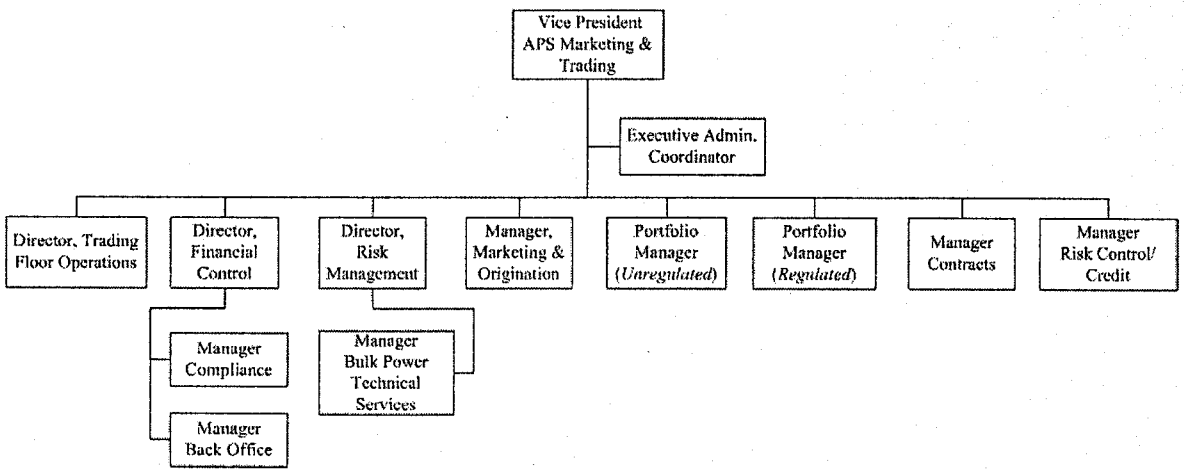
The Regulatory Compliance department conducts compliance programs for FERC and ACC requirements. The department reports to the Executive Vice President for Customer Service and Regulatory Affairs. The next table shows the department's organization chart.

Table V.2 APS Regulatory Compliance Department



Relationships between the Company's utility and non-utility activities are the focus of the ACC compliance effort. The Company reports that it has been discussing these relationships with the ACC Staff for some time. Hearings on these relationships and related matters concluded in November 2005, and the Company was awaiting a final order in the proceeding as this report was written.[3] APS M&T uses separate traders to conduct its regulated and non-utility businesses, although both are located on the same trading floor. The organization chart for APS M&T below shows how the Company has segregated the non-utility business from the utility business.

Table V.3 APS Marketing & Trading Department



All non-utility traders, except the real-time traders, report to the Portfolio Manager (Unregulated). Utility traders report to the Portfolio Manager (Regulated). Utility and non-utility real-time traders report to the Director, Trading Floor Operations because of their singular focus on operations and reliability. Those reporting to the Director, Trading Floor Operations include:

- System Native Load

[3] That order came on June 5, 2006. It requires the filing of an amended code of conduct and supporting policies and procedures to conform to the order. APS recently reported that these documents remain under discussion with Commission Staff.

  - BOM Senior Trader
  - Day-Ahead Senior Short Term Traders
  - Day-Ahead Gas Trader
  - Senior Real Time Traders
- Power Marketing Schedulers
- Merchant Real Time Traders.

Liberty conducted work observations and interviews on the APS M&T's trading floor. Liberty observed that the traders for the utility and non-utility businesses were physically segregated, with the exception of the real-time traders. For reasons of reliability maintenance, the real-time traders for the utility and non-utility businesses sit at adjoining desks. The role of the real-time traders in reliability maintenance requires considerable infrastructure: special communications systems, special computers, special systems for electrical power, etc. Moreover, both real-time desks must be staffed continuously: 24 hours per day, 365 days per year.

All traders use a deal log to enter their trades as they are made. The real-time traders dispatch generating units and other sources of power on a real-time basis, and use their deal logs to record what they have done. The day-ahead traders line up sources of fuel and power for the next day, in time for nomination and scheduling deadlines. The trading floor's schedulers perform the scheduling function for both the utility and non-utility businesses, as they are providing information to control area operators that is generally not interchangeable between the two businesses. For transactions beyond the next day, the traders time-stamp their deal logs as agreement is reached on transactions. The trader or an administrative assistant then enters each transaction into TranZ by the end of each day. As noted earlier, APS's ERM department verifies each transaction with each counter-party by comparing the TranZ entry with confirmation received from the counter-party.

C. Conclusions

1. APS has designed and operates a sound hedging program.

The Company's Energy Risk Management Guidelines and Procedures and its administration of its risk-management program are as strong as any that Liberty has examined. An outside expert reviewed the fuel and purchased-power hedging program during [redacted]. The consultant found that [redacted]. Liberty's review confirmed this assessment.

Liberty found the capabilities of the systems and staff involved in hedging to be strengths. All persons interviewed demonstrated job experience and proficiency, and familiarity with program aspects and job functions related to their direct roles. All support systems are also strong.

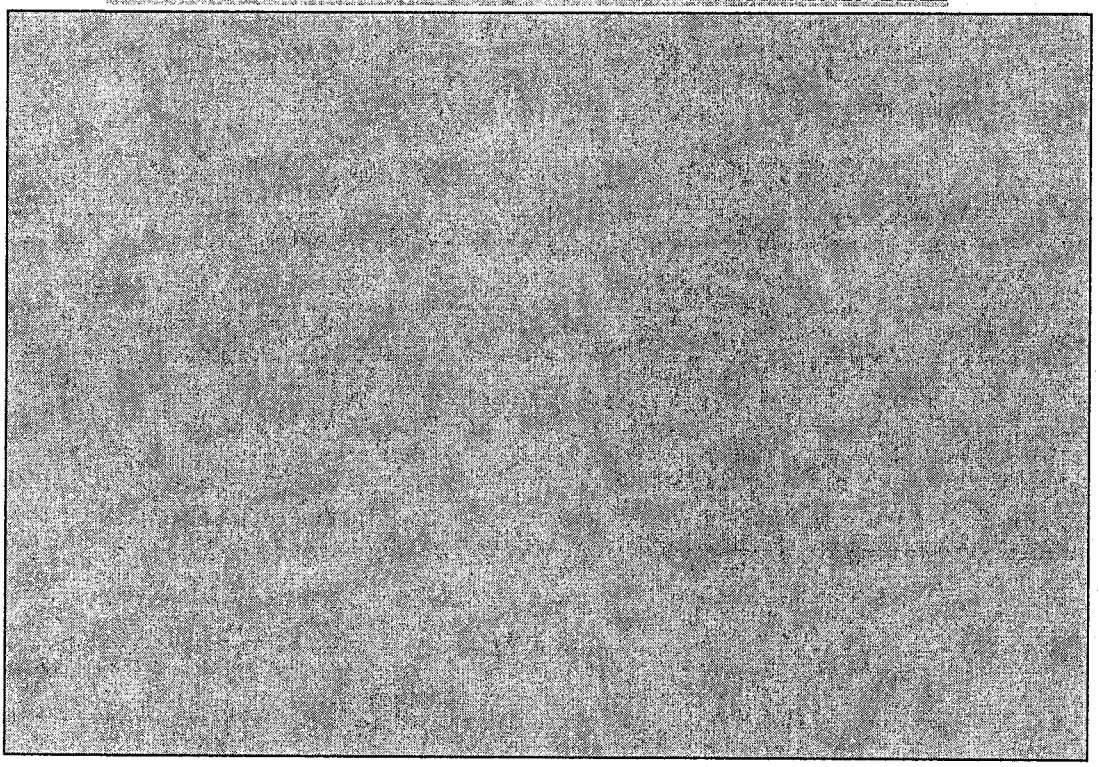
Increased market volatility, however, underscores need for strong communication and agreement with regulators about hedging program goals. APS has given internal thought to the matter; what is less clear is the position of customers and of the Commission. Other objectives are possible; the Company should address them with its customers and regulators.

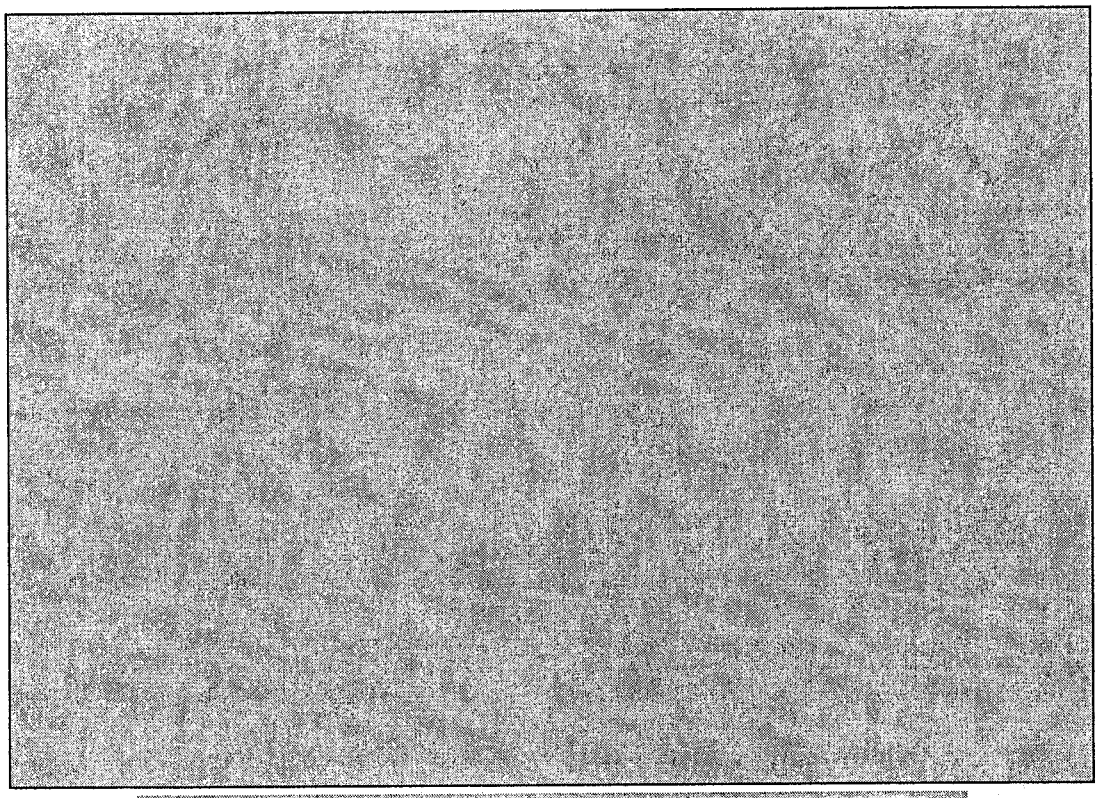
2. The Company's program has been successful in meeting its primary objective.

The following charts estimate the impact of the APS hedging program on fuel and purchased-power costs for calendar 2005 and 2006. The charts show total annual fuel and purchased-power costs would have been on each day plotted. One curve tracks what costs would have been had APS needed to buy fuel and power on the open market. The other (lower) curve shows changes in costs from applying owned hedges. For example, if the Company were to have purchased its entire requirements for fuel and purchased power for the year 2006 on one day in late September of 2005, the total cost would have been about $[redacted]. Applying the hedges that were in place on that day would have brought that total cost down to about $[redacted]. The charts make clear that the hedges have had a significant stabilizing effect on costs for those periods.

Figure V.4 APS Hedged System Costs

ENTIRE FOLLOWING TWO CHARTS ARE CONFIDENTIAL





ENTIRE PRECEDING TWO CHARTS ARE CONFIDENTIAL

3. **The Company's hedging program will, however, prevent costs from falling.** *(Recommendation #1)*

A consequence of the Company's focus on stability in its fuel costs is that those costs will not decline rapidly if market prices go down. The hedged positions that are today preventing the Company's costs from rising will prevent them from falling if market prices go down.

APS recognizes this possibility, and is concerned about it. The Company has tried to prepare stakeholders for this possibility, but Liberty believes that the matter deserves more extended discussion. That discussion should focus specifically on whether there are effective and acceptable strategies for allowing customers or particular groups of them to benefit more quickly if energy prices decline.

4. **The segregation of utility and non-utility activities is not as complete as it should be.** *(Recommendation #2)*

With the resolution of the Company's 2003 Rate Case, APS M&T personnel speak of "new clarity about the unit's identity and mission". The Company characterized its non-utility activities as "vestiges" of the "Merchant Period," and offered its expectation that they would disappear when the last of the full-requirements contracts expires in May 2008. Company representatives observe, however, that they have yet to advise the Commission formally of its

intentions in this matter. Liberty's concerns about continuation of non-utility trading include a number of issues.

Credit Support: After a period of time trading as Pinnacle West Capital Corporation for its non-utility wholesale trading activities, the Company has now gone back to trading as Arizona Public Service Company. As the responsible party, the utility is providing credit support to the wholesale trading activity, unless specific actions are taken to prevent that result. Wholesale trading involves considerably greater risk than does the utility business. Consequently, a utility company that backs a wholesale trading operation, all other things equal, will have a lower-quality credit than one that does not. Thus, allowing wholesale trading activity to be conducted in the name of Arizona Public Service Company may hurt APS's credit, and also represents a value transfer from the utility to affiliate(s).

Physical Separation of Traders: APS observed that the ACC Staff has expressed comfort with the "separate traders, same trading floor" resolution of potential conflicts of interest arising from simultaneous conduct of two sets of marketing and trading activities: one for the regulated utility and another for the non-utility wholesale trading activity. As indicated by the organization chart presented above, the traders have indeed been separated organizationally. Moreover, Liberty's site visit revealed that the regulated and unregulated traders are also physically segregated on the trading floor, except for the real-time traders. As noted earlier, because of infrastructure requirements necessitated by maintenance of reliability, the real-time traders for the utility and non-utility activities continue to sit next to each other.

Risk Metrics for Utility Activities: PWCC is careful about measuring and managing the risks associated with its non-utility trading operations. Risk metrics, such as Value at Risk ("VaR") and Capital at Risk ("CaR") have been calibrated to the scope of activity that PWCC is comfortable with conducting. Changing any of those limits requires approval by the parent company's board of directors.

Risk metrics for the Company's utility activities are less well developed. Credit limits for individual counter-parties, for example, are computed on the basis of APS M&T's overall assessments of each party's creditworthiness. Each limit is then shared between PWCC's utility and non-utility trading activities as their transactions require. If it were to happen that non-utility trading used up the credit limits assigned to the most creditworthy counter-parties, then the utility would be obliged to trade with less credit-worthy ones. Alternatively, the utility might trade less, with consequent loss to its customers. Other risk metrics remain to be developed for the utility.[4]

Agenda for Internal Audit: When traders for the utility and non-utility parts of PWCC's business are transacting in the same commodities or instruments, at the same locations or the same exchanges, and at the same time, there is potential for error, particularly if the names of the two entities are similar. There is also potential for deliberate misassignment. With independent confirmation by the middle office, these risks can be reduced, but not eliminated.

[4] PWCC's Energy Risk Management Guidelines, dated May 2005 (and furnished to Liberty as part of the Company's response to DR No. STF 1.9), states (at p. 7) that "Risk metrics for the Regulated activities are under development."

Liberty reviewed the Company's recent internal and external audits related to fuel procurement, power procurement and price risk management. This review revealed that nine of them addressed various topics within the marketing and trading function, but none dealt with the utility/ non-utility split. Going forward, it is an area that requires audit attention as long as the two entities continue to trade in parallel.

D. Recommendations

1. Engage stakeholders in a discussion of hedging program objectives. *(Conclusion #3)*

The preferred approach to setting the objectives of the Company's hedging program would be to work with customers, other stakeholders, and the Commission in a process that includes dialogue and consensus building, where possible. APS should establish ways to explore the needs, expectations, concerns, values and preferences of its customer groups, seek to rationalize them, if possible, and then report on them to the Commission.

Broadly speaking, energy users hedge in pursuit of two objectives: stabilizing prices or lowering prices. It is frequently believed that commercial and industrial customers generally prefer price stability over obtaining the lowest possible price, where there is tension between the two results. Price stability facilitates their budgeting for their costs of doing business, and may help them determine how to price their own products and services. In contrast, it is frequently asserted that residential customers prefer the lowest possible price. Most residential customers, on the other hand, understand the need for protection from sudden or sharp price increases (price "spikes"), but they may prefer to gain the benefit of lower prices as soon as that benefit can be made available.

Pursuit of hedging objectives other than price stability would involve different strategies and different instruments. The different strategies would have different risks, and the different instruments would have different costs. Making a different and potentially more complex set of options available would take a well-designed communications program addressing these matters with customers in a manner that explains the trade-offs in ways that could be understood by different customer groups. Customers' reactions to these trade-offs can and should be made part of the Company's report to the Commission in this area.

Obtaining input from commercial and industrial customers should be relatively straightforward; conducting a "dialogue" with residential customers may prove more difficult. Arizona's Residential Utility Consumer Office ("RUCO") is one potential resource that is knowledgeable about the utility business. Some utilities have also used customer focus groups to explore customer attitudes in some detail.

Liberty recommends that efforts to determine customer preferences in this area begin soon, and take place over a defined time interval. Liberty recommends the next six months. Allowing some time for synthesizing various inputs and preparing a report, Liberty recommends that the Company present a report to the Commission on customer preferences for hedging, and adjustments (if any) to the Company's program in light of these preferences, nine months after acceptance of this recommendation.

2. Report to the Commission on the future plans for non-utility activities. *(Conclusion #4)*

If the Company's non-utility trading activities are to continue, it has work to do in further segregating those activities from similar activities at the utility. The Commission needs a definitive statement of the Company's intentions in this area. If non-utility trading activities are to continue, the Company should also present a plan for the further segregation of those activities. The plan should address at least the following areas:

- Credit support: How will the Company keep the credit requirements of the wholesale trading operation from affecting the conduct and costs of the utility business?
- Physical separation of traders: The Company maintains a "hot back-up" facility for its communications and control systems, complete with its own power supply, in Deer Valley. This facility is essential to continued operation of the Company's control systems in the event of loss of power to the downtown location for any reason. As the back-up facility is completely equipped but rarely used, would it provide a suitable location for non-utility trading operations?
- Risk metrics for the utility: As an asset-based business, the utility has risks that are different from the trading business. What metrics are appropriate to those risks, and what limits should apply?

VI. Forecasting and Modeling

A. Scope

Liberty reviewed how the Company develops fuel and purchased power budgets by use of simulation models for both long and short-term markets, and analyzed the effectiveness in achieving least-cost dispatch.

B. Findings

The multitude of capacity and energy resources available in today's electric power industry requires the development of accurate fuel budgets and the use of computer simulation models. Effective forecasting requires a significant and detailed information about many aspects of each individual generating unit, including:

- Nameplate capacity
- High operating limit
- Minimum operating limit
- Mid-point control points
- Heat rates for each operating point
- Full heat rate curve
- Ramp rates
- Minimum run times
- Minimum outage times
- Maintenance schedules
- Forced outage rates
- Primary and secondary fuels
- Emission limitations.

Information on fuel supply, fuel prices, heat rate content, minimum fuel inventory levels, monthly peaks, monthly energy sales, transmission path limitations, load shapes, and system reserve requirements must all be gathered, analyzed and input into the models.

Developing an effective database requires coordination of several utility functions and information from other utilities or the independent system operator. The database requires constant updating as resources and load changes. These requirements apply for the simulation models used to develop the budget for the PSA; they apply equally to the model used to develop the dispatch list for the day-ahead traders.

1. Model Selection

The principal model used in the determination of near term fuel requirements is a probabilistic, production cost model, known by the trade name *RTSim* (Real Time Simulation). RTSim is a licensed, proprietary product of Simtec, Inc. of Madison, Wisconsin. Simtec has a wide variety of clients across the country. APS chose it because of its accuracy and ease of use.

The model employs unit commitment and dispatch logic to simulate optimal daily system operations, and to facilitate the determination of the optimal mix of fuel burns. The goal is to

develop the lowest cost of power production. Inputs to the model include an hourly system load forecast, operating characteristics (*e.g.*, heat rates, capacities, minimum load levels, start-up costs) for all resources (*e.g.*, gas, coal, nuclear, wind) employed in the system or planned for future operation, fuel prices and market prices for power purchases (*e.g.*, standard block products, options, day-ahead and hourly products).

Model outputs include cost projections, projected individual generating unit energy production, power purchases required to serve forecasted load, and any economic sale opportunities. The energy production projections attempt to establish the quantities of gas, coal, or nuclear fuel requirements for the company.

APS first acquired RTSim under a test agreement in mid-1998. APS tested RTSim for almost a year, and performed several months of parallel processing with the then-existing production cost model known as *RES*. APS had developed RES in house many years before, custom designing it to capture the unique operations of the APS system under the traditional utility operations of the time. During testing and benchmarking, APS requested a number of enhancements to the model. APS acquired the non-test version of the model, incorporating the enhancements, in January 1999. APS stopped running RES and began to use the new model exclusively to perform the Company's operating studies in May 1999.

APS addresses daily unit dispatch by daily runs of a resource commitment model that optimizes unit commitment. This short-term model, *Resource Commitment System*, operates as a deterministic model that calculates dispatch order. APS purchased the original software platform for this task from Staggs Software Co. APS uses the same data to maintain the RTSim database and Resource Commitment System. Speed of calculations represents the primary difference between them. Resource Commitment System only calculates dispatch order; therefore it can calculate faster because it does not require the extensive data base that RTSim needs.

Most of the APS RTSim users have prior experience with other production cost models. All personnel responsible for executing the model have received the one-week intensive training course offered by RTSim's developer, Simtec, Inc. The one-week course enables experienced model users to understand the unique features of RTSim as compared to other models. New users to the model acquire additional on-the-job training under the mentoring of the experienced operational planners, who have had years of prior experience using production cost models, and who have a sound understanding of system operations. Depending upon their background, new users typically spend a year or two working under the guidance of these more experienced users before they take responsibility for independent work.

The APS M&T Department has four individuals trained to execute the model. The Forecast Department has two individuals trained to execute the model.

2. Data Accuracy

The Company uses several management processes to ensure the accuracy of RTSim input data:

- *Data Control*: APS uses a formal input approval process combined with a secure database that houses all official data and assumptions underlying the execution of RTSim. APS controls access to this database, which it limits to personnel who must enter

data into the database or who have a need to use the data. Formal processes exist for the collection of data and for approval of data entry. The Vice President of Fossil Generation, the Executive Vice President, APS Generation, and the Vice President of Marketing and Trading approve all data that their own organizations enter into the data base.

- *Information Updating*: inputs updates take place formally at least twice each year: in the fall, during budget development and in the spring during Long Range Forecast development. Between these semi-annual activities, adjustments get made as changes to assumptions and data occur in order to assure that operating studies continue to use the most current data and assumptions.
- *Forecast Benchmarking*: at the time of each official forecast update, APS compares the results to a previous case to ensure that the changes show consistency with those anticipated. Detailed analyses are occasionally required to confirm the validity of the updated results. In cases where these comparisons reveal inappropriate or inaccurate inputs in the model, the inputs are corrected and the model is re-run to produce the correct results.
- *Operations Benchmarking*: APS performs monthly, detailed comparisons of actual power plant operations and fuel and purchased power expense results with budgeted amounts. APS makes these comparisons at an hourly level of detail to account for such factors as energy load variations, dispatch prices for natural gas and power, power plant availability, and dispatch operations. Findings from these comparisons may result in changes to the modeling of fuel and purchased power volumes and expenses if warranted.

APS continuously maintains the database because it runs the model on a weekly schedule to meet term-trader operational needs. APS takes care to maintain accurate maintenance schedules and fuel forecasts. In addition, studies can also be run as needed to assess the economic impact of changes in power plant operations and/or to assess specific purchase or sale opportunities.

3. Use of Model Outputs

APS runs RTSim in an operational role to establish the volume of power and natural gas requirements, to evaluate power plant maintenance plans, and to evaluate sales and purchase opportunities. The Company formally updates the model twice per year as part of the fuel and purchase power budgeting process. It establishes cost and volume projections for the coming and subsequent years. Because of the different nature of gas, coal and nuclear fuel markets, the fuel projections are provided to different departments. The APS system term trading group has responsibility for managing the company's gas procurement requirements in accordance with the company's hedging plan.

APS uses ad hoc operational studies to assess the economic impact of changes in power plant operations and to assess specific purchase or sale opportunities. Additionally, RTSim runs periodically throughout the year to provide updated fuel and purchased power expense forecasts for financial model projections. These projections include the development of the Company's annual budget and the long range forecast, but may include other analyses as well.

Finally, APS M&T uses the model continuously. This group manages the procurement of power purchases (together with natural gas) using weekly RTSim volume and price projections (known as the *Balance Report*) to trade with other market participants.

4. Production Modeling and the PSA

APS used RTSim to develop its 2003 Base Fuel Rate of 2.0743¢/kWh to establish fuel and purchased power expense levels. For that 2003 Base Fuel Rate, APS normalized for fuel and power prices, customer levels and energy usage, power plant availability and other factors.

C. Conclusions

1. APS uses sufficiently accurate modeling to predict fuel and purchased power volume and cost.

APS continually monitors the accuracy of database inputs, which comprises an important step in assuring the accuracy of its short-term forecasts, given APS's hedging strategy to control gas costs. The Company reports an inaccuracy level of 1 to 2 percent in those forecasts. The models are sufficient for predicting fuel and purchase volume and cost during periods of stable fuel prices and stable loads. As is typical, the accuracy of the model is less predictable in times of unstable costs.

Given that the model output is used to develop the operating plan for the next day, management has the model updated daily and audited weekly for accuracy. As conditions change during "real-time," efforts are made to modify the plan as needed, and new model runs are made. The importance that APS places on the model and its accuracy is reflected in the fact that the manager in charge of running the model is assigned to the Marketing and Trading Department

2. APS has taken appropriate actions to ensure that least cost total dispatch is achieved.

By most metrics of success APS is doing a good job of modeling its fuel and purchased power budget. APS is using tools that are accepted by the industry. The Company took care in benchmarking the model's accuracy for use on its system. APS trains its people well and continually maintains the database (and associated output) with the most up to date information to maintain the accuracy of its forecast. This is all done by management to ensure that least cost total dispatch is achieved.

3. APS uses outside reviews appropriately to improve management and operations.

APS conducted three reviews relevant to forecast accuracy: a term trading audit, a unit dispatch audit, and a power plant operating parameters audit. The first two audits reviewed whether APS had the appropriate tools and training available for their trading personnel to minimize the cost of purchased power. In both cases the audits found that APS [redacted]. The power plant operations performance audit recognized that the [redacted]. The preliminary audit found that [redacted]

APS performed the three reviews at about 10-month intervals, which is sufficient. APS scoped the audits narrowly to address specific actions to improve forecast accuracy, which demonstrates an appropriate commitment to improving operations.

4. APS maintains adequate documentation to support regulatory oversight and review.

The amount of documentation is extensive and thorough. It includes bi-annual fuel budgets, monthly variance reports, weekly balancing reports, and ad-hoc operational studies.

D. Recommendations

Liberty has no recommendations addressing the area of Forecasting and Modeling.

VII. Plant Operations

A. Scope

This chapter of Liberty's report addresses the following topics related to operations of the generating stations at APS:

- APS Dispatch Order and Constraints
- Fossil Unit Availabilities, Capacity Factors, and Heat Rates
- Unit Capital and O&M Expenditures
- Fossil Unit Outage Scheduling
- Economic Evaluations Regarding Fossil Unit Outages
- Outage Scheduling and Interface with the Market
- 2005 Fossil Unit Outages
- Net Replacement Power Costs.

Liberty's audit excluded operations of the Palo Verde Nuclear Plant, which are being addressed in a separate examination.

B. Findings

1. APS Dispatch Order and Constraints

The Phoenix Load Pocket

The greater Phoenix area has been designated the "Phoenix Load Pocket," because sufficient generation within this area must be operated to provide security, voltage control, or spinning reserve for this part of the APS system. Both APS and the Salt River Project ("SRP") serve load in the 11,149MW Phoenix Load Pocket. Total transmission and generation capability for this area amounts to 12,375MW, which provides a reserve margin of 1,226MW. APS's Ocotillo (330MW) and West Phoenix (988MW) generating stations and SRP's Kyrene (520MW), Santan (1200MW), and Aqua Fria (600MW) generating stations lie within the Phoenix Load Pocket. Total generation within the actual Load Pocket amounts to 3,638MW.

In 1999, the Company began to structure its fleet of generating units to operate in a more competitive market regime. After 1999, the Company built Redhawk Units #1 and #2 about 40 miles west of Phoenix, and West Phoenix Unit #5 within the Phoenix Load Pocket. The Company did not build market generation in any other locations. Subsequently, in 2002, the ACC ordered that these former merchant units be brought into rate base. The parties including the other merchant generators reached a settlement agreement, which the Commission approved, effective April 2005.

APS Dispatch Order

The following table illustrates the general order in which APS must dispatch its fleet of generating units. The table includes the former merchant units. The table also illustrates the magnitude of replacement power costs faced by APS. The former merchant units have operated

under frequent cycling as part of the APS dispatch regime. That form of operation affects the unit heat rates and capacity factors of the more expensive gas units and the combustion turbines.

Table VII.1 APS Generation Dispatch Order

Unit Type	Accredited MW[5]	Cumulative Total MW	Op. Cost ¢/kWh[6]
[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]

APS expects a summer 2006 system peak load of approximately 7,300MW. The summer peak has been increasing at approximately 300MW per year. Reserve requirements at 15 percent bring total APS requirements to 8,395MW. Minimum load on the APS system is between 2,500MW and 3,000MW. APS uses the Cholla units to follow load at these lighter load levels; SRP uses the Navajo units for that purpose. Both the APS and SRP power systems rotate load-following responsibilities among the units at those stations.

APS must integrate its system power supply contracts into this dispatch order. APS has a long-term 340MW, hourly dispatched, 10,000 BTU/kWh contract with SRP. This capability can be ramped at 110MW/minute, which makes it useful for spinning reserve requirements. APS also has a no-cost 480MW seasonal swap contract with PacificCorp. The contract provides for swaps on a one-for-one MWh basis, with day-ahead scheduling. Energy not used by either party is lost.

The APS dispatch order now includes West Phoenix Unit #5 and Redhawk Units #1 and #2. These large, very efficient gas-fired former merchant generating units have heat rates of approximately 7,400 BTU/kWh. They were originally designed to operate as base load units, but now must run in the intermediate range, and follow load. Their April 2005 introduction into the dispatch order changed the operation of the units above them (*i.e.*, more expensive) in the dispatch order. Thus, these more expensive units now run less often, and run less often at full load. This change adversely affects their performance metrics, which this chapter will discuss subsequently. The impacts affect heat rates, maintenance requirements, and economics.

[redacted]

2. Fossil Unit Availabilities, Capacity Factors, and Heat Rates

Background

Power suppliers measure the performance of generating units in numerous ways over a variety of time periods. Unit Availability Factor ("UAF") serves as a primary measure.[14] A unit is considered to be available for this calculation even if it is running at a reduced output in support of system control, or because of equipment problems. To address this reduced output issue, the industry uses the measurement of the unit Equivalent Availability Factor ("EAF"),[15] which restates the UAF assuming full load operation. Net Capacity Factor ("NCF") serves frequently as a measure of unit output.[16] Some utilities modify this measurement by calculating it for the time period the units were requested to run. This change makes the measurements more comparable to desired performance. The efficiency of the unit is measured by the unit Net Heat Rate.[17]

The values of these measurements can be affected by many factors, which include:

- Frequency and duration of planned maintenance
- Frequency and duration of outages due to equipment failure
- Running a unit to provide spinning reserve or voltage control for the system
- Fuel used and its quality
- Unit design
- Unit placement in the dispatch order
- Equipment selection
- Environmental protection requirements
- Air ambient temperature or relative humidity.

Base Load Plants

Unit efficiency and long-duration of operation are key factors for base-load units. The APS base-load units include five coal units at Four Corners, three coal units at Cholla, and three coal units at SRP's Navajo plant.[18] The next table lists the UAF, EAF, and NCF for those plants. Net MW reflects the APS ownership share. The table also restates each unit's UAF and NCF by deducting

[14] Availability Factor is an expression in percent of the time (in hours) that a unit was running or ready to run if called upon to do so compared with the time in the period. A unit with a 50 percent annual availability was therefore ready to run for 4,380 hours in that year.

[15] Equivalent Availability Factor is an expression in percent of the equivalent time (in hours) that a unit was running at its full net load or ready to run if called upon to do so compared with the time in the period. A unit with a 50 percent annual availability that ran 50 percent of the time it was available, and ran at 80 percent load for 25 percent of the time it was running would have an Equivalent Availability Factor of 2,190 hours (available, not running), plus 1642.5 hours (running, full load), plus 438 hours (equivalent full load hours of 547.5 hours at 80 percent load) or 4,270.5 hours in that year. That would equate to an Equivalent Availability Factor of 48.75 percent.

[16] Net Capacity Factor is an expression in percent of the net generation (in kWh) that a unit generated compared to the maximum amount of net generation it could have generated during the period. If our example unit had a net output of 100MW, it would have a capacity factor of 164,250MWh plus 43,800MWh compared to the possible 876,000MWh that could have been generated during the year. That Capacity Factor would be 23.8 percent.

[17] Net Heat Rate is an expression of the amount of heat energy put into the unit to get net electrical energy out. Generally, it is expressed as the number of British Thermal Units (unit of heat equaling about 252 calories) of fuel input to the unit to obtain one net kWh of output.

[18] Palo Verde nuclear units have similar desirability, but are not part of this examination.

the time the unit was out of service for planned minor, major, and reliability outages. This restatement of these metrics permits a more direct comparison among the units, by recognizing that not all units underwent maintenance during the year. The performance measurements for the base-loaded coal plants were not affected by the introduction of the former merchant plants into the APS dispatch in April 2005 because the operational costs of the merchant plants were higher.

Table VII.2 Major Unit 2005 Actual and Restated Measurements (%)

Unit Name	Net MW	2005 UAF	2005 EAF	2005 NCF	Planned Outage Days/Type	2005 UAF Restated	2005 NCF Restated
Four Corners #1	170						
Four Corners #2	170						
Four Corners #3	220						
Four Corners #4	113						
Four Corners #5	113						
Cholla #1	110						
Cholla #2	260						
Cholla #3	260						
Navajo #1	105						
Navajo #2	105						
Navajo #3	105						

The table illustrates that EAF is lower than UAF by to percent. These lower values are expected to reflect hours of reduced operation due to equipment problems or the necessity to match minimum loads on the system. APS has 1,164MW of nuclear generation and 1,731MW of base-loaded coal generation, totaling 2,895MW. Minimum system load in the 2,500MW range sometimes requires reduction in coal generation. Given the load conditions that APS faces, the observed reduction in EAF is expected.

Liberty restated the UAF and NCF in the table by deducting the hours when the units were in major, minor, or reliability outages for planned maintenance. All unplanned maintenance, unit reduction, and forced outage time remains in the calculations. From the restated data, UAFs for the time where the units were expected to be available ranged from approximately to percent. NCFs for the time where the units were expected to be running ranged from approximately to percent. SRP uses one unit at the Navajo station to follow load during light periods on its system. In 2005, Navajo Unit #3 served in this capacity and accounts for an approximate percent reduction in NCF. Liberty found the restated values to be within the range it would expect for these base-loaded coal plants.

The 2005 heat rates at the Four Corners Plant showed an approximate BTU/kWh improvement over 2004. Fluctuation in heat rate value can result from the number of startups and other operating conditions. Liberty believes, however, that the improvement obtained in 2005 resulted from better plant operations. Cholla Units #1 and #3 heat rates are approximately BTU/kWh, and have remained in a fairly close range around this value for a number of years. The Cholla Unit #2 heat rate dropped from approximately BTU/kWh to BTU/kWh in 2005. Liberty believes that this improvement resulted from the replacement of the

low-pressure turbine in 2005. The 2005 Navajo Units #1, #2, and #3 heat rates of approximately [redacted] BTU/kWh showed an approximate [redacted] BTU/kWh improvement over 2004. Liberty believes that these improvements are due to better plant operations.

Large, Efficient Gas Units

Performance metrics for the gas plants and the combustion turbines were adversely affected by introduction of the former merchant plants into the APS dispatch order in April 2005. The large former merchant units ran at a [redacted] to [redacted] percent NCF for 2005. These measures include the first three months of the year, during which they remained merchant plants and appeared to be running at lower NCFs. Liberty considers it likely, therefore, that NCFs for these plants will rise in 2006. These large units run after the base-loaded coal units in the dispatch order. Accordingly, APS operates them in an intermediate dispatch position, and must follow load variations. The [redacted] BTU/kWh range heat rates of these large units push the less efficient gas units[19] higher on the dispatch curve. UAFs remained high at [redacted] to [redacted] percent for the large efficient gas units. The West Phoenix Unit #5 location within the Phoenix Load Pocket has also affected its operation. The unpredictable operating conditions necessary to support system control can have adverse impacts on the performance metrics of the unit. Overall, Liberty found the performance metrics of the former merchant units to fall within an expected range, given dispatch conditions.

Less Efficient Gas Units

Movement upwards on the dispatch curve results in lower NCFs for less efficient units, because APS does not call upon them as often. Higher heat rates result because the units must operate at reduced loads more frequently. UAFs and EAFs, however, should remain relatively unchanged. Review of the APS data shows that the less efficient APS unit performance measurements show expected results. West Phoenix Units #1 - #4 and the units at Ocotillo can also be affected by their location within the Phoenix Load Pocket. Liberty found that the performance metrics of these less efficient units were consistent with their movement in the APS dispatch order.

3. Unit Capital and O&M Expenditures

The following table shows major capital expenditures at APS generating stations. The number in parentheses represents the number of major unit maintenance outages taken in that calendar year.

Table VII.3 Major Capital Expenditures[20] at APS Generating Stations

Power Plant	Units	2001	2002	2003	2004	2005
Four Corners	5	9.7 (1)	25.9 (2)	19.7 (1)	25.6 (2)	18.2 (1)
Cholla	3	5.9 (0)	9.7 (0)	13.2 (0)	7.1 (0)	15.0 (1)
West Phoenix	5	8.9 (2)	- (1)	- (2)	- (1)	5.9 (1)
Redhawk	2	*	1.2 (1)	- (0)	- (0)	1.4 (0)
Ocotillo	2	- (0)	- (0)	- (0)	- (0)	- (0)
Saguaro	2	1.7 (0)	2.6 (0)	- (0)	- (0)	- (0)

Millions of dollars * - Units not in operation.

[19] West Phoenix #1 - #4, Ocotillo #1-#2, Saguaro #1-#2, Sundance #1-#10, and all combustion turbines.

[20] Liberty defined a major capital expenditure as a project that APS expended in excess of $1 million for illustrative purposes. Many smaller projects aggregate to significantly greater capital expenditures and a small ownership interest in a plant can mask a major project.

The table shows an expected correlation between capital expenditures and major unit outages, because larger, more capital intensive projects occur generally during major outages. The table also shows that APS has continued to make significant capital expenditures at the coal plants, even during years without major outages. This result is also consistent with general experience. The importance of the coal units in keeping electricity costs low makes them important priorities when capital expenditures are set. Performance metrics indicate that the Cholla and Four Corners units have been running well. Liberty saw no indicators of insufficient attention to equipment upgrades and modifications. The Navajo units have also been running well.

The following table summarizes O&M expenditures at the APS fossil stations. The number in parentheses represents the number of major unit maintenance outages taken in that calendar year.

Table VII.4 O&M Expenditures at APS Generating Stations

Plant	Units	2001	2002	2003	2004	2005
Four Corners	5	38.2 (1)	41.6 (2)	43.0 (1)	43.5 (2)	47.6 (1)
Cholla	3	33.0 (0)	28.8 (0)	32.9 (0)	33.3 (0)	37.8 (1)
Navajo	3	11.2 (0)	9.9 (0)	13.8 (1)	15.5 (1)	15.0 (1)
West Phoenix	5	10.1 (2)	7.3 (1)	10.1 (2)	12.2 (1)	13.7 (1)
Redhawk	2	*	4.4 (1)	13.6 (0)	14.1 (0)	18.0 (0)
Ocotillo	2	5.0 (0)	5.8 (0)	3.8 (0)	4.4 (0)	4.6 (0)
Saguaro	2	4.6 (0)	4.1 (0)	4.3 (0)	3.9 (0)	3.3 (0)

Millions of dollars
* - Units not in operation.

The table shows that APS has been making consistent O&M expenditures at its major plants. There has actually been a marked increase in O&M expenditures at APS coal plants and the former merchant plants. Liberty found O&M expenditure patterns to be consistent with system operational requirements.

4. Fossil Unit Outage Scheduling

Four Corners Units #1 and #2 – 170MW Coal (each)
These units experience scheduled, [redacted]-day major maintenance outages (boiler, total turbine, and all components except generator) every [redacted] years, except that scheduled generator maintenance is on a [redacted]-year cycle. No reliability outages have been taken recently, but APS now plans to take such outages at the [redacted] -month time point between the major outages, in order to reduce the [redacted] to [redacted] forced outage days experienced on average.

Four Corners Unit #3 – 220MW Coal
The maintenance schedule for this unit is the same as that for Units #1 and #2.

Four Corners Units #4 and #5 – 113MW Coal (each)
These units experience scheduled, major [redacted]-day maintenance outages (boiler, total turbine, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans) in the [redacted] year of the [redacted] -year cycle. APS now takes reliability outages at the [redacted]-month time point between the major and minor outages in order to reduce the [redacted] to [redacted] forced outage days experienced on average.

Cholla Unit #1 – 110MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) outages every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans, common scrubber) in the [redacted] and [redacted] years of the [redacted]-year cycle. [redacted]-day reliability outages (directed at the scrubber) are taken at the [redacted]-month time point between the minor and major outages.

Cholla Unit #2 – 260MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, induced draft fans, common scrubber, and dust collection) in the third and [redacted] years of the [redacted]-year cycle. [redacted]-day reliability outages (induced draft fans) are taken at the [redacted]-month time point between the minor and major outages. This unit had its high-pressure and intermediate-pressure turbine replaced in 2005.

Cholla Unit #3 – 260MW Coal

This unit experiences scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, and all components) every [redacted] years and minor, [redacted]-day maintenance outages (boiler, electrostatic precipitator) in the [redacted] and [redacted] years of the [redacted]-year cycle. No reliability outages are taken because of the difference in pollution control equipment. Unit #2 has a scrubber; Unit #3 does not. The absence of a scrubber reduces maintenance requirements on Unit #3. This unit will have its [redacted].

Navajo Units #1, #2, and #3 – 105MW Coal (each)

These SRP-operated units undergo scheduled, major [redacted]-day maintenance outages (boiler, total turbine, generator, coal handling) every [redacted] years and minor, [redacted]-day maintenance outages (boiler) in the [redacted] year of the [redacted]-year cycle. Liberty does not know if reliability outages occur.

Ocotillo Units #1 and #2 – 110MW Gas (each)

The boilers, turbines, and generators at these units are the same. The boilers are sensitive to thermal cycling. A [redacted]-day reliability outage is taken prior to [redacted] in an effort to maximize generation in that [redacted] period. The turbine-generator is on a [redacted] equivalent factored hour inspection schedule for major inspections.

Saguaro Unit #1 - 110MW Gas and Unit #2 – 100MW Gas

The maintenance schedules for these units are identical to those for Ocotillo.

Redhawk Units #1 and #2 – 492MW Gas (each)

These units have a super-efficient design consisting of two combustion turbines and one steam unit, with design heat rate of approximately 7,000 BTU/kWh. These General Electric Model 7FA units have a triple reheat Heat Recovery Steam Generator ("HRSG") designed for base load operation. Thermal cycling was not designed into these units. In bypass mode, one combustion turbine can run at the 70 percent power level. A [redacted] day reliability outage is taken prior to [redacted] in an effort to [redacted].

Maintenance can be driven by the number of starts or the number of hours operated. If the average of hours per run is greater than [redacted], the unit maintenance is hours driven; otherwise, it is driven by the number of starts. Currently, hours are the controlling maintenance factor for both units. The turbine-generator of the combustion turbine is on a [redacted] factored-fired hour inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored fired operation requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. The steam unit undergoes a B level inspection (valves, controls) also at this time. Every [redacted] hours of factored fired operation requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

West Phoenix Units #1, #2, and #3 – 85MW Gas (each)

These units are Stag 100 simple cycle units, with one combustion turbine per steam unit. If no inspections are scheduled, a [redacted]day reliability outage is taken prior to [redacted] in an effort to maximize generation in that [redacted] period. The turbine-generator of the combustion turbine is on an [redacted] factored fired hour inspection schedule, with each inspection scheduled for [redacted] days.[21] Every [redacted] hours of factored fired operation requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factored fired operation requires an [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

West Phoenix #4 – 117MW Gas

Maintenance can be driven by the number of starts or the number of hours operated. Currently, number of starts controls maintenance for this unit. The turbine-generator of the combustion turbine is on a [redacted] factored fired hour or [redacted] equivalent factored starts inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored fired operation or [redacted] equivalent factored starts requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factor-fired operation or [redacted] equivalent factored starts requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

West Phoenix #5 – 506MW Gas

Maintenance can be driven by the number of starts or the number of hours operated. Currently, the unit starts drive the maintenance schedule. The turbine-generator of the combustion turbines is on an [redacted] factored fired hour or [redacted] equivalent factored starts inspection schedule, with each inspection scheduled for [redacted] days. Every [redacted] hours of factored-fired operation or [redacted] equivalent factored starts requires a [redacted]-day combustion turbine hot gas path inspection and includes the minor inspection. Every [redacted] hours of factored fired operation or [redacted] equivalent factored starts requires a [redacted]-day major outage for the main unit turbine generator (all equipment) and includes the hot gas path and minor inspections.

[21] The outage times for these units appear long because they are only done on a straight-time basis in the off peak period.

5. Generation Unit Capital Project Planning

Capital project priorities are set on a system-wide basis. APS uses a single-point-of-failure analysis and a centralized database to perform capital project evaluations. APS gives planners direct responsibility for performing assigned analyses. The analysis of potential capital projects considers plant availability, equipment age, and other issues arising from unique plant conditions and emerging industry knowledge and issues. APS uses a 10-year horizon for identifying capital projects at its generating units. The plan and its components undergo annual review and updating. APS uses a simple payback of approximately three to five years (an internal rate of return of 15 percent)[22] as the economic threshold for the evaluation of capital projects.

Plant personnel evaluate smaller potential projects; larger projects are evaluated centrally. The Vice President, Fossil reviews all proposed projects. The Fossil Generation department at APS has developed a two-day course addressing economic evaluations of generating units. APS planners and evaluators from both the central office and from the generating stations attend these courses. APS offers a refresher course as well.

6. Spare Parts for Generating Stations

APS maintains a company-wide materials management system; it tracks warehouse spare-parts inventories at Four Corners, Cholla, Redhawk, and West Phoenix. APS sets inventories on the basis of the criticality of each part, and accounts for them accordingly. The stations share common spare parts. Economic analysis supports the purchase of new capitalized spare parts. APS was not able to demonstrate the existence of such analyses to Liberty during the audit.

The Saguaro and Ocotillo Power Plants have minimal spare part inventories; APS expenses them as it purchases them. The Navajo Power Plant, operated by SRP, has participated in benchmarking studies of plant inventory. The latest occurred in 2004, using 2003 inventory values. APS states that Navajo shares specific parts that might be requested by fellow members of several industry organizations, as well as with other SRP plants. Equipment redundancy was determined by economic evaluation during the design of the plant.

Liberty examined whether the APS approach in evaluating spare parts inventories appropriately considered the potential need for and cost of replacement power that may be required should parts not be available as needed. Liberty found that APS does perform soundly those economic evaluations that it conducts. However, Liberty did not find that APS has pursued potentially economical approaches; for example:

- The appropriateness of redundancy at Navajo has not been evaluated since its construction
- SRP does not share parts with APS, a joint owner of the project.

[22] Simple payback without the time value of money, Internal Rate of Return, and cost/benefit ratios are all related ways in which the profitability of a project can be measured and compared to other projects.

7. Scheduled Outage Timing

Load Forecasting Uncertainty

APS uses its long-term load forecast for outage scheduling. That load forecast uses econometric modeling for forecasting commercial and industrial loads and end use modeling for residential loads. APS uses a 10-year mean forecast, with a 50 percent probability of being exceeded each year. The industry terms such an estimate a "50/50 forecast." Some utilities and power pools with summer load peaks have moved towards a load forecast that would expected to be exceeded once in 10 years; *i.e.*, the so called 90/10 forecast) because of significant loading strains on the power system.

A 90/10 load forecast can exceed a 50/50 forecast by 5 percent or so. The APS system carries reserves of 12 to 15 percent, and assumes timely completion of scheduled transmission and generation construction. The APS system has been experiencing significant growth – about 300MW per year. APS also recognizes that conditions in the Phoenix Load Pocket can limit the ability to transfer power.[23] However, the use of a 50/50 forecast with the assumption that there will be no delays in new construction can have the effect of eliminating much of the margin for the constrained Phoenix Load Pocket. Designing the system to weather conditions, where the weather itself can cause the load forecast to be exceeded every other year, thus potentially usurping a large portion of system reserves and the margin of the constrained Phoenix Load Pocket (assuming construction is timely completed), can be questioned. For example, if load in the Phoenix Load Pocket exceeds projections by five percent, the effect is the same as having a large unit out of service; *i.e.*, almost half of the capacity reserve in that area is used.

Outage Condition Modeling

APS uses a program called RTSim to simulate conditions of one month and more out to a horizon of three years. The next chapter of this report addresses this program in more detail. RTSim performs hourly dispatch production simulation that incorporates expected loads and known outages. APS uses it to help minimize production costs during scheduled outages. The model discretely treats known planned outages, and probabilistically models forced outages.[24] For periods of less than 30 days, APS looks at the results of RTSim modeling, market data, expected system transmission and generation conditions, and expected loads to fine-tune its bulk power market activity. APS states that its short-term (day-to-day) predictions have been within one percent of what actually occurs.

The outage requirements of the three Palo Verde nuclear units comprise the first building block in long-term outage scheduling at APS. Their outage schedules are a given for purposes of scheduling outages at the remaining stations. The Four Corners, Navajo, and Cholla coal stations are all jointly owned.[25] The outage schedules for the units at these plants[26] must be developed through consensus that meets the needs of all joint owners. This consensus-building process produces a three-year outage schedule that is "cast in stone," and added to the overall outage

[23] Liberty is unaware if APS specifically models these constraints in their reliability calculations.
[24] When probabilistically modeled, the unit is derated equally in all hours of operation to equate to its forced outage rate.
[25] A jointly owned plant can be one where different utilities own a portion of a unit or different units in total.
[26] The outage schedules consist of major outages, minor outages, and reliability outages at differing frequency levels.

schedule. The availability of skilled workers is a large consideration in the outage scheduling of the base-load coal plants. The outage schedules for the gas plants are determined by run times or starts, economics, and other requirements, such as the skilled labor pool and time requirement for the refurbishment of parts, which in some cases can take up to 6 months. The following table illustrates the timing and layering of major unit coal outages for 2005 on top of the nuclear outage schedule. To the schedule shown, gas plant outages would have to be added.

Table VII.5 APS Coal Unit Major Outages for 2005

Time Period	Units Out	Total MW Out
1/1 – 1/25	-	0
1/25 – 2/18	Navajo #1	105
2/18 – 3/27	Navajo #1, Four Corners #1	275
3/27 – 3/31	Four Corners #1	170
4/1 – 4/18	Cholla #2	260
4/18 – 5/7	Cholla #2, Four Corners #5	373
5/7 – 5/13	Cholla #2	260
5/13 – 9/21	-	0
9/21 – 9/26	Cholla #1	110
9/26 – 11/7	-	0
11/7 – 11/18	Four Corners #4	113
11/18 – 12/31	-	0

Consideration of Market Conditions

The plants have hourly market information available to them. APS M&T trading personnel continuously communicate with personnel at the plants in order to stay abreast of operational and outage conditions. Day-ahead trader reaction to market conditions may initiate these conversations; so may plant personnel knowledgeable of relevant (particularly unexpected) plant conditions. Transitory plant equipment difficulty or market conditions, for examples, can lead to deferrals of outages for repairs to the weekend, if possible. APS uses real-time, 24/7 communication and schedule adjustments to balance the goals of minimizing costs to customers and maintaining safety and equipment integrity. Economy is an important objective, but plant personnel must agree to deferring maintenance in such conditions, in order to assure that decisions fully consider safety and equipment integrity.

8. 2005 Coal Unit Outages

The following table shows 2005 outages of at least two days at APS coal units.

Table VII.6 2005 Coal Unit Outages Exceeding Two Days

Unit and Year Installed	Start	Days	Description
Four Corners #1 – 1963	2/18	40.28	Planned 40 day major boiler overhaul
Four Corners #2 – 1963	4/7	3.60	Backpressure pluggage removal
Four Corners #3 – 1964	5/23	4.59	Superheater tube leak
	7/14	2.99	Reheater tube leak
	11/3	3.49	Reheater tube leak
Four Corners #4 – 1969	1/3	3.09	Waterwall tube leak
	3/7	2.80	Reheater tube leak

	7/15	2.99	Waterwall tube leak
	7/27	3.83	Reheater tube leak
	11/7	10.44	Planned reliability outage
	12/17	2.75	North reserve transformer ground
Four Corners #5 – 1970	1/3	5.12	Reheater tube leak
	4/18	18.31	Minor overhaul (20 day planned)
	5/7	3.82	North main transformer isophase alterations
	6/16	2.62	Reheater tube leak
	8/18	2.82	Waterwall tube leak
	9/20	3.46	Reheater tube leak
	10/9	4.59	Reheater tube leak
	12/1	2.14	Reheater tube leak
	12/17	3.58	North reserve transformer ground
Cholla #1 – 1962	9/21	5.65	Planned mini boiler overhaul
	9/26	2.55	Hydrogen cooler problem on startup
Cholla #2 – 1973	4/1	53.63	41 day planned major overhaul
	10/2	2.67	Boiler tube leak
	12/2	3.19	Boiler tube leak
Navajo #1	1/25	56.37	58 day planned major overhaul
	4/5	2.14	Main steam control valve strainer removal
	11/6	4.05	Waterwall tube leak
Navajo #2	1/1	4.35	Waterwall tube leak
	2/22	3.98	Waterwall tube leak
	9/12	3.12	Waterwall tube leak
	12/14	3.09	Waterwall tube leak
Navajo #3	2/8	2.92	Waterwall tube leak
	2/28	3.04	Spacer tube leak
	5/21	4.54	Superheater tube leak
	6/20	2.64	Superheater tube leak
	9/25	2.64	Waterwall tube leak
	11/22	3.53	Scheduled superheater fouling cleaning

Two causes account for the vast majority of 2005 coal-unit outages: scheduled outages and boiler tube leaks. APS completed all but one scheduled outages within the scheduled window; there was a 12-day extension during the major maintenance outage at Cholla #2. Liberty understands that emergent work (rather than a delay in accomplishing scheduled work) formed the primary cause of the schedule overrun.

The 2005 outages resulting from boiler tube leaks at the coal plants accounted for the need for approximately 272GWh of replacement power. This sum represents 42 percent (272GWh out of a total of 645GWh) of the need for replacement power associated with coal units. The net replacement power cost was $16 million. The table below breaks down this total by unit.

Table VII.7 2005 Replacement Costs Associated With Boiler Tube Leaks

Unit	Size (MW)	Replacement Power (GWh)	Net Replacement Costs ($ Millions)
Four Corners #1	170	-	-
Four Corners #2	170	-	-
Four Corners #3	220	58.4	3.4
Four Corners #4	113	34.4	2.0

Four Corners #5	113	56.2	3.3
Cholla #1	110	-	-
Cholla #2	260	36.5	2.1
Cholla #3	260	-	-
Navajo #1	105	10.2	0.6
Navajo #2	105	36.6	2.2
Navajo #3	105	39.7	2.3
Totals		272.0	15.9

APS has scheduled the Four Corners Unit #3 reheater for replacement in 2006. The reheater at Four Corners Unit #5 is 36 years old; plans for its replacement, however, do not show on the capital expenditure plan out to 2010.

Liberty did not observe an economic analysis comparing the costs of replacing the aging reheater at Four Corners #5 with reduced forced outages for leaks and the accompanying savings that might result in reduced replacement power costs. Those replacement costs are considerable. Similar concerns exist at Navajo #2 and #3. Likewise, Liberty has seen no similar evaluations of boiler equipment replacement at those units.

Liberty's review of the causes of outages having less than 2-day durations revealed that the number of outages caused by operator or maintenance errors appeared unusual. These errors appeared to be concentrated in the operation of Four Corners Unit #3 and Navajo Unit #3. Both APS and SRP have stated that a [redacted]. Liberty also noted that efforts have been made to produce a climate that encourages personnel to discuss issues and problems without fear of job repercussions.

As an example, APS states that there has been an [redacted].[27] APS further states that [redacted]. APS has also stated that an [redacted].[28] APS further states that [redacted]. Such action plans appear to be specifically directed to an individual operator. While individual action may be appropriate, the number of events suggests that the true root cause may include items such as insufficient personnel to allow adequate training time, lack of expectations, or insufficient management support of the overall training process. Liberty would expect that operational errors would not be a problem four years after the installation of a simulator. Liberty believes that the root causes of operational and maintenance errors need review.

[27] APS omitted an additional outage in its response occurring due to operator error at Unit #1 on 3/27/05.
[28] Liberty believes that the installation of the simulator was to address operator and maintenance issues.

9. 2005 Gas Unit Outages

The following table lists 2005 gas unit outages of greater than two days.[29]

Table VII.8 2005 Gas Unit Outages Exceeding Two Days

Unit and Year Installed	Start	Days	Description
Ocotillo #1 – 1960	2/19	41.35	Planned outage
Ocotillo #2 – 1960	2/5	43.32	Planned outage
Saguaro #1 – 1954	2/14	34.71	Planned outage
Saguaro #2 – 1955	2/21	4.58	Maintenance outage
	10/24	17.58	Planned mini overhaul
West Phoenix #1 – 1976	4/16	28.88	Planned minor overhaul
West Phoenix #2 – 1976	2/21	41.25	Hot gas path overhaul
	5/4	2.37	Heat Steam Recovery Generator tube leak
West Phoenix #3 – 1976	3/18	94.28	Generator ground
West Phoenix #4 – 2001	1/1	2.86	Plugged servo
	4/11	4.76	Hot end inspection
	7/17	5.14	Generator bearing repair
	8/29	29.40	HP steam turbine vibration
West Phoenix #5 – 2003			
Steam 5	7/8	2.29	Condenser tube leak
	7/14	2.78	L-O blade inspection
	9/3	2.92	L-O blade inspection
	12/15	2.65	LP blade inspection
CT-5A	4/2	8.60	Combustor inspection
	7/8	2.29	Condenser tube leak
	7/14	2.24	L-O blade inspection
	9/3	2.92	L-O blade inspection
	9/29	4.86	Air cooler leak
	12/15	2.65	Compressor inspection
CT-5B	1/3	2.37	Combustor spread problem
	4/11	2.86	Main gas regulator failure
	7/8	2.29	Condenser tube leak
	7/14	2.24	L-O blade inspection
	9/1	4.92	L-O blade inspection and kettle tube repair
	9/20	2.12	Air cooler tube failure
	10/22	9.75	Planned overhaul
	12/15	2.65	LP blade inspection
Redhawk #1 - 2002			
Steam 1	11/3	10.03	Planned outage
	12/6	9.62	High vibration problem
	12/16	3.57	High vibration problem
	12/21	13.93	High vibration problem

[29] Outages are tracked as outages if unit UAF is affected. The outage may not be an actual outage if it was not called upon to run.

CT-1A	11/3	10.07	Planned outage
CT-1B	11/3	10.10	Planned outage
	12/10	3.36	Replace ST1 potential transformers
Redhawk #2 - 2002			
Steam 2	3/20	5.93	Hot end inspection
	4/1	4.32	Protection relay failure
CT-2A	3/20	5.93	Hot end inspection
	8/7	5.42	Brush failure
CT-2B	3/20	5.93	Hot end inspection
	4/5	2.57	High exhaust temperatures

Small Gas Units[30]

The majority of major outages for the small gas units were planned. Those planned outages appeared to be unusually long. These units have low capacity factors and maintenance is only conducted on a straight time basis. Additionally, parts that are in need of refurbishment are often sent back to the manufacturer, and then reinstalled. This process may lengthen downtime, but it does minimize customer costs, because the units are not needed to run in the dispatch order.

One outage of special interest is the 29-day outage associated with a vibration problem on West Phoenix #4. The steam turbine shaft was found to be warped. APS investigation found that the warping was due to water intrusion and that the water intrusion resulted from a rerouting of drains to an incorrect location during construction. APS replaced the shaft, corrected the routing of the drains, and inspected all other units in the fleet to assure that a similar problem did not exist elsewhere.

Large Gas Units[31]

The new, large gas units all have design problems regardless of their manufacturer. These problems are a result of efforts by each manufacturer to push metallurgical technology, clearances, and operational stability to their limits in order to reduce the heat rates to produce a generating unit that occupies a more economical place in the stack of available resources. All of the large 7,400 BTU/kWh units were designed in this manner; these kinds of design problems are outside of APS control.

West Phoenix #5

West Phoenix #5 is one of approximately 20 new Siemens 501F units in the United States. This category of steam turbines has a blade design problem that can cause the L-O turbine blades (the largest blades) to crack and break.[32] The unit is under an L-O blade inspection mandate (dictated by the manufacturer) after every 1,500 hours of operation.[33] The majority of major outages associated with this unit have arisen from the required inspections of the L-O turbine blades or other required maintenance. Such other outages have generally related to condenser or other leaks. These types of problems are attributed to the cycling duty placed on this unit after it was

[30] Ocotillo #1 and #2, Saguaro #1 and #2, and West Phoenix #1, #2, #3, and #4.
[31] West Phoenix #5, and Redhawk #1 and #2.
[32] This problem has been solved and retrofits are being conducted. Until such retrofits are conducted, strict inspections have been put into place.
[33] Recently increased to 3,000 hours by the manufacturer.

brought into the APS dispatch order in April 2005. This unit was built to run base-loaded, and to remain in a thermally expanded state. Greater cycling causes it to be subjected to more thermal expansion and contraction. The unit is also still undergoing minor outages caused by shakedown issues. To address these problems, APS is actively re-engineering the unit for cycling operation to address these problems. These efforts include collaboration with owners of similar units. An example of re-engineering is the modification of control schemes to eliminate fluctuation of the turbine blades.

APS applies a lost MWh analysis policy that requires a root-cause analysis when any generation is lost at its coal units. APS recently initiated this lost-generation analysis policy at Redhawk, and is considering its implementation at West Phoenix #4 and #5.

Redhawk #1 and #2

The Redhawk units are General Electric 7EA machines. Like the Siemens machines, they too are not designed to be run on a cyclical basis, and suffer generic problems. Compressor rubs from inadequate clearance in the design of the combustion turbines and vibration in the Alstrom generator comprise these generic problems. This vibration problem was not originally found because the old vibration monitoring technology used in the design by Alstrom could not detect the vibration problem. The majority of major outages associated with these units are the required planned inspections based on operational factors. Those planned outages appeared to be longer than they could be. Parts that are in need of refurbishment are often sent back to the manufacturer and then reinstalled.

This approach may lengthen downtime, but does minimize costs. Planned outages take place during off-peak periods where the units are not required to run, which makes outage cost minimization more important than minimization of downtime. Unit #1 also has the vibration problem noted above.[34] Once a new vibration monitoring system was installed and new information obtained, Alstrom designed and installed a correction. In order to minimize forced outage time when the unit is required to run, APS now schedules a short outage approximately one month prior to the regularly scheduled outage, to allow a boroscope inspection of the combustion turbine compressors. More detailed information about turbine compressor condition, which this inspection provides, assists in preparation for the regularly scheduled outage.

Other outages resulted predominantly from condenser or other leaks. These types of problems typify the cycling duty placed on this unit after it was brought into the APS dispatch order in April 2005. This unit was built to run base-loaded, and remain in a thermally expanded state. The unit is also still undergoing minor outages caused by shakedown issues. To address these problems and problems resulting from thermal cycling, APS is actively re-engineering the unit for cycling operation, and is collaboratively working with owners of similar units. An example of re-engineering is that steam injection is being discontinued for greater operational flexibility when cycling the units.[35] APS believes that the small loss of efficiency through discontinuation of steam injection is more than offset by the gains in improved flexibility that results when the units do not experience the metallurgical stress imposed by the steam injection.

[34] This vibration problem has not materialized in Unit #2.

[35] Steam injection is an efficiency process where steam is diverted from the main steam turbine and is reinjected into the combustion turbines.

10. Net Replacement Power Costs

The table below depicts the 2005 replacement power requirements and costs for various segments of the APS system.

Table VII.9 2005 APS Replacement Power Costs

	Replacement Power ($x1,000,000)					
Unit Type	**MWh**	**Cost**	**$/MWh**	**Avoided Costs**	**Net Costs**	**Net $/MWh**
Nuclear	878	67	76	4	63	72
Coal	645	46	71	8	38	59
All Gas	870	77	89	58	19	22
7,400 BTU Gas	760	66	87	50	16	21
Peaking Gas[36]	110	10	91	8	3	27

The table shows that the need to replace low-cost nuclear and coal energy led to the most costly portion of net replacement power costs. It is also noteworthy that the unit costs of replacing power from the intermediate gas units and from the peaking gas units did not differ by more than $4/MWh. These factors indicate a market that is long on supply and comprised largely of gas units. Such conditions would explain relatively small net replacement power cost differentials, because of the replacement of one gas unit with another.

Future conditions may well tend to increase the costs that APS will experience when it must replace base-loaded coal and nuclear generation with gas units. Similarly, the gap between intermediate gas units and peaking gas units on the APS system may also widen as the market tightens in the future. APS is aware of these potential market trends. There is likely to be significant future value in reducing the duration of its gas unit outages.

11. Plant Inspections

On April 4, 2006, Liberty performed a walk through inspection of Units #4 and #5 at the West Phoenix Power Plant. Liberty conducted a similar inspection of Units #1 and #2 at the Redhawk Power Plant on April 5, 2006. West Phoenix #4 (117MW) began commercial operation in 2001 and West Phoenix #5 (506MW) began operation in 2003. Units #1 and #2 at Redhawk (492MW) began operation in 2002. Liberty chose these units for inspection because they:

- Are large and their operation is of significant economic consequence
- As new plants, have experienced significant outages, and account for the bulk of net replacement costs associated with gas plants
- Have had to make the transition from merchant to vertically integrated utility planning and operation.

The primary inspection goal was to identify potential outage contributors. Not all these indicators clearly evidence performance problems, but together comprise a sound list of factors to consider. The indicators include tidiness, unsafe conditions, leaking valves or equipment bushings, other

[36] APS does not calculate the net replacement power costs associated with the outage of its combustion turbines because of the similarity of the replacement fuel.

out of the ordinary conditions, the type of material posted on plant bulletin boards, improperly installed cotter pins, missing bolts, other workmanship issues, impressions of the skill levels of plant operators, and observations about the dedication and values of senior plant personnel.

Liberty made the following observations at both stations:

- No apparent safety conditions
- No bushing oil leaks
- Proper connection of all electrical grounds
- No visible grounding mat problems
- Spare or new equipment, indicating that capital or maintenance projects were underway
- Equipment operating temperatures within normal operating ranges
- No workmanship concerns
- One leaking valve and one fabric heated air joint at West Phoenix Unit #5
- Knowledgeable and enthusiastic plant operators
- Senior plant management review and establishment of specific operation standards and safety expectations regarding plant operations throughout the West Phoenix plant[37]
- Good overall conditions
- No evidence of disrepair or neglect
- Neat and tidy conditions, with no spare equipment cluttering.

The leaking West Phoenix Unit #5 valve could not be repaired until the unit was shut down, at which time APS has scheduled that repair. The fabric-joint problem arose from unit design; APS has been re-engineering it.

Liberty also examined the transmission yards from the fence line. The transmission yards at both plants were neat, tidy, and not cluttered with spare equipment. Liberty observed:

- No apparent safety conditions
- No bushing oil leaks were observed
- Proper connection of all electrical grounds
- No exposed grounding mat material
- Good overall conditions
- No indication of disrepair or neglect.

C. Conclusions

1. The performance metrics of the base-loaded coal units demonstrate effective operation.

The heat rates, capacity factors and availability of the APS coal fired units have been reasonable. Efficiency has increased at the Four Corners Units. The performance metrics for the base-loaded

[37] The West Phoenix Plant Manager was recently transferred from Redhawk where such expectations are in place.

coal plants did not change with the introduction of the former merchant plants into the APS dispatch in April 2005 because the operational costs of the merchant plants were higher.

2. **The performance metrics of the large gas units also demonstrate effective operation; however, performance metrics of these units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.**

The heat rates, capacity factors, and availability of the APS large gas units have been reasonable, considering their modes of operation. However, these units must cycle more than was anticipated in their design. This change has adversely affected their overall performance.

3. **The performance metrics of the less efficient gas units also demonstrate effective operation; however, performance metrics of the large gas units have been adversely affected by their cycling as part of the APS dispatch order since April 2005.**

The less efficient gas units have been moved upwards on the dispatch curve because of the introduction of the APS merchant fleet into the dispatch order. This has resulted in lower net capacity factors for these units, because APS does not call upon them to operate as often. This reduced level of operation also results in higher heat rates, because the units will operate at reduced loads more frequently. The availability metrics have remained relatively unchanged.

4. **The capital expenditure and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements.**

APS expenditure data indicates that the Company has been making consistent or increasing capital and O&M expenditures at its major plants. The data indicates a marked increase in O&M expenditures at APS coal plants and the former merchant plants. These increased expenditures are reasonable, considering the need to maintain adequately the low cost coal units, and the need to meet the increased maintenance requirements at its gas units because of changes in operating conditions brought about by introduction of the APS merchant fleet into the dispatch order.

5. **APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement.** (*Recommendation #1*)

APS does not sufficiently consider net replacement power costs when it conducts its evaluations of which spare parts to carry and in what amounts. APS does not sufficiently consider these net replacement power costs when it determines whether certain pieces of equipment should be made redundant in order to facilitate on line maintenance or reduce outage time. APS also does not analyze the potential for avoiding net replacement power costs through early replacement of equipment at its power plants and at the Navajo plant operated by SRP.

6. **The use of a 50/50 load forecast, coupled with the fast growth of the Phoenix Load Pocket, and system constraints of the Phoenix Load Pocket, makes achievement of targeted reserves less certain.** (*Recommendation #2*)

The APS system carries system reserves in the order of 12 percent to 15 percent, and assumes that scheduled transmission and generation construction will be completed on time. If such construction slips, then the capacity margin of the Phoenix Load Pocket transfer capability can

be significantly affected. Adding weather uncertainties calls into question the ability to achieve consistent reliability levels in the Phoenix Load Pocket under a 50/50 forecast.

7. **The timing and layering of APS unit outage schedules follows industry practice, and is effective.**

APS uses an appropriate hourly-dispatch production simulation program that incorporates expected loads and known outages in order to minimize production costs during outage schedules. APS also considers the operating requirements of all of its generating units, including nuclear, coal and gas fired ones. Especially important are the outage schedules for the gas plants, which are greatly influenced by run times or starts, economics, and other requirements, such as the skilled labor pool and time requirement for the refurbishment of parts. APS also incorporates a sound process for integrating power market conditions into its outage scheduling process, through ongoing communication between plant personnel and power traders. Throughout this process, APS maintains safety and equipment integrity as the prime directive.

8. **Major, scheduled outages at the base load coal plants have had an appropriate length; however, outages at some of these plants from boiler leaks account for a conspicuously high percentage of net replacement power costs associated with these units.** *(Recommendation #3)*

Boiler tube leaks in 2005 accounted for 42 percent (272GWh compared to a total of 645GWh coal replacement power) of the need for replacement power at a cost of approximately $16 million of the $38 million in net replacement power costs for coal units. Studying means for reducing such outages is a worthwhile effort in seeking ways to minimize costs.

9. **The level of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3 is high.** *(Recommendation #4)*

APS has recognized the concentration of operator and maintenance errors at Four Corners Unit #3 and Navajo Unit #3, and relied on an action plan of either training or both simulator use and training on a case-by-case basis.

10. **Improving West Phoenix Unit #5 availability is important to the dispatch and keeping net replacement power costs at minimum levels.** (*Recommendation #5*)

West Phoenix Unit #5 is important to dispatch because of its size and the reliability and operational problems associated with its cycling use in the Phoenix Load Pocket. The unit was built to run base-loaded, and remain in a thermally expanded state. That form of operation minimizes the stress of thermal expansion and contraction brought about by cyclical operation. When reliability problems are encountered, not only is power supply in the Phoenix Load Pocket an issue, but power supply from more expensive generating units must be obtained.

11. **APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing with Redhawk #1 and #2 and West Phoenix #5 issues involving the units and the need for re-engineering them for intermediate dispatch operation.**

To address the reliability and operating problems of these units, APS is actively re-engineering them for cycling operation, and is collaboratively working with owners of similar units. An

example of re-engineering is that control schemes have been modified to eliminate fluctuation of the turbine blades.

APS also is beginning to use at its gas units a lost MWh analysis policy that has been used at coal units. This process involves conducting a root cause analysis when any generation is lost. This lost generation analysis policy was recently initiated at Redhawk, and is being considered for implementation at West Phoenix #5.

12. The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation.

New generating units, such as the large gas-fired ones, typically have operational problems of the type APS has been experiencing. Generic problems are also typical with new large units, and with units that operate under different conditions from those for which they have been designed. These units were built to run base-loaded and remain in a thermally expanded state and not be subjected to the stress of thermal expansion and contraction brought about by cyclical operation.

D. Recommendations

1. Prepare and execute an action plan that will improve economic evaluations related to minimization of outage time. *(Conclusion #5)*

APS should consider the impacts of net replacement power costs when it conducts its various evaluations related to minimizing outage time. This list of evaluations includes the following:

- Which spare parts to carry and the numbers of these spare parts to carry
- Whether to carry certain pieces of redundant equipment in order to facilitate on-line maintenance or reduce outage time
- Consideration of the benefits of premature replacement of certain equipment.

2. Analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket. *(Conclusion #6)*

APS should reevaluate its system reserve calculations by considering both the 50/50 and the 90/10 load forecast methodology, and justify the continued use of the 50/50 load forecast as the optimum means for assuring that desired reliability levels are actually achieved in the Phoenix Load Pocket. This reevaluation should consider impacts that may be caused by slippages in transmission and generation construction, by the fast growth of the Phoenix area, and the load effects of weather conditions that have a 50 percent chance of being exceeded every year.

3. Evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3 in light of current high net replacement power costs. *(Conclusion #8)*

High replacement power costs from Four Corners #5, Navajo #2 and Navajo #3 boiler tube leaks justify a quantitative evaluation of the effects of replacing boiler sections of these units.

4. Conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly

identified and addressed; determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. *(Conclusion #9)*

Operator and maintenance errors appear frequently in APS data as causes of outages. In particular, it is surprising to find a significant level of operational errors four years after the installation of a simulator. The relative costs of reducing such outages may prove quite small; therefore, the root causes of these outages should be examined. Items investigated should include such potential causes as insufficient personnel to allow adequate training time, lack of expectations, or insufficient management support of the overall training process.

5. **Implement for West Phoenix #5 the requirement for root cause analysis when generation is lost.** *(Conclusion #10)*

The root cause analysis used for coal units, and recently used for the Redhawk units, should now be applied to the West Phoenix #5 Unit.

VIII. Purchased Power and Off-System Sales

A. Scope

This chapter of Liberty's report addresses APS's purchased power contracts and off-system sales. Liberty's examination included the following activities:

- Determining the overall magnitude and major counterparties of APS purchases and sales
- Assessment of the off-system sale activities
- Comparison of APS off-system sales with those of other regional utilities in response to Decision No. 68685
- Verification that APS has optimized purchase and sale values from the utility-cost perspective
- Review of a sample of APS's fuel and purchased power contracts for reasonableness and for compliance with the terms and conditions.

B. Power Purchase Findings

1. Regional Conditions

APS's utility native electric load, its generating portfolio and operations, and opportunities for purchases and profitable sales in the marketplace drive the utility's purchased power and sales for resale. Liberty reviewed APS's power contracts and records, and examined summaries of power purchase transactions and sale for resale transactions. APS belongs to the Western Electricity Coordinating Council ("WECC"), whose nearly 1.8 million square-mile operating area includes portions of Canada, Mexico and all or portions of 14 western states. APS's service territory belongs to a sub-region of the WECC known as the Desert Southwest. This sub-region includes portions of Texas, Southern Nevada, New Mexico and Arizona.

WECC reports as of January 1, 2005 for the Desert Southwest sub-region show an excess of capacity at the region's peak and a large amount of excess capacity for virtually every hour of the year. Pertinent WECC-reported data include the following:

- Capacity of 36,917MW
- Load responsibility of 26,262MW
- Average hourly load of approximately 14,000MW.

Low-cost Desert Southwest nuclear, coal, hydro and pumped storage resources comprise approximately 50 percent of the region's capacity. The remainder consists of units with higher running costs. Gas-fired steam and combined cycle units and combustion turbines comprise much of these costlier facilities. Among them, the relatively newer and thermally more efficient combined-cycle units provide approximately 36 percent of available capacity. The region's substantial excess of capacity requires the large number of combined cycle units that have roughly equivalent efficiencies to vie to serve load opportunities on an incremental basis.

2. APS Portfolio

The following table shows the generation and major contract purchase components of the APS portfolio.

Table VIII.1 APS Capacity by Fuel Type

Generation	MW	Percent
Nuclear	1,164	18.1%
Natural Gas	3,411	53.2%
Coal	1,835	28.6%
Solar	5	0.1%
Subtotal	6,415	100.0%
Purchases		
SRP	350	
PacifiCorp	480	
Subtotal	830	
Total	7,245	

APS had a 2005 peak demand of about 7,000MW. APS can serve this load with about 3,000MW from units with low-operating costs consisting of the Palo Verde nuclear, coal, and (to a very small extent) solar units. Meeting the remaining load, however, requires APS to rely on a combination of its combined cycle units and gas-fired combustion turbines, as supplemented by wholesale market transactions. The largest portion of this higher-cost APS capacity comes from new, gas-fired combined cycle units. They total approximately 1,800MW and 28 percent of the Company's total available capacity. APS meets, as is typical of the sub-region, its incremental demand by using gas-fired combined cycle units. The Company, however, is shorter on base-load capacity as compared with the region as a whole. APS therefore can make its relatively inexpensive base-load capacity available for off-system sales less frequently. It must also meet a significantly larger percentage of its peak needs with its more expensive units. The following tables show APS versus regional loads as percentages of base load capacity.

Table VIII.2 APS and Regional Base Load Capacity Ratios

Capacity	Region	Region Less APS	APS
Hourly Load/Base Load Capacity	76%	70%	107%
Load Responsibility/Base Load Capacity	142%	125%	233%

APS obtained a substantial amount of its purchased power from Pinnacle West Energy prior to 2005. This non-utility affiliate operated a number of Arizona merchant generating units. A settlement of the 2003 APS rate case resulted in a transfer of these merchant units to APS, which has placed them into the utility rate base. APS now operates them as an integral part of its utility generation portfolio. This change occurred in 2005, bringing into the APS utility portfolio 1,700MW of additional gas-fired combined cycle plants, including Redhawk #1 and #2 and West Phoenix #4 and #5. APS has also added to its utility generating portfolio 11 combustion turbines, totaling almost 500MW. These units included the Saguaro #3 and the Sundance #1 through #10 units. These additions have altered the Company's power purchase and sale opportunities.

APS has a limited number of: (a) long-term power purchase or sale contracts for a term of greater than one year, and (b) short-term power purchase or sale contracts for a term of less than

one year. APS enters into some short-term contracts for price hedging purposes, which Liberty addresses in a separate chapter of this report, titled *Hedging and Risk Management.*

3. APS Purchased Power Contracts

APS has not historically contracted for large amounts of purchased power to meet native load. APS does, however, buy power under two large, important agreements. The largest power purchase contract is with the Salt River Project ("SRP"). This agreement bases the amount of electricity available to APS in large part on customer demand in certain areas served by APS pursuant to a territorial agreement dating from the 1950s and pursuant to supplemental agreements entered thereafter. APS has generating capacity of about 350MW available to it under the contract. SRP may cancel this agreement on three years' notice. APS may also cancel the contract on five years' notice, which may be given no earlier than December 31, 2006. SRP has given notice under this agreement (dated June 7, 2004) of its intent to reduce capacity available to APS by 150MW, effective June 16, 2007.

The second important large purchase power agreement is with PacifiCorp. APS entered into a 30-year seasonal capacity exchange agreement with PacifiCorp in September 1990. APS takes electricity from PacifiCorp during the summer peak season, from May 15 to September 15. APS returns electricity to PacifiCorp during the winter peak season, from October 15 to February 15. APS and PacifiCorp each have 480MW of capacity and a related amount of energy available to them until 2020. Each has the same capacity amounts for their respective seasons. The agreement provides, however, for energy flows that vary from a low of 40 percent load factor to a high of 100 percent. Actual production expense determines the energy price for these transactions.

APS also has less than a dozen small long-term power purchase contracts, which it entered before restructuring in Arizona. Many of these contracts are exchange agreements with small Electric/Irrigation Districts with which APS interconnects.

The following table summarizes historical APS utility purchased power volume and cost data. Non-utility affiliates PWCC and PWEC also made sales to APS before the April 2005 transfer to APS. PWCC also arranged for the sale of some of APS's system output.

Table VIII.3 APS Historical Power Purchases

Year	GWh Purchased	Expense $(000)	$/MWh
2002	7,351	323,417	$43,99
2003	7,389	322,689	$43.67
2004	8,214	412,332	$50.20
2005	6,983	441,487	$63.22

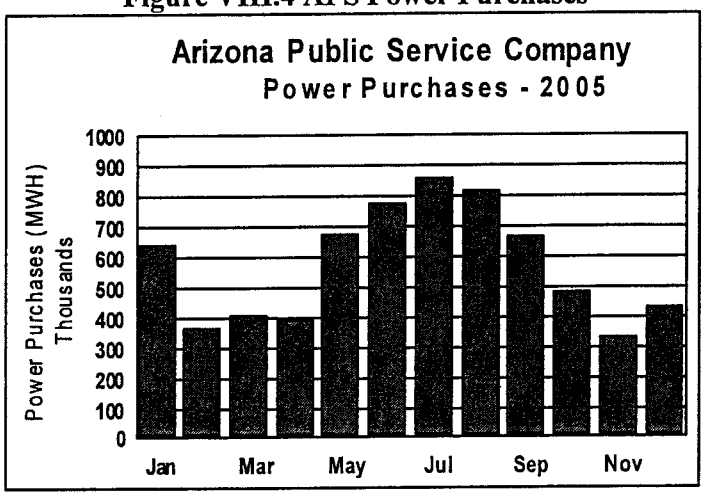
4. Short-Term Purchases for Native Load

APS supplements the output of its generation portfolio and its long-term contract purchases with shorter-term purchases. APS makes these purchases for two primary reasons:

- To purchase market power to serve native load during the May-September peak season
- To hedge APS's exposure to changing market prices in accordance with its hedging policy.

The following table shows APS utility power purchase activity by month for the year 2005. The chart shows that APS traded actively in power purchases and sales. Power purchases increase sharply to meet summer system peak loads. Large peaks in both sales and purchases in January reflect activity under the exchange agreement with PacifiCorp. The increase in purchases during the peak summer months is expected, given that APS must rely on off-system, natural-gas fired generation to meet load during this time.

Figure VIII.4 APS Power Purchases



Liberty's review of individual APS trades, especially with [redacted], shows that APS uses many trades to establish and liquidate hedge positions. For example, of the [redacted] MWh sold to [redacted] for the month of October 2005, [redacted] percent [redacted]. The October 2005 [redacted] transactions include both power purchase and sales, on which APS made $[redacted].

Liberty's review of detailed transaction data shows that about one-half of APS's power purchases and off-system sales occur to establish and liquidate native-load hedges. Hedges accounted for approximately 40 percent of all power purchases and 64 percent of all off-system sales for the period of March 2005 through November 2005.

Liberty also examined the number and volume of APS trades for May 2005. The number of trades per day was low, but the energy volumes reached as high as 30,000MWh per day. This volume is high when compared to APS's approximately 80,000MWh daily average load of May 2005. A review of the specific trades, however, shows that approximately 40 percent of the volume was for the swing call index trades discussed above. Most of the other trades were transactions made for single days in blocks of 25 to 100MW.

5. New Long-Term Power Agreements

A major change in long-term contracts for the purchase of power has resulted from the APS 2005 Settlement Agreement, Decision No. 67744, dated April 7, 2005 ("April 2005 Decision"). The

April 2005 Decision called for APS to acquire Pinnacle West's merchant generation, whose output was being sold to APS to support the utility's load. In lieu of the former capacity and electrical output purchases, APS now has substantially more intermediate and cycling generation assets under utility ownership and operation. These intermediate cycling units replace the need to purchase power from Pinnacle West affiliates, and reduce purchases in the marketplace.

Even so, continuing strong load growth requires frequent additions of new supply sources. APS issued a request for power supply proposals on May 31, 2005. This request for proposals for up to 1,000MW of capacity and energy has been termed the "Reliability RFP." This RFP provides an alternative for securing future power sources. APS has contracted for power as a result of this RFP, with deliveries scheduled to begin in 2007. APS has also issued a separate request for proposals for long-term renewable energy purchase contracts, following the April 2005 Decision. That RFP led to the procurement of renewable power scheduled for delivery beginning in 2007.

C. Off-System Sales Findings

1. Background

APS sells excess energy on an opportunistic basis. The Company includes margins or profits from off-system sales in the PSA mechanism rates. The sources of APS's excess energy include both generation and purchases that prove to be unneeded at times for serving native load.

APS and PWCC keep separate trading books, one for APS utility business, and several others for the PWCC non-utility trading business. APS purchases power to serve a portion of the needs of its utility native load customers, and purchases power to hedge costs for serving such customers. During a given trading day, or for certain longer periods during the year, APS may also have available for off-system sales energy from its owned generating units.

Off-system sales from APS's regulated generating units are generally short-term in nature, for durations of one to six hours and come primarily from generating units already running. APS occasionally arranges for longer-term off-system sales around the APS native load peaks for the low-cost generation already running. The APS available excess generation comes usually from combined cycle generating units fired by natural gas. Consequently, potential sales opportunities face competition from the region's many other similar plants. Its relatively low level of low-cost baseload generation means that APS's low-cost nuclear and coal units serve APS's native load most of the time. APS therefore generally does not have an opportunity for large sales (and higher margins) from its cheaper units, even at low points on its native load curve.

APS generally does not [redacted].

APS provided off-system sales information from monthly PSA reports for the 12-month period from April 2005 through March 2006. APS sold during this period 4,802,761MWh off-system, which produced gross revenue of $318.9 million, or $66.40 per megawatt hour. Gross revenue for PSA off-system sales includes all off-system sales revenue realized, including the liquidation of APS's native load hedges. For financial statement purposes, only the margin realized from the liquidation of native load hedges is recorded as revenue. The following table shows the APS net margin for all off-system sales for this 12-month PSA period and for calendar 2005.

Table VIII.5 APS Off-System Sales Summary

Revenue	April 2005 to March 2006 PSA	Calendar 2005 (Financial)
Native Load Hedge Liquidation	$163.0	N/A
Other Off-System Sales	$155.9	$58.5
Gross Revenue	$318.9	$58.5
Expenses		
Native Load Hedges	$154.4	N/A
Purchases and APS Generation	$137.3	$46.2
Total Expenses	$291.7	$46.2
Margin		
Liquidation of Native Load Hedge	$8.6	$(7.0)
Other Off-system Sales	$18.5	$12.3
APS Pre-tax Margin	$27.2	$5.3

The period for the data in the two columns differs by three months. The data show that off-system margins for APS vary greatly, depending on natural gas and power market prices. Actual APS margins, as well as any forecasts for APS margins, are highly dependent on the time period in question and the prices for natural gas and power at the time.

2. Sources of Energy for Off-System Sales

The sources of energy for APS's off-system sales fall into three major categories: liquidation of native load hedges, APS purchased power, and excess APS generation. APS makes significant purchases to hedge energy prices for utility native load in accordance with the Company's hedging policy. APS has sometimes made a profit when its hedge positions have been liquidated.

Another source of energy used for APS off-system sales are various sources of purchased power. APS has only two sizable long-term purchase contract arrangements. The first is the Salt River Project Territorial and Power Coordination Agreements, which currently total approximately 350MW of generating capacity, but will drop by 150MW in 2007. The second is the PacifiCorp Exchange Agreement, which allows APS up to 480MW in the summer months only. The earlier, sizeable contracts with PWEC were cancelled following the 2005 summer season, as part of the transition of the former merchant plants to APS ownership and operation. All term contracts that are arranged by APS to serve utility native load (including capacity costs) are recoverable in rates. APS therefore does not include capacity payments for purchased power contracts as an expense in the calculation of margins for off-system sales. Margins for off system sales are calculated using incremental energy costs only.

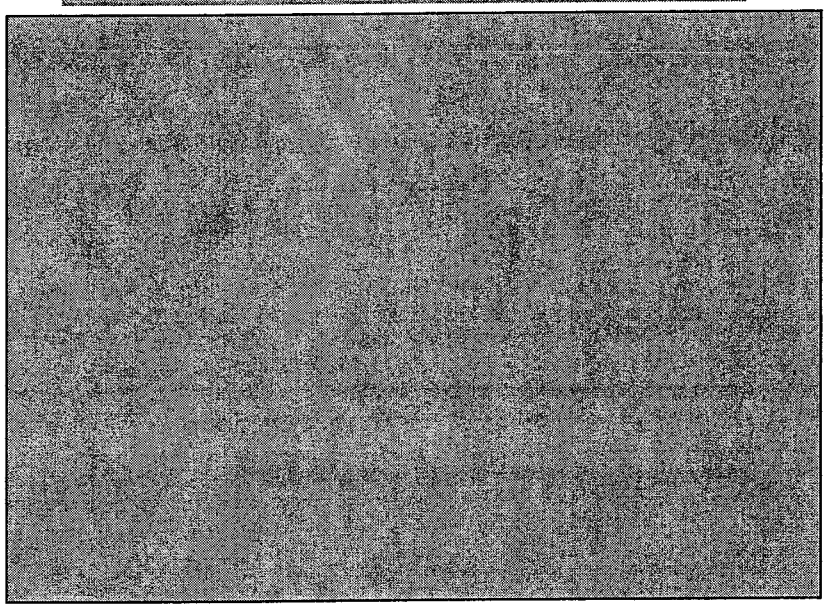
A third source for off-system sales is excess APS generation. This source is limited because APS's low-cost nuclear and coal serve utility native load nearly all the time. APS can sell its natural gas-fired combined cycle and peaking resources into the marketplace, primarily in the fall, winter and spring seasons. APS assigns its lowest-cost energy, whether from purchases or generation, to its regulated native load first. APS will attempt to re-market any excess power at a profit, if available, in the wholesale market. APS's ability to make high-margin and large volume off-system sales using its gas-fired resources is limited due to competition caused by the Desert Southwest region's significant availability of gas-fired resources with comparable costs.

The table below (compiled from APS PSA Reports to the ACC, April 2005-March 2006) shows the relative size of the off-system sales volumes, revenue, and margins. The following chart shows the buyers and percentages of APS off-system sales during the 2005 calendar year. Gila River, PacifiCorp, and Morgan Stanley were 2005's largest buyers.

Table VIII.6 APS Off-System Sales Sources of Energy and Margins
April 2005 – March 2006

Sales Sources	MWh Volume	Revenue $(MM)	Expenses $(MM)	Margin	Revenue/ MWh	Margin/ MWh
Native Load Hedges	2,438,500	$163,023	$154,394	$8,629	$66.85	$ 3.54
Purchased Power	1,717,974	$112,656	$105,185	$7,471	$65.57	$ 4.35
APS Generation	642,602	$ 40,568	$32,854	$7,713	$63.13	$12.00
Mark-to-Market, other[38]	3,685	$ 2,666	$ (695)	$3,361	N/A	N/A
12-month Totals	4,802,761	$318,913	$291,737	$27,175	$66.40	$5.66

Table VIII.7 APS Trading Partners
ENTIRE FOLLOWING TABLE IS CONFIDENTIAL



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[38] Includes mark-to-market amounts, broker fees, option premiums, and prior period true-ups. Source: response to LCG-3-4

3. Off-System Sales Comparisons to Regional Utilities

On May 5, 2006, the Commission issued Decision No. 68685 in the APS emergency interim rate increase docket. It states:

> *In Decision No. 67744 Staff was directed to commence a review of APS' off-system sales practices within three years of the effective date of the Order. Because of APS' disappointing off-system sales revenues, it is imperative that said review take place as part of the pending permanent rate proceeding...*
>
> *It is Further Ordered that Staff shall commence a review of APS' off-system sales practices as part of the pending permanent rate proceeding, including a comparison of APS' off-system sales revenues and practices with other electricity providers in the West. The review shall also include an analysis of Pinnacle West Capital Corporation, its affiliates and subsidiaries' wholesale energy sales, including, but not limited to, how these wholesale transactions impacted, if at all, APS' off-system sales revenues. The parties will fully explore ways of increasing APS 'off-system sales revenues that will benefit both the Utility and its customers.*

At Staff's request, the audit work sought to address the issues raised by this decision. The analysis had to rely on limited data, because energy providers consider the kind of information underlying these issues to be competitively sensitive. We were able to secure some public information bearing on the issues. It is not certain that all of the sellers that Liberty examined account for off-system sales in the same manner; *e.g.*, APS off-system sales include only short-term sales for the utility, while its non-utility affiliate sales are accounted for separately, and include former long-term contracts of APS, such as with Citizens/UniSource. Off-system sales of the other regional companies generally include long-term contractual sales. Given the limits on available data, the following paragraphs address generally the sources of difference between APS and other regional utilities with respect to off-system sales.

<u>Salt River Project</u>
SRP ("Salt River Agricultural, Irrigation and Power District") is a neighboring electric generator whose service territory is adjacent to and surrounded by APS. SRP operates a sizable electric system; 2005 sales to ultimate customers amounted to around 25 million MWh and sales for resale to almost 12 million MWh.[39]

SRP and its customers benefit from participation in a number of low-cost coal and nuclear generation projects and from purchases of significant amounts of hydro power from the Western Area Power Authority ("WAPA"). The SRP electric supply portfolio produces low power-supply sourcing costs, especially when compared to companies more dependent on gas-fired generation during extremely high-priced periods in natural gas markets (such as 2005). SRP is an owner participant in six coal-fired, multi-plant generation complexes, and owns 654MW of the Palo Verde nuclear complex. SRP has total ownership of over 2,700MW of low-cost coal and nuclear generating capacity in its portfolio. SRP also receives a large allocation of power from WAPA,

[39] 2005 information provided by SRP

which arranges purchases of power from federal government projects. Access to this lower-cost power also helps to reduce SRP's power sourcing costs.

SRP reported off-system sales of 11.87 million MWh and revenues of $616.9 million in 2005. The sales included the liquidation of SRP's native load hedges, excess generation sales, and sales of purchased power.[40] SRP did not provide access to cost information for its generation, but rough estimates could be made from publicly available information from jointly-owned plants and from purchased power information that SRP did provide.

SRP received $51.96 per MWh for its off-system sales in 2005. Liberty estimated a range for SRP's realized margins from these sales. On the lower end of the range, if SRP were to source its off-system sales with its power purchases only, its margin would have been about $84 million in 2005. However, if SRP were to source all of its off-system sales with SRP's average generation costs, the margins would widen to about $230 million. SRP's actual margins realized probably fell within the bounds of this wide range in 2005.

Tucson Electric Power (UniSource)

TEP ("Tucson Electric Power") is another neighboring utility in the Desert Southwest region. TEP has had excess generating capacity for many years, and continues to have substantial generation available for sale to off-system buyers. TEP has about 2,000MW of total generating capacity, of which 1,582 is coal-fired, and has comparably very low operating costs. TEP's 10-K filing with the SEC shows an average production cost per MWh for coal generation of only $17.50 in 2005. Adding in all other sources only increased its average cost to $20.10 per MWh.

TEP generally expects to have excess coal-generating capacity and energy in the first, second and fourth calendar quarters to make sales to wholesale off-system customers. TEP currently has long-term contracts to sell firm capacity and energy to SRP, the Navajo Utility Authority, and the Tohono O'odham Utility Authority. These long-term sales account for approximately 30 percent of TEP's wholesale sales. TEP also sells capacity or energy using short-term forward contracts, typically for one month, three-month or one-year periods, and sells energy in the daily or hourly markets at fluctuating spot market prices.[41]

TEP reported total 2005 revenue from all wholesale sales of about $178 million on 3.182 million MWh of sales, or $55.90 per MWh. TEP's low generating costs made its margins on these 2005 sales very substantial. TEP's financial statements group all wholesale sales together. Taking conservative assumptions for TEP's sourcing costs produces estimated pre-tax margins at around $83 million in 2005. More aggressive assumptions, such as assuming that wholesale sales were made from TEP's coal generation at its average cost, would produce an estimated pre-tax margin of about $118 million. TEP's off-system sales are not voluminous, but likely produced very high 2005 margins because of its low cost of excess generation relative to high 2005 market prices. Those who used natural gas to make off-system sales benefited from those same high market prices for energy, but faced the high fuel prices necessary to operate their units.

[40] Ibid.
[41] TEP 2005 10-K, "Wholesale Business"

PNM Resources

PNM Resources, another regional utility, has had substantial excess generating capacity for a number of years. In fact, some of its excess capacity has been excluded from retail electric rates. PNM Wholesale sells off-system under long-term contracts and short-term sales supported by the unused capacity of Public Service Company of New Mexico's jurisdictional assets and the capacity of PNM's wholesale plants excluded from retail rates. PNM jointly dispatches both utility and non-utility generation in order to improve reliability, provide the most economic power to utility retail customers, and maximize profits on wholesale transactions.[42]

PNM's wholesale operations realized 2005 operating revenues of $628.0 million on sales of 10.59 million MWh, or $59.33 per MWh. Approximately 25 percent of the sales came under long-term contracts; the remaining 75 percent were short-term, off-system sales. PNM reported that the 2005 margin from these wholesale sales was $85.3 million.[43] PNM Wholesale also paid the utility for the transfer of excess power from the utility to PNM Wholesale. Liberty estimates that the utility realized a margin of about $16 million on these transfers.

4. Affiliate Transactions

APS limited 2005 sales to affiliated non-utility operations (PWCC, which engages in wholesale transactions and APSES, which provides retail service) to:

- A balancing agreement associated with several term, wholesale contracts of PWCC
- Sales to optimize transmission capabilities secured as part of a seasonal exchange agreement with PacifiCorp.

Balancing Agreement

APS makes sales to PWCC under a balancing agreement that permits PWCC to match its resources with its requirements to supply a few all-requirements wholesale customers. APS receives a [redacted] under this agreement. APS includes that fee in its monthly PSA filings as "Other Items Accounted For." APS then makes the necessary sales at [redacted]. The following table shows the revenues and expenses of APS under the agreement, separated into two categories:

- Sales for the 2005 months covered by the PSA
- Monthly revenues and expenses through the first quarter of 2006 (to provide a 12-month consecutive period).

[42] PNM Resources 2005 10-K, page A-5
[43] PNM Resources 2005 10-K, pages A-48 and A-49

Table VIII.8 APS Margin on Index-priced Sales made under Balancing Agreement

ENTIRE FOLLOWING CHART IS CONFIDENTIAL

Month	MWH	Fee	Revenue	Total	Expense	Margin
Apr-05						
May-05						
Jun-05						
Jul-05						
Aug-05						
Sep-05						
Oct-05						
Nov-05						
Dec-05						
2005 PSA Totals						
Jan-06						
Feb-06						
Mar-06						
2006 YTD Totals						
Grand Total						

ENTIRE PRECEDING CHART IS CONFIDENTIAL

Transmission Optimization

APS acquired certain transmission capabilities as part of the seasonal exchange agreement with PacifiCorp, originally concluded in 1990. These facilities provide a transmission path between Four Corners and Borah Brady, a delivery point in Idaho. These facilities enable movement of power from south to north in non-summer months.

In 2005, PWCC found an opportunity to use that transmission path to sell power in the Pacific Northwest. PWCC required additional transmission from Borah Brady to Mid-Columbia or other Pacific Northwest delivery points to take advantage of this market opportunity.

PWCC began to use the Four Corners-to-Borah Brady asset to make its own transactions in 2005. PWCC intended to keep the margins from these sales within the non-utility sector, and did so through October of 2005. After APS personnel noted the existence of the transactions, APS secured changes in how they had been and would be credited, in order to make APS the beneficiary of them. These changes included a crediting of transactions that already closed and assurance that those remaining to be executed would be directly credited to APS. The effect of these changes was to provide APS with the full benefit of the margins produced by the transactions.

PSA accounting therefore already reflects the changes. These transactions have not occurred since March 2006. APS discontinued new arrangements for such transactions, on the ground that their speculative nature made them inappropriate. Acquiring added transmission in order to make distant sales comprised a principal risk factor in taking advantage of the capability of the

transmission assets associated with the PacifiCorp exchange. APS also has not permitted PWCC to resume its use. As a result, no party is conducting transactions of this type at present.

The following table shows the magnitude of these transactions in the months where they were substantial.

Table VIII.9 Transmission Optimization Sales

REVENUE, EXPENSE, MARGIN AMOUNTS ARE CONFIDENTIAL

Month	MWH	Revenue	Expense	Margin
Nov-05	49,875			
Dec-05	118,246			
Jan-06	134,839			
Feb-06	52,923			
Mar-06	58,800			
Totals	414,683			

REVENUE, EXPENSE, MARGIN AMOUNTS ARE CONFIDENTIAL

APS has undertaken three measures that address this situation:

- It conducted a review of its other transactions to verify that no other instance of non-utility use of utility assets has taken place
- It has prepared a procedure that will call for ongoing review of transactions by all affiliates to identify any potential cross uses of assets
- It has amended its code of conduct and has drafted supporting policies and procedures to address potential cross-use in the future.

The description given of the transaction review, when coupled with Liberty's survey of transactions by affiliated entities, indicates an appropriate effort to examine the potential for other inappropriate uses of APS resources by the non-utility sector. The code, procedures, and policies have only very recently been filed with the Commission. Moreover, the internal procedure for ongoing review is not yet in place. The pending nature of these other activities makes it impossible to assess their effectiveness at present.

D. Conclusions

1. The trading activities of APS M&T are based on sound hedging policies and procedures, and ensure that the procurement and sale of electric power is conducted in a manner that will meet least-cost dispatch guidelines.

The APS revenue level, prices, and costs of sales and purchases show that power trading has produced economical transactions. There does not appear to be a concentration of sales or purchases with any one trading partner or a discernable pattern of favoring any trading partner.

2. APS effectively utilizes its portfolio of generating resources and power purchases to optimize value in the marketplace.

The APS economic dispatch procedures and operations appear to have operated smoothly since the integration of the merchant generating assets after April 2005. Given the new generation

portfolio, APS has been filling in the gaps in resource requirements with appropriate short-term purchases, and with the May 2005 RFP, has supplemented supply resources with additional long-term contracts. APS has also taken advantage of market opportunities inherent in the new generation portfolio to optimize off-system margins in order to reduce PSA costs.

3. **APS has developed the necessary documentation and tools to ensure that electric power trading can be conducted in accordance with the goal of achievement of the least-cost total dispatch.**

The *Forecasting and Modeling* chapter of this report demonstrates that APS does a sound job of providing models and forecasts for regular use of APS M&T. The database is audited regularly by APS, and is available to electric power traders to provide them with accurate and up to date information of costs and availability of APS's own resources so that power transactions that meet the goal of least-cost dispatch can be secured.

4. **APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale.**

Liberty found that APS internal auditing had conducted sufficient audits of APS M&T to ensure that the appropriate controls and procedures were in place for procurement and sale of electric power for native load customers.

5. **The APS internal documentation separating the activities of utility versus non-utility electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between this information.** *(Recommendation #1)*

Electric power purchase and sale data related to both regulated and unregulated APS activities is not delineated in some publicly available documents, specifically the FERC Form 1.

6. **The APS and non-utility trading operations are not sufficiently physically segregated.** *(Recommendation #1)*

In its on-site visit, Liberty observed that an APS trader and a non-utility trader sit opposite each other on the trading floor. Due to their close proximity, the clear separation of their trading activities is not assured. During the visit, one took a telephone call intended for the other.

7. **PWCC made some inappropriate commitments to trades using utility assets in 2005; but APS has eliminated them, transferred their margins to the utility accounts of APS, and begun changes to prevent the future use of utility assets by affiliates.** *(Recommendation #2)*

Liberty undertook a survey of transactions with affiliates during the PSA's 2005 application and into early 2006, and did not find any other than those associated with the balancing agreement and transmission optimization. There were a number of sales by APS to PWCC under the balancing agreement. APS received appropriate compensation for those transactions and APS structured the agreement to mitigate its risk and to maximize value for its customers. The transmission optimization transactions, however, allowed PWCC to capture margins from the use of utility assets.

APS has corrected the accounting to return to APS the positive margins from those transactions; PSA accounting already credited those margins to customers. APS has initiated a procedure to prevent future problems of this type. It has not yet applied that procedure; therefore, its sufficiency remains to be proven. APS is also in the process of addressing its code of conduct and associated policies and procedures with Staff; this audit's scope did not include an assessment of those documents.

APS does not conduct the transmission optimization transactions that PWCC was entering. Those transactions would require APS to take future market risk; it is appropriate that APS not undertake them at utility customer risk. However, APS has not as yet determined whether there are means for an arrangement that would provide some moderate level of low-risk compensation to PWCC or a third party, in exchange for the right of that party to continue the transactions, which proved profitable in 2005.

8. **The primary reason that sales for resale have produced smaller margins than those of neighboring utilities is APS's lower proportional levels of excess coal and nuclear generation.**

In today's wholesale electric markets, the greatest opportunity for profits rests with producers who have low-cost coal, hydroelectric or nuclear generation available for sale to the marketplace. Due to the fact that the market price for power is at many times set by combined cycle gas-fired generation in the Desert Southwest and most other U.S. markets, the "black spread" or profit margin on coal and other low-cost generation is substantial.

The key to generating large positive margins on off-system sales is to have a relatively high proportion of low-cost capacity in the portfolio, which expands the periods during which it is available to support off-system sales. Some of APS's neighboring utilities, such as SRP, TEP and PNM, have excess coal generation available for comparatively greater portions of the year. In contrast, APS native load has grown past the company's coal and nuclear resources. These base load resources are needed to serve utility native load all year around, with very limited excess available. APS's "black spread" opportunities will essentially disappear completely in the near future.

APS's positive margins generated by the sale of available combined cycle gas units during off-peak seasons are relatively lower due to their higher costs in relation to market prices, which are set by similar units. The fact that APS's off-system margins are much lower than those of SRP, TEP and PNM is due to these differences in excess supply portfolios.

E. Recommendations

1. **Clearly segregate utility and non-utility trading in all operations and reporting to ensure that utility trading is conducted to maximize utility opportunities.** *(Conclusions #5 and #6)*

Liberty believes that all data, both public and internal, should be separate and make a clear distinction between the power trading activities of the regulated APS business and the unregulated portion of Pinnacle West's business. APS should have separate and distinct procedures, accounting records, and reports that completely segregate regulated from non-

regulated trading activities, and the individuals that conduct this trading activity should be physically separated from each other.

2. **Complete the process of preventing future affiliate use of utility assets and examine means for continuing transmission optimization transactions through some form of sharing mechanism.** *(Conclusion #7)*.

PWCC should not have had the opportunity to use utility assets without proper compensation. The methods that APS proposes to prevent such opportunities in the future include a new (but as yet, unused) procedure and the provisions of a code of conduct and associated policies and procedures. Liberty understands that the code, the policies, and the procedures, remain under discussion between APS and the Staff. Liberty's audit did not include a review of them. It is important that the procedure and the code, policies, and procedures adequately address limits on transactions between APS and non-utility affiliated operations.

The transactions at issue cannot make a large difference in PSA calculations; their total margins during their period of heavy use in 2005 and early 2006 was less than $5 million. Moreover, it is not realistic to expect that the utility can capture all of that margin, because it requires taking future market risk. However, depending on the existence of any potential regulatory obstacles (*e.g.*, FERC transmission access requirements), there may be means for APS to capture some portion of those margins without taking such risk. The transactions associated with the balancing agreement, which produced fixed income streams to APS and a sharing of transaction costs/benefits, may provide a model.

IX. Nuclear Fuel

A. Findings

1. Organization

The Palo Verde organization has responsibility for nuclear fuel procurement and management. Palo Verde procedure 05DP-0NF23 identifies the requirements and describes the process for nuclear fuel material contracts. It assigns to the Director, Nuclear Fuel Management primary responsibility for preparing requests for proposals, evaluating bids, negotiating terms, and ensuring the correct execution of nuclear fuel contracts. The administrative procedure covers all the fundamental steps required in a procurement practice. Approval of all nuclear fuel agreements must come from all Palo Verde participants.

The Director, Nuclear Fuel Management, reports to the Vice President – Engineering in the Palo Verde organization. That vice president reports to the chief nuclear officer at Palo Verde. The nuclear fuel management organization has responsibility for nuclear fuel from the initial procurement to spent fuel storage and contains about 100 people. The functions within the organization include:

- Fuel Procurement
- Nuclear analysis
- Transient analysis
- Reload analysis
- Reactor engineering
- Fuel services (movement of fuel into and out of the reactors)
- Projects.

The Manager, Nuclear Fuel Procurement, leads the procurement function. Somewhat more than two years ago, APS ended dual reporting of this manager. He previously reported also to the APS fuel procurement organization but now reports solely within the Palo Verde organization. He still draws upon APS services such as the law department and the insurance management department. The procurement group contains six people reporting to the manager.

2. The Nuclear Fuel Cycle

The nuclear fuel cycle consists of the integrated set of activities necessary to take uranium ore from production to disposal. The key procurement elements in that cycle include:

- Securing uranium in the form of ore or concentrates
- Converting the material to concentrate it in the form of uranium oxide, or "yellowcake"
- Enriching the material to make it useable as a fuel for generating electricity
- Fabrication of the fuel into assemblies that can be placed into the reactor for electricity generation.

Uranium, a slightly radioactive metal, exists in most rocks and soils, in many rivers, and in seawater. A number of the Earth's regions have ground concentrations of uranium at levels sufficient to make extraction of it for use as nuclear fuel economical. Extraction of these concentrations of ore takes place through underground or open pit mining. Natural uranium

consists, primarily, of a mixture of two isotopes (atomic forms) of uranium. Only 0.7% of natural uranium is "fissile," or capable of undergoing fission, the process by which energy is produced in a nuclear reactor. The fissile isotope of uranium is uranium 235 (U-235). The remainder is uranium 238 (U-238).

Uranium milling extracts the uranium from the ore. Milling produces the uranium oxide concentrate; *i.e.*, yellowcake, which contains more that 80 percent uranium. Additional processing through enrichment prepares the uranium for use as fuel. This process requires uranium to be in gaseous form. Enrichment strips away the U-238 isotope, and increases the concentration of the fissile isotope, U-235, from about 0.7 percent in natural uranium to between three and five percent.

Palo Verde's reactor fuel is in the form of ceramic pellets encased in metal tubes to form fuel rods, which are arranged into assemblies containing 236 rods. The manufacturer controls precisely the dimensions of the fuel pellets and other components of the fuel assembly to ensure consistency in the characteristics of fuel bundles. Inside a nuclear reactor, the nuclei of U-235 atoms split (fission) and release energy that is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas, or oil is used as a source of heat in a fossil fuel power plant.

As the fission process proceeds over time, the concentration of fission fragments and heavy elements formed in a fuel assembly will increase to the point where it is no longer practical to continue to use the assembly. After about 18 months, APS removes some of the "spent" fuel from each reactor. With the three units at Palo Verde, and an 18-month refueling cycle for each unit, APS typically conducts two refueling outages each year, one in the spring and one in the fall.

When removed from a reactor, a fuel assembly will be emitting both radiation, principally from the fission fragments, and heat. Used fuel is unloaded into a storage pool adjacent to the reactor to allow the radiation levels to decrease. The water in the pools shields the radiation and absorbs the heat. Used fuel can be held in such pools for several years.

In addition to the Palo Verde fuel storage pools, APS is operating a facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

3. APS Nuclear Fuel Agreements

APS used to contract separately for the uranium, conversion, enrichment, and fabrication elements of the Palo Verde nuclear fuel cycle. It has now combined the four cycle elements into

The [redacted] resulted from an RFP under which APS solicited individual and combination bids for these elements. APS then analyzed the combinations that would produce the greatest net economy. The Company found that [redacted].

Price escalation provisions are typical of contracts for these four elements of the fuel cycle. Some use market prices. [redacted].

Table IX.1 [redacted] Contract Pricing

Contract	[redacted] Portion	[redacted] Portion	[redacted] Basis
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

The use of broad economic measures such as GDP, base prices, labor costs, and materials costs has left APS price changes generally consistent with overall inflation, with some protection reflected by the portion of the original prices that remain fixed. Recently, nuclear fuel cycle prices, after a period of depression, have increased at greater rates. Therefore, contracts with market-based escalation provisions, all other things equal, would lately have produced more significant increases. The following table shows market prices for comparable months in 1997 and 2005, as taken from a trade publication, *Ux Weekly*.[44] The last column shows that prices have remained strong, as shown on the publisher's web site (uxc.com) at May 12, 2006.

Table IX.2 Nuclear Fuel Cycle Market Price Trends

Element	April 1997	April 2005	Increase		May 2006
U3O8 (lb)	$11.97	$22.50	$10.53	87.97%	$41.50
Conversion (kgU)	$5.97	$12.00	$6.03	101.01%	$11.50
UF6 (kgU)	$29.95	$70.00	$40.05	133.72%	$119.93

The [redacted] agreements cover [redacted]:

- End of xxxx
  - [redacted] of reactor requirements for uranium concentrates
  - [redacted] of reactor requirements for conversion services
- End of [redacted]
  - [redacted] of reactor requirements for enrichment services
- End of [redacted]
  - [redacted] of reactor requirements for enrichment services
- End of [redacted]
  - [redacted] of reactor requirements for fabrication services.

[44] Volume 11, Issue 14, April 7, 1977 and Volume 11, Issue 14, April 2005

Accordingly, APS has secured all of its reactor requirements for a period beginning well before and extending well beyond 2005. APS has negotiated a contract with [redacted] to supply [redacted] percent of Palo Verde's enriched uranium requirements starting in 2011. APS's analysis shows that this contract produces favorable terms and will diversify the nuclear fuel supply chain in the future.

4. APS Variable Nuclear Fuel Costs

APS expenses the costs of nuclear fuel using the unit-of-production method, which amortizes costs based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense. APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation.

APS determines the amortization rate for each group of fuel assemblies that it inserts and removes from the reactor at the same time. The rate is simply the remaining cost (original cost less amortization to date) divided by the difference between the estimated thermal output and the actual thermal output to date. The table below shows the generation, fuel costs determined by applying the amortization rate, and the resulting unit cost of production for APS's share of all Palo Verde units.

Table IX.3 Nuclear Generation and Fuel Costs

Nuclear Generation and Fuel – APS			
Month	**MWh**	**Fuel Costs**	**¢/kWh**
Mar-05	[redacted]	[redacted]	[redacted]
Apr-05	[redacted]	[redacted]	[redacted]
May-05	[redacted]	[redacted]	[redacted]
Jun-05	[redacted]	[redacted]	[redacted]
Jul-05	[redacted]	[redacted]	[redacted]
Aug-05	[redacted]	[redacted]	[redacted]
Sep-05	[redacted]	[redacted]	[redacted]
Oct-05	[redacted]	[redacted]	[redacted]
Nov-05	[redacted]	[redacted]	[redacted]
Dec-05	[redacted]	[redacted]	[redacted]

The monthly summary of PSA Report fuel costs submitted by APS contains an amount for nuclear fuel costs that is greater than that shown above because it includes an amount for the amortization of the dry spent fuel storage facility, ISFSI ("Independent Spent Fuel Storage Installation").

The nuclear fuel production costs (¢/kWh) for these months varied from the lowest to the highest by 24 percent. For all other forms of generation for these same months, the variability was 89 percent. The average nuclear production cost was 0.51 ¢/kWh, while that for all other APS

generation was more than six times greater at 3.16 ¢/kWh. During the period shown on the table above, nuclear fuel costs made up only 5.2 percent of APS's total generation fuel costs.

5. Fuel Accounting

APS uses FERC accounting for nuclear fuel costs.

6. Non-Generation Sensitive APS Nuclear Fuel Costs

Liberty's audit scope did not include an examination of the impacts of plant operations and their appropriateness on APS's nuclear fuel costs. However, Liberty was able to isolate the critical and dominant element in costs that do not vary with production. The APS method for amortizing nuclear fuel costs, described above, applies the following formula.

$$(A-B)/(C-D) = ExF = G$$

The components of that formula are:

- A: Original costs including AFUDC
- B: Amortization recorded to date
- C: Estimated Life in terms of thermal energy megawatt days
- D: Actual thermal energy megawatt days to date
- E: Cost per remaining thermal energy megawatt days
- F: Actual thermal energy megawatt days for the month
- G: Amortization.

APS calculates a separate "A" component for each fuel-assembly batch loaded into each of the three Palo Verde units. APS makes that calculation essentially contemporaneously with the loading of each fuel batch, which occurs at approximately 18-month intervals for each unit. Once calculated, the "A" component remains essentially fixed for the approximately 18-month interval across which amortization (the "G" component) for that batch takes place. Costs under the fuel cycle contracts form the overwhelming portion of the "A" costs of each batch, supplemented by the addition of some (far lesser) costs associated with APS activities related to fuel cycle work. Liberty found this "A" component to be the best benchmark for assessing nuclear fuel costs independently of outages at the units. The following table shows the recent costs for the "A" components at Palo Verde and the current estimate for the next such component.

Table IX.4 Fixed Portion of Palo Verde Fuel Costs

ENTIRE FOLLOWING TABLE IS CONFIDENTIAL

Measure	Cycle Number		
	Twelve	Thirteen	Fourteen
Unit 1			
Date			
Assemblies			
Cost			
Yearly Change			
Unit 2			
Date			
Assemblies			
Cost			
Yearly Change			
Unit 3			
Date			
Assemblies			
Cost			
Total Unit Change			
Total Plant			
Total Plant Costs			
Yearly Change			
Period Change			

ENTIRE PRECEDING TABLE IS CONFIDENTIAL

B. Conclusions

1. APS conducts nuclear fuel procurement and management through an effective organization.

The unique requirements of the nuclear fuel cycle, and the criticality of handling, analysis, planning, and other technical issues makes it appropriate to assign the function to the organization dedicated to the units' operations. APS has provided for dedicated, experienced leadership and staffing of nuclear fuel procurement and contract administration, and has linked it effectively with the other organizations having important interfaces.

2. APS has developed and used effective procedures for procuring nuclear fuel.

The procedures address procurement activities. APS has procured long-term agreements through competitive bids, which APS solicited on a broad and flexible basis, and which APS evaluated on the basis of best cost, considering options for combining contracts for some cycle elements. The pricing structure that APS chose has proven beneficial in keeping nuclear fuel costs in line with more general measures of inflation, rather than with the more significant increases experienced recently in the nuclear fuel market.

A comparison of the current, prior, and next fuel loads for each unit confirms that there have been only nominal changes in those costs for fuel loads that are not sensitive to unit generation levels.

3. APS uses an appropriate basis to account for its nuclear fuel costs for ratemaking purposes.

Accounting is based on FERC Accounts 120.1 through 120.5.

C. Recommendations

Liberty does not have any recommendations in the area of nuclear fuel management.

X. Financial Audit of PSA Costs

A. Scope

This chapter of Liberty's report addresses the APS financial process for assembling, preparing, and submitting the monthly Power Supply Adjustor ("PSA") filings to the ACC. Liberty undertook the following activities and reviews as part of this examination:

- PSA Overview
- Accounting Systems
- PSA Filing Policy and Procedures
- General Review of PSA Monthly Filings
- Detail Review and Testing of August 2005 PSA Filing
- PSA Over/Under Recovery Filings
- Impact of Supplemental Charges or Refunds.

B. Findings

1. PSA Overview and Guidelines

An August 18, 2004 Settlement Agreement and Decision No. 67744 at Docket No. E-01345A-03-0437 resolved issues related to an APS application to increase rates. Section IV of that agreement provided for a PSA designed to track changes in the Company's cost of obtaining power supplies; *i.e.*, the difference of the going forward costs of fuel and purchased power (capped at an annual amount of $776.2 million) compared to costs embedded in APS's base rates. The decision set the base rate of fuel at $0.020743 per kWh and the initial Adjustor Rate at zero, with annual April 1 resets, beginning with 2006. The main components of the PSA include:

- An incentive/risk sharing mechanism sharing of costs or savings (90/10: customers/Company)
- A bandwidth limiting the change in the Adjustor to +/- $0.004 per kilowatt hour
- A balancing account to track recoverable or refundable amounts during the current period
- A balancing account surcharge mechanism separate from the adjustor to clear the accumulated recoverable or refundable amount for purposes of resetting the balance to zero
- Making customers the beneficiaries of benefits of all off-system sales margins through a credit to the PSA.

APS must maintain accounting records and reporting statements through a set of processes that provides adequate comfort about completeness and accuracy to those who rely upon them. Maintaining adequate internal controls and reporting measures allows those who rely upon the books and records and reports to have reasonable assurances that they can use them to form opinions and make judgments concerning financial, regulatory, and operational compliance. APS's accounting and reporting records thus form an integral, necessary part in assuring compliance with the PSA.

2. Accounting Systems

APS maintains its books and records in accordance with the FERC's Uniform System of Accounts ("USofA") which the ACC has adopted. APS has its own accounting system and set of books. APS's computerized accounting system known as "GECA" is approximately nine years old, and consists of approximately twelve different accounting modules. The accounting system's main module, the general ledger, serves as the central element for financial reporting purposes. A number of accounting interface modules; *e.g.*, payroll and accounts payable, have links to this general ledger module. The current system has "*detail general ledger*" reporting capabilities, which enables it to generate, on an account-by-account basis, reports that provide summary descriptions of each accounting entry transaction. The capability includes the provision of appropriate cross references, cost center codes, and relevant dollar value transactions, among others.

The general ledger system also provides the capability to "drill down" through the transaction to explore the underlying supporting information. The accounting system also includes the capability to download information into PC-based worksheet programs, such as Microsoft Excel, which can support a variety of sub-reports and analyses. The Company currently is evaluating a new accounting system from PeopleSoft, which is a leading provider of applications designed for large, complex business operations, many of them utilities.

APS M&T uses a proprietary system (called "TranZ" and discussed more extensively earlier in this report) to control fuel and energy deal information. TranZ tracks power and natural gas transactions from deal entry to settlement and reporting. TranZ also allows the use of Microsoft Excel worksheets and various Microsoft Access queries, which APS uses for detailed analysis and sub-reporting.

3. PSA Filing Policy and Procedures

APS filed with the ACC on June 6, 2005 an initial "Plan of Administration ("POA"), which provides the basis for the filing of monthly PSA reports. The APS POA describes the process that APS used for 2005 and early 2006 for calculating the applicable monthly PSA kWh sales and related fuel and purchased power costs, including benefits of off-system sales, which the PSA filings must include. The APS Regulatory Department had initial responsibility for assembling and filing PSA reports with the ACC. APS transferred this responsibility to its Fuel Forecast and Analysis Department in October 2005. This department prepares the required monthly filings, taking assistance from the Generation Accounting Department, the Financial Accounting Departments, the Generation Business Services Department and the APS M&T BackOffice (the "PSA Team"). APS submits all monthly reports under a certified statement by a responsible company official.

The ACC Staff submitted its POA on March 20, 2006. APS used this POA to guide its March 30, 2006 monthly PSA filing. Liberty understands that the purpose of the Staff POA was to define more clearly the scope and framework of the PSA, and to provide for the inclusion of the monthly/annual filing requirements minimally necessary to comply with the PSA, as approved by the ACC.

Liberty conducted an examination of the APS procedures for preparing its PSA filings. Liberty requested that APS provide a detailed narrative description of the process used to develop, assemble, review, authorize, and submit fuel and power purchase information in the PSA filings. APS provided a copy of the POA as submitted by the ACC Staff on March 20, 2006. Liberty found that APS has yet to prepare formal, written processes and procedures. APS personnel commonly reported to Liberty that the current, unwritten processes were developed after consultation with members of the responsible Company departments, in order to assure its completeness and accuracy.

4. General Review of Monthly PSA Filings

The PSA has been designed to track changes in the Company's cost of obtaining power supplies; *i.e.*, the difference between: (a) the going forward costs of fuel and purchased power (capped at an annual amount of $776.2 million), and (b) the base rate of $0.020743 per kWh embedded in APS's base rates beginning in April 2005. Liberty examined the Company's financial information collection and reporting processes to test the accuracy and reasonableness of APS's compliance with ACC reporting requirements. Liberty also examined entries for the major cost elements that the PSA includes; *e.g.*, fuel and energy procurement, power plant reliability, fuel usage, purchased power, off system sales, and hedging transactions.

APS submitted monthly compliance reports under its POA from June 6, 2005 until the March 30, 2006 report, which APS prepared in accord with the Staff POA. The APS monthly filings have required the filing of both confidential and non-confidential information. The non-confidential or publicly available information required under both of the POAs includes the following:

- Balancing Account calculations
- Total power and fuel costs
- Customer sales in kWh and dollars by customer class
- Number of customers by customer class
- Detailed listing of items excluded from PSA calculation
- Detailed listing of any adjustments to the adjustor reports
- Total off-system sales revenues
- System losses in MW and MWh
- Monthly maximum retail demand in MW
- Identification of Company contact person and phone number.

The confidential information required under each POA basically remained the same providing for the following:

- For each Generating unit
    - Net generation, in MWh per month, and 12 months cumulatively
    - Average heat rate, both monthly and 12-month average
    - Equivalent forced-outage rate, both monthly and 12-month average
    - Outage information for each month, including event type description, start and end dates

  - Total fuel costs per month
  - Total fuel costs per kWh per month
- Power purchases
  - Quantity purchased in MWh
  - Demand purchased in MW to extent specified in contract
  - Total costs for demand to extent specified in contract
  - Total cost of energy
- Off-system sales
  - Itemization of off-system sales margins by buyer
  - Details on negative off-system sales margins
- Natural Gas Purchases
  - Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
  - Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer-term purchases, including price per therm, total cost, supply basis, and volume by contract
- Monthly projection for next 12-month period showing estimated (Over)/Under-collected amounts. (As provided for in Staff POA, APS began providing this information with January 2006 data.)
- Summary of unplanned outage costs by resource type. (As provided for in Staff POA, APS began providing this information with December 2005 data).

The defined and allowable PSA costs include prudently incurred fuel and purchased power costs incurred to provide service to retail customers, including direct costs of contracts used for hedging system fuel and purchased power. APS captures and reports the allowable costs under the following accounts from the FERC USofA:

- 501 Fuel – Steam
- 518 Fuel – Nuclear less ISFSI regulatory amortization
- 547 Fuel – Other production
- 555 Purchased Power
- 565 Wheeling – Transmission of Electricity by Others.

There are a number of PSA exclusions. ACC Decision No. 66567 provided APS the ability to recover reasonable and prudent costs associated with customers who left APS standard offer service, including those under special contract rates, but then returned to APS. The PSA provides that a direct assignment or special adjustment may be applied to recognize the cost differential between the power purchases needed to accommodate the returning customer, and the power supply cost component of otherwise applicable standard-offer rates. Additionally, purchases under specific terms on behalf of standard-offer special contract customers may also be directly assigned. Schedule E-36 customers are also directly assigned power supply costs based on APS system incremental costs at time of consuming power.

5. Review and Testing of August 2005 PSA Filing

Liberty selected the month of August 2005 as a representative period for a test of PSA filings. APS submitted the August 2005 confidential data to the ACC on November 1, 2005 in accordance with the Settlement Agreement approved by Decision No. 67744. APS used its POA to guide this filing. The confidential filing consisted of a 12-page document that included a cover sheet, financial data, and a certification by the Company, as required under the agreement.

The filing's major elements included:

- Fuel and fuel generation; *i.e.*, gas, oil, coal, and nuclear to also include revenues from gas hedges and mark-to-market expense
- Purchased power; *i.e.*, long-term, market purchases, and other purchases
- Revenues from off-system sales.

The sum of these elements reflects native load costs. Dividing this sum by the kWh of energy to serve native load produces the cost per kWh. This cost for August 2005 was $0.025762. The supporting schedules provide an additional level of data to assist for simple monthly reviews; however, the underlying fuel and purchase power costs, including off-system sales data related to each is contained within APS's accounting systems, including the APS M&T TranZ system. APS's Plant Purchase and Generation ("PP&G"), Plant Net Generation Report sets forth other relevant data such as kWh generated. The generation information contained in the PSA filing lists only APS's share; the PP&G reports provide both Total Generation and APS share basis.

Given the lack of formal, written procedures for the preparation of the PSA filings, Liberty used working meetings with the PSA team representatives to obtain a description of the relevant processes, including the sources and uses of detailed supporting data. APS personnel described relevant accounting entries as follows:

- Fuel cost consumed or used in the production of steam generation is booked to Account 501 Fuel; this account includes the costs of coal, oil, and gas consumed or burned to generate steam and the handling costs for each.
- Residual waste related to these fuels is also booked to Account 501.
- The cost of fuel (including freight and handling) when first purchased is initially booked to Account 151, Fuel Stock; when consumed the cost is credited from this account and then charged to Account 501.
- APS books the costs of nuclear fuel consumed in the production of power to Account 518; inventory accounts are also used, first debited when acquired and then credited when consumed and charged to Account 518.
- Account 547 fuel includes the cost of fuel delivered at the station used in other power generation. This account also includes summary transactions for gas hedges and mark-to-market expenses; the primary supporting data for the underlying transactions is maintained by APS M&T through its TranZ reporting programs.

APS provided a detail general ledger summary transaction report for August 2005 in support of activities for each of these accounts. APS uses this report as the primary source data for preparation of the PSA filings. APS secures kWh generated data from the PP&G Plant

generation report. The information contained therein includes all related transactions, and included the following information:

- Charge Number: a source code posting reference to include general description of the transaction
- Operational Identification: generating station and unit#
- Process: description of fuel type
- Amount (or expense).

Liberty selected specific (sometimes multiple) transactions of each relevant type for more detailed review. This testing sought to trace data back to the core or originating documents associated with the transactions being tested.

Liberty tested transactions for "Purchased Power," whose costs APS books to Account 555. These costs include long-term, market, other purchases, and off-system sales. Liberty found that the lack of written procedures necessitates a considerable amount of review and analysis in order to verify proper classification for PSA reporting purposes. APS derives the values it reports from a number of sources, which include a report titled "Level Three Purchased Power and Fuel," supported by information from APS M&T. A report titled "Power Marketing Detail," which APS M&T supports, supplemented by information from a PP&G report entitled "Purchase Power Supply" serves as the source of kWh captured as purchased power. Liberty's sampling of specific purchase-power transactions included one of the largest off-system sales transactions, an APS M&T short-term physical gas purchase on the spot market, and a short-term purchase and sale of gas.

6. PSA Over/Under Filings

Pursuant to Decision No. 67744, APS provides a non-confidential PSA report on a monthly basis. The filing consists of approximately five schedules, which set forth the applicable retail energy costs subject to PSA consideration, a subtraction of retail energy costs recovered under base rates, and a remainder, which consists of those costs considered to comprise the pre-sharing over/under recovered cost value. Only 90 percent of the pre-sharing over/under recovery value is considered as potentially recoverable. The current monthly value is added to the prior month's balance, and an interest charge is calculated against that balance and added to the total cumulative value. The calculation is repeated and tracked on a monthly basis through the 12-month PSA period. The filing also provides customer count, sales in kWh, and revenues by customer class on a monthly and cumulative basis through the 12-month PSA period. This non-confidential filing is also certified by an officer of the Company.

The total PSA energy cost is calculated as follows:

- The book fuel and purchased power costs less off-system sales produce the Native Load Power Supply Costs
- The PSA retail energy cost results from multiplying the ratio of the PSA retail energy kWh sales to total native load energy kWh sales by the Native Load Power Supply Costs
- Retail base energy cost is simply determined by multiplying the PSA retail energy kWh sales times the $.020743 base rate per kWh

- Subtracting the retail base energy cost from the calculated PSA retail energy costs to determine the pre-sharing over/under recovery value.

7. Railroad Rates

APS became involved in a 1997 rate case proceeding before the Surface Transportation Board. APS received a favorable ruling related to fuel transportation rates for deliveries of coal to its Cholla Power Plant. In 2003, the case was reopened, after which the railroad, BNSF, secured an increase in rates between May 23, 2003 and December 2004. APS was required to pay $[redacted] in February 2005. APS made an accrual adjustment on its books at year-end 2004, booking $[redacted] APS entered the sum total of $[redacted] as a payable due to BNSF. APS stated that this adjustment has not affected the PSA since all entries were for periods before the effective date of the PSA.

Effective [redacted] APS and BNSF [redacted]. APS owns three of the four Cholla generating units; its [redacted] APS did not book any portion to inventory because the fuel received during these time periods would have already been burned. APS notes the entry does affect the PSA as it relates to a period after the effective date.

C. Conclusions

1. APS's accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing.

Liberty reviewed APS's current accounting and reporting systems. Liberty also examined and tested the capabilities of APS's accounting and reporting systems during its detailed documentation and testing process. The Company follows the FERC USofA, has adequate controls and accounting policies and procedures in place, and subjects the underlying collection and reporting of data to internal and external audits. The internal audit group has been actively involved in conducting reviews on many of the fuel and purchased power elements contained within the PSA.

2. APS audits, however, have yet to address PSA filing preparation. *(Recommendation #1)*

Liberty confirmed that no internal audits had yet been conducted on APS's in-house procedures and sources for developing the monthly PSA reports to the ACC. Even though PSA filings began fairly recently (early 2005), Liberty believes that it is timely to begin periodic examination of those filings and the processes supporting them, given the importance in assuring their completeness and accuracy.

3. APS documents its filing information well, but lacks a formal written procedure addressing preparation of the monthly PSA filings. *(Recommendation #2)*

Liberty requested that APS provide a detailed narrative description of the process used to develop, assemble, review, authorize, and submit fuel and power purchase information in the PSA filings. Interviewees expressed some level of agreement that such a procedure should be developed. Due to the lack of such a formal procedure, Liberty took an oral description of the process, as provided by the PSA team representatives, and undertook testing of the completeness and accuracy of that process to verify it was appropriate, well understood, and followed. Liberty's testing found the information in the filing to be well documented and supported.

4. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate.

Liberty requested and obtained copies of the confidential and non-confidential information for all of the PSA reports, beginning with the initial information for March 2005. Liberty reviewed the monthly filings for:

- General compliance with the POA filing requirements
- Mathematical accuracy
- Quality of detail schedules supporting the filing.

In general, monthly information submitted was consistent with the requirements of the POAs in effect at the time, *i.e.,* the Company's beginning on June 6, 2005 and Staff's as filed on March 20, 2006. Liberty notes that on February 28, 2006 the Company submitted a combined filing which included both December 2005 and January 2006 data. This step was taken to provide more timely data; *i.e.*, within 30 days of the close of the period. Additionally, December 2005 data reflected the first time the Company included a projected 12-month period showing estimated (Over)/Under-collected amounts. January 2006 data reflected the first summary of unplanned outage costs by resource type. These steps moved the Company more closely into compliance with the Staff's March 20, 2006 POA filing requirements.

5. Despite their general accuracy, including the total costs of generation, APS over- or under-stated individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation. *(Recommendation #3)*

Liberty tested a number of the filings for mathematical accuracy, and found minor discrepancies. These minor differences in part are related to tracing supporting schedule information to the monthly summary page that lists the various fuel and purchased-power cost elements contained within the PSA format.

The first page of the PSA filing provides a summary of each of the cost elements, which include, for example: (a) gas generation, (b) gas generation tolling arrangements, (c) gas hedges and mark-to-market expenses, (d) oil generation, (e) coal generation, and (f) nuclear generation, the sum of which comprises the total Generation Fuel Expense. The underlying cost of each of these items is supported in greater detail in a supporting schedule identified as "Plant Capability, Generation, Fuel Costs, Heat Rate and EFDR for APS Generation". This schedule provides plant generation and costs by fuel type and generating unit.

Liberty found that the sum total of Generation Fuel Expense on the summary schedule agreed with the sum total on the detail supporting schedule just described. However, Liberty found it difficult to cross-reference some cost elements on an individual basis. For example, it took only a straightforward process for Liberty to determine that the sum of the nuclear cost activity on the supporting schedule tied to the summary schedule. Liberty found the same for gas hedges and mark-to-market expenses. However, Liberty could not match the summary costs for gas, oil, and coal generation line items to the supporting schedule.

Liberty's detailed analysis of the August 2005 data revealed that coal generation costs reported on the detail schedule included fuel oil and gas expenses, which are used as a supplement to coal. The detail schedule also listed a separate line item for coal handling costs; Liberty expected that the sum of these would reflect the total costs of coal generation expenses. However, when coal generation was reported on the summary page, the ancillary fuel oil and gas cost was removed, and the sum was reported as coal generation. The fuel oil cost used for coal generation was then included in the oil generation mix, which Liberty construes as a misclassification. In a similar misclassification, gas used for coal generation was reported under gas generation costs. In sum, while the totals may be accurate, some minor improvements in presentation may be warranted for easy tracing of expenses on a cost element basis to correct for these misclassifications of generation.

The remaining purchased power costs items, such as long-term purchases, market purchases, other purchases, and revenues from off-system sales, were easy to trace from the summary schedule back to supporting schedules. The sum of these costs produces the net native load fuel and purchased power expenses, which are then divided by the associated energy in kWh to serve native load customers, producing a unit cost per kWh. While each of the supporting expense schedules discussed earlier also reflects the corresponding kWh for each item, there is no mechanism or process for efficiently providing a summary of each to verify the sum total of kWh energy. For example, the summary page has just two columns. The first provides a description of the major component. Each row therefore lists the major element; *e.g.*, gas-generation fuel expense or oil-generation fuel expense. The second column provides the corresponding dollar cost value of each. A simple solution would be to add a third column "kWh energy" to which the corresponding kWh values would be entered for each respective element, such as gas, oil, coal generation, purchase power, and sales.

6. Liberty's detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

Liberty found no inaccuracies that would materially affect the accuracy of cost totals as reported, and found only minor discrepancies. As noted in the previous conclusion, such discrepancies do not affect the total costs of generation, but do cause APS to overstate or understate individual coal, oil, and gas generation costs due to a misclassification of costs among the three types of generation.

Liberty was able to verify the accuracy of the underlying information back to the individual transaction level; however, the process was made more cumbersome by the lack of a formal narrative or written procedure. Excluding the previously noted exception dealing with the

treatment of natural gas and oil used in coal plants, Liberty was able to verify and tie-in the total costs reported for each element within the PSA filing. With the exception of fuel oil, Liberty examined the underlying supporting data in order to test individual transactions in each of the various costs elements. Liberty excluded fuel oil from testing because the approximately $50,000 costs were nominal.

Liberty found that the APS August 2005 data included brokers' fees for Gas and Purchase Power of $34,515 and wheeling costs of $2,087,952. Liberty succeeded in tracing these costs items to supporting documents; however, the June 6, 2005 POA did not clearly provide for the inclusion of such costs. Staff's March 20, 2006 POA does support the inclusion of wheeling costs, which Liberty finds consistent with the purpose and nature of PSAs generally. Liberty's review of later PSA over/under filings indicates that APS has removed the cost of brokers' fees, and thereby resolved that matter. This adjustment was reflected in APS's December 2005 over/under filing account balance as submitted on February 28, 2006. The Company's potential recovery of the account balance is currently pending; therefore, customers will only be responsible for the balance approved.

7. **Liberty's detail review of the non-confidential PSA Over/Under values found them to be accurate, but they should be more transparently supported.** *(Recommendation #4)*

Liberty performed the same kind of review of the August 2005 non-confidential over/under recovery filing as it did for the confidential filing for that month. This review found the over/under recovery filing to be accurate.

Liberty started with the premise that the source data contained within the confidential filing; *i.e.*, total system fuel and purchased power costs along with other supporting information contained therein would provide the necessary data to arrive at the book fuel and purchased power costs reflected on the non-confidential filing. This proved not to be the case. One of the weaknesses of the confidential filing is that it does not provide sufficient data to perform this calculation. As discussed earlier, the Company did not have a written procedure to guide or explain how the values in the non-confidential filing are developed.

Liberty requested that the PSA team prepare a schedule that would begin with the August 2005 confidential filing information, and list the supporting adjustments to arrive at the values presented on Schedule 1 in the non-confidential filing. In a working session with the PSA team, Liberty was able to verify that the underlying adjustments to the August 2005 confidential data reasonably support the values reflected in the August 2005 non-confidential filing.

8. **A review of APS handling of supplemental fuel charges and refunds indicates that supplemental charges and refunds have been accounted for in the PSA when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA.** *(Recommendation #5)*

Liberty found APS's consideration and rationale for booking supplemental charges and refunds to be reasonable. Supplemental charges and refunds should be booked in a manner that tracks as closely as possible the impact such events would have had on the product had it been correctly priced at the time.

In the case of the $[redacted] for the [redacted], APS correctly considered and balanced its accounting entries, assigning a portion as a direct charge to expenses and a portion to inventory. This method appropriately matched the time when the product would have been put into inventory and then ultimately consumed. For example, the [redacted]. Based upon normal target inventory levels, it is reasonable to assume that the [redacted] deliveries would have already been consumed, while a portion of the more recent [redacted] deliveries would still be in inventory. The correct approach would be to book a portion to both expense and inventory. Liberty also agrees that this transaction would have no effect on the PSA and precedes the effective date.

The [redacted]. APS booked all of the costs as [redacted] to expense. Liberty found it reasonable to book the $[redacted]; therefore, the associated inventory would more than likely have already been burned. Liberty questions, however, the APS accounting for the $[redacted] period. Recording that as [redacted] ignores the fact that a portion of the [redacted] purchases would still be presumed to be in inventory when the entry was recorded. Liberty believes that, from an accounting perspective, the more appropriate entry would have been to book a portion of the [redacted], rather than to book it all as [redacted]. This split method would more accurately correspond to purchase-to-consumption activity.

That said, however, Liberty also found that APS's method did not materially affect the PSA. Had APS recorded the entry as proposed by Liberty the refund would merely have taken longer to flow through the monthly PSA filings, and would more than likely have been fully refunded by the end of the annual PSA period.

D. Recommendations

1. **Conduct periodic internal audits of the PSA filings to verify the soundness, completeness, and accuracy of the activities that produce them, with the first such audit to be conducted as part of the next audit plan.** (*Conclusion #2*)

Liberty understands that the PSA filing process recently began in early 2005, but believes that periodic audits of the PSA filings is important in assuring their completeness and accuracy and in building confidence in the PSA mechanism.

2. **Develop a written policy and procedure for the preparation of the confidential PSA filings.** (*Conclusion #3*)

The PSA filings require input from five different departments. The development of a formal policy and procedure would assist in assuring that the filings are complete and prepared consistently. A written procedure also provides assistance for those employees who may need to

prepare such filings in the absence of ones currently assigned that task. Liberty, discussed the matter with the Company, and understands that it is in general agreement and is in the process of preparing a formal written procedure.

3. **Correct PSA reporting methods to assure more accurate classification and reporting of coal, oil, and gas generation information.** *(Conclusion #5)*

While the total costs of generation may be accurate, the individual coal, oil, and gas generation costs either were over or understated due to a misclassification of costs between the three types of generation.

4. **Revise the PSA confidential filing format to provide a sufficient level of detail to support the calculation of the components contained within PSA non-confidential filing.** *(Conclusion #7)*

The confidential filings should provide support for the fuel and purchase power costs and energy sales levels contained within the non-confidential filing. This process would be more transparent, and assist the ACC Staff in evaluating the underlying costs and determining how such costs ultimately affect the values in the balancing account.

5. **Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes.** *(Conclusion #8)*

Supplemental charges or refunds should be booked in a manner which tracks as closely as possible the impact such events would have had on the product had it been correctly priced at the time. A consistent policy applying such principals on a monthly basis provides a reasonable presentation for financial reporting purposes.

EXHIBIT
S-34
admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND

ATTACHMENTS OF

JAMES R. DITTMER

ON BEHALF OF THE
UTILITIES DIVISION STAFF

PUBLIC VERSION

Data Deemed to be Confidential by APS has Been Redacted

AUGUST 18, 2006

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DIRECT TESTIMONY
OF
JAMES R. DITTMER

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc., a consulting firm engaged primarily in utility rate work. The firm's engagements include review of utility rate applications on behalf of various federal, state and municipal governmental agencies as well as industrial groups. In addition to utility intervention work, the firm has been engaged to perform special studies for use in utility contract negotiations.

Q. On whose behalf are you appearing?

A. Utilitech, Inc. has been retained by the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") to undertake a review of Arizona Public Service Company's ("APS" or "Company") application for a change in base rates.

Q. Is Utilitech responsible for the review of all elements of APS' rate request?

A. No. Utilitech has subcontracted with two firms to assist in this review. Liberty Consulting Group, Inc. ("Liberty") has been retained to review APS' proposed roll-in amount of ongoing fuel and purchased power expense – net of margins from off-system sales. Additionally, Liberty is responsible for addressing conceptual and mechanical changes that APS is proposing to the existing Power Supply Adjustor ("PSA").

Technical Associates, Inc. has also been retained as a subcontractor to Utilitech to address capital structure and cost of capital issues. Additionally, the ACC Staff is internally addressing some issue areas, including rate design, Demand Side Management Programs, Environmental Portfolio Standards, and quality of service issues – just to name a few.

Under the direction of the Utilities Division Staff, Utilitech has been responsible for the review and development of the majority of remaining issue areas, including proforma rate base and operating income, as well as a revised class cost of service study. Additionally, Utilitech is responsible for aggregating, summarizing and presenting the cumulative results of the recommendations of all Staff personnel and all ACC Staff consultants.

QUALIFICATIONS

Q. Before discussing in greater detail the issues and various recommendations that you will be addressing, please state your educational background.

1 A. I graduated from the University of Missouri - Columbia, with a Bachelor of
2 Science Degree in Business Administration, with an Accounting Major, in 1975.
3 I hold a Certified Public Accountant Certificate in the State of Missouri. I am a
4 member of the American Institute of Certified Public Accountants.
5
6 Q. Please summarize your professional experience.
7 A. Subsequent to graduation from the University of Missouri, I accepted a position
8 as auditor for the Missouri Public Service Commission. In 1978, I was
9 promoted to Accounting Manager of the Kansas City Office of the Commission
10 Staff. In that position, I was responsible for all utility audits performed in the
11 western third of the State of Missouri. During my service with the Missouri
12 Public Service Commission, I was involved in the audits of numerous electric,
13 gas, water and sewer utility companies. Additionally, I was involved in
14 numerous fuel adjustment clause audits, and played an active part in the
15 formulation and implementation of accounting staff policies with regard to rate
16 case audits and accounting issue presentations in Missouri. In 1979, I left the
17 Missouri Public Service Commission to start my own consulting business.
18 From 1979 through 1985 I practiced as an independent regulatory utility
19 consultant. In 1985, Dittmer, Brosch and Associates was organized. Dittmer,
20 Brosch and Associates, Inc. changed its name to Utilitech, Inc in 1992.
21
22 My professional experience since leaving the Missouri Public Service
23 Commission has consisted primarily with issues associated with utility rate,

contract and acquisition matters. For the past twenty-seven years, I have appeared on behalf of clients in utility rate proceedings before various federal and state regulatory agencies. In representing those clients, I performed revenue requirement studies for electric, gas, water and sewer utilities and testified as an expert witness on a variety of rate matters. As a consultant, I have filed testimony on behalf of industrial consumers, consumer groups, the Missouri Office of the Public Counsel, the Missouri Public Service Commission Staff, the Indiana Utility Consumer Counselor, the Mississippi Public Service Commission Staff, the Arizona Corporation Commission Staff, the Arizona Residential Utility Consumer Office, the Nevada Office of the Consumer Advocate, the Washington Attorney General's Office, the Hawaii Consumer Advocate's Staff, the Oklahoma Attorney General's Office, the West Virginia Public Service Commission Consumer Advocate's Staff, municipalities and the Federal government before regulatory agencies in the states of Arizona, Alaska, Michigan, Missouri, Oklahoma, Ohio, Oregon, Florida, Colorado, Hawaii, Kansas, Mississippi, New Mexico, Nevada, New York, West Virginia, Washington and Indiana, as well as the Federal Energy Regulatory Commission.

SUMMARY OF UTILITIES DIVISION STAFF'S RECOMMENDATIONS

Q. Please summarize your understanding of APS' request for rate relief in this docket.

A. Within its January 31, 2006 updated filing in this docket, APS requests and purports to justify an annual increase in base rates in the amount of $449.6 million over that which was approved in Decision No. 67744 on April 1, 2005 (i.e., APS' 2003 rate case – Docket No. E-01345A-03-437). In addition to the noted *base rate* increase requested, APS also seeks to implement an Environmental Improvement Charge ("EIC") tracker that would be initially established at a level designed to annually collect $4.3 million in addition to the requested $449.6 million base rate increase. The Company's requested $449.6 million increase in base rates represents an average increase to Arizona retail customers of 21.14%. With the additional EIC request, if each of APS' requested rate changes were to be approved, the average Arizona retail customer would experience a total increase of 21.34% over existing base rates.

The Company's base rate relief request can be further broken down into a "fuel" or "Power Supply Adjustor" component versus a "non-fuel" or "other" component. Specifically, of the total requested $449.6 million base rate increase, $298.7 million relates to APS' request for a 1.1161 cents per kWh increase in the PSA factor, while $150.9 million of the Company's total base rate increase request relates to "non-fuel" or costs "other than" power supply. If the Company's PSA factor roll-in request were approved the amount of PSA

costs collected in base rates would rise from the current amount of 2.0743 cents per kWh to 3.1904 cents per kWh.

Q. What is the overall recommendation of the Utilities Division Staff that incorporates the cumulative proposals of all the various Staff in-house personnel as well as outside consultants testifying within this proceeding?

A. Staff is recommending an overall increase in base rates above that approved within Decision No. 67744 (i.e., the 2003 APS rate order) in the amount of $204.0 million. Such overall increase will result in an average increase to Arizona retail customers of 9.6%.

Further, Staff's recommended increase can also be broken into a PSA/fuel component of $193.5 million and a "non-fuel" or "other" component of $10.5 million. Liberty Consulting Group is recommending on behalf of the Utilities Division Staff that the PSA amount included in base rates be raised from the currently collected amount of 2.0743 cents per kWh to 2.7975 cents per kWh based upon an updated 2006 fuel forecast run.

Mr. Matthew Rowell appearing on behalf of the Utilities Division Staff is also recommending rejection of APS' proposed Environmental Improvement Charge tracker – that again, was requested by APS to be initially implemented to collect $4.3 million annually. While not a component of Staff's "base rate" recommendation, Staff witness Ms. Barbara Keene is recommending that

Environmental Portfolio Standard ("EPS") surcharges be increased to provide for annual collection of an additional $4.3 million.

Staff retained GDS Associates, Inc. ("GDS") to investigate prolonged outages that occurred at the Palo Verde Nuclear Generating Station during 2005 that, in turn, caused APS to incur higher power supply replacement costs that were initially deferred during 2005. As a result of the GDS investigation, Staff will be recommending that a portion of deferred power supply costs currently recorded within the "Paragraph 19d Balancing Account" be written off. However, Ms. Keene will be recommending implementation of a "second step" Paragraph 19 d Balancing Account surcharge that will provide for recovery of additional 2005 deferred power supply costs that remain to be collected after removing the Palo-Verde-outage related costs determined to have been imprudently incurred. Ms. Keene's recommendations regarding a "second step" Paragraph 19 Balancing Account surcharge has not been quantified as of this point in time, but will be included with rate design testimony to be filed on September 1, 2006

For convenience I have prepared Table A below that summarizes the Company's request versus the Staff's recommendation, including a further breakdown between the "fuel/PSA" components and "all other" components:

Table A Summary of APS' Request Versus Staff's Recommendations		
	APS' Request	Staff's Recommenda-tion
Annual Dollar Increase in Base Rates (millions):		
Fuel/power supply increase recommended	$298.7	$193.5
Non-fuel Increase Recommended	$150.9	$10.5
Total Overall Base Rate Increase Recommended	**$449.6**	**$204.0**
Environmental Improvement Charge	$4.3	
Incremental EPS		**4.3**
Paragraph 19 d Bal. Account "second step" (to be filed with Staff rate design testimony)		[1]
Total Increase – Base & Trackers	**$453.9**	**$208.3**
% Impact to Average Retail Customer:		
Fuel/power supply increase recommended	14.0%	9.1%
Non-fuel Increase Recommended	7.10%	0.5%
Total Overall Base Rate Increase Recommended	**21.1%**	**9.6%**
Environmental Improvement Charge	0.02%	–
Incremental EPS		**.2%**
Paragraph 19 d Bal. Account "second step" (to be filed with Staff rate design testimony)		
Total Increase – Base & Trackers	**21.3%**	**9.8%**

Q. Are the increases proposed by APS and recommended by Staff in addition to, or above and beyond, those increases that this Commission has thus far approved during the first half of 2006?

A. No. It is important for the Commission as well as ratepayers to understand that the increases being proposed are, for the most part, *not* additive to increases already granted. The increases granted by this Commission during the first half of 2006 all dealt with recovery of fuel/other power supply costs. As noted from

[1] As noted, this Staff recommendation has not been quantified as of the time this direct testimony is being filed. It will, however, be included with Staff's rate design testimony expected to be filed on September 1, 2006.

Table A above, approximately two-thirds of the Company's requested increase, and the majority of Staff's recommended increase in this docket, relate directly to recovery of fuel/other power supply costs. Thus, for the fuel/power supply portion of the recommended base rate increase – which represent the majority of each parties' rate proposals – the increases being recommended are largely in place of, or in lieu of, increases granted earlier in 2006.

Q. Please provide a brief description of your understanding of increases granted by the ACC thus far in 2006.

A. Thus far in 2006 the ACC has granted APS three rate increases – again, all regarding recovery of "ongoing" as well as previously deferred or "banked" power supply costs. First, within Decision No. 68437 issued in Docket No. E-01345A-03-0437 et al, this Commission authorized APS to increase its PSA factor by four mills per kWh ($.004 cents/kWh) effective on February 1, 2006. This increase will allow APS to recover approximately $110 million annually, and resulted in an average increase in Arizona retail rates of approximately 5.2 percent (5.2%). In 2005 APS under recovered in total approximately $170 million of PSA-includable power supply costs. Because of the current four mill cap on the PSA adjustor, the most that APS is permitted to collect under the annual PSA adjustor is the noted approximate $110 million. The remaining approximate $60 million of 2005 under collected PSA-includable costs were transferred to a separate account – commonly referred to as the "Paragraph 19 d Balancing Account."

In Decision No. 67744 issued following APS' 2003 rate case the Commission envisioned that the PSA would be adjusted annually, or in other words, it would not be adjusted for the first time following the issuance of Decision No. 67744 until April 1, 2006. However, given the dramatic increase in fuel and purchased power expense being incurred by APS in late 2005, this Commission elected to authorize earlier-than-originally-anticipated implementation of a new "annual" PSA factor. Further, as noted, APS was authorized to implement the maximum four mill PSA adder provided for within Decision No. 67744. As explained in greater detail below, it is currently expected that the four mill adder approved to collect 2005 under recovered power supply costs will be automatically renewed to continue recovering anticipated 2006 under recovered power supply costs.

Q. Please discuss the next APS increase authorized by this Commission in 2006.

A. In Decision No. 68646 issued within Docket No. E-01345A-06-0063 the ACC authorized APS to implement a surcharge in the amount $.000554 per kWh (.554 mills/kWh). As previously described, approximately $60 million of under recovered 2005 power supply costs could not be collected under the four mill PSA annual adjustor cap, and was therefore transferred to the Paragraph 19 d Balancing Account. In February 2006 APS sought to implement two separate surcharges designed to collect the $60 million transferred to the Paragraph 19 d Balancing Account over a twelve month period. Anticipating concerns regarding under recovery of power supply costs resulting from abnormal Palo Verde Nuclear Generating Station outages, APS elected to request a "first step"

or immediate recovery of some $15.3 million of power supply costs that it had calculated would have occurred even absent the prolonged Palo Verde outages. APS requested that the remaining $44.6 million of under recoveries calculated to have occurred as a result of the prolonged Palo Verde outages be collected with a "second step" surcharge that would be implemented upon completion of this Commission's inquiry regarding the unplanned 2005 outages at the Palo Verde Station. Thus, the surcharge approved in Decision 68646 is designed to allow APS to recover over a one year period approximately $15.3 million of deferred fuel cost that was not impacted, or caused, by the 2005 Palo Verde outages. This surcharge became effective on May 1, 2006 and will remain in effect until the earlier of 1) the end of a twelve month collection period (i.e., April 30, 2007) or 2) full recovery of the $15.3 million deferred fuel balances. Arizona retail customers experienced a 0.7 percent (0.7%) average increase in rates as a result of this Commission decision.

Q. Please discuss the third increase authorized for APS in 2006.

A. In Decision No. 68685 issued within Docket No. E-01345A-06-0009, the ACC authorized APS to implement an "interim PSA" factor of seven mill per kWh ($.007/kWh). The noted seven mill "interim PSA" increase was in addition to the four mill "annual PSA" factor increase authorized on February 1, 2006 within Decision No. 68437. The "interim PSA" resulted in approximately a $192 million annual increase in retail rates and APS retail customers are experiencing approximately a 9.0% overall increase as a result of this final ACC

order authorizing APS to change rates in 2006. The "interim PSA" which also became effective on May 1, 2006 is designed to alleviate an otherwise expected significant under recovery of 2006 power supply costs. Unlike the "annual" PSA adjustor that is designed to collect any prior year under recovery of power supply costs, the "interim" PSA adjustor approved was forward looking in nature – considering forecasted 2006 power supply costs that otherwise would have resulted in a very significant under recovery of "2006 Annual Tracking Account" costs. It will remain in affect until all 2006 Annual Tracking Account costs are recovered except for the amount that can be expected to be collected under the February 2007 4 mill bandwidth limitation (about $110 million as is currently being collected pursuant to the 2005 under recovery).

Q. What amount of power supply costs, subject to future PSA factor modification, was rolled into base rates in APS' prior base rate case?

A. 20.743 mills per kWh (2.0743 cents per kWh).

Q. What amount of comparable power supply costs are being collected as a result of ACC authorizations occurring during the first half of 2006?

A. As described, Decision No. 68437 authorized an "annual PSA" modification of four mills effective February 1, 2006 designed to collect approximately $110 million out of approximately $170 million of total 2005 under recovered PSA-includable costs. Decision No. 68685 authorized an "interim PSA" modification of an *additional* seven mills designed to recover increased power

supply costs being experienced, and forecasted to occur, in 2006. Thus, through an "annual" and an "interim" PSA modification, APS is currently recovering 31.743 mills per kWh (3.1743 cents per kWh). Additionally, APS is surcharging an additional .0554 mills per kWh for the recovery of the 2005-related Paragraph 19 d Balancing Account.

Q. How does Staff's recommendation compare to, and fit with, PSA increases granted during 2006?

A. First, APS' February 2006 "annual" PSA adjustor is set at the current cap of four mills per kWh. As discussed earlier, the "interim" PSA adjustor has been designed in anticipation that the February 2007 "annual" PSA adjustor would remain at the four mill cap. Accordingly, it is now anticipated that rates will not be increased or decreased on February 1, 2007 as the four mill "annual" PSA adjustor is expected to remain in effect to recover 2006 under recovered fuel costs.

Second, APS is currently charging an "interim" PSA of seven mills per kWh. Staff's proposal is to reset the PSA factor at zero and increase the base rate fuel component by .7232 cents per kWh – from the current amount of 2.0743 cents per kWh being collect within existing base rates – to 2.7975 cents per kWh. Presumably new base rates that incorporate or roll in the higher ongoing power supply costs in base rates at 2.7975 cents per kWh will go into effect following the expiration of the 2006 "interim" PSA adjustor, or concurrent with the

expiration of the 2006 "interim" PSA adjustor. If new base rates that incorporate the higher PSA base (2.7975 cents per kWh) are implemented concurrent with the expiration of the 7 mill per kWh "interim" PSA and "existing" base rates that are collecting PSA cost of 2.0743 cents per kWh, ratepayers will experience a small .232 mills per kWh increase in rates.

Under the Staff's recommendations ratepayers will also experience a modest ($10.5 million annually) increase in base rates related to costs other than PSA-includable costs.

If Staff's recommendation to increase the various EPS surcharges is approved, retail rates will additionally be increased by approximately $21.4 million annually.

The "first step" Paragraph 19 d Balancing Account surcharge will expire under the terms described earlier. It is unaffected by Staff's other recommendations in this case. Further, as previously noted, Staff will be proposing with its rate design testimony to be filed on September 1, 2006 a "second step" Paragraph 19 d Balancing Account surcharge. Any "second step" Paragraph 19 d Balancing Account surcharge will be initiated and terminated under the terms that this Commission ultimately approves.

Q. Please summarize Staff's current PSA recommendations in relationship to Commission increases granted to APS thus far in 2006.

A. On Table B below I summarize the previous PSA increases granted APS thus far in 2006. I also show Staff's position regarding the PSA roll-in amount being recommended within this current base rate proceeding, as well as show Staff's various other "base" and "tracker" changes being proposed:

Table B

	Prior Decisions			
	No. 68437	No. 68646	No. 68685	Staff's Current Recommendations
Related Docket No.	E-01345A-03-0437 et al	E-01345A-0063	E-01345A-06-0009	E-01345A-05-0816
Nature of increase	PSA "annual" factor – collecting 2005 deferred PSA costs with 4 mill cap	Paragraph 19 d surcharge designed to recover deferred costs above 4 mill PSA annual adjustor limitation	PSA "interim" increase designed to recover increased 2006 power supply costs to avoid significant 2006 under recovery	Base rate increase – includes new PSA roll-in of 2.7975 cents per kWh versus the current base rate factor of 2.0743 cents per kWh
Implementation date	February 1, 2006	May 1, 2006	May 1, 2006	Early 2007
Termination date	When replaced by a February 1, 2007 "annual" adjustor. It is currently anticipated that the four mill cap will remain in effect on February 1, 2007	Earlier of April 30, 2007 or whenever the bank balance of $15.3 million is collected	Until all 2006 Annual Tracking Account costs are recovered except the amount to be collected under the Feb. 2007 4 mil adjustor cap (about $110 million)	Upon approval of new base rates following the filing and review of a new APS base rate case

Approximate Incr'l Annual Revenues to be Collected pursuant to each Decision	$110 million	$15 million	$192 million	- Base fuel $193.5 - Base Other$10.5 - Step 2 Sur. [2] EPS Incr. $4.3 Overall $208.3
Cumulative increase in rates over *Existing* Base Rates Established in Dec. No. 67744	$110 million	$125 million	$317 million	- Base fuel $193.5 - Base Other$10.5 - Step 2 Sur. [3] EPS Incr. $4.3 Overall $208.3
Incremental kWh charge	4.0 mills	.0554 mills	7.0 mills	7.232 mill increase to reflect an updated PSA roll-in amount; remaining non-fuel increase based upon Class COS Study
Cumulative kWh charge increase	4.0 mills	4.0554 mills	11.0554 mills	7.232 mill increase to reflect an updated PSA roll-in amount; remaining non-fuel increase based upon Class COS Study

I would note that Staff consultant Mr. John Antonuk is recommending that the 2007 PSA adjustor be established by considering forecasted 2007 fuel, purchased power and off-system sales margins. He is not recommending that the 2007 PSA factor be established based upon estimates available at this time. However, at his request APS prepared a 2007 fuel forecast that calculates – utilizing current 2007 price forecast inputs – that annual power supply costs would increase by approximately $157.4 million above the 2006 power supply

[2] To be provided with Staff's September 1, 2006 rate design testimony
[3] To be provided with Staff's September 1, 2006 rate design testimony

cost level which Staff is recommending be rolled into base rate at this point in time.

DEVELOPMENT OF JURISDICTIONAL REVENUE REQUIREMENT ACCOUNTING EXHIBITS

Q. Have you prepared exhibits which quantify, summarize and incorporate the results of the various recommendations being made by ACC Staff witnesses, other co-consultants, as well as yourself?

A. Yes. I have prepared Staff Exhibit __ which consists of a series of Joint Accounting Schedules. The noted Joint Accounting Schedules reflect the individual and cumulative results of all the various recommendations being made by or on behalf of the Utilities Division Staff.

Q. Please describe how Staff Exhibit __ has been prepared and organized.

A. Staff Exhibit __ largely follows the style and format of the accounting exhibits prepared by the Company as part of the Standard Filing Requirements. Specifically, Schedule A is the Revenue Requirement Summary, which reflects the cumulative impact of the various revenue, operating expense, rate base and cost of capital recommendations being sponsored by witnesses appearing on behalf of the ACC Staff. Also shown on Schedule A are the values of the various components underlying the Company's revenue requirement recommendation. Thus, one can observe on a summary level basis how the various components of Staff's revenue requirement recommendation contrast

with the Company's proposal (i.e., rate base, adjusted operating income, overall cost of capital).

Q. Does Schedule A – Revenue Requirement Summary also show a required return on a "fair value" rate base?

A. Yes, consistent with Arizona's legal requirements, Staff has developed a return requirement on a "fair value" basis. For purposes of this calculation and consistent with the Company's presentation, I have calculated a "fair value" rate base which consists of an average of a Reconstruction Cost New – Depreciated ("RCND") and original cost rate base. I have developed a RCND net plant in service value by applying ratios developed from APS' original cost and RCND plant in service values. Other RCND rate base components were deemed to be equal to their original cost values.

In order to determine a "fair value" return I calculated the rate of return that would be necessary, when applied to my calculated "fair value" rate base in order to allow the same revenue requirement as is required by my original cost rate base and rate of return calculations. Since I do not conclude that there is any reason to adjust my original cost calculations as a result of any factors that might result from calculating a "fair value" return, I am recommending the "fair value" rate base and rate of return that results from this calculation. Based on

my review, I believe that APS has proposed the same method of addressing the "fair value" requirement.

Q. Please continue your discussion of the development of the Joint Accounting Schedules.

A. Schedule B is the Rate Base Summary. In developing Staff's proposed retail rate base I have started by showing APS' proposed jurisdictional rate base by detailed component (i.e., Column A). On page 1,Column C of Schedule B I show the sum of all Staff rate base adjustments, and in Column D one can observe Staff's proposed "as adjusted" retail rate base by detailed category. Page 2 of Schedule B provides a summary of each Staff rate base adjustment being proposed. Immediately following Schedule B – Rate Base Summary are a number of supporting schedules which set forth each individual Staff rate base adjustment. Each individual rate base adjustment has a separate designation such as B-1, B-2, etc. Thus, each rate base adjustment identified and presented with a separate "B-__" designation becomes a reconciling item between APS' and Staff's rate base recommendation.

Schedule C is the Net Operating Income Summary. In a manner similar to the rate base schedules, I begin on Schedule C by showing the Company's "proposed" or "as adjusted" net operating income by major component. The sum of all of Staff's adjustments to net operating income can be found in Column C of Schedule C, with the support for each income statement

adjustment developed on separate schedules designated as Schedule C-1, C-2, etc. Thus, like the rate base schedules, each "Schedule C-__" reflects a reconciling component or adjustment between APS' proposed net operating income and Staff's proposed net operating income. Through the remainder of my testimony I will use the terms "Adjustment B-__" and "Schedule B-__" as well as "Adjustment C-__" and "Schedule C-__" interchangeably.

Schedule D reflects the Company's as well as the Staff's proposed capital structure, including the weighted cost of debt, preferred stock and recommended return on equity. Staff's proposed capital structure and component cost recommendations are sponsored by Mr. David Parcell. Mr. Parcell is Vice President of TAI – one of the consulting firms that Utilitech subcontracted with for this engagement.

Q. Please describe Schedule E.

A. Schedule E provides a reconciliation between the Company's requested rate increase and Staff's recommended increase by adjustment or issue area. I would note that the revenue requirement value assigned to rate base issues versus return issues is dependent upon the order in which calculations are undertaken. For instance, the revenue requirement value of the "return" issue will be greater if calculated on APS' proposed rate base rather than Staff's (lower) rate base recommendation. Similarly, the revenue requirement value assigned to an individual rate base adjustment will be higher if calculated

utilizing the Company's proposed rate of return rather than Staff's (lower) rate of return recommendation. Schedule E reflects the revenue requirement impact of the Company-versus-Staff return difference based upon APS' proposed retail jurisdictional rate base and reflects the revenue requirement value of each Staff rate base adjustment based upon Staff's proposed rate of return recommendation.

SFAS 112 – OTHER DEFERRED CREDITS RATE BASE OFFSET (Schedule B-1)

Q. Have you reviewed APS' rate base proposal for various deferred debits and deferred credits?

A. Yes.

Q. Are you in agreement with the components that APS has included within its rate base development, as well as the amounts included for the various components?

A. No. Through discovery APS has acknowledged the propriety of including one additional deferred credit item as a rate base offset that was not included within its original rate base proposal. Specifically, in response to Data Request No. UTI-10-302, APS has indicated that it would be appropriate to include the end-of-test-year balance for the Accumulated Provision for SFAS 112. These SFAS 112 costs relate to payments to employees on long-term disability – costs that are ultimately included in the above-the-line cost of service. Accordingly, it is equitable to include these cost free funds as a rate base offset.

Q. Have you prepared a schedule posting this necessary rate base adjustment?

A. Yes. On Schedule B-1 I reflect the rate base adjustment for the Accumulated Provision of SFAS 112 costs that APS acknowledges should be reflected as an offset to rate base.

BARK BEETLE REMEDIATION COSTS (Schedule B-2 and Schedule C-14)

Q. Please give your understanding of the Company's request to reflect recovery of deferred bark beetle remediation costs in this docket.

A. In Docket No. E-01345A-03-0437 a Proposed Settlement was reached between APS and a number of parties – including the ACC Utilities Division Staff – that was in large measure adopted by this Commission. One element of the Proposed Settlement that was accepted by the ACC authorized APS to defer bark beetle remediation costs. The Commission may recall that in that previous rate case docket APS requested in rebuttal testimony to be allowed to recover an estimated amount of costs anticipated to be incurred in removing trees in northern portions of its service territory that had died from bark beetle infestation. The retail rates ultimately approved did not include any allowance for incremental tree and brush removal expense related to bark beetle remediation efforts, but the noted rate order did authorize APS to defer for later recovery reasonable and prudent costs for bark beetle remediation that exceed the prior test year level of tree and brush control expense.

In this proceeding APS has requested rate base inclusion of bark beetle remediation costs deferred on its books as of the end of the test year plus an estimate of additional bark beetle remediation costs expected to be incurred throughout the remainder of 2005 and 2006. Additionally, APS seeks to incorporate within the development of new base rates amortization expense designed to recover over a three year period end-of-test-year-actual plus estimated-through-end-of-2006 deferred bark beetle remediation costs.

Q. Are you in agreement with APS' deferred bark beetle rate base request and amortization expense proposal incorporated within its recommended retail cost of service?

A. No. APS essentially began deferring bark beetle remediation expenditures following the April 1, 2005 rate order from Docket No. E-01345A-03-0437 *retroactively* back to January 1, 2005. APS had no specific authority, nor was there any implied authority pursuant to the settlement or the final ACC decision from Docket No. E-01345A-03-0437, to begin deferring bark beetle costs prior to the effective date of Decision No. 67744. Accordingly, the bark beetle remediation costs incurred and later deferred by APS related to work undertaken between January 1, 2005 and March 31, 2005 (i.e., the period preceding the April 1, 2005 ordered effective date) should be removed from APS' proposed retail rate base. Further, that portion of APS' bark beetle amortization expense proposal related to the first quarter of 2005 deferrals should, similarly, be adjusted.

1 Q. Are there any other adjustments that need to be made to APS' proposed bark
2 beetle deferral balance beyond removing the first quarter 2005 costs?
3 A. Yes. First, through discovery APS acknowledged two other problems with its
4 proposed bark beetle deferral balance. First, when calculating its proposed
5 proforma rate base adjustment, APS started with its projected end-of-2006
6 deferral balance. From the projected end-of-2006 deferral balance APS
7 inadvertently subtracted out the November 30, 2005 actual balance of recorded
8 deferred bark beetle costs *rather than* correctly subtracting out the September
9 30, 2005 historic test year ending balance that had already been included in the
10 "per books" or "unadjusted test year" rate base values that became the starting
11 point for the test year cost of service. Second, APS also acknowledged that it
12 had failed to reflect or recognize related accumulated deferred income taxes as a
13 reduction to its proforma rate base adjustment. (See response to Data Request
14 No. UTI-14-351)
15
16 Q. Have you prepared adjustments to reflect all the needed corrections to bark
17 beetle remediation costs that you have just described?
18 A. Yes. First, on Schedule B-2 I reflect the calculations necessary to properly
19 recognize rate base adjustments that 1) eliminate deferrals related to
20 expenditures incurred prior to April 1, 2005, 2) reflect related accumulated
21 deferred income taxes associated with APS' before-tax proforma rate base
22 adjustment, and 3) to correct for the problem of subtracting out the incorrect

"per book" deferral balances to arrive at the Company's original proforma adjustment.

Further, on the income statement, I have proposed Adjustment No. C-14 to reduce the amount of amortization expense related to the deferral of expenditures occurring prior to April 1, 2005.

CASH WORKING CAPITAL (Schedule B-4)

Q. Please describe Staff Adjustment B-4.

A. Staff Adjustment B-4 reduces rate base to reflect the proper quantification of Cash Working Capital ("CWC") as a source of ratepayer supplied "zero" cost capital, using methodologies consistent with prior ACC decisions.

Q. Has APS proposed a rate base allowance for CWC?

A. Yes. As discussed in the direct testimony of Company witnesses Laura L. Rockenberger and Fred H. Balluff,[4] APS has prepared a lead lag study for its Arizona retail operations for purposes of quantifying CWC in the instant proceeding. Referring to Ms. Rockenberger's Attachment LLR-4 and Mr. Balluff's Attachment FB-1, APS has proposed a net CWC allowance of approximately $(29.1) million,[5] net of special deposits and working funds -- a $29.1 million *reduction* to rate base.

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[4] Direct testimony of Company witnesses Rockenberger, pages 26-27, and Balluff, pages 4-11.

[5] APS' proposed $(29.4) million net negative CWC allowance offset by $234,000 for special deposits and working funds, before jurisdictional allocation to Arizona retail operations.

1 Q. How does the Company's negative CWC allowance of $(29.1) million, before
2 retail allocation, as proposed in the current proceeding compare to APS'
3 recommendation in its last Arizona rate case?
4 A. In direct testimony in the last APS rate case, the Company proposed to include
5 in rate base a net *positive* CWC allowance of $54.1 million.[6] As summarized in
6 the following table, the CWC allowance APS proposes to include in rate base in
7 the current rate case is about $83 million lower than the amount initially
8 requested in the last rate case:

Description		Net Working Capital Allowance (000's)
Last APS Rate Case (Docket No. E-01345A-03-0437)	(a)	$ 54,098
Current APS Rate Case (Docket No. E-01345A-05-0816)	(b)	(29,139)
Net Change in Working Capital		$ (83,237)

Sources:
(a) Rockenberger Direct, page 11 & Attachment LLR-2 (last rate case).
(b) Rockenberger Direct, page 27 & Attachment LLR-4 (current rate case).

9
10 Q. Could you briefly identify the key changes in the Company's valuation of cash
11 working capital that materially contributed to this $83 million reduction in this
12 component of the APS rate base?
13 A. Yes. About $42 million of the $83 million reduction is attributable to the
14 reduction in the revenue lag from 41.81 days in the last study to 36.95 days in
15 the current study. Another $12 million of the reduction is associated with the
16 recognition of Sales and Franchise taxes in the current study, which were not

[6] Direct testimony of Company witness Rockenberger, page 11, Docket No. E-01345A-03-0437.

1 considered by APS in the last case. The majority of the remaining reduction in
2 CWC is a result of interrelated changes in overall expense levels and expense
3 lags between the two studies, as set forth below:
4

Change in Expense Amounts & Expense Lags	Change in APS CWC Allowance (000s)
Fuel Expense	$ (708)
Purchased Power	9,525
Other O&M	237
Depreciation & Amortization	(9,242)
Income Taxes – Current	(7,687)
Income Taxes – Deferred	(14,778)
Property Taxes	(8,809)
Total	$ (31,462)

Source:
UTI Workpaper "CWC_reconciliation.xls" based on constant revenue lag of 41.81 days.

5
6 Q. The above table shows reductions in APS' requested net CWC allowance from
7 the last case associated with depreciation and amortization as well as income
8 taxes-deferred. Are these reductions due to the fact that APS is not seeking to
9 include non-cash items in the determination of CWC in the current case?
10 A. No. APS' proposed lead lag study treatment for non-cash items of depreciation
11 and amortization expense as well as deferred income tax expense continues to
12 reflect a full revenue lag and zero expense lag – the same position presented by
13 APS in the last rate case. It is the change in the overall level of these non-cash
14 expense items that causes the reductions noted in the above table.
15

Q. In quantifying the $(29.1) million negative CWC allowance in the current rate case, did APS employ a methodology that was consistent with the longstanding approach used by this Commission as applied in the Company's last litigated rate case?

A. No. Although the following excerpt from Ms. Rockenberger's direct testimony implies that the Company's lead lag study methodology is consistent with the quantification approach previously adopted by this Commission, certain of the detailed study components are definitely contrary to past ACC decisions:

> "I am testifying to all of the data in SFR Schedule B-5, with the exception of the Working Capital calculation (line 1 of page 1), which Mr. Fred Balluff will address. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component determined using the lead/lag study methodology required by Decision No. 55931."
> [Rockenberger Direct, p. 27]

The Company's calculation of the $(29.1) million negative CWC allowance clearly includes non-cash items (e.g., depreciation, amortization and deferred income tax expense) and fails to consider interest expense – contrary to the Commission's findings in Decision No. 55931. These significant exceptions to the precedents established in Decision No. 55931 will be discussed in detail later in this testimony section.

Q. In his direct testimony, does Mr. Balluff discuss Decision No. 55931 or the treatment of these non-cash items and interest expense?

A. Mr. Balluff does not discuss Decision No. 55931 in his direct testimony. However, Mr. Balluff's direct testimony is clear that depreciation, amortization

and deferred income tax expenses were included in the Company's lead lag study and that interest expense was not considered in the lead lag study.[7]

Contrary to implications in Ms. Rockenberger's testimony, APS' proposed lead lag study approach goes far beyond the Commission's longstanding lead lag study methodology, as addressed within Decision No. 55931, and thus materially overstates the rate base allowance for CWC, by including non-cash items and excluding interest expense.

Q. The above quote from Ms. Rockenberger's direct testimony appears to indicate that she is not sponsoring the Company's CWC recommendation, which is instead the subject of Mr. Balluff's testimony. To your knowledge, is Mr. Balluff or Ms. Rockenberger responsible for the detailed analyses underlying the quantification of the APS lead lag study results?

A. This question was the subject of several data requests submitted by Utilitech, as the detailed workpapers underlying APS' lead lag study recommendation were actually provided by Ms. Rockenberger. Based on my review of APS' response to the relevant data requests,[8] it is my belief that Mr. Balluff is responsible for the theory and approach used by APS in quantifying CWC, but Ms. Rockenberger is responsible for the detailed workpapers and calculations necessary to implement that theory.

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[7] Balluff Direct, pages 9-11, and Attachment FB-1.
[8] APS responses to Data Request Nos. UTI-5-214, UTI-9-275 and UTI-9-277.

Q. In quantifying Staff Adjustment B-4, did you prepare a stand-alone lead lag study in order to correctly present this component of rate base?

A. No. Since a regulated entity does not record CWC in its general accounting records, the valuation of the amount of CWC to be included in rate base must be quantified through complex, labor intensive specialized analyses (i.e., a lead lag study) conducted within the context of a general rate case proceeding. Significant resources are required to prepare, maintain and review detailed lead lag studies. In lieu of preparing an independent study, resources were committed to the analysis, testing and correction of the lead lag study presented by APS.

Differences in CWC Recommendations

Q. Could you summarize the specific changes and corrections you have proposed with respect to APS' valuation of the CWC allowance?

A. Yes. In quantifying Staff's proposed rate base allowance for CWC, the following modifications and revisions were made to the Company's lead lag study. It is my opinion that recognition of these changes will more accurately quantify the cash working capital needs of APS in conformance with the Commission's CWC policies, as expressed in prior rate orders:

- Remove non-cash expenses (e.g., depreciation and amortization expense, deferred income tax expense, etc.) to limit study results to "cash" expense requirements;

- Recognize pro forma ratemaking interest expense and the extended (i.e., weekly, monthly, semiannual, etc.) interest payment patterns in the lead lag study;

- Revise purchase power expense level to reflect the elimination of significant unregulated power marketing activity from the quantification of CWC; and

- Incorporate the following miscellaneous corrections identified during the analysis of the APS study workpapers and supporting documentation:

    - Revenue lag: recalculate the composite revenue lag using test year revenues, rather than 2004 revenues used by APS, thereby using a re-weighting methodology that is consistent with the purchased power expense adjustment noted previously.

    - Palo Verde Lease expense lag: restate APS' expense lag calculation to reflect a material shift in semi-annual payment requirements beginning in 2005.

    - State Income Tax Expense: revise the payment lag for Arizona state income taxes consistent with the statutory payment due dates.

After removing the non-cash items, recognizing the interest expense lag and posting the other corrections to the APS lead lag study, Staff Adjustment B-4 results in a larger *negative* CWC allowance than proposed by APS.

Q. Please summarize the primary differences in the CWC recommendations being proposed by you and the Company.

A. The following table provides a general summary of the primary CWC quantification issues:

		Approximate CWC Issue Value[9]
APS Recommendation	(a)	$(29.3) million
Remove Non-Cash Items		(43.7) million
Recognize Interest Expense		(15.9) million
Revise Palo Verde Lease Payment Lag		(7.1) million
Adjust Level of Purchased Power Expense		2.6 million
Re-weight Revenue Lag		(.5) million
Staff Proposed CWC Allowance	(b)	$(93.9) million

Note (a): APS witness Balluff, Attachment FB-1.
Note (b): Staff Adjustment B-4.

Q. Why is it appropriate for the lead lag study methodology to produce a negative allowance that reduces rate base?

A. A "negative" CWC valuation, which reduces rate base, is appropriate for several reasons. First, a negative amount indicates that, on average, the Company collects electric sales revenues from ratepayers prior to the need to disburse cash to pay expenses incurred in the provision of electric service. Consequently, the Company has the advance use of ratepayer-provided funds for which ratepayers should be compensated through a rate base offset in the form of negative cash working capital.

Second, the fact that a properly prepared lead lag study results in a "negative" value for CWC should not be surprising or problematic in determining rate base. Just as the Company has previously collected customer advances, accumulated deferred income taxes and accumulated depreciation from ratepayers, which are

[9] Amounts shown are before jurisdictional allocation.

1 used to reduce rate base (i.e., recognized as zero-cost capital), it is relatively
2 common for a utility to collect operational cash flows from ratepayers in
3 advance of the disbursement of those funds to pay expenses. If a lead lag study
4 shows that CWC is a "negative" amount, it is just as reasonable and appropriate
5 to reduce rate base as it would be to increase rate base if the result were
6 positive.

7

8 Third, by definition, a fully developed and properly prepared lead lag study is
9 not limited to producing a "zero" or positive rate base allowance. Consistent
10 with this Commission's longstanding practice and procedure, it is possible and
11 appropriate for CWC to yield a significant reduction to rate base, when
12 circumstances warrant.

13

14 **Overview of Cash Working Capital**

15 Q. What is cash working capital and why should it be included in rate base?

16 A. Cash working capital is commonly defined as the amount of cash needed by a
17 utility to pay day-to-day expenses incurred in providing service in relation to the
18 timing of the collection of revenues for those services. In applying this
19 definition, if the timing of a company's cash expenditures, in the aggregate,
20 precedes the cash recovery of those expenses, investors must provide cash
21 working capital. On the other hand, ratepayers are considered the providers of
22 cash working capital in instances where their remittances, on the average,
23 precede the company's cash disbursements for expenses. Whether "positive" or

1 "negative" in amount, cash working capital is typically included in utility rate
2 base to recognize the timing of cash flows through the utility.
3
4 Q. In your opinion, how should cash working capital be quantified for inclusion in
5 rate base?
6 A. Sample-based lead lag studies represent the best available method for
7 quantifying the revenue and expense component lags that are used in
8 determining cash working capital. Although it may not be feasible to
9 completely update such studies when a utility routinely seeks a periodic rate
10 increase, due to the complex and detailed nature of such an undertaking, major
11 components of the lead lag study should be updated periodically to ensure that
12 the revenue and expense lag calculations reasonably represent current
13 operational conditions and reflect the effects of recent changes in corporate
14 policies as well as organizational structure.
15
16 Evaluation of the Company's lead lag study results included a review of data
17 inputs and computational formulae within multiple lag day spreadsheet study
18 files prepared by Company personnel, as well as judgmental sampling
19 techniques to assess the relative accuracy of transaction source documentation.
20
21 Q. You previously referred to use of a "lead lag study" to quantify CWC. Please
22 explain that reference.

A. Many years ago, it was fairly common for regulators to estimate a "provision" for the amount of CWC includable in rate base using an arbitrary "formula" method. The most common method was referred to as the 45-day, or 1/8th of O&M, formula. Variations of this formula method were generally used by regulators until the mid-1970's, as modified from time to time to include or exclude certain items from the formula calculation. Since that time, regulators have often relied on actual measurements of cash flows using detailed lead lag studies to quantify the rate base allowance for CWC.

In contrast, a lead lag study represents a systematic measurement of the timing of cash flows through the utility. Detailed analyses are conducted to calculate the utility's revenue lag – that is, the number of days between the provision of service to customers and the collection of related cash revenues for those services. The timing of cash outflows for the major cash expense elements comprising cost of service are also measured to determine the average number of days between the Company's receipt of goods or services supplied by vendors/ contractors/ employees used in the provision of electric service and the ultimate cash payment for such items.

If more "lag days" on average are involved in the collection of revenues from ratepayers than are available to a utility in the delayed payment of expenses incurred in the provision of related services, investors are required to provide the necessary cash working capital to bridge this gap between payment and

collection, resulting in an addition to rate base. On the other hand, if cash disbursements are sufficiently delayed, or revenue collections are accelerated, so that the average expense payment lag days exceed the revenue lag days, ratepayers become cost free providers of cash working capital, causing a reduction to rate base.

Q. Could you explain the significance of the definition of cash working capital?

A. Yes. The definition of cash working capital is significant for purposes of determining and identifying the particular transactions that should be considered in quantifying the CWC allowance includable in rate base. This definition leads to, or implies, the establishment of certain boundaries as to which cash flows are relevant for ratemaking purposes, thereby defining the scope of the lead lag study.

Q. Please identify the major cash flows of a typical public utility, indicating those relevant to the measurement of utility cash working capital requirements.

A. The major sources and uses of cash are observable in a utility's statement of cash flows, or its equivalent, as follows:

Sources of cash for a utility ordinarily include:

- Operating revenues.
- Non-operating and non-jurisdictional revenues.
- Proceeds from outside financings or debt/ equity infusions from parent.
- Asset sales.

Uses of utility cash include:

- Payment of utility expenses.
- Utility plant construction expenditures.
- Payment of non-operating or non-jurisdictional expenses.

- Net change in other assets (inventory, cash, prepayments).
- Retirement of debt or equity.

Given the definition of cash working capital discussed previously (i.e., "the amount of cash needed by a utility to pay its day-to-day expenses . . ."), cash flow timing and measurement focuses on the first cash "source" and the first cash "use" listed above. All other sources and uses are either separately considered in the ratemaking process or are non-operational, financing or non-jurisdictional functions – not transactions related to the day-to-day payment of expenses. It is also important to note that some operating revenues represent a utility's recovery of recorded non-cash expenses, such as depreciation and deferred tax expense. These accrued expenses are properly recognized in determining overall revenue requirement, but do not require the current expenditure of cash. Consequently, these "non-cash" expenses fall outside the scope of a properly prepared lead/lag study.

CWC & Non-Cash Items

Q. Would you briefly explain your proposal to eliminate non-cash items from the lead lag study?

A. Similar to APS' last Arizona rate case, the most significant lead lag methodology difference relates to APS improper inclusion of non-cash expenses (e.g., depreciation, amortization, deferred taxes, etc.) in its lead lag study, which I am proposing to remove consistent with past ACC rate orders. As previously discussed, such items are not reasonably allowed or considered within lead lag

studies because they are "non-cash" transactions. These substantive non-cash expenses improperly and significantly overstate the cash working capital required to pay APS' ongoing, day to day expenses. As previously noted, removal of non-cash expenses also complies with previous ACC Decisions addressing this issue.

Q. What is the CWC rate base impact of APS' inclusion of non-cash items in its lead lag study?

A. For ease of reference, Attachment JRD-A reproduces the APS exhibit (i.e., Balluff Attachment FB-1) supporting the calculation of the Company's $(29.4)[10] million decrease to rate base, which includes these non-cash, accrual-basis expense items. The following table summarizes the non-cash elements of APS' lead lag study results.

Description	APS Proposed CWC Allowance [11]
Nuclear Amortization	$ 3.5 million
Palo Verde S/L Gain Amortization	(.5) million
Insurance	.5 million
Depreciation and Amortization	32.5 million
Amort. of Prop. Losses & Reg. Study Costs	(.3) million
Deferred Income Taxes	7.9 million
Total Non-Cash Items	$43.6 million

Sources: Rockenberger LLR_WP11, page 1, & Balluff Attachment FB-1.
Note: Slight rounding difference from amount included in earlier table.

[10] The $(29.1) million working capital allowance cited previously represents the $(29.4) million lead lag study result less about $234,000 of working cash and special deposits.
[11] Amounts shown are before jurisdictional allocation.

1 Q. Referring to Attachment JRD – A the Company has assigned a "zero" expense
2 lag day to each of the items in the above table. If the assigned expense lag is
3 "zero", why do you believe that the Company has improperly overstated its cash
4 working capital needs?
5 A. The use of an assumed "zero" expense lag in and of itself is not a problem.
6 However, the Company has employed a study methodology which applies a
7 revenue lag (i.e., 36.95 days)[12] to each of these "non-cash" expense items.
8 Consequently, the Company's method results in the assignment of a positive
9 revenue lag (see Column 2 of Attachment JRD – A) and a "zero" expense lag
10 (see Column 3 of Attachment JRD – A) to each non-cash item (i.e., lines 6, 29,
11 30, 34, 36 and 43), thereby improperly overstating CWC by about $43.6 million
12 as a result. By including these non-cash items, the Company's approach has
13 essentially expanded the scope of cash working capital to include cash flows
14 related to the construction and depreciation of plant and the accrual and later
15 payment of deferred income taxes.
16
17 Assuming that the purpose of a lead/lag study was expanded to track the timing
18 of <u>all</u> cash flows into and out of the utility, the analysis and measurement would
19 then encompass <u>all</u> cash transactions, whether related to current period
20 expenses, dividend payouts or construction activity. However, other rate base
21 elements would also require analysis, as construction costs are not typically paid
22 immediately in "cash" – as implied by an assumed zero expense payment lag for
23 depreciation.

[12] See Rockenberger LLR_WP11, page 1, and Balluff Attachment FB-1.

Further, except for the Palo Verde Steam Generator Replacement completed near the end of 2005, the balance of APS' gross plant investment included in rate base is as of September 30, 2005. Certain payments for recently completed construction projects closed to plant in service or otherwise included in rate base would not have been fully paid for in cash as of September 30, 2005. However, neither APS nor I are proposing to reduce the recorded balance of gross plant at September 30, 2005 or the installed cost of the Palo Verde Steam Generator Replacement to reflect any delay in disbursement of funds on then-outstanding construction invoices and billings.

Furthermore, the rate base valuation date for both the accumulated depreciation reserve and accumulated deferred income tax reserve, adopted by Company and Staff, is September 30, 2005. Because this valuation date materially precedes the expected rate-effective date of this proceeding,[13] APS will have fully collected accruals to these September 2005 reserve balances from ratepayers months, if not over a year, before any rate change is granted by the Commission. Consequently, APS' proposed expansion to include non-cash items in CWC fails to analyze or account for delayed cash outflows in payment of construction costs, the collection of the reserve balances from ratepayers, or the turn-around and ultimate cash payment of deferred income taxes.

Q. Why are deferred income tax expenses considered to be non-cash items?

[13] The Commission's current procedural schedule has hearings scheduled for October 2006. As a consequence, it is not envisioned that a final rate order in the pending rate case will be issued prior to the first quarter of 2007.

1 A. Deferred income tax expenses, as the name implies, represent non-cash,
2 deferred accounting transactions. In other words, the Company does not
3 disburse cash in the current year for payment of deferred income tax expenses to
4 Federal or State taxing authorities. Such income tax expenses arise from the
5 normalization method of accounting for tax/ book timing differences – that is,
6 differences that originate in one year and reverse or "turn-around" in other
7 years. Since non-cash deferred income tax expenses are included in revenue
8 requirement and "collected" from ratepayers, but are not "currently" paid to the
9 taxing authorities, the cumulative balance of prior deferred income tax expenses
10 (i.e., the accumulated deferred income tax reserve) is recognized as a source of
11 cost free capital separately considered in determining overall revenue
12 requirement (i.e., ratepayer funded "zero" cost capital typically reduces rate
13 base) that need not be financed or provided by investors. Consequently,
14 deferred income taxes should be excluded from the determination of the
15 Company's cash working capital requirements, because there are no current
16 period cash requirements or outflows.
17
18 Deferred income tax expenses are somewhat similar to depreciation expenses:
19 both represent accrued expenses; both expenses are recovered through utility
20 rates; the cumulative recoveries of both expenses are recognized as zero cost
21 capital and used to reduce rate base; neither of these expenses involve current
22 period payments to suppliers, vendors or taxing authorities; and both expenses

provide a source of cash, or positive cash flow, that can be used for investment in plant construction or to support other corporate activity.

Q. Why should non-cash expense items be excluded from a lead lag study?

A. As indicated previously, non-cash expense items represent elements of cost of service that do not require a current period cash payment. Therefore, they do not increase a Company's need for cash working capital, under the commonly used approach to lead lag analysis, but serve as a source of cash flow. Such accrued expense items themselves do not involve the issuance of a cash voucher or wire transfer to pay, for example, for depreciation expense or deferred income tax expense.

Thus, non-cash expense items are properly excluded from a lead lag study. Their inclusion would be inconsistent with the widely accepted view of cash working capital as the amount of invested capital required to bridge the gap between the payment of cash expenses and the collection of related revenues. When there is no expense payment, no cash working capital is required. Depreciation and deferred income tax expenses do not require current period cash payments. Since investors are not required to provide cash advances for these expense items prior to the collection of revenues, it would be improper to include such items in a study of cash working capital requirements.

1 **CWC & Interest Expense**

2 Q. Why should the Commission adopt your recommendation that interest expense
3 be included in the lead lag study?

4 A. Interest expense arises as a direct result of the Company's debt obligations.
5 Each debt issue requires the periodic cash payment of interest expense in known
6 amounts that are due and payable at predetermined points in time (e.g., quarterly
7 or semi-annual interest payments).

8

9 In the traditional revenue requirement formula, interest costs are included in the
10 weighted cost of capital that is applied to rate base. Through this ratemaking
11 formula, interest expense becomes as much a part of jurisdictional revenue
12 requirement (i.e., costs borne by ratepayers) as do operating expenses such as
13 fuel and payroll costs. Since the ratemaking process allows recovery of capital
14 costs that include these periodic payments to debt holders and ratepayers pay for
15 utility service on a monthly basis, fairness requires that the lead lag study
16 recognize the Company's use of these interest funds for the extended time
17 period between collection from ratepayers and payout of interest to debt
18 holders.

19

20 Q. Should the lead lag study also include quarterly common equity dividends, since
21 you are proposing to recognize interest expense?

22 A. No. While I am aware of utility recommendations in other proceedings that
23 have proposed such treatment, common equity cash flows (including common

stock dividends) are less certain as to timing and do not represent "cash" expenses. "Net income," from which common dividends are paid, represents the residual equity return remaining for shareholders after all other expenses are deducted from revenues, rendering it comparatively unpredictable in amount. However, CWC recognition of quarterly dividend payments would yield an estimated payment lag in excess of 45 days (i.e., 90 days in calendar quarter divided by two plus additional lag from end of quarter to dividend disbursement date), ignoring the retention of "current" earnings. A presumed "expense" lag over 45 days would exceed the Company's proposed 36.95 day revenue lag, resulting in a negative CWC allowance for common "dividends". As a result, any recognition of common dividends for lead lag study purposes would further decrease Staff's proposed "negative" CWC recommendation.

Consistency with Prior ACC Decisions

Q. You previously indicated that non-cash items, including depreciation and deferred income tax expenses, are not reasonably included within lead lag studies. How has the ACC previously treated these non-cash items?

A. While exhaustive research has not been conducted in this area, I am familiar with the Commission's treatment of non-cash items in a number of rate proceedings dating back to the early 1980's. Attachment JRD – B contains excerpts from a series of prior ACC decisions concerning lead lag studies and CWC theory. Based on my prior experience with Arizona utility regulation and a review of the excerpts included in JRD – B, I am not aware of any ACC order

adopting the inclusion of non-cash expenses in determining CWC, as proposed by APS witness Balluff in the pending case.

Perhaps of greatest immediate relevance, the Commission specifically excluded non-cash expense items and recognized interest expense in quantifying the CWC allowance adopted in the rate order (Decision No. 55931) of APS' last fully litigated rate case – an ACC decision specifically referenced by Company witness Rockenberger:[14]

> The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital. E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.

The Commission has issued numerous orders applying and interpreting the appropriate lead lag study approach to cash working capital. Although not exhaustive in scope, Attachment JRD - B contains excerpts from ten (10)

[14] See Rockenberger Direct, page 27.

different ACC decisions that discuss various CWC topics, including non-cash items, interest expense and use of pro forma (i.e., adjusted) operating expenses.

Corrections / Modifications to APS Study

Q. Have you or other members of your firm reviewed the Company's lead lag study workpapers and identified any specific corrections which should be recognized therein?

A. Yes. The Company's lead lag study workpapers and supporting calculations have been reviewed and analyzed. However, this work did not verify the accuracy of the Company's transaction data (i.e., receipt dates, payment dates, payment amounts, etc.) underlying each of the thousands of transactions contained in the multiple worksheets and spreadsheet files supporting APS' study results. Instead, our review was focused on the analysis, testing and correction of material lead lag study elements sponsored by APS, including reliance on judgmental sampling techniques to obtain transaction source documentation. As a result of this effort, certain corrections specific to the Company's study have been identified. The following table briefly summarizes the corrections, which have been reflected in the CWC calculation set forth in Staff Adjustment B-4:

Item	Correction
Expense Levels:	• Include pro forma interest expense; and • Exclude significant costs associated with power marketing activity from test year purchased power expense
Revenue lag:	*[Staff 36.85 days vs. APS 36.95 days]* Modify revenue lag weighting to reflect test year revenue levels, net of power marketing activity.
PV Lease expense lag:	*[Staff 103.99 days vs. APS 47.32 days]* Restate expense lag to reflect material shift in semi-annual payment requirements beginning in 2005.
State Income Taxes:	*[Staff 62.05 days vs. APS 58.95 days]* Recognize Arizona statutory payment due dates.

Q. In quantifying its proposed CWC allowance, did APS incorporate pro forma levels of expense in determining lead lag study results?

A. No. In quantifying its proposed rate base allowance for CWC, APS considered only actual, per book unadjusted test year expenses.[15] Generally, the use of unadjusted test year expenses for CWC quantification purposes can be considered reasonable, absent material ratemaking adjustments to the various expense components reflected in the study. However, referring to APS Schedule C-1, the Company's direct filing contains proposed ratemaking adjustments that increase O&M expenses and taxes by $360.6 million on a total Company basis (or $355.4 million on an Arizona jurisdictional basis).

[15] Total Company unadjusted, per book expenses per APS Schedule C-1, column (a) ties to column (1) of Rockenberger LLR-WP11, and Balluff Attachment FB-1, with several limited exceptions: fuel & purchased power expense (exclude mark to market costs on trading contract), sales and franchise taxes (not recorded on income statement), and the classification of other taxes. Also, see APS response to Staff Data Request No. UTI-5-213.

The magnitude of these collective expense adjustments suggest potentially large shifts in the calculation of the net CWC allowance (i.e., dollars times net lag day factor) that could distort lead lag study results – thereby warranting use of pro forma, rather than unadjusted, test year expense amounts.

Q. Given the reality of significant ratemaking adjustments to test year actual expenses levels, what amounts should be included in the APS lead lag study?

A. When feasible and significant to the outcome, material ratemaking adjustments to test year expense levels should be recognized in the lead lag study results, in order to ensure that the CWC rate base allowance is not materially misstated due to inconsistencies between actual and pro forma test year expense levels.

Q. Does Staff Adjustment B-4 fully reflect the net effect of all pro forma adjustments proposed by Staff and the Company?

A. No. While the Company has proposed ratemaking adjustments increasing jurisdictional O&M expense by about $355.4 million, Staff Schedule C (page 1) summarizes the various adjustments proposed by Staff that reduce jurisdictional O&M expense and taxes in excess of $960 million. Because of the diverse ratemaking recommendations of the parties in this proceeding and the complexity of compiling all Company and Staff adjustments into the various expense categories comprising the lead lag study, I have generally adopted APS' proposed use of per book expense levels for CWC valuation purposes – except for those items where per book levels would materially misstate the

overall study results (i.e., purchased power expense adjustment and pro forma interest expense). When readily identifiable, quantifiable and material in amount, I recommend that it is appropriate for a lead lag study to recognize pro forma expense levels in quantifying the rate base allowance for CWC.

Q. Are there any lead lag study components where you have not used test year per book expense for CWC purposes?

A. Yes. I have proposed to revise the expense levels for two lead lag study components where reliance on "per book" expense levels would yield distorted results. During the test year, APS recorded $1.8 billion of fuel and purchased power expense, which included $1.3 billion of purchased power expense alone.[16] Although APS has proposed to increase actual fuel and purchase power expense by an aggregate $351 million,[17] Staff has recommended a reduction to APS' pro forma fuel and purchased power expense of about $966 million, including an $842 million to purchased power expense.[18] This material change in pro forma purchased power expense should be recognized in quantifying CWC – a change that increases rate base by about $2.6 million before jurisdictional allocation.

In addition I am proposing inclusion of interest expense in the lead lag study, contrary to APS' proposed exclusion. For ratemaking purposes, Staff's CWC allowance recognizes the amount of pro forma interest expense resulting from

[16] See APS Schedule C-1, page 1; Rockenberger LLR_WP11, page 1; and Balluff Attachment FB-1.
[17] See APS Schedule C-1, page 1.
[18] See Staff Schedule C and Staff Adjustment C-4.

the interest synchronization adjustment set forth on Staff Adjustment C-19, in lieu of the actual amount of interest expense recorded by APS during the test year.

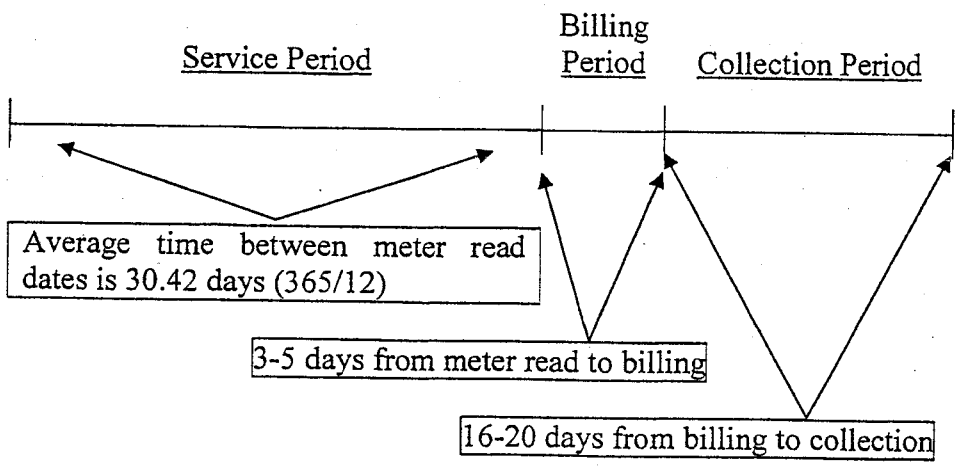
Q. You previously stated that material ratemaking adjustments to test year expense levels should be recognized in the lead lag study results when feasible and significant to the outcome. Is Staff largely accepting APS' proposed use of actual test year expense levels because it is not feasible to fully adjust each component of the lead lag study to reflect pro forma amounts or because the result of such an undertaking is not expected to be significant to the CWC outcome?

A. Both. Since APS did not assemble its rate filing in a manner that provided a clear breakdown of each pro forma adjustment between lead lag study components, the process required to dissect and reassemble each Company adjustment in the necessary format would be unduly time consuming and complex. However, an effort was undertaken to estimate the effect of APS' ratemaking adjustments on the Company's CWC approach, using certain simplifying assumptions. The results of that rather lengthy undertaking indicated that the magnitude of recognizing APS' ratemaking adjustments was relatively immaterial (i.e., slightly in excess of $1 million on rate base). Because significant resources would be required to conduct relatively complex data analyses, the decision to not pursue this course was considered to be rather conservative, as the expected result of a detailed break out and synchronization

of into the lead lag study would appear to support an even larger negative CWC allowance further reducing rate base.

Q. Please explain how the revenue lag is employed in a lead lag study.

A. As mentioned earlier, a lead lag study is a means of measuring cash flows through the utility. In other words: Does the company, on average, collect revenues from its customers before or after it is required to disburse cash in payment of the goods and services consumed in support of its day to day operations? In answering this question, it is necessary to quantify the revenue lag, which is the average time lapse between the provision of utility service to customers and the collection of the related revenues. The following chart summarizes the components of the revenue lag, using hypothetical billing and collection lags:



Assuming utility service is provided to customers evenly throughout the service period, the follow table illustrates the components comprising the typical revenue lag, using values proposed by APS:[19]

Description	Days
Service Lag (1/2 the service period)	15.21
Billing Lag	5.03
Collection Lag	16.70
Revenue Lag	36.94

The revenue lag (i.e., 36.94 days in this example) would then compared to the expense lag quantified for each cash expense component (e.g., coal expense, payroll expense, etc.) of the lead lag study, in a manner similar to Staff Adjustment B-4.

Q. Please explain how the collection lag element of the revenue lag is estimated in the Company's lead lag study.

A. Rather than conducting a detailed, sample-based analysis of actual customer bill payment patterns, APS employed an accounting technique generally referred to as the "accounts receivable turnover ratio" to quantify the collection lag. In essence, this turnover ratio estimates how many days-worth of average daily revenues are in the accounts receivable balance, using the following algorithm:

Average Daily Accounts Receivable Balance $ /
(Annual Revenue $ / 365 Days)

This formula has been modified by APS since the last rate case, which had previously relied on average *month-end* rather than *daily* receivable balances.

[19] See APS LLR_WP11, page 5.

In the last rate case, Staff disagreed with the Company's reliance on average month-end receivable balances and instead proposed an average daily balance approach. Accurate application of the accounts receivable turnover ratio is highly dependent upon the reasonable quantification of average accounts receivable balances throughout each of the 365 days of the year. Thus, an average daily balance is preferred over employment of month-end balances inasmuch as it provides a more accurate calculation of the true revenue lag being experienced by the Company.

Q. Have you adopted APS' proposed use of average daily accounts receivable balances for purposes of quantifying the revenue collection lag in the current lead lag study?

A. Yes. I have adopted the Company's calculation of the CIS revenue lag for purposes of this case.

Q. Earlier in this testimony section, you identified the key changes in the Company's valuation of CWC that resulted in an $83 million reduction in the proposed rate base allowance from the last APS rate case. One of the key changes was a $42 million reduction in CWC due to a decrease in the revenue lag from 41.81 days in the last rate case to 36.95 days in the current study. Can you explain the primary factors contributing to this reduction in the revenue lag?

A. Although there are certain revenue lag weightings that cause a slight change in the composite revenue lag, the following table generally compares the Company's CIS revenue[20] lag in the current rate case with the lag from the last rate case:

Description	CIS Revenue Lag Current Rate Case	CIS Revenue Lag Last Rate Case
Service Lag (1/2 service period)	15.21	15.21
Billing Lag	5.03	5.10
Collection Lag	16.70	22.21
Revenue Lag	36.94	42.52

Source:
Current Case – Rockenberger LLR_WP11, page 5.
Last Case – Rockenberger LLR_WP2, page 38.

Except for a slight shift in the billing lag from 5.10 to 5.03 days, the entire reduction in the composite CIS revenue[21] lag is attributable to the reduction in the collection lag. As mentioned previously, APS calculated its collection lag in the last rate case using an accounts receivable turnover ratio that relied on average monthly balances. On behalf of Staff, testimony sponsored by Mr. Steven Carver of Utilitech contested the Company's turnover ratio approach and proposed an average daily accounts receivable approach. In the current proceeding, APS has endorsed the daily accounts receivable method, which is the key driver for about $42 million of the $83 million reduction in the Company's proposed level of overall CWC since the last rate case.

[20] CIS revenues represent 80%-90% of annual APS revenues.
[21] CIS Revenue represents only one component of the weighted revenue lag. In APS' last Arizona rate case, the composite revenue lag proposed by the Company was 41.81 days (Rockenberger Attachment LLR-3, Docket No. E-01345A-03-0437) as compared to the composite revenue in the current case of 36.95 days (Balluff Attachment FB-1).

1 Q. For lead lag study purposes, have you and APS applied the full revenue lag in
2 quantifying the sales tax and franchise tax impact on CWC?
3 A. No. In general terms, sales taxes are due on the 25th day of the month following
4 customer "billing". At the time a customer is actually billed, it does not take the
5 full revenue lag (either APS' 36.95 days or Staff's 36.85 days) for the Company
6 to collect the revenues billed, including sales taxes, from its customers. Instead,
7 I have adopted the Company's proposed collection lag of 16.69 days,
8 representing the average time between customer billing and collection.
9 Consequently, the collection lag, in this case 16.69 days, would be used as the
10 revenue lag in computing the net lag associated with sales taxes.
11
12 Q. In the direct filing in APS' last Arizona rate case, did the Company recognize
13 either sales taxes or franchise taxes in the calculation of CWC?
14 A. No. In the last APS rate case, Staff adjusted the Company's lead lag study to
15 separately recognize sales taxes; however, prior to the last rate case, franchise
16 taxes had been included in O&M expense and collected from customers as a
17 component of base utility rates.[22] As indicated in response to Data Request
18 UTI-15-369, APS began billing franchise tax as a separate line item on
19 customer bills, like sales taxes, following the effective date (i.e., April 1, 2005)
20 of the settlement in the Company's last Arizona rate case. Consequently, the
21 treatment of franchise taxes in the lead lag study has changed since the last case.
22 Although an argument could be presented that APS' proposed split of franchise

[22] See Staff Schedule B-7 included in the joint accounting exhibits, ACC Docket No. E-10345A-03-0437.

payments/ taxes between base rates and customer bill rider[23] for CWC purposes should be adjusted to represent the full annual effect of the bill rider treatment, I have adopted APS's proposed treatment of both sales taxes and franchise taxes for CWC purposes in order to conservatively limit the lead lag study issues in the current proceeding (see Balluff Attachment FB-1 and Staff Adjustment B-4).

Q. Do you have any further comments regarding APS' lead lag study calculations?

A. Yes. At the time this testimony was finalized, there were two areas in which our review and analysis had not yet been completed. During the review of the other taxes (i.e., taxes other than income taxes) detail set forth on pages 262-263 of APS' 2005 FERC Form 1, it was noted that the Company's lead lag study appears to have recognized the net lag associated with the employees' share of payroll tax withholdings, but may have overlooked the employer's share of such taxes (e.g., FICA and Medicare). Data Request No. UTI-17-382 was submitted to confirm this oversight and quantify a correction to APS' lead lag study, if necessary.

Further, Data Request No. UTI-19-387 was recently submitted in order to follow-up on what may be an inconsistency in the Company's calculation of the proposed 77.71 day pension and OPEB lag[24] and pension funding requirements, as discussed in the pension actuarial studies provided in the confidential

[23] See lines 25 and 49 of Balluff Attachment FB-1.
[24] See Rockenberger LLR_WP11, page 48.

response to Data Request RUCO 1.9. In quantifying the 77.71 day pension and OPEB lag, APS appears to have assumed that the pension contribution in the "current" year is related to the "current" pension plan year, rather than the "prior" plan year.[25] The referenced data request sought information to either confirm APS' assumption or support a recalculation of the composite payment lag.

At the time this testimony was prepared, the responses to these data requests remained outstanding. I intend to revise the lead lag study, as necessary and appropriate, upon receipt of the responses to the identified discovery requests.

CWC Issue Summary

Q. Please summarize the CWC issues in dispute.

A. The primary factors driving the significant difference (i.e., over $64 million before jurisdictional allocation) in the CWC recommendations of Company and Staff fall into four general areas – each of which are consistent with the Commission's longstanding, lead lag study policies:

- Exclude non-cash items (e.g., depreciation, amortization and deferred income tax expense);
- Recognize payment lags related to interest expense;
- Use pro forma/ adjusted revenue amounts to developed composite revenue lag; and

[25] For example, do the pension contributions made in 2004 relate to the 2004 or 2003 plan year?

- Use pro forma/ adjusted expenses, particularly interest expense and purchased power expense, to the extent feasible and material.

ADJUSTMENT FOR LOST MARGINS FROM DSM PROGRAMS (Schedule C-1)

Q. Please discuss the first adjustment to test year operating income.

A. The adjustment shown on Schedule C-1 reflects the reversal of a portion of the APS adjustment found on the Company's Accounting Schedule C-2, page 1, columns E and F. Specifically, this adjustment reverses the adjustment posted by APS to reflect "lost" retail margins it anticipates from implementation of various demand side management programs. This adjustment is sponsored by Staff witness Mr. Jerry D. Anderson.

MISCELLANEOUS OTHER REVENUES ADJUSTMENT (Schedule C-2)

Q. Please explain the purpose of Staff Adjustment C-2.

A. This adjustment is a correction of the Company's pro-forma adjustment for Schedule 1 Charges that APS has acknowledged is needed. The correction is needed to restate the transaction volumes used by the Company in calculating its adjustment, based upon actual test period data. In addition, APS has agreed in response to Staff discovery to remove the adjustment to expenses it had proposed for expected impacts associated with foregoing paper bills. Specifically, APS never instituted a $5.00 incentive to new paperless bill subscribers that it was once proposing because enrollment into this program has

been strong even without the incentive. Thus, the estimated expense related to the $5.00 incentive designed to encourage customers to forego a paper bill has been eliminated. The revisions contained in Staff Schedule C-2 were provided in a "Revised DJR_WP8" attachment to Data Request UTI 13-344 while the paperless bill revision is more fully described in the APS response to Data Request No. UTI 13-345.

NORMALIZED FUEL, PURCHASED POWER EXPENSE AND OFF-SYSTEM SALES MARGINS (Schedule C-3)

Q. Please discuss your next adjustment to test year revenue and expense.

A. The adjustment found on Schedule C-3 reflects the proforma level of fuel, purchased power expense and off-systems sales revenues and related expense that Staff is proposing to be utilized in the development of base rates. Further, the proforma levels for these components become the basis for rebasing the PSA factor that will be employed in future PSA filings, reports and adjustor development. The inputs for this adjustment are being sponsored by Mr. John Antonuk of Liberty Consulting Group.

ELIMINATE EXPENSES ASSOCIATED WITH UNREGULATED MARKETING AND TRADING OPERATIONS (Schedule C-4 and Schedule C-5)

Q. Does APS continue to undertake unregulated marketing and trading ("M&T") operation?

A. Yes.

Q. Have the revenues and expenses associated with such activities been eliminated in the development of APS' retail jurisdictional cost of service?

A. No. According to answers received in response to discovery questions, the costs of such activities were inadvertently included within the development of the test year cost of service. Specifically, in response to Data Request No. UTI-10-315 the Company stated:

> In reviewing this information, the Company became aware that the revenue, purchased power costs, and operations and maintenance expenses associated with APS un-regulated Marketing and Trading were inadvertently included in the test year. All of these costs should have been excluded from the test year, as they relate to un-regulated operations.
>
> APS will propose a proforma adjustment addressing these costs, which will be included in the reply to Data Request UTI-14-350.

Q. What amount of revenues and expenses were inadvertently included within the development of the test year cost of service?

A. In response to UTI-14-350 APS has quantified the total revenues and expenses that should be eliminated from the test year cost of service. At this point I would emphasize that during the test year unregulated Marketing and Trading operations incurred a net loss of approximately $15 million. Thus, the removal of M&T revenues and expenses from test year operating results has the impact of reducing APS' adjusted test year cost of service – or reducing the otherwise justified requested revenue increase.

On Schedule C-5 I show the elimination of M&T operations and maintenance expense other than purchased power. However, Liberty Consulting Group is sponsoring a separate but related adjustment to eliminate M&T off-system sales revenues and related purchased power expense. This Liberty-sponsored adjustment is reflected on Schedule C-4. Thus, the net M&T loss of $8,273,000 sponsored by the Liberty Consulting Group shown on Schedule C-4 plus the removal of non-purchased power O&M expenses reflected on Schedule C-5 sum to the total $15 million of M&T before-tax loss included within APS' adjusted test year operations that I noted above.

PENSION EXPENSE ADJUSTMENT (Schedule C-6)

Q. Has APS proposed a proforma adjustment to test year operating expense for pension cost?

A. Yes. Ms. Laura Rockenberger proposes a significant upward adjustment to test year actual operating expense. Specifically, as discussed at pages 24 and 25 of her direct testimony, Ms. Rockenberger proposes to increase test year pension expense by approximately $44 million, purportedly to provide for a five-year amortization recovery of the Company's "underfunded pension liability."

Q. Please expand upon your understanding of the Company's request for recovery of the underfunded pension liability.

A. Ms. Rockenberger notes in direct testimony that, as of December 31, 2004, the Company's pension actuaries had calculated a projected benefit obligation of $1,371 million. Ms. Rockenberger further points out that the "fair value" or "market value" of the assets in the external pension trust was approximately $982 million, leaving approximately $389 million of the projected pension obligation "unfunded" or "underfunded" as of December 31, 2004. A significant portion (approximately 39%) of this underfunded amount will ultimately be the responsibility of other Pinnacle West Capital Corporation subsidiaries or other owners of production and transmission properties jointly owned with APS. Ms. Rockenberger and APS propose that the portion of the underfunded pension liability related to APS retail electric operations (i.e., 61% or approximately $218 million) be recovered from APS ratepayers over a five-year period – resulting in a test year proforma adjustment in the amount of approximately $44 million.[26]

Q. Please describe the calculations shown on Schedule C-6 wherein you develop your proposed adjustment to the Company's proposed adjusted test year level of pension expense.

A. First, the calculations shown on lines 1 through 3 of Schedule C-6 simply reverse the Company's proposed five-year amortization of the unfunded Projected Benefit Obligation – that is, the Company's $44 million amortization adjustment.

[26] APS' pro forma adjustment of about $44 million represents the $218 million underfunded pension liability divided by five years.

Line 5 on Schedule C-6 reflects the monthly amount of total APS pension expense currently being accrued within calendar year 2006. This monthly amount is multiplied times twelve to arrive at an *annualized* level of APS pension expense. From such annualized level of pension expense I subtract on line 7 the test year actual recorded pension expense, and on line 9 I also subtract out an additional proforma level of pension expense that APS has reflected in the development of its adjustment to annualize payroll and benefits costs.

Q. Are you stating that in addition to the Company's proposal to amortize the unfunded Pension Benefit Obligation that the Company has also proposed to increase test year pension expense in conjunction with its payroll annualization adjustment?

A. Yes. After annualizing payroll costs to reflect end-of-test year number of employees and wage increases granted through April of 2006, APS applied a benefits loading rate to the "payroll" adjustment amount to consider a purported corresponding increases in pension expense, post retirement medical benefits, health/medical costs, as well as payroll taxes. I have accepted the Company's implicit assumption that there is reasonable correlation between payroll cost and payroll taxes as well as health/medical costs for active employees. However, I disagree with the assumption implicit in the Company's adjustment that pension expense and post retirement medical expenses will go up correspondingly with payroll costs. As noted previously, I am proposing to include within Staff's

recommended cost of service the 2006 estimated level of pension expense currently being accrued. It would be unnecessary, and duplicative, to also allow that portion of the Company's benefits loading on its payroll annualization adjustment that also considers incremental post-test year pension benefits cost changes. Thus, on lines 7 through 9 of Schedule C-6 I subtract out the increased pension expense that was captured with the Company's payroll/benefits adjustment, as well as test year actual recorded APS pension expense, from my proposed annualized level of APS pension expense.

To summarize my pension expense proposal, Schedule C-6 reverses the Company-proposed $44 million amortization expense adjustment, but adds back the increase in 2006 pension expense above the sum of the pension expense actually recorded during the test year and the pension expense component included within the Company's payroll/benefits loading adjustment. Schedule C-6 results in a net reduction in total APS-proposed pension expense of $33,483,000.

Pension Amortization – Adjustment Overview

Q. Why do you disagree with APS' proposed pension amortization adjustment?

A. I am opposed to this APS-proposed adjustment for several reasons. My arguments in opposition to this Company adjustment include:

- While it is not desirable that the Projected Benefit Obligation become significantly " under" *or* "over" funded relative to the current market

value of plan assets, the "underfunded" position at December 31, 2004, is not highly unusual, nor a situation to become particularly alarmed about.

- The "underfunded" position of the Projected Benefit Obligation is, to a large extent, already considered within the determination of net periodic pension cost and test year pension expense included within the development of the retail cost of service. To add an *additional pension amortization* expense amount as proposed by the Company's proforma adjustment could, to some extent, lead to a *doubling up* of the collection of these so-called "underfunded" amounts from ratepayers.
- The Company's stated goal of fully funding the Projected Benefit Obligation is overly conservative and will likely lead to intergenerational inequity between existing and future ratepayers.
- The Company's proposed ratemaking departure from FAS 87 based pension expense is inconsistent with past ACC precedent, previous APS requests, as well the treatment being afforded pension expense in other regulatory jurisdictions that I am familiar with.
- If the Company's proposal were to be adopted, it is unclear whether the additional monies collected from ratepayers would actually be used to increase contributions to the pension trust or whether they could instead be used for other corporate purposes.
- The so-called underfunded position of the Projected Benefit Obligation is attributable to payroll dollars charged to expense as well as capital

activities. Additional intergenerational equity issues arise when current ratepayers are not only asked to fund a so-called funding deficiency on an accelerated basis, but also asked to fund the deficiency associated with payroll dollars that are typically capitalized rather than expensed.

- There is no evidence to suggest that the significant increase in costs that APS proposes to pass on to ratepayers at this time will eventually lead to long term savings for ratepayers.

While I reject, and strongly recommend that this Commission reject, APS' proposal for an accelerated amortization recovery of the alleged "underfunded pension liability," I am nonetheless proposing an upward adjustment to test year actual pension expense to reflect the latest available actuarial pension cost estimate for 2006. I believe the approach I am proposing to develop adjusted test year cost of service pension expense is identical in concept to what the Company proposed in its last rate case – an approach that was accepted by Staff and ultimately considered within the settlement agreement approved by the ACC.

Pension Cost Accounting & Projected Obligations

Q. Before expanding upon the various reasons why you oppose the Company's adjustment, could you please define certain terms that you will be utilizing and briefly discuss how pension expense and pension contributions are established?

1 A. Yes. First, it is important to understand that the pension costs and contributions
2 that I will be discussing pertain to APS' *defined benefit* plan. In recent years,
3 there has been much discussion in the media regarding corporate America's
4 movement away from traditional *defined benefit* plans towards *defined*
5 *contribution* plans – such as 401k or profit sharing plans.
6
7 In this case, APS offers a *defined benefit* plan wherein the Company has
8 committed to providing prescribed pension benefits from the date of an
9 employee's retirement until his or her death. The actual annual payments to, or
10 on behalf of, a retiree are a function of each individual's wages paid during the
11 later years of his or her employment as well as the number of years of service.
12
13 Estimating the retirement benefits a given individual employee will be entitled
14 following retirement involves considering past *actual* historical wages and years
15 of service, as well as estimating future years of service and future pay raises –
16 all of which will also be considered in the calculations to determine actual
17 annual pension benefits ultimately paid to each employee following retirement.
18 Finally, in order to estimate the total amount that will *eventually* be paid to a
19 given employee, one must also estimate the expected life of employees.
20
21 Thus, one step in the process of determining an appropriate level of pension cost
22 is to estimate in *nominal dollars* the total pension payments that will be made to
23 future retirees that considers actual employment history to date, as well as

1 estimated future employment expectations – including years of service and
2 future pay increases that are likely to be granted over the remaining
3 employment period of all employees.
4
5 Q. When discussing the Company's proposed proforma adjustment you stated that
6 as of December 31, 2004 the Company had a total company projected benefit
7 obligation of $1,371 million. Does this projected benefit obligation represent
8 the cumulative estimate of all PWCC employee pension obligations as of
9 December 31, 2004?
10 A. The noted $1,371 million is the *net present value* of expected future pension pay
11 outs that are initially calculated in *nominal* dollars. In other words, the nominal
12 dollars represent the amounts expected to be paid out in future years, including
13 increases in expected benefits resulting from assumed future years of service
14 and future pay raises. Those nominal dollar payments are then discounted to
15 "present day" dollars. Thus, the noted $1,371 million projected benefit
16 obligation effectively represents an estimate of the *eventual* pension obligation
17 of the Company stated in "today's" dollars – or the net present value of future
18 nominal dollar pension obligations.
19
20 Q. Who calculates the projected benefit obligation?
21 A. The Company's actuaries, utilizing the Company's payroll and employee data
22 (age, sex, years of service, historical pay, expected mortality, etc.), calculate the
23 Company's projected benefit obligation.

1 Q. Obviously, the actuaries are dealing with estimates and assumption many years
2 into the future. How do companies following generally accepted accounting
3 principles ("GAAP") determine the amount of pension costs associated with a
4 projected benefit obligation to attribute to and recognize within a given financial
5 reporting period?
6 A. The guidelines for calculating *net periodic pension cost* are set forth within
7 Statement of Financial Accounting Standards No. 87 (hereinafter referred to as
8 "FAS 87"). Pursuant to those guidelines, one component of net periodic
9 pension cost – service cost – consists of the actuarial present value of benefits
10 attributed to, and assumed to be accrued/earned by, employees within the given
11 reporting period. The precise calculation of the attribution/accrual of benefits
12 earned within a given reporting period must consider remaining years of service
13 as well as future pay increases. As I will discuss later, there are other elements
14 that together sum to reported *net periodic pension cost.* However, the starting
15 point in the measurement of total net periodic pension cost is the calculation of
16 the "service cost" described above.
17
18 Q. In your prior answer, you used the term *net periodic pension cost.* Is *net*
19 *periodic pension cost* the same as *pension expense*?
20 A. No. *Net periodic pension cost* calculates the total amount of the cost of pension
21 benefits assumed to have been earned by all employees regardless of their
22 activities during a given financial reporting period. Not all labor activities in a
23 given reporting period are *expensed.* Some labor activities are properly

capitalized to construction projects while other payroll costs are appropriately charged to other balance sheet accounts rather than to income statement *expense* accounts. Thus, *pension expense* refers to that portion of total *net periodic pension cost*, determined pursuant to FAS 87 guidelines, that is attributed to payroll costs incurred within a given reporting period associated with labor activities that are *expensed.* Later when I expand upon all the various reasons why I oppose the Company's proposed amortization adjustment, the importance of the distinction between *net periodic pension cost* and *pension expense* will become evident.

Q. Please expand upon the data that is considered in the development of the Projected Benefit Obligation.

A. As briefly noted, the Projected Benefit Obligation consists of the net present value of expected pay outs of retirement benefits that are initially calculated in nominal dollars, considering past and future years of service and pay increases. To be clear on this point, the Projected Benefit Obligation considers previous, actual pay and years of service *as well as* future pay increases and future years of service by existing employees. Thus, if the current market value of the external pension trust fund gets to a point where it equals or exceeds the Projected Benefit Obligation and actual future experience closely follows the assumptions included in the development of the Projected Benefit Obligation,[27] the Company should be required to recognize only a modest amount of future

[27] Actual returns on plan assets, pay raises, retirement/termination dates, mortality statistics, etc. equal the estimates used in developing the pension benefit obligation.

1 net periodic pension cost related to the existing workforce, even though the
2 existing work force may not have earned or fully "vested" in a significant
3 portion of the Projected Benefit Obligation.
4
5 Q. What "discount rate" do actuaries utilize to calculate the net present value of
6 future pension obligations – obligations that are calculated by considering future
7 pay raises and future years of employment service?
8 A. When estimating the Projected Benefit Obligation, FAS 87 requires that
9 companies employ a discount rate based on a fairly conservative, low risk
10 investment vehicle. Specifically, FAS 87 indicates that it is appropriate to
11 consider an implicit interest rate underlying current annuity contracts or rates of
12 return on high-quality fixed-income investments[28]. The FAS 87 *requirement* to
13 employ a relatively low risk discount rate has had a significant impact on the
14 calculation of the Projected Benefit Obligation in recent years, when interest
15 rates have fallen to levels not experienced for several decades.
16
17 Q. Please further explain how low interest rates in recent years have impacted the
18 calculation of the Projected Benefit Obligation.
19 A. Defined pension benefit plans, such as PWCC has in place, pay out retirement
20 benefits based upon a formula that considers age, years of service and actual
21 wages paid during the final years of employment. Thus, as previously noted,
22 the calculation of the Projected Benefit Obligation includes estimates of future
23 years of service and future pay raises, both of which directly and significantly

[28] Paragraph No. 44 of FAS 87 provides the noted guidance on the appropriate discount rate to employ.

impact the estimate of actual, *nominal dollar,* pay outs that will eventually be made. When future payouts are discounted to present day dollars utilizing a relatively high discount rate, the net present value of those future payouts become relatively low. Conversely, when future payouts are discounted to present day dollars utilizing a relatively low discount rate, as is currently the situation in today's relatively low interest rate environment, the net present value of those future payouts become relatively high. This occurrence is obvious when one views any present value table. For example, the present value of a dollar to be paid out 20 years in the future assuming a discount rate of 6% is approximately 31% -- or 31 cents. The present value of a dollar to be paid out 20 years in the future assuming a discount rate of 9% is approximately 18% -- or 18 cents. Thus, a three percent increase in an assumed discount rate for transactions occurring 20 years down the road reduces the present value of the transactions by over 40 percent.

As everyone is aware, interest rates in recent years have fallen to levels that have not been experienced for decades. The fall in interest rates has dramatically impacted the assumed interest rate the Company has been *required* to use for purposes of discounting the projected pension obligation. Specifically, in calendar year 2001 the Company utilized a discount rate of 7.75% based upon the then-prevailing interest rates being paid on high quality corporate bonds. For calendar year 2005, the discount rate used in the present value calculation had fallen to 5.84%. So significant is the impact of a change

in discount rate assumptions that footnote disclosure of what a one percent (1.0%) change in interest rates would have on the present value of the Projected Benefit Obligation as well as pension expense is provided within the Company's public financials.

Specifically, as reported with PWCC's 2005 annual shareholders report, a one percent (1.0%) increase in the discount rate assumption would decrease the Projected Benefit Obligation and pension expense by $207 million and $8 million, respectively. Conversely, a one percent (1.0%) decrease in the discount rate assumption would increase the Projected Benefit Obligation and pension expense by $237 million and $8 million, respectively. Thus, one can easily observe, holding all other items and assumptions constant, if long term interest rates were simply to increase one percent (1.0%), over half of the $389 million (i.e., before allocation to APS) so-called "unfunded" pension obligation that the Company proposes to amortize and collect in rates over five years would automatically go away.

Q. Is the assumed discount rate the only element affecting the calculation of the relative "over" or "under" funding amount of the Projected Benefit Obligation?

A. No. Whether or not, and the extent to which, the Projected Benefit Obligation may be "over" or "under" funded is also significantly impacted by how well the external pension trust has earned on invested plan assets. Typically defined pension benefit plans will invest plan assets in a diversified portfolio of bonds

1 and equity securities. While history has demonstrated that the returns on these
2 investment vehicles *over the long term* can be expected to be in the high single
3 digit range, for a given year or even for a few consecutive years, the actual
4 returns can be significantly higher or lower (even negative) than the typical
5 high-single-digit return rate that has been achieved historically *over the long*
6 *term.* Thus, the under or over funded status of the Projected Benefit Obligation
7 at a particular point in time can be significantly impacted in the short run by
8 actual returns (or losses) experienced in recent years that are materially different
9 than the rate of plan earnings assumed in actuarial studies.
10
11 Q. Do companies such as PWCC always make contributions to the external
12 pension trust fund in amounts equal to the net periodic pension cost they report
13 pursuant to FAS 87?
14 A. No. Whereas generally accepted accounting principles/financial accounting
15 standards dictate the amount of *net periodic pension cost* and *pension expense*
16 that must be recorded on the Company's financial statement, it is the Employee
17 Retirement Income Security Act of 1974 ("ERISA") and the Internal Revenue
18 Code ("IRC") provisions that dictate minimum and maximum *contributions,*
19 respectively, that must be adhered to so that the retirement plan can meet
20 required standards and remain "qualified." Specifically, it is very desirable that
21 defined pension benefit plans be tax efficient by meeting certain requirements
22 that allow them to be "qualified" plans. With a "qualified" plan, contributions
23 are tax deductible for the employer while the earnings on the external trust are

never taxable to the employer (the distributions to retirees, which actually consist of a combination of employer contributions and earnings on funds invested in the external trust will be taxable to the employee, but the earnings from the trust are never taxable to the employer so long as the plan remains "qualified"). Thus, it is very desirable to make sure a plan remains "qualified" and correspondingly tax efficient. Failure to make minimum funding contributions could lead to the termination of the plan, while making contributions in excess of the maximum allowed can result in the assessment of excise taxes on contributions made above the maximum tax deductible limitation.

Q. Do the ERISA and IRC regulations require use of the same assumptions and calculations for purposes establishing the minimum and maximum tax deductible contributions to the trust as are employed for purposes of calculating net periodic pension costs and the Projected Benefit Obligation under FAS 87?

A. No. While the assumptions might be the same or very close at times, my understanding is that the regulations require that funding calculations be based on assumptions that the actuary believes properly reflects the plan's long-term operations, and that the selection of these assumptions allow some subjective judgment.

Q. How have PWCC's actual contributions, as well as the ERISA minimum and IRC determined maximum contributions, compared to net periodic pension costs recorded over recent years?

A. Table C below shows actual net periodic pension costs, actual contributions, as well as the minimum/maximum contribution range for the years 2001 through 2005:

Table C

Table Contains Data Deemed Confidential by APS

Year	Net Periodic Pension Cost	Actual Contributions to the Trust	Maximum Allowable Contributions	Minimum Required Contribution
2001	[redacted]	[redacted]	[redacted]	[redacted]
2002	[redacted]	[redacted]	[redacted]	[redacted]
2003	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]

Source: RUCO 1.9 and UTI-2-106

Thus, it is easily observed that actual contributions have deviated significantly from the amount of net periodic pension costs recorded for financial statement reporting purposes in recent years. Further, it is noted that the minimum required contribution [redacted]

1 Q. At page 24 of her direct testimony, Company witness Rockenberger indicates
2 that the assets in its pension trust have caused the pension liability to be
3 underfunded at this point in time. Are there other measurements of over or
4 under funding of the external trust beyond comparing the market value of the
5 trust to the Projected Benefit Obligation?
6 A. Yes. Companies also compare the market value of trust fund assets to the
7 Accumulated Benefit Obligation. As the name implies, the Accumulated
8 Benefit Obligation represents the net present value of benefits that have accrued
9 to existing working employees as well as retired employees as of the reporting
10 date. Since this measurement does not consider future years of service and
11 future pay raises that are recognized in the development of the Projected Benefit
12 Obligation, this value will typically be significantly less than the calculated
13 Projected Benefit Obligation.
14
15 Q. How does the Accumulated Benefit Obligation compare to the Projected Benefit
16 Obligation?
17 A. Table D below compares the historical estimates of the Projected Benefit
18 Obligation and the Accumulated Benefit Obligation during the years 2001
19 through 2005. In order to enhance this comparison, the table also sets forth the
20 market value of the pension trust balance during this same time frame, as well
21 as the percentage of the Projected Benefit Obligation and the Accumulated
22 Benefit Obligation funded by the market value of pension trust assets for each
23 year.

Table D

Table Contains Data Deemed Confidential by APS

Year	Market Value of Trust	Projected Benefit Obligation	Accumulated Benefit Obligation	% PBO Funded	% ABO Funded
2001	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2002	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: RUCO 1.9 and UTI-2-106

Several noteworthy observations arise from a review of Table D. First, both the Accumulated Benefit Obligation and the Projected Benefit Obligation were "over funded" in 2001 and 2002, in the sense that the market value of the trust fund assets actually exceeded both the Accumulated Benefit Obligation as well as the Projected Benefit Obligation.

Second, between 2001 and 2003, the trust fund balance actually declined – which is not too surprising when one recalls that overall stock indexes also fell during this time frame. This "under performance" of the return on plan assets during the 2001 - 2003 time frame has undoubtedly contributed to the widening spread between trust fund assets and both the Projected and Accumulated Benefit Obligations.

1 Finally, in the context of my earlier discussion that the Projected Benefit
2 Obligation is significantly influenced by the interest rate utilized to discount
3 future benefit obligations, I noted that the discount rate fell from 7.75% to
4 5.84% between 2001 and 2005. While other relatively minor events have
5 affected the calculation of the Projected and Accumulated Benefit Obligations, I
6 believe the significant increase in each noted obligation has been most affected
7 by the dramatic decline in the assumed discount rate used to calculate the net
8 present values of Projected and Accumulated Benefit Obligations.
9
10 Q. Is the determination of net periodic pension cost impacted over time when the
11 return on plan assets significantly falls short of, or significantly exceeds, the
12 expected or forecasted return on plan assets?
13 A. When the *actual* return significantly exceeds or falls short of the *expected* or
14 *assumed* return on plan assets, FAS 87 provides for a smoothing or levelizing
15 adjustment designed to reduce the volatility in reported net periodic pension
16 cost. Similarly, when the Projected Benefit Obligation significantly exceeds or
17 falls short of the expected Projected Benefit Obligation made in the prior year,
18 FAS 87 also provides for a smoothing or levelizing of such event – again, to
19 reduce volatility in reported net periodic pension cost.
20 Q. Has net periodic pension cost been impacted by either the below-expected
21 returns earned on plan assets in the years 2001 through 2003, or the significant
22 rise in the Projected Benefit Obligation that has resulted from the requirement to

1 discount future obligations utilizing ever lower interest rate assumptions
2 between the years 2001 through 2005?
3 A. Yes.
4
5 Q. Table C above shows that net periodic pension costs have increased from
6 approximately [redacted] in 2001 to amounts ranging between [redacted]
7 million for years 2003 through 2005. Are you stating that the dramatic increase
8 in net periodic pension costs in recent years is attributable, at least in part, to the
9 FAS 87 adjustment made to capture or reflect the under performance of the
10 return on trust assets as well as the significant increase in the Projected Benefit
11 Obligation caused by the requirement to reflect ever-lower interest rates to
12 discount such future obligations?
13 A. Yes. Paragraph Nos. 29 through 32 of FAS 87 require calculations to
14 essentially require recognition of a "catch up" amortization provision as a
15 component of net periodic pension cost whenever actual returns on plan assets
16 or current estimates of the Projected Benefit Obligation deviate substantially
17 from earlier assumptions and projections. For 2005, this "catch up" provision
18 of net periodic pension cost that is amortizing the shortfall from previous
19 projections totals to $19.8 million.
20
21 **Discussion – Bases for Opposition to APS' Proposed Amortization**
22 Q. If that concludes your background discussion on pension cost development and
23 pension funding, let us return to your arguments in opposition to the Company's

1 proposal. Please expand upon your first argument that it is not highly unusual,
2 nor should it be particularly alarming, when one observes that the Projected
3 Benefit Obligation appears to be significantly under funded.

4 A. As I have pointed out in my background discussion, the so-called
5 "underfunded" position of the Projected Benefit Obligation is largely a function
6 of: 1) under performance of return on plan assets for a short period of years,
7 and 2) a significant increase in the calculated Projected Benefit Obligation
8 directly linked to the FAS 87 requirement to utilize the interest rate of a
9 conservative, low risk investment for purposes of discounting the future
10 obligation. I am not necessarily predicting a rise in interest rates, but am merely
11 emphasizing that a return to more "normal" interest rate levels, as would be
12 defined by considering interest rates experienced during the three decades prior
13 to 2000, would dramatically reduce the Projected Benefit Obligation and, in
14 turn, the so-called "underfunded" position. Additionally, while I am certainly
15 not predicting above-average returns on pension plan assets for the next few
16 years, it is also important to realize that a short-term rally in the stock market
17 could result in the realization of above-expected returns on plan assets that
18 would, in turn, narrow the gap between the market value of plan assets and the
19 Projected Benefit Obligation.
20

21 The important point of this discussion is to simply emphasize that the <u>difference</u>
22 between the market value of plan assets and the Projected Benefit Obligation
23 will vary – and vary significantly – over time (see Table D). While the current

1 spread could be considered significant, I do not believe this Commission should
2 necessarily be alarmed by the current spread. Further, even though there may
3 be some concern about this spread, I certainly do not believe the current spread
4 demands the drastic and unprecedented reaction being proposed by APS.
5
6 Q. Please further explain your second point that adoption of the Company's
7 proforma pension amortization adjustment will lead to a "doubling up" of
8 recovery of pension costs.
9 A. As also noted in the background discussion of this issue, when the return on
10 plan assets falls significantly short of previous expectations and/or when the
11 current calculation of the Projected Benefit Obligation significantly exceeds
12 prior projections, FAS 87 provides for a component of net periodic pension cost
13 to include an amortization of significant shortfalls from earlier projections. The
14 2005 total net periodic pension costs was $62,797,000, before allocation to
15 APS' retail operations, which included $19,810,000 attributable to the
16 amortization of the shortfalls from earlier projections of asset return/Projected
17 Benefit Obligation. Thus, nearly a third of net periodic pension cost for 2005
18 consisted of the amortization of the net actuarial loss relating to plan return
19 underperformance and/or growth in the Projected Benefit Obligation stemming
20 from the reduction in the discount rate.
21 To my knowledge, the retail cost of service in all APS rate cases for at least the
22 last two decades have been developed utilizing FAS 87-determined net periodic
23 pension cost and related net pension expense. Thus, whenever retail rates

include FAS 87-determined pension expense, such rates will automatically include the "catch up" or "correcting" amortization impact of the below-or-above-previously-estimated returns on plan assets or the growth/decline in the Projected Benefit Obligation above/below that assumed in prior projections. Consequently, the Company's proposal to amortize a point-in-time so-called underfunding of the Projected Benefit Obligation as an *incremental* above-the-line operating expense effectively duplicates, or *doubles up*, the recovery of such shortfall that is already occurring with the inclusion of the "amortization of the net actuarial loss" as a significant component of net periodic pension costs.

Q. Please elaborate upon your next argument that the Company's stated goal of fully funding the Projected Benefit Obligation is overly conservative and will likely lead to intergenerational inequity between existing and future ratepayers.

A. As noted previously, the Projected Benefit Obligation considers *future* years of employment as well as future pay raises. In my opinion, it would be an ultra conservative target for any company to seek to fully fund a Projected Benefit Obligation that has been estimated by considering future years of service to be provided by employees as well as expected future compensation levels.

Under the Company's proposal, ratepayers would be required to pay the FAS 87-determined pension expense (including the "catch up" amortization of net actuarial losses caused by under performance on returns earned on plan assets plus the increases in the Projected Benefit Obligation caused by discounting the

1 future pension obligation utilizing ever-lower interest rate assumptions) as well
2 as the Company-proposed five-year amortization of the so-called "underfunded"
3 Pension Benefit Obligation. Specifically, under the Company's proposal,
4 Arizona retail ratepayers are being asked to pay total annual pension expense in
5 the approximate amount of $69 million[29]. Barring a long term
6 "underperforming" trend of the plan assets or the Projected Benefit Obligation
7 significantly growing, future ratepayers would likely pay little, if any, pension
8 expense in rates after completion of the five year accelerated cost recovery
9 period. In my opinion, it is both unnecessary and inequitable to design a cost
10 recovery plan that front loads pension costs to existing ratepayers – while future
11 ratepayers will significantly benefit from the services yet to be provided by
12 active employees in future years. In other words, each generation of ratepayers
13 should be responsible for their fair share of APS' cost of providing utility
14 service, including pension and other benefit costs.
15
16 Q. You also argue that the Company's proposal is inconsistent with past ACC
17 precedent, as well as the ratemaking treatment afforded pension expense by
18 other regulatory jurisdictions. Please expand upon this observation.
19 A. At least for the last 20 years in which I have been involved in APS rate
20 proceedings, APS has sought, and this Commission has authorized that rates be
21 established by considering FAS 87-determined pension expense. Further, Data
22 Request No. UTI-2-108 requested APS to provide any research that it may have

[29] Test year actual pension expense of $23,484,000 plus the pension benefits loading included with the APS payroll adjustment of $1,769,000 plus the amortization of the "underfunded" Projected Benefit Obligation of $43,695,000 equals a total pension expense request of $68,948,000.

1 undertaken in support of its proposal to accelerate recovery of the under funded
2 Projected Benefit Obligation over a five-year period. APS' response to the
3 noted request stated, in part:

> 4 APS conducted no such research prior to proposing this
> 5 adjustment. Subsequently, APS requested its outside counsel,
> 6 Snell & Wilmer to conduct a brief review and analysis of
> 7 instances involving pension expenses. APS has not compared
> 8 the factual circumstances in any other proceeding to determine
> 9 their similarity to the Company's situation. [Response to request
> 10 number UTI-2-108 (a)]
> 11

12 In response to UTI-2-108, APS also provided copies of the orders resulting from
13 the noted "brief review and analysis" undertaken by its outside counsel – an
14 undertaking that occurred subsequent to the filing of APS' proposal regarding
15 the issue of pension expense. I have reviewed the noted orders and observe *no*
16 factual situations that appear identical to the Company's request in this docket
17 or any instance where another regulatory commission has adopted such
18 recovery mechanism. Based upon my personal observations in numerous rate
19 cases over approximately 30 years as well as a review of the orders thus far
20 provided by APS, I am not aware of a single instance where a regulatory
21 commission has adopted the amortization proposal presented by APS for the
22 first time in this case.
23

24 Q. You also make an argument that it is unclear whether funds that would be
25 collected from ratepayers on an accelerated basis would be contributed to the
26 pension fund so as to actually reduce the current gap between the market value

of the pension trust fund assets and the Projected Benefit Obligation. Please explain this statement.

A. In response to Data Request No. UTI-2-137, APS was asked, among other things, to:

> Please confirm that, if the Commission adopts Company's accelerated amortization proposal, APS will make an additional annual contribution to the pension fund equal to the amount included in rates (e.g., $44 million) which will be above and beyond the contribution that would have otherwise been made. If this cannot be confirmed, please explain.

The Company's response to this part of the question went as follows:

> The funding decision will depend upon the minimum pension funding requirements and IRS maximum tax deduction limitations. This may or may not require the full $44 million to be contributed to bring the fund to an approximate 100% funded status. APS, of course, is proposing to credit customer with all amounts received as a result of accelerated funding through creation of a regulatory liability to be amortized beginning in 2012.

Based upon this response, it is not clear that APS is actually committing to take all monies being collected from ratepayers and make an additional, incremental contribution to the external trust fund. Based upon a follow up conversation with APS accountants and rate personnel as well as a review of the response to follow up Data Request No. UTI-7-266, my understanding is that APS is committed to funding $44 million *more than it would have otherwise contributed to the pension trust* so long as such calculated contribution amount does not exceed the IRS maximum.

1 Q. Does this verbal commitment, assuming you understand it correctly, quell your
2 concerns as to whether monies collected from ratepayers would actually be used
3 to fund the pension trust?
4 A. No. In the future, I believe it will be impossible to know how much APS might
5 have contributed to the pension trust *absent the amortization of the so-called*
6 *underfunded Projected Pension Obligation.* As demonstrated in Table C above,
7 APS' pension fund contributions have differed significantly from the actuary's
8 calculated net periodic pension costs in recent years. Further, such
9 contributions were always significantly less than the IRS maximum allowed
10 contribution. Thus, I believe it will be impossible to know what APS would
11 have contributed to the pension fund absent the approval of its requested
12 amortization.
13
14 Referring again to Table C, I would also emphasize that APS recorded net
15 periodic pension cost of $[redacted] in 2005 but elected to contribute only [redacted]
16 [redacted] to the pension trust. In the 2003 rate case, the FAS 87-determined net
17 periodic pension cost used to established rates was even higher than the net
18 periodic pension cost recorded in 2005. In my opinion, it would be reasonable
19 and appropriate to expect APS to at least fund the pension trust in the amount
20 being collected within rates before requesting ratepayers to fund an additional
21 liability deficiency on an accelerated basis.
22

1 Q. Please elaborate on your next argument that implementation of the Company's
2 proposal would lead to other intergenerational equity issues inasmuch as some
3 of the "underfunding" is attributable to payroll dollars being "capitalized" as
4 well as "expensed."
5 A. Earlier I explained that the level of *net periodic pension cost* calculated by the
6 Company's actuaries pertain to *total* payroll costs incurred within a given
7 reporting period – regardless of whether such payroll dollars were "expensed"
8 or "capitalized." The amount of *pension expense* recorded within a given
9 reporting period relate to payroll dollars *expensed* during that same given
10 reporting period. Similarly, for ratemaking purposes, only *pension expense*
11 associated payroll dollars *expensed* are included within the test year cost of
12 service.
13
14 The Company proposes to collect in rates a level of amortization expense that
15 would recover a point-in-time calculation of the Projected Benefit Obligation in
16 excess the market value of the pension trust assets. A portion of such difference
17 is attributable to future payroll dollars that will be capitalized. Yet, under the
18 Company's proposal, the unfunded amount would be charged in its entirety to
19 existing ratepayers even though a portion of such costs should be capitalized.
20 This disregard for the fact that a portion of such amount should be capitalized
21 will lead to further intergenerational inequity among ratepayers as current
22 ratepayers will be paying on an accelerated basis "costs" that should be properly

1 capitalized into plant in service where *future* ratepayers would pay a return on
2 and return of (i.e., depreciation) such capitalized costs.
3
4 Q. Turning to your final argument, is the Company claiming that the accelerated
5 recovery of the unfunded Projected Benefit Obligation will ultimately result in
6 savings to ratepayers?
7 A. No. Data Request No. UTI-2-140 asked APS to provide the amount of pension
8 expense savings the Company estimates would be achieved over the next fifteen
9 years if the Company's accelerated pension contribution proposal was adopted
10 by the Commission. However, in response APS simply states that "[w]e have
11 not quantified the amount of pension *expense* savings, if any, over the entire
12 period in your question."
13
14 Q. You have stated numerous reasons for your opposition to the Company's
15 proposed amortization of the unfunded Projected Benefit Obligation. Are you,
16 nonetheless, proposing any adjustment to test year actual recorded pension
17 expense?
18 A. Yes. Based upon preliminary actuary estimates, PWCC/APS began recording a
19 level of pension expense in 2006 that exceeded the amount recorded during the
20 historic test year ending September 30, 2005. While these estimates are not
21 final – they will be trued up later in 2006 – I believe they may provide a better
22 estimate of ongoing pension expense than what was recorded within the test
23 year ending September 2005. Accordingly, Staff Schedule C-6 includes an

allowance for the higher 2006 pension expense. While this "2006 estimate" has been included in Staff's calculation of overall revenue requirement at this point in time, I would recommend that APS be required to provide to the Commission and the Staff the final 2006 actuarial study as soon as such document becomes available so that the "final" calculation can be considered as a basis for establishing pension expense in this proceeding.

POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT (Schedule C-7)

Q. Please discuss your next adjustment to test year operating expense.

A. On Schedule C-7 I post an adjustment to reflect ongoing post-retirement medical benefits ("PRMB") expense based upon the actuarial estimate that APS is relying upon for recording PRMB expense during 2006. The estimate used as a basis for recording PRMB expense in 2006 has been prepared prior to issuance of a final 2006 actuarial report. APS did not propose an adjustment to amortize "underfunded" PRMB expense comparable to that which it proposed regarding pension costs. Nonetheless, for consistency as well as to simply incorporate last known changes for this significant employee benefit, I am proposing a PRMB adjustment calculated identically to that which I am proposing for pension expense.

Q. Please explain the basis for the calculations shown on Schedule C-7.

A. As with pension expense, I first determined an "ongoing" or "normalized" level of PRMB expense by multiplying the monthly PRMB expense recorded during

the first half of 2006 times twelve. From this annualized amount I subtracted 1) test year actual recorded PRMB expense and 2) the incremental PRMB expense amount that APS had calculated and included as part of it payroll annualization adjustment. Again, this adjustment is consistent with the approach I am recommending for pension expense. Further, I believe such approach is superior to the Company's "payroll annualization" methodology inasmuch as there is not always a strong correlation between increased payroll costs and increased PRMB expense which is implicit in the approach utilized by APS to annualize PRMB expense.

ADVERTISING EXPENSE (Schedule C-8)

Q. Has APS proposed a proforma adjustment to test year operating expense for advertising expenses?

A. Yes. Ms. Laura Rockenberger proposes a $6.1 million downward adjustment to test year actual operating expense to remove advertising costs related to Company branding, as set forth in her Attachment LLR-2-16. According to APS workpaper LLR_WP23, the Company's adjustment excludes costs for sports team sponsorships such as the Diamondbacks, Suns and Coyotes, as well as media advertising to promote the Company's brand identity. I concur with APS that such a disallowance of brand advertising is appropriate because these types of expenses are not required in order to provide utility services. On behalf of the ACC Staff, I proposed a comparable adjustment in the last APS rate case

and Ms. Rockenberger's testimony at page 25 states, "This approach is consistent with Staff's recommendation in the Company's prior rate case."

Q. Is there a problem with the quantification of the APS-proposed advertising disallowance?

A. Yes. Through discovery, we learned that certain additional expenses should also be removed that were not captured in the APS-proposed adjustment. These additional expenses include APS Dodge Theatre sponsorship costs, sports suite costs and various other Pinnacle West advertising costs allocated to APS in the test year that are not necessary costs in the provision of utility services. In its responses to Staff Data Requests UTI 1-17 (Revised), UTI 5-239 and UTI 5-240, the Company has conceded that these additional expenses should also be removed from the revenue requirement and that such an additional adjustment will be made in the Company's rebuttal testimony.

Q. Does the Staff adjustment appearing at Schedule C-8 reflect the amounts of additional advertising expense disallowance that APS has conceded should be removed?

A. Yes.

NON-RECURRING OUT-OF-PERIOD SHARED SERVICES EXPENSES (Schedule C-9)

Q. Please continue by explaining your next adjustment to operating expense shown on Schedule C-9.

A. The adjustment reflected on Schedule C-9 is made to eliminate two out-of-period accruals recorded as PWEC administrative and general expense during the historic test year. Inasmuch as this adjustment has been conceded by APS in discovery as a needed adjustment it intends to make in rebuttal, I will not elaborate on the transactions recorded during the test year that now give rise to a need to eliminate such out-of-period expense accruals. I am affixing as Attachment JRD - C two data requests wherein APS 1) acknowledged the need for such adjustments, and 2) further explained the events giving rise to the transactions that were recorded during the historic test year.

LEGAL COSTS INCURRED IN SELLING THE PWEC SILVERHAWK POWER PLANT (Schedule C-10)

Q. Please discuss your next adjustment reducing test year operating expense?

A. Adjustment C-10 eliminates legal expenses incurred by PWEC during the historic test year related to the sale of the Silverhawk Power Plant that occurred in January, 2006. While the sale itself did not occur until after the end of the test year, many costs incurred to facilitate the sale were incurred during the historic test year and charged to PWEC operation and maintenance expense. In the prior APS rate case the parties agreed to, and ultimately this Commission approved, the rate basing of a number of PWEC units located in Arizona. However, the Commission may recall that the Silverhawk Power Plant, owned by PWEC, but located in Nevada, was not acquired to specifically serve APS' retail and firm wholesale load and was not one of the PWEC facilities rate based in the last

1 APS rate case. PWEC/PWCC elected to sell this "non-jurisdictional" plant in
2 the fall of 2005.
3
4 When developing its PWEC O&M expense adjustment, the Company made an
5 estimate of the percentage of costs incurred at the various shared services
6 departments that would have been devoted to owning and operating the
7 Silverhawk Plant during the historic test year. APS then eliminated the
8 estimated percentage of shared services costs attributed to the Silverhawk Plant
9 from PWEC test year operating and maintenance expense. However, it is
10 apparent that at least with regard to the shared services Law Department such
11 "estimation" process understated test year costs directly incurred for the benefit
12 of the Silverhawk Plant. Accordingly, Adjustment C-10 appropriately
13 eliminates the cost of an outside law firm's legal services incurred in the test
14 year that exceeds the APS estimate of costs devoted to Silverhawk Plant
15 Operations.
16
17 Q. Please further explain how your Adjustment C-10 was derived.
18 A. In the historic test year, prior to the transfer of PWEC assets and operations to
19 APS, the shared services Law Department incurred $1,394,011 of costs. When
20 developing its PWEC O&M expense adjustment, APS estimated that 10% of
21 such department's costs – or $139,401 – was attributable to the non-
22 jurisdictional Silverhawk Plant. Accordingly, when piecing together its PWEC
23 O&M expense adjustment APS removed $139,401 of the Law Department's

cost. However, in response to Data Request No. UTI-10-312 APS identified two charges totaling $$289,400 that were specifically attributable to the sale of the Silverhawk Plant. Accordingly, Adjustment C-10 eliminates the costs specifically attributable to the Silverhawk sale that exceeded the original APS estimate of total Silverhawk-related legal expenses in the amount of $139,401. This adjustment can be viewed as very conservative inasmuch as it implicitly assumes that *no* other legal costs incurred during the historic test year were associated with owning and operating the Silverhawk Plant.

SUNDANCE UNITS MAJOR OVERHAUL COSTS (Schedule C-11)

Q. APS has proposed to include within the development of its proposed retail jurisdictional cost of service operations and maintenance expense associated with its recently acquired Sundance Combustion Turbine Units. Are you in agreement with this APS proposed adjustment?

A. Inasmuch as Staff is not opposing retail rate recognition of return, depreciation and expenses associated with these newly acquired units, I have no conceptual disagreement with inclusion of O&M expenses associated with these units in the development the retail cost of service being established in this proceeding. That said, I do take issue with certain estimated Sundance maintenance costs included within APS' adjustment that will not actually be incurred for many years into the future. Accordingly, I am proposing an adjustment reflected on

1 Schedule C-11 wherein I eliminate the costs of major overhaul costs that will
2 not be incurred during the period that I expect these rates to be in effect.
3
4 Q. Please elaborate upon the maintenance activities and costs that you are
5 proposing to exclude because you understand they will not be undertaken and
6 incurred for many years into the future.
7 A. As part of its O&M expense adjustment, APS has proposed to include $2.75
8 million for "non-routine" maintenance expense for the ten recently acquired
9 Sundance units. The "non-routine" maintenance portion of APS' Sundance
10 adjustment was calculated by considering the expected cost of certain major or
11 non-routine maintenance activities, and dividing such projected costs into the
12 expected number of hours of usage between such activities, to arrive at an
13 average non-routine maintenance cost per hour of usage. The calculated
14 average non-routine maintenance cost-per-hour-of-usage was then multiplied
15 times the expected normalized annual usage to arrive at a normalized annual
16 cost level for such non-routine maintenance activities.
17
18 Q. Please elaborate upon the types and timing of non-routine maintenance
19 activities for which the Company's proforma Sundance O&M adjustment is
20 intended to provide.
21 A. The non-routine maintenance adjustment is broken out between "Hot Gas
22 Paths" and "Major" overhauls. The Hot Gas Paths overhauls are scheduled to
23 occur at 18,000 usage hour intervals while the Major overhauls are scheduled to

occur at 36,000 hour intervals. Each machine is predicted to be run *on average* approximately 1,500 hours a year. Accordingly, the average interval between Hot Gas Path overhauls and Major overhauls, assuming average annual hours of usage for each unit, is approximately 12 years and 24 years, respectively (i.e., 18,000/1,500 equals 12 years; 36,000/1,500 equals 24 years). It is the Company's intention to not run each unit equally during the early years of operations so that some units will reach the usage interval for the Hot Gas Path and Major overhaul earlier than other units. In other words, the Company intends to initially unevenly load certain of the ten units so as to begin a staggered overhaul cycle that will avoid a need to overhaul all or most of the ten units at the approximately the same time.

Q. Notwithstanding the predicted initial uneven loading of the ten units, when will the first Sundance Unit undergo the two noted non-routine maintenance activities?

A. It is predicted that the [redacted]. (Response to UTI-10-328) Thus, the Company's proforma adjustment to reflect non-routine maintenance expense begins to capture the cost of events that will not occur for many years into the future. Accordingly, the adjustment shown on Schedule C-11 eliminates that portion of the Company's Sundance Units expense component that will not be expended during the time that these rates will be in effect.

1 Q. Given that these non-routine maintenance activities are related to hours of
2 usage, why is it not appropriate to begin to accrue for the cost of such activities
3 as the units are being run prior to the actual cost incurrence?
4 A. There is some conceptual support for beginning to accrue for costs expected to
5 be incurred in the future that are related to usage being experienced today.
6 However, unless the cost for future expenses being recovered within retail rates
7 today are accrued on the Company's balance sheet for consideration and
8 "return" to ratepayer in future rate proceedings, there is a high probability that
9 ratepayers will be "overcharged" or "double charged" for such non-routine
10 maintenance. APS has indicated in discovery that it has no intentions of
11 accruing on its balance sheet for consideration in future rate proceedings non-
12 routine maintenance costs that – under its proposal – it would collect in rates
13 today. (Response to UTI-11-336)
14
15 Q. Please explain why you believe there is a high probability for an overcharge for
16 such costs unless expenses being recovered in rates today are accrued on the
17 Company's balance sheet.
18 A. In this current rate case, and in the prior rate cases I have been involved in, APS
19 has proposed to normalize maintenance costs for mature generating units by
20 calculating a multi-year historical average of maintenance costs incurred,
21 adjusted for inflation over time, to arrive at an "ongoing" or "normalized" level
22 of maintenance expense. This methodology has the intended effect of
23 smoothing the somewhat volatile and significant costs of major planned

1 overhauls and other non-routine events. In the future, assuming this
2 methodology continues to be employed, presumably when the Sundance Units
3 eventually experience costs for the noted non-routine maintenance activities,
4 such costs will be considered in the multi-year averaging process. *At that point*
5 *in time in a future rate proceeding,* unless regulators remember and are aware
6 that many of the Sundance Units non-routine maintenance expenses have
7 already been recovered from ratepayers through rates that have been developed
8 by considering such costs, I submit that it is very likely that ratepayers will be
9 again be charged for these same costs. I would emphasize that we are
10 discussing rate proceedings that will occur many years in the future.
11
12 Q. If the Commission were inclined to grant – over your recommendation in
13 opposition – the Company's request to begin to recover non-routine
14 maintenance expense for the Sundance Units, do you have any conditions that
15 you would recommend the Commission impose?
16 A. Yes. Very simply, if the Commission were inclined to begin to allow for the
17 recovery of these expenditures that will not be incurred until years in the future,
18 I would recommend that the Commission order the Company to recognize as
19 current period expense monies for non-routine maintenance being collected
20 within rates and concurrently establish a regulatory liability on its balance sheet.
21 When the non-routine maintenance costs are eventually incurred, such costs
22 could then be charged against the deferred liability account rather than being
23 charged to maintenance expense – where they would otherwise be considered in

the development of future rates. Again, this is not my primary recommendation. I believe accruing for and deferring such relatively minor expenses is unnecessary and unduly complicated. Accordingly, I continue to recommend that the non-routine portion of the Company's Sundance Units O&M expense adjustment be rejected in its entirety. The accounting treatment I recommend should only be imposed if the Commission accepts the Company's adjustment and begins to allow for recovery of such costs in current rates.

NON-RECURRING TAX RESEARCH COSTS (Schedule C-12 and Schedule B-3)

Q. Please discuss the need for your next adjustment reflected on Schedule C-12.

A. There are two components to the adjustment reflected on Schedule C-12, both of which are related to non-recurring tax research charges which were recorded during the historic test year. By way of background, APS retained the independent certified public accounting firm of Deloitte and Touche, LLP ("Deloitte") to research whether prior federal income tax returns could be amended so as to be able to claim additional Investment Tax Credits ("ITC") related to properties being constructed in the mid-to-late 1980s. Federal Investment Tax Credits related to construction and acquisition of utility had, prior to 1987, been available to corporate utility taxpayers for a number of years. The Tax Reform Act of 1986 generally eliminated the ITC for tax years beginning 1987 concurrent with implementation of a significantly lower corporate federal income tax rate. While the elimination was generally eliminated post-1986, there existed the ability to claim some amount of ITC

1 related to plant that was under construction, but not yet in service, at the end of
2 1986. In the case of APS, the Palo Verde Nuclear Units, with their very
3 significant capital costs, were still under construction at that time.
4
5 Apparently in recent years APS, or perhaps its outside auditors – Deloitte –
6 came to a conclusion that the ITCs claimed in the late 1980s associated with
7 plant still under construction in the mid-1980s had been conservatively
8 calculated. Or in other words, APS or its auditors came to a determination that
9 it appeared possible that prior year tax returns could be amended so as to claim
10 additional ITC related to plant under construction in the mid-1980s. Originally
11 APS retained Deloitte on a contingency basis whereby Deloitte would only be
12 paid for research undertaken out of "tax savings" realized if and when
13 additional ITCs were claimed. In 2003, prior to the current test year, APS
14 accrued $2,385,468 in anticipation of a payment to be made to Deloitte resulting
15 from expected ITCs to be claimed resulting from Deloitte's tax research. The
16 noted accrual occurred following the prior APS rate case test year (i.e., 2002)
17 and clearly before the start of the current rate case test year that ends on
18 September 30, 2005.
19
20 As the Commission is aware, APS jointly owns a number of generating facilities
21 – including the Palo Verde Units and the Cholla units. Pursuant to operating
22 agreements with joint owners of such production plant, APS is permitted to
23 "load" direct production costs incurred at the jointly owned plants with

administrative and general ("A&G") costs incurred by APS. In 2003, a portion of the A&G costs loaded onto the direct-assigned production costs considered, or included, the accrual for the contingency fee expected to be paid to Deloitte Touche for tax research.

Following an audit of 2003 joint production plant costs that occurred in 2004, the joint owners of production facilities contested the "loading" of A&G costs that consisted, in part, of the Deloitte contingency fee. Ultimately APS conceded that it would not be equitable to indirectly charge the joint owners of production facilities for tax research that would never result in benefits or savings to them. Accordingly, in December 2004, APS "credited" the joint owners for payments made in 2003 related to the Deloitte tax research. The "credit" given to the joint owners in December 2004 related to over billings occurring in 2003 ultimately resulted in the recording of incremental APS production expense during the test year in the amount of $1,224,795. Thus, one component of the adjustment reflected on Schedule C-12 eliminates or reverses the non-recurring credit to joint owners of certain production facilities that was recorded during the test year as additional APS production expense.

As noted, the initial tax research performed by Deloitte Touch was undertaken on a contingency basis. However, at some point that arrangement was renegotiated, and the work continued on a fee-for-service basis. As a result, during the test year APS recorded $1,533,333 of outside services expense for

1 additional tax work undertaken by Deloitte Touch related to the ITC research.
2 Thus, in addition to the reversal of the A&G credit given joint owners of
3 production facilities in December 2004, I propose on Schedule C-12 to
4 eliminate additional non-recurring tax research costs recorded during the
5 historic test year. Thus, the total company adjustment on Schedule C-12
6 eliminates total non-recurring expense of $2,778,128 related to ITC research.
7
8 Q. What was the result of the ITC research issue?
9 A. According to the response to Data Request No. UTI-10-299, a tax refund in the
10 amount of $6,483,389 is expected and "imminent." Thus, for a total outlay of
11 cash resources of $3,918,801 (contingency fee of $2,385,468 recorded in 2003
12 and a fee-for-service charge of $1,533,333 recorded in December 2004), APS is
13 expected to receive $6,483,389 of tax savings – or increased after-tax earnings.
14 Stated in "revenue requirement" terms, APS is receiving approximately $10
15 million of before-tax savings in exchange for incurring $3,918,801 of tax
16 research expense effectively resulting in a before-tax gain from the entire
17 transaction of approximately $6.1 million.
18
19 Q. Are you proposing that APS be allowed to retain the approximate $6.1 million
20 of before-tax savings net of the $3.9 million of costs incurred to achieve the
21 savings?
22 A. I am proposing that APS be allowed to effectively retain half of "net" savings
23 achieved. More specifically, I am proposing that the Company be allowed to

1 retain for its shareholders 50% of the $6.1 million of revenue requirement
2 savings achieved. The remaining 50% I am proposing to credit to ratepayers in
3 the form of a rate base offset.
4
5 Q. Why are you proposing that the Company be allowed to retain for its
6 shareholders one-half of the expected tax savings?
7 A. On the one hand, an argument could be made that 100% of the net savings
8 should be credited to ratepayers. It is generally recognized that regulated
9 monopoly utilities have an obligation to reduce costs whenever possible without
10 jeopardizing safety concerns or quality of service. To that end, a good argument
11 could be made that APS had an obligation to undertake such efforts and return
12 net savings realized to its ratepayers. Further, it is possible that the ITCs being
13 belatedly claimed today are as a result of less-than-diligent tax research efforts
14 undertaken in the mid-to-late 1980s. If this were the case, arguably *all* savings
15 should be passed on to ratepayers today – without consideration of costs
16 incurred to achieve.
17
18 Conversely, if APS had not undertaken the extra efforts and costs to research
19 this issue, it is a near certainty that these tax savings would have been
20 permanently foregone. If 100% of tax savings achieved are passed on to
21 ratepayers in this case, arguably in the future APS would have no incentive to
22 pursue legitimate tax strategies that would only benefit ratepayers. Further, in
23 this particular situation, it is difficult to speculate upon how such ITCs may

1 have been considered in regulatory proceedings had they been claimed and
2 known at a much earlier date.
3
4 Q. Please explain that last comment.
5 A. In APS rate cases occurring prior to 1994, any unamortized ITCs were reflected
6 as a rate base offset. Thus, ratepayers received the benefit of this cost free
7 source of capital within the development of retail rates. While ratepayers
8 received savings in the form of ITCs as a rate base offset, the ITCs claimed
9 were amortized as a "credit" or reduction to income tax expense "below the
10 line." Or in other words, shareholders received the benefit of reduced federal
11 income taxes resulting from the ITCs claim over the life of the facilities that
12 generated the ITCs.
13
14 Pursuant to a 1994 Settlement Agreement, APS agreed to amortize over five
15 years remaining unamortized Investment Tax Credits[30]. It is possible that if
16 these recently claimed ITCs had been known and quantified at the time of the
17 1994 agreement that such ITCs would have simply been lumped in with other
18 unamortized ITCs on APS' balance sheet existing at that time and amortized
19 over the same five year period as other ITCs existing at that time.
20
21 In light of all the uncertainty surrounding how these ITCs might have been
22 recognized in prior regulatory proceedings, the di minimus amount at issue, as
23 well as all the other arguments for and against ratepayer participation in benefits

[30] Response to Data Request No. UTI-8-269

from the transaction, I am recommending that the costs incurred to achieve the ITC saving be deducted from the total revenue requirement benefits expected to be realized. I am proposing that one-half of the remaining benefits or savings resulting from the transaction be used as a rate base offset – as had been the precedent for ITCs prior to 1994. This outcome insures that APS is reimbursed for all out of pocket costs incurred to achieve the ITC savings, and further, that it is allowed to additionally retain some of the benefits realized from the transaction for its shareholders.

Q. Have you prepared an adjustment to capture the rate base offset adjustment you just described?

A. Yes. On Schedule B-3 I reflect the ITC rate base offset adjustment previously described.

INCENTIVE COMPENSATION (Schedule C-13)

Q. What is the purpose of Staff Adjustment C-13?

A. Staff Adjustment C-13 represents a partial disallowance of test period incentive compensation expense. I am proposing to eliminate the costs associated with APS' stock-based incentive compensation, while allowing ratemaking recovery of test period expense associated with the cash-based incentive compensation plans included within the Company's adjusted test year cost of service. After Staff's adjustment, the historic test period will still include approximately $17.8

1 million[31] of "cash" incentive compensation expense (before jurisdictional
2 allocation) – providing APS with a conservatively generous recovery of various
3 non-stock based incentive plan costs that are driven by both financial and
4 operational performance measures.
5
6 Q. Please describe the stock-based incentive program Staff is proposing be
7 disallowed from test period expenses.
8 A. Several types of incentives are provided to executives and directors under
9 certain Long Term Incentive Plans in the form of Pinnacle West common stock,
10 including: Performance Stock Option Awards, Performance Share Awards,
11 Performance Accelerated Stock Option Awards, Stock Ownership Awards and
12 Restricted Stock grants.[32] These awards were granted to APS executives and
13 management team members during the test year, resulting in the incurrence of
14 about $4.8 million of expenses that I am recommending be disallowed.
15
16 Q. What is the purpose of the noted stock based incentives?
17 A. The stated purpose of the Long Term Incentive Plan, as discussed in a March
18 22, 2006-dated PWCC prospectus, is as follows:[33]

19 The Plan's goals are to promote the success and enhance the value
20 of Pinnacle West Capital Corporation (the Company") ***by linking***
21 ***your personal interests to those of our shareholders*** by providing
22 you with an incentive for outstanding performance. The Plan is

[31] Per Company's response to UTI-1-76 (g) total variable incentive compensation expense in the test year was $21,727,033. However, the Company voluntarily eliminated Officers' variable incentive compensation in the amount of $3,895,147, leaving $17,831,886 of remaining cash based test year variable incentive compensation within the Company's proposed test year cost of service that Staff is not objecting to.

[32] See APS responses to Staff Data Request No. UTI-1-83.

[33] See APS response to Staff Data Request No. UTI-1-83, attachment APS09850

> further intended to provide flexibility to the Company to choose among a broad range of awards to create appropriate incentive arrangements that allow the Company to attract, motivate, and retain the services of employees upon whose judgment, interest, and special effort the successful conduct of the Company's operation is largely dependent. (***emphasis added***)

Notably, these incentive compensation programs are driven by the financial performance of Pinnacle West, rather than performance criteria directly linked to customer service, employee safety, cost reductions or utility operational achievements.

Q. Please further describe the mechanics of the cash-based incentive compensation programs that resulted in expenses recorded during the test period that you are *not* proposing to eliminate.

A. In 2004 and 2005, an annual cash bonus Variable Incentive Plan ("VIP") was effective for Pinnacle West and subsidiary company employees that consisted of two primary components: (1) a Company plan and (2) various Business Unit plans. Cash bonuses payable under the VIP were established for different employee groups in a range of specified percentages relative to salary levels or a bonus pool established for particular groups. The following Table E generally summarizes plan parameters for various employee groups that were in effect for 2005, with more complex plan details for some groups simply noted as "complex" where plan terms were not conducive to this summarization:

Table E

	Company Earnings Plan		Business Unit Plan	
	$ Millions	Payout %	Indicators	Payout %
APS Var. Incentive Plan	$250-310	0% - 3%	various	0% - 3%
PVNGS Var. Incentive	$250-310	0% - 1.8%	various	0% -4.3%
Shared Services	$250-310	0% - 3%	various	0% - 3%
Management Incentive	$250-310	0% - 7.5%	various	0% -7.5%
Senior Management	$250-310	0% - 15%	various	0% - 15%
Officer Incentives	$250-310	0% - range	various	Various
Attorney Incentives	$250-310	0% - 7.5%	various	0% - 7.5%
Power Marketing/Trading		Complex	complex	complex
Nuclear Safety Plan		Complex	complex	complex
Nuclear Outage Plan		Complex	complex	complex
Fossil Incentive Plans		Complex	complex	complex

Note: For some groups, after the threshold earnings level of $250 million is met, if total customer satisfaction surveys achieve greater than 44% "very satisfied" an additional one percent is added. Further, if the total customer survey achieves greater than 90% "satisfied and very satisfied" an additional one percent is added, to a maximum payout of five percent.
Source: UTI-1-76

According to the terms of this plan, the funding of the "Company Plan" component of the 2005 VIP is conditioned upon Pinnacle West consolidated earnings reaching the $250 million threshold target level, with amounts payable under this portion of the incentive plan driven by the achievement of earnings above the threshold level. The Business Unit Plan component involved the establishment of Critical Success Indicators tailored to the responsibilities and goals of the individual business units, which are simply noted as "various"[34] on Table E above. Examples of Critical Success Indicators generally include: minimization of recordable injuries, achievement of targeted cost levels,

[34] See APS response to Staff Data Request No. UTI-1-76

1 equipment reliability and availability target achievements, outage
2 minimizations, and various other operational and financial metrics. However,
3 even the Business Unit incentives were not to be funded unless Pinnacle West
4 achieved the threshold earnings levels in calendar year 2005. In effect, the
5 Company's entire cash-based incentive program is primarily driven by Pinnacle
6 West's attainment of the minimum earnings level.
7
8 Q. What amount of incentive compensation expense, for each of the plans and in
9 total, has APS included in its test period revenue requirement?
10 A. APS' proposed test year expense includes approximately $4.8[35] million of
11 stock-based incentive compensation and another $17.8[36] million in cash-based
12 incentive compensation (discussed previously), resulting in total Company "as
13 adjusted" incentive compensation costs of approximately $22.6 million.[37]
14
15 Q. Why are you proposing to allow full recovery of the Company-proposed "as
16 adjusted" cost of the *cash-based* incentive plans, while excluding the cost
17 associated with the *stock-based* incentives expensed in the historic test period?
18 A. Even though corporate earnings also serve as a threshold or precondition to the
19 payout of cash-based incentive compensation, the Company-proposed level of
20 test year cash incentives are tied primarily to performance measures that directly
21 benefit APS consumers. In contrast, the stock-based incentives are entirely

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35 See APS response to Staff Data Request No. UTI-1-87, attachment APS09852
36 See APS response to Staff Data Request No. UTI-12-298.
37 Amounts before allocation to regulated retail operations.

driven by Pinnacle West earnings objectives that, only very indirectly, might benefit consumers.

For example, the targets used to award stock-based incentives under the Performance Shares Plan are based upon Pinnacle West Earnings per Share ("EPS") growth from one year to the next in relation to a comparison group of electric utilities. Comparative EPS growth is not a criteria or element directly considered as a cost component in establishing electric utility rates. In and of itself, efforts to enhance EPS growth may not be consistent with the interests of utility customers or reasonable pricing for the regulated business, where changes in the level of rate base assets and the cost of capital are more directly relevant to earnings achievable by the utility.

Therefore, as a matter of regulatory policy, I believe it is unwise to encourage incentive compensation programs that are entirely or even primarily driven by earnings achievements or total return to shareholders vis-à-vis allowing recovery of such plan costs through regulated utility rates. "Superior," "above authorized," "exceeding peers," or "above targeted" earnings can sometimes be achieved or influenced by short term management decisions that, while temporarily boosting earnings, may not encourage the development of safe and reliable service at the lowest long term achievable costs.

1 For instance, some maintenance may be deferred temporarily – thereby boosting
2 earnings. But deferral of maintenance can lead to safety concerns or higher
3 subsequent "catch-up" costs. Additionally, incentive compensation based on
4 achievement of earnings can lead to exaggerated or aggressive rate filings
5 which, under a best case scenario leads to extra audit and litigation work, and
6 under a worst case scenario leads simply to unnecessarily high utility rates. In
7 short and in sum on this point, rate recovery of incentive compensation that is
8 based entirely upon earnings or stock performance is simply bad regulatory
9 policy. As noted within the quote from the PWCC prospectus, the stated
10 purpose of the Company's stock based incentive compensation plan is to "to
11 promote the success and enhance the value of Pinnacle West Capital
12 Corporation (the Company") ***by linking your personal interests to those of our***
13 ***shareholders*** by providing you with an incentive for outstanding performance."
14
15 Accordingly, I am recommending the full disallowance of the Company's stock
16 based incentive compensation plan that is entirely earnings driven and
17 shareholder aligned while accepting the Company-proposed level of cash based
18 incentive compensation that includes the achievement of goals that are customer
19 oriented toward lowering costs, increasing reliability, or improving customer
20 service and satisfaction.
21
22 Q. Will a "disallowance" of stock based compensation necessarily lead to a cost
23 that must be absorbed by PWCC's shareholders?

1 A. No. The stock based compensation is dependent upon achievement of earnings
2 that may or may not be realized. Thus, if earnings targets are not achieved,
3 awards may not be granted – or perhaps only granted in part. Conversely, if
4 above-targeted earnings are achieved, a good argument could be made that it is
5 shareholders – and not ratepayers – that should pay for such costs inasmuch as it
6 is the shareholders who have primarily benefited from the achievement of the
7 targeted earnings.
8
9 I would also point out that if the threshold earnings established for the cash
10 based incentive compensation are not met, and ultimately little or no cash based
11 incentive compensation is awarded, ratepayers will nonetheless continue to pay
12 within retail rates the test year adjusted level of cash based incentive
13 compensation considered within the development of retail rates being
14 established within this proceeding.
15
16
17 **LOBBYING EXPENSES (Schedule C-15)**
18 Q. Please discuss your next adjustment to test year operating expense.
19 A. The adjustment reflected on Schedule C-15 eliminates test year above-the-line
20 charges for lobbying expense.
21
22 Q. Are lobbying costs generally included within the development of utility
23 companies' cost of service?

1 A. No. I do not know of any regulatory jurisdiction that regularly or even
2 occasionally allows recovery of lobbying costs in rates. Pursuant to the Federal
3 Energy Regulatory Commission's ("FERC") Uniform System of Account
4 ("USOA"), lobbying costs are supposed to be recorded within the "below-the-
5 line" Account No. 426.4 where there is a presumption of non-recovery from
6 ratepayers.
7
8 Q. Please explain your previous answer wherein you state that there is a
9 "presumption of non-recovery from ratepayers" when lobbying costs are
10 properly recorded within Account No. 426.4.
11 A. FERC Account No. 426 has several subcomponents to capture "miscellaneous
12 expense items which are nonoperating in nature." Examples of nonoperating
13 expenses recorded in Account 426 include payments and donations for
14 charitable, social or community welfare purposes; penalties or fines for
15 violation of regulatory statutes – as well as expenditures for the "purpose of
16 influencing public opinion with respect to the election or appointment of public
17 officials, referenda, legislation, or ordinances." While the FERC Uniform
18 System of Accounts does not use the word "lobbying" when discussing charges
19 to be recorded within Account No. 426.4, in my experience the quoted phrase
20 "influencing public opinion" has been routinely interpreted by utility regulators
21 to include all lobbying costs.
22

1 Further, the FERC Uniform System of Accounts instructions for Account No.
2 426 also state, in part:

> 3 The classification of expenses as nonoperating and their
> 4 inclusion in these accounts is for accounting purposes. It does
> 5 not preclude the Commission consideration of proof to the
> 6 contrary for ratemaking or other purposes.
> 7

8 On the income statement, Account No. 426 is located *below the* utility net
9 *operating* income *line*. Typically, only utility *operating* revenues and expenses
10 are considered within a cost of service determination. Non-operating revenues
11 and expenses recorded "below-the-line" are typically *not* included within the
12 development of retail or wholesale rate determinations. Thus, while the FERC
13 USOA *accounting requirement* to record lobbying expenses in below-the-line
14 account 426 are not binding for ratemaking purposes, it has been my
15 observation in the various jurisdictions that I have worked in that there is a
16 presumptive ratemaking disallowance for charges recorded to this below-the-
17 line account.
18
19 Q. Please explain the rationale for disallowing recovery of lobbying costs.
20 A. The potential detriment to ratepayers and other constituents that could occur if
21 utilities were effectively encouraged to lobby vis-à-vis the recovery of lobbying
22 costs within utility rates could be significant. With the unique monopoly
23 powers that utilities enjoy in providing "essential services" within exclusive
24 certificated service territories, the potential for abuse through promotion of
25 unfair or unnecessary legislation is obvious. This statement is not to suggest or

imply that all lobbying efforts of utility companies – funded by their shareholders – are detrimental to ratepayers or other constituents. Indeed, viewed in isolation, enactment of certain specific utility-backed legislation has, no doubt, been beneficial to ratepayers in Arizona. However, it is virtually impossible to know at what "cost" the achievement of even the "pro-consumer" legislation was accomplished.

Q. Did APS record lobbying expenses to Account No. 426.4 during the historic test year?

A. APS recorded some lobbing costs to Account No. 426.4, and those charges were *not* included within its proposed test year cost of service. However, APS charged a number of its lobbying efforts to above-the-line administrative and general expense accounts that it did not adjust for cost of service ratemaking purposes. For reasons stated, I am proposing that all lobbying expenses recorded above-the-line be eliminated from the adjusted test year cost of service. As noted, test year lobbying expenses have been eliminated on Schedule C-15.

Q. Do you have any other recommendations regarding this issue?

A. Yes. APS should be directed to record all lobbying efforts to FERC USOA Account No. 426.4. My understanding is that APS is already required to follow the FERC USOA, and accordingly, arguably this specific directive should not be required. Inasmuch as APS does not appear to be fully following this

accounting guideline, I would recommend that the ACC specifically require APS to record all lobbying costs to Account No. 426.4.

Q. Would a requirement to record lobbying costs below-the-line for accounting purposes be binding for ratemaking purposes?

A. No. APS would be free to request cost of service recognition for lobbying efforts. However, if costs are appropriately recorded below-the-line it would require a specific adjustment to utility operating income to achieve rate recovery of specifically identified lobbying costs. This accounting requirement would ensure that the issue was highlighted for review by rate auditors. Rate auditors are reliant upon proper accounting to assist in the rate review process. Notably, rate auditors rely upon the fact that utilities are properly recording a number of non-recoverable nonoperating expenses – including lobbying costs – within below-the-line Account No. 426.

ISFSI EXPENSE (Schedule C-16)

Q. Please provide your understanding of the Company's proposal regarding recovery of Independent Spent Fuel Storage Installation ("ISFSI") expense.

A. ISFSI is a dry storage facility for spent nuclear fuel constructed at the Company's Palo Verde Generating Station. The fuel pools where the spent nuclear fuel is currently stored will soon reach their maximum capacity. Because the U.S. Department of Energy has been delayed in siting and

constructing permanent spent nuclear fuel storage facilities, the Palo Verde plant is required to construct an interim storage facility where spent nuclear fuel can be stored until DOE-funded permanent storage can be constructed.

The need for the interim storage facilities has been known for a number of years. Pursuant to a 1999 settlement, APS was permitted to defer ISFSI costs within a regulatory asset account for later recovery from ratepayers. In APS' 2003 rate case, the Company sought, and ultimately the ACC approved, recovery of previously deferred ISFSI costs. Additionally, the prior rate settlement provided for recovery of *ongoing* ISFSI cost related to current nuclear fuel burns. The basis for recovery of ISFSI costs previously deferred, as well as "ongoing" ISFSI expense to be included within base rates for current nuclear burns, was a study undertaken by TLG Services, Inc. in February 2002.

In the current case, APS is again posting an ISFSI adjustment. The order from the prior rate case (Decision No. 67744 from Docket No. E-01345A-03-0437) did not become effective until April 1, 2005. Thus, the test year ending September 30, 2005 only reflects one-half of the annual amortization level of deferred ISFSI costs that was approved in the prior docket. Therefore, the Company's ISFSI adjustment in this case, in part, reflects the "annualization" of amortization expense related to recovery of ISFSI deferrals approved in the prior case. However, additionally, the Company proposes to reflect incremental "ongoing" ISFSI expense as well as incremental ISFSI amortization expense resulting from the TLG Services, Inc. study that was updated in 2004. Also, the

prior case settlement only calculated and considered deferrals then expected through June 30, 2004. The Company's proforma ISFSI amortization expense adjustment also considers additional deferrals following the June 30, 2004 cutoff employed in the last case through December 30, 2006 (i.e., the approximate effective date for rates being developed within this proceeding).

Q. Please provide additional detail regarding the recovery of deferred ISFSI costs approved in the prior APS case versus what is being requested by APS in the current case.

A. The Commission may recall that in the last case it issued an order approving APS' request to recover over a five-year period deferred ISFSI cost estimated to be attributable to pre-shutdown activities, while ISFSI cost deferred in prior periods estimated to be attributable to post-shutdown periods were to be recoverable over the license life of Palo Verde Units 1 and 3, and over the term of the sale/leaseback agreement for Unit 2. The estimates for costs attributable to pre- versus post-shutdown activities were derived from a TLG Services, Inc. study issued in 2002. In addition to providing for recovery of ISFSI costs related to previously burned nuclear fuel through reflection of amortization expense, the settlement also provided for recovery of "ongoing" ISFSI costs associated with "ongoing" or normalized nuclear fuel burns.

The 2004 TLG Services, Inc. study not only updated the projected *total* ISFSI costs expected to be incurred, but also provided a new estimated *split* between

1 pre- and post-shutdown activities. There was a fairly significant increase in
2 *total* overall projected ISFSI costs, but also, there was a significant shift in
3 projected ISFSI costs between pre- and post-shutdown activities. Specifically,
4 the 2004 TLG study estimated that the pre-shutdown activities would represent
5 88.3% of total ISFSI costs while the post-shutdown activities would represent
6 11.7% of total ISFSI costs. By comparison, in the 2002 TLG study it was
7 estimated that pre-shutdown activities would be 73.9% of total ISFSI costs
8 while post-shutdown activities would be 26.1% of total ISFSI costs.
9
10 In the current case the Company continues to recommend recovery of deferred
11 ISFSI costs attributable to pre-shutdown activities over five years and recovery
12 of deferred ISFSI costs attributable to post-shutdown activities over the longer
13 life-of-plant/life-of-lease amortization schedule. The Company's adjustment for
14 ISFSI amortization expense in this case is large, in part, because of a fairly
15 significant increase in estimated overall ISFSI costs, but also because of the
16 significant shift in percentages from post- to pre-shutdown activities between
17 the two TLG studies. Stated more succinctly, a part of the increase in ISFSI
18 amortization expense being requested results from the shift in estimated ISFSI
19 from post-shutdown activities that were being amortized on a much longer life-
20 of-plant/life-of-lease amortization schedule to pre-shutdown activities that are
21 being recovered on a much shorter five-year amortization schedule.
22
23 Q. Are you in agreement with this Company adjustment?

1 A. No. While I have accepted the majority of the Company's proposed test year
2 adjustment, certain relatively minor modifications to the Company's proposal
3 are required. The ISFSI adjustment I am sponsoring is found on Schedule C-16.
4
5 Q. Please explain.
6 A. There are three components to my ISFSI adjustment. First, the Company
7 calculated the amount of ISFSI costs that has been or is expected to be deferred
8 between the cut off period considered in the prior case (June 30, 2004) and the
9 end of the historic test year (September 30, 2005). Further, the Company split
10 its deferral estimate into pre- and post-shutdown activities based upon the 2004
11 updated TLG study. The Company's ISFSI adjustment includes a calculation to
12 provide for recovery of ISFSI costs deferred subsequent to the cutoff period
13 utilized in the prior case related to pre-shutdown activities over a five-year
14 period. However, the Company's ISFSI adjustment fails to consider and
15 include any additional amortization expense associated with incremental ISFSI
16 cost related to post-shutdown activities that were also deferred during this same
17 June 30, 2004-through-September 30, 2005 time period. Thus, one element of
18 my proposed adjustment picks up added amortization expense related to deferral
19 of ISFSI costs occurring between June 30, 2004 and September 30, 2005
20 associated with post-shutdown activities.
21
22 Second, in a separate calculation, APS considers expected ISFSI deferrals to be
23 recorded between the end of the historic test year (September 30, 2005) and the

approximate effective date of rates resulting from this proceeding (January 1, 2007). Once again, APS' adjustment includes a five-year amortization for incremental ISFSI costs related to pre-shutdown activities, but it fails to include the amortization for changes in deferral of post-shutdown costs. Because of the updated 2004 TLG study's conclusion that a lower percentage of ISFSI costs will relate to post-shutdown activities, ISFSI post-shutdown costs are actually estimated to decline from previous projections. Or in other words, between the end of the historic test year (September 30, 2005) and the approximate rate effective period (January 1, 2007), APS now expects the post-shutdown deferral balance to decline. Accordingly, consistent with the prior rate settlement and rate order, APS should be required to amortize the *reduction* in the post-shutdown deferral balance expected to occur between September 30, 2005 and January 1, 2006 over a five-year period.

Finally, regarding the "ongoing" ISFSI costs to be collected in rates related to the current burn of nuclear fuel, APS has captured within its adjustment the *increase* in pre-shutdown costs based upon the updated 2004 TLG study, but has ignored the *net decrease* in post-shutdown costs derived from the same updated 2004 TLG study. For ongoing post-shutdown ISFSI costs APS continues to propose to reflect the *higher* estimate derived from the outdated 2002 TLG study. Thus, the third element of my ISFSI adjustment is calculated to reflect the *reduced* ongoing ISFSI costs as estimated within the updated 2004 TLG study.

1 Q. Do you understand why the Company's ISFSI adjustment relies, in part, upon
2 the updated 2004 TLG study, but also ignores portions of the updated estimates
3 included within the 2004 TLG study for other ISFSI components?
4 A. In addition to updating ISFSI costs, the noted 2004 TLG study estimated *overall*
5 Palo Verde decommissioning costs. For reasons I do not fully understand, the
6 Company elected *not* to update its overall decommissioning cost study, but only
7 the ISFSI costs derived from the 2004 TLG study. According to the Company,
8 monies collected for ISFSI post-shutdown activities are being contributed to a
9 qualified external trust. Further, such contributions to the decommissioning
10 trust for post-shutdown activities are tax deductible to APS so long as they
11 remain "qualified" by being collected pursuant to regulatory authority (i.e.,
12 specific ACC authorization). Since APS is not proposing to change retail rates
13 based upon the *overall* updated decommissioning cost estimates included within
14 the 2004 TLG study, APS may believe it is required to continue collecting in
15 rates – and contributing to the decommissioning fund – post-shutdown ISFSI
16 activity costs based upon the 2003 rate case order. Or in other words, there may
17 be a belief by the Company that it needs to continue to making contributions to
18 the trust for post-shutdown ISFSI activities based upon the prior rate case
19 funding levels in order to ensure that the trust remains "qualified" for IRC
20 purposes – and that all contributions to the trust remain tax deductible.
21
22 Q. Does the possible loss of a deduction for contributions to the external
23 decommissioning trust concern you?

1 A. No. I would suggest that APS continue to make contributions to the trust for
2 post-shutdown ISFSI activities based upon the prior rate case findings.
3 However, I would simply suggest that the difference between ongoing post-
4 shutdown ISFSI cost determined to be reasonable in the last case and the
5 ongoing post-shutdown ISFSI cost determined to be reasonable in the current
6 case ($324,000) be recorded as a reduction to the otherwise-calculated ongoing
7 pre-shutdown costs for which there are no IRC funding requirements or other
8 restrictions. In so doing, overall ongoing ISFSI costs will be based upon the
9 latest TLG study even though the *distribution* between pre- and post-shutdown
10 activities will be somewhat different than suggested by the updated TLG study
11 – at least until some future rate case wherein presumably updated TLG studies
12 and rates will again be fully synchronized.
13
14 Q. The adjustments to the Company's ISFSI proposal that you have described are
15 quite detailed and complex. Can you summarize the conceptual exception that
16 you take to the Company's calculation?
17 A. As previously noted, the updated 2004 TLG study predicts an overall increase in
18 ISFSI costs from that projected within the 2002 study. Further, the 2004 study
19 predicts a fairly significant shift in ISFSI expenditures from post-shut down
20 activities that have a relatively long amortization period to pre-shutdown
21 activities that have only a five-year amortization period. In essence, APS' rate
22 case adjustment incorporates the higher overall ISFSI estimate, and the shift to
23 pre-shutdown activities that have the shorter five-year amortization period.

What APS' ISFSI adjustment fails to capture, however, is the reduction in costs attributed to lower post-shut down activities from that estimated in the 2002 TLG study. For the most part, my proposed adjustment simply captures the admittedly-small reduction in costs for post-shutdown activities that were ignored in APS' adjustment. In my opinion, it would be unfair to only reflect in new rates those elements of the updated 2004 TLG study that have risen from previous estimates while ignoring those elements that have actually declined from the earlier estimates.

PROPERTY TAX EXPENSE (Schedule C-17)

Q. Are you proposing any adjustment to APS' proposed level of property tax expense?

A. Yes. On Schedule C-17 I propose to eliminate that portion of APS' proforma property tax adjustment that is calculated to capture a property tax increase anticipated to occur in 2007. More specifically, one element of APS' proposed property tax adjustment is designed to capture the statutory phase-in of increases in property taxes associated with the former PWEC units. While it is probable at this point in time that some increased property tax related to these production facilities will occur pursuant to statute, selective reaching for post test year changes occurring so far beyond the end of the test year will cause a mismatch in cost-of-services revenues, expenses and rate base. Accordingly, I am proposing that that portion of the APS property tax adjustment attributable

to anticipated 2007 phased-production-plant-related increases be eliminated from the test year cost of service.

GENERATION PRODUCTION INCOME TAX DEDUCTION (Schedule C-18)

Q. APS witness Mr. Chris Froggatt has proposed an income tax adjustment to reflect additional tax deductions, along with attendant income tax savings, resulting from the American Jobs Creation Act. Are you in agreement with Mr. Froggatt's calculation and ultimately the adjustment that he posts?

A. I am in agreement with Mr. Froggatt's approach to developing the additional tax deductions that should be generated as a result of passage of the American Jobs Creation Act. That said, Mr. Froggatt undertook his calculation based upon language contained within *proposed* Treasury Regulations that was providing guidance as to the intended application of the American Jobs Creation Act available at the time APS filed its case. Pursuant to those *proposed* Treasury Regulations, the additional production function deductions were not expected to be available for the operations of generating facilities that were less than 50% owned by a given utility taxpayer. APS owns less than 50% interest in a number of generating units. In fact, APS owns less than 50% interest in the majority of its generation investment. Thus, the noted ownership requirement significantly limited the incremental production deduction that would otherwise be available under the recently passed tax act. Accordingly, relying upon the *proposed* Treasury Regulations, APS calculated that it would only receive approximately

30% of the production deduction it otherwise would receive absent the 50% ownership requirement.

Subsequent to the time that the Company prepared its direct testimony, final Treasury Regulations regarding the American Jobs Creation Act have been issued. The original 50% ownership requirement included within the proposed Treasury Regulations was *not* included within the final Treasury Regulations. Accordingly, it is appropriate to recalculate the additional production deductions that should be available based upon *all* of APS' ownership of generation facilities. It is my understanding that APS fully agrees with the propriety of such a recalculation.

Q. Are there any other revisions required to the APS calculation of additional production function deductions?

A. The additional production deductions are a function of production income. When calculating the new production function deductions resulting from the American Jobs Creation Act, APS started with an assumption that it would receive the overall and common equity return that it is requesting in this case. Since Staff is recommending a lower equity and overall return than APS is requesting, it is necessary to revise the original APS calculation so that it is properly synchronized with the return that Staff is recommending.

Also, the additional production function deductions are being phased in over the period 2005 through 2010. For 2005 and 2006 the deduction starts at three percent of qualified production activities income. For 2007 through 2009 the deduction rises to six percent, and for 2010 and later years the deduction rises to nine percent. APS prepared its production tax credit adjustment by considering the 2007-2009 deduction percentage of six percent. Because Staff is generally recommending that cost of service component quantifications be limited to only a few significant components occurring through 2006, I am proposing to reflect the production tax credit with the 2006 three percent limitation.

Q. Does Schedule C-18 reflect the calculations and adjustment necessary to 1) remove the impact of the 50% ownership requirement, 2) synchronize the computations to reflect Staff's proposed overall and common equity return, and 3) reflect the three percent deduction limitation in effect for 2006?

A. Yes. I would again emphasize that I am in conceptual agreement with the Company's approach to calculating savings stemming from the recently enacted American Jobs Creation Act. The changes I have undertaken are only to consider the impact of the final Treasury Regulations that were not available to APS when it filed its case *and* to synchronize the calculation for Staff's proposed return recommendation.

INTEREST SYNCHRONIZATION (Schedule C-19)

Q. Please discuss your next adjustment to APS' proforma level of income tax expense.

A. The adjustment shown on Schedule C-19 is undertaken to synchronize the interest deduction for consideration in the development of Staff's cost of service income tax expense with the jurisdictional rate base and weighted cost of debt being proposed or recommended by various Staff witnesses. This adjustment, which is routinely calculated and adopted by regulatory commissions in utility rate cases, is derived by multiplying Staff's proposed retail jurisdictional rate base times the weighed cost of debt included within Staff's development of the overall cost of capital. To the extent this Commission may adopt a different rate base or cost of capital than that being proposed by the Utilities Division Staff, it would be appropriate to revise this calculation or adjustment for the return and rate base found reasonable by the ACC

FEDERAL AND STATE INCOME TAX EXPENSE (Schedule C-20)

Q. Please discuss your final adjustment to APS' proposed level of income tax expense.

A. I would describe the adjustment found on Schedule C-20 as a *correcting* calculation to the APS-proposed level of cost of service income tax expense. By way of background, most accountants can agree to the appropriate

1 *conceptual* development of cost-of-service allowable income tax expense[38].
2 However, the mathematical or mechanical calculation of an appropriate test year
3 income tax expense adjustment can become quite complicated – particularly
4 when addressing an historic test year that spans two calendar years that may
5 each include unique or non-recurring tax accrual entries.
6
7 I requested in discovery what is commonly referred to as a "top down" cost-of-
8 service income tax expense calculation that is designed to determine whether,
9 after considering all tax-related as well as non-tax adjustments, income tax
10 expense included within the "as adjusted" cost of service is properly
11 synchronized with the "as adjusted" utility operating income as well as an
12 ongoing level of other permanent book and tax differences. As a result of a
13 series of discussions and exchanges of data with the Company, I am of the
14 opinion that a problem exists in the Company's development of its proposed "as
15 adjusted" test year cost of service income tax expense – though no specific error
16 in the Company's calculation or logic has thus far been identified.
17
18 Q. If you were unable to determine the specific problem in the Company's
19 calculation, how then are you able to propose the "correcting" adjustment on
20 Schedule C-20?

[38] There can be conceptual differences in cost of service determination of income tax expense regarding *normalization* versus *flow through* accounting, the appropriate composite federal or state income tax rate, or the appropriate turnaround amortization period for previously deferred items. Once those conceptual differences are agreed upon, the cost of service income tax expense calculation should become mathematical or mechanical in nature.

1 A. I am proposing an adjustment based upon a "top down" calculation that utilized
2 estimated 2006 permanent book/tax differences and other income tax credits.
3 Through discussions with APS rate, accounting and tax personnel, I am of the
4 opinion that the Company agrees with this approach as well as the amounts I
5 have used to calculate the adjustment on Schedule C-20. In other words, I
6 believe it is a moot point that no specific "error" was found regarding the series
7 of calculations that APS undertook to arrive at its initial cost-of-service income
8 tax adjustment.
9
10 A. Yes.
11 Q. Does that conclude your direct testimony?
12 A. Yes, it does.

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	AMOUNT	REVENUE LAG DAYS	EXPENSE LAG DAYS	NET LAG DAYS	CWC FACTOR	WORKING CAPITAL REQUIREMENT
		(1)	(2)	(3)	(4)	(5)	(6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	200,856,342	36.95027	32.36664	4.58363	0.01256	2,522,756
3	NATURAL GAS	237,557,927	36.95027	44.25857	-7.30830	-0.02002	(4,755,910)
4	FUEL OIL	1,077,082	36.95027	32.34060	4.60967	0.01263	13,604
5	NUCLEAR:						
6	AMORTIZATION	34,445,413	36.95027	0.00000	36.95027	0.10123	3,486,909
7	SPENT FUEL	7,336,099	36.95027	76.35359	-39.40333	-0.10795	(791,932)
8	TOTAL NUCLEAR FUEL	41,781,512					2,694,977
9							
10	TOTAL FUEL	481,272,863					475,427
11							
12	PURCHASED POWER	1,313,764,296	36.95027	38.15020	-1.19994	-0.00329	(4,322,285)
13	TRANSMISSION BY OTHERS	14,391,245	36.95027	33.69389	3.25638	0.00892	128,370
14	TOTAL PURCHASED POWER & TRANSMISSION	1,328,155,540					(4,193,915)
15							
16	TOTAL FUEL AND PURCHASED POWER	1,809,428,404					(3,718,488)
17							
18	OTHER OPERATIONS & MAINTENANCE:						
19	PAYROLL	240,714,447	36.95027	15.00192	21.94835	0.06013	14,474,160
20	INCENTIVE	8,653,091	36.95027	214.50000	-177.54973	-0.48644	(4,209,209)
21	PENSION AND OPEB	38,986,000	36.95027	77.71371	-40.76344	-0.11168	(4,353,956)
22	EMPLOYEE BENEFITS	26,995,515	36.95027	20.35895	16.59132	0.04546	1,227,216
23	PAYROLL TAXES	18,118,131	36.95027	21.78589	15.16438	0.04155	752,808
24	MATERIALS & SUPPLIES	53,466,114	36.95027	24.22000	12.73027	0.03488	1,864,898
25	FRANCHISE PAYMENTS	11,986,402	36.95027	52.83966	-15.88940	-0.04353	(521,768)
26	VEHICLE LEASE PAYMENTS	3,169,771	36.95027	7.43789	29.51238	0.08086	256,308
27	RENTS	6,776,038	36.95027	-33.48601	70.43627	0.19298	1,307,640
28	PALO VERDE LEASE	45,900,681	36.95027	47.31849	-10.36823	-0.02841	(1,304,038)
29	PALO VERDE S/L GAIN AMORT	(4,575,722)	36.95027	0.00000	36.95027	0.10123	(463,200)
30	INSURANCE	4,639,562	36.95027	0.00000	36.95027	0.10123	469,663
31	OTHER	119,131,971	36.95027	35.39000	1.56027	0.00427	508,694
32	TOTAL	573,962,000					10,009,216
33							
34	DEPRECIATION & AMORTIZATION	321,525,565	36.95027	0.00000	36.95027	0.10123	32,548,033
35	AMORT OF ELECTRIC PLT ACQ ADJ	0	36.95027	0.00000	36.95027	0.10123	0
36	AMORT OF PROP LOSSES & REG STUDY COSTS	(2,564,492)	36.95027	0.00000	36.95027	0.10123	(259,604)
37	TOTAL	318,961,073					32,288,429
38							
39	INCOME TAXES:						
40	CURRENT:						
41	FEDERAL	59,824,326	36.95027	58.95000	-21.99973	-0.06027	(3,605,612)
42	STATE	16,379,288	36.95027	58.95000	-21.99973	-0.06027	(987,180)
43	DEFERRED	77,758,889	36.95027	0.00000	36.95027	0.10123	7,871,532
44	TOTAL	153,962,503					3,278,740
45							
46	OTHER TAXES:						
47	PROPERTY TAXES	123,403,653	36.95027	211.94223	-174.99196	-0.47943	(59,163,413)
48	SALES TAXES	158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,193,857)
49	FRANCHISE TAXES	18,920,381	16.69615	52.83966	-36.14352	-0.09902	(1,873,496)
50	TOTAL OTHER TAXES	300,564,589					(71,230,766)
51							
52	TOTAL	3,156,878,568					(29,372,869)

Mountain States Telephone and Telegraph Company
[Decision 53849; Page 18; Docket No. E-1051-83-035; December 22, 1983]

Needless to say, the primary discrepancy between Staff and Mountain States came in the area of cash working capital. **Both parties utilized a modified "formula" method.** The Commission has on several occasions indicated the numerous problems associated with the "formula" method of determining cash working capital. See Decision Nos. 53174 (August 11, 1982), 53612 (June 15, 1983), and 53665 (July 27, 1983). **Mountain States should consider itself forewarned that no allowance for cash working capital will henceforth be permitted to Mountain States unless supported by a valid "lead-lag" study.**

In the instant matter, the Commission is bound by the record at hand. Staff and Mountain States agreed that the usual "formula" had to be modified by an allowance for the fact that Mountain States receives local service revenues in advance of rendering local service, a situation contrary to that prevailing with other types of public service corporation. Staff further adjusted the "formula" to reflect the greatly deferred payment schedule for various state and federal taxes as well as the **lag in interest payments**. Mountain States opposed both adjustments, contending that Staff was "double-dipping" since an allowance had already been made for prepaid revenue. We disagree. There is no double counting since the pre-payment of revenue and the deferral of expense are two (2) separate items. Simply because both indicate a lower cash working capital requirement does not make out a case for "double-dipping."

In Decision No. 53761, the Commission, after considerable debate by the parties therein, concluded that interest was not a proper deduction in a "lead-lag" calculation of cash working capital. Upon further analysis, we are now convinced that Decision No. 53761 was in error in that determination. To the extent that the interest payment lag contributes to the common equity return, it is subsumed in our market derived cost of common equity. Although interest is a non-operating expense, we find that this is not dispositive. **Accrued but unpaid interest represents a consumer supplied source of cash working capital and should properly be treated as such.** Any remaining difference between the Commission's determination of a reasonable allowance for cash working capital and that of Mountain States is attributable to the different level of operating and interest expense utilized in the "formula" as modified herein.
[Emphasis Added]

Mountain States Telephone and Telegraph Company
[Decision 54843; Page 27; Docket No. E-1051-84-100 et al.; January 10, 1986]

We are in no such quandary when it comes to cash working capital. **The Commission has repeatedly rejected the inclusion of non-cash items such as deferred taxes and depreciation in cash working capital. Moreover, Staff erred in its exclusion of interest expense from the calculation of cash working capital. The Commission has admittedly taken conflicting positions on this issue in previous Decisions. However, in Decision No. 53849, the Commission finally concluded that the classification of interest expense as a non-operating expense did not preclude its inclusion in a cash working capital "lead/lag" study.** Intervenor Phoenix has utilized its calculation of pro forma interest expense (derived through "interest synchronization") to reduce recommended cash working capital to a negative figure. See Phoenix Exhibit No. 2. **The concept of negative cash working capital was expressly approved by the Commission in Decision No. 53761.**
[Emphasis Added]

Arizona Public Service
[Decision 55931; Page 66; Docket Nos. U-1345-86-062, U-1345-85-367; April 1, 1988]
6. Cash Working Capital

As previously mentioned, APS performed a lead/lag study of its cash working capital requirements. Although this study showed a requirement of $34,706,000, APS made no adjustment to include cash working capital in rate base. Thus, its proposed requirement is zero. APS witness Post testified that APS made this proposal to be consistent with Decision No. 55228 which held cash working capital at zero (in the absence of a lead/lag study), to minimize any Palo Verde rate increase, and to reduce the number of issues to be addressed in this case. (Ex. A-27 at 36.) Both FEA witness Miller and Staff witness Brosch recommended a negative cash working capital.

The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. **We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital**. E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.
[Emphasis Added]

Citizens Utilities Company
[Decision 56807; Page 41; Docket No. U-1954-88-102 et al.; February 1990]
8. Cash Working Capital

Citizens did not include any cash working capital allowance in its OCRB and opposed the use of a lead/lag study.

...

With respect to the cost and benefits of a lead/lag study, the annualized intrastate cost of Citizens' study which will be reflected in rates is $5,095. On the other hand, as a result of Citizens' study and the Staff and RUCO adjustments, our cash working capital determination is a negative $593,514, rather than zero (which was used in Citizens' last rate case, in the absence of a lead/lag study). This rate base adjustment represents approximately $97,500 in gross annual revenues. Thus, although for a company of Citizens' size, the benefit of a lead/lag study is not substantial, the benefit does outweigh the cost. Further, Citizens is a rapidly growing company and, with experience, the cost of preparing a lead/lag study should decline, if only because not all of the lead/lag days need to be recomputed for every study.

In Decision No. 55493, we discussed the benefits of a case-by-case approach to lead/lag studies. Citizens has not presented herein any new arguments or information which would warrant abandonment of that approach in favor of the use of a zero cash working capital requirement for Citizens (and presumably all of the larger utilities) pending completion of unnecessary and counter-productive rule making proceedings.

In summary, we agree with Staff and RUCO on the use of a lead/lag study in this proceeding and will not change our previous order requiring Citizens to prepare and include the results of a lead/lag study in its general rate applications. Further, our cash working capital adjustment to Citizens' OCRB reflects Staff's intrastate approach, **adjusted to reflect any differences in revenues and expenses** as determined hereinabove and inclusion of rate case

expense, the RUCO adjustments to the revenue and expense lags and the minimum bank and working funds balances, **and inclusion of interest expense based on our determination of Citizens' OCRB and embedded cost of debt.**
[Emphasis Added]

Southwest Gas Corporation
[Decision 57075; Page 45; Docket No. U-1551-89-102, et al.; August 31, 1990]
B. CASH WORKING CAPITAL
1. Non-Cash Items

Applicant, Staff, and RUCO relied upon lead/lag studies to calculate the cash component of the working capital allowance for the Central and Southern divisions. **The primary difference between the studies involves the treatment accorded non-cash expense items and interest expense. Staff excluded from its calculation those expenses which do not require current period cash payments, i.e., depreciation expense, deferred income tax expense, and return on equity capital, and included interest expense to capture its working capital effect although it is classified as a non-operating expense.** RUCO agrees that the non-cash items should be excluded.

Applicant contests the exclusion, but the opposition need not detain us. The Commission has repeatedly held that the determination of the cash working capital requirement does not properly encompass non-cash items. The Commission has also found that accrued but unpaid interest, as a customer-supplied source of cash working capital, is a proper deduction in the lead/lag calculation. See, e.g., Mountain States Telephone and Telegraph Company, Decision Nos. 53849 (December 22, 1983) and 54843 (January 10, 1986); APS, Decision No. 55931 (April 1, 1988); and TEP, Decision No. 55659 (October 24, 1989). Applicant has presented no arguments which persuade us to depart from this precedent.

2. Other Methodological Issues

Applicant maintains that the lead/lag methodology followed by Staff to determine cash working capital erroneously used adjusted income statement amounts rather than unadjusted test year values. As Staff witness Brosch explained, consistency requires that the income statement amounts used for purposes of the lead/lag study be synchronized with the adjusted amounts used elsewhere in the revenue requirement calculation. RUCO also used adjusted amounts in its lead/lag study.

...

For the reasons articulated by Mr. Brosch, the Commission will adopt the lead/lag methodology Staff followed.

3. Cash Working Capital Summary

For the Central division, the foregoing adjustments adopted by the Commission will reduce Applicant's proposed cash working capital by approximately $9.1 million and result in a negative component of approximately $3.9 million.

For the Southern division, the adjustments reduce Applicant's figure by approximately $3.9 million and produce a negative cash working capital component of approximately $2.2 million.
[Emphasis Added]

Southern Union Gas
[Decision 57396; Page 12; Docket No. U-1240-90-051; May 24, 1991]
A. Cash Working Capital

...

2. RUCO Adjustment

In its post-hearing briefs and in late-filed Ex. RUCO-9, RUCO refers to a $161,262 reduction to cash working capital as being an adjustment remaining in dispute. According to Ex. RUCO-2, pg. 15, this "working cash adjustment reflects [Commission] precedent because it results mainly from including the lag effect of long term-bond interest, as required by the Commission in [Southwest] and previous decisions." However, **Staff's working capital adjustment, as accepted by Southern Union, already recognizes the interest on long-term debt**. RUCO has provided no explanation of whether or how its adjustment differs from that sponsored by Staff. The Commission will, therefore, reject RUCO's adjustment because it lacks foundation.
[Emphasis Added]

Southwest Gas Corporation
[Decision 57745; Page 19; Docket No. U-1551-90-322; February 28, 1992]
I. Cash Working Capital

In its initial filing in this case, the Company asserted a zero working capital request. Both RUCO and Staff responded by filing lead/lag studies. The Commission in Decision No. 57075 had relied upon such studies to calculate the working allowance for the Company's Central and Southern divisions and determined both were in excess of a negative $4 million. In this case, Staff and RUCO calculated the cash working capital to be a negative $3,734,000 and a negative $2,408,652, respectively.

As in the previous case, Applicant was critical of Staff and RUCO's cash working capital because it did not take into consideration certain "non-cash" items such as depreciation. **As we stated in Decision No. 57075 as well as other Decisions cited therein, the calculation is for "cash working capital" and not "cash and non-cash working capital".** Similarly, as we stated in Decision No. 57075, "Applicant has presented no arguments which persuade us to depart from this precedent." Since Staff simply updated the cash working capital amount approach in Decision No. 57075, we will approve Staff's recommended cash working capital. As a result of criticism by the Company regarding Staff's adjustments to prepayments, Staff revised its calculations and reduced its negative cash working capital to $3,680,000.
[Emphasis Added]

Southwest Gas Corporation
[Decision 58377; Page 12; Docket No. U-1551-92-253; August 13, 1993]
Working Capital

Based on its lead/lag study, the Company determined its cash working capital requirement was ($2,513,921). This amount was then offset by $2,339,698 of prepayments and $1,761,907 for materials and supplies to arrive at the Company's proposed working capital of $1,587,684. Staff proposed a reduction to the Company's cash working capital in the amount of $1,521,237 and a reduction to prepayments in the amount of $433,183. RUCO proposed a reduction in cash working capital in the amount of $268,324 and a reduction to prepayments in the amount of $883,412.

Staff was critical of the Company for using unadjusted test year values in the Company's lead/lag study in calculating cash working capital. Accordingly, Staff modified the study to include adjusted TY amounts. Staff was also critical of the Company for assigning zero lag to items amortized into expenses. According to Staff, such treatment is inappropriate because it nets a cash item with a non-cash item. Included in the Company's proposed cash working capital were the average cash balances related to working funds, petty

cash, and cash held by depository banks. Both RUCO and Staff eliminated these average cash balances from the cash working capital requirements. Staff indicated that the cash balances are funds provided by ratepayers while RUCO indicated inclusion of cash balances was not consistent with the use of lead/lag study. In response, the Company indicated the cash balances did represent stockholder funds in providing service to ratepayers. In addition, the Company indicated similar balances had been included in the Company's last five Arizona rate cases.

We generally concur with Staff's modification of the Company's lead/lag study. However, we concur with the Company that a reasonable amount of cash-on-hand is appropriate. There has been no evidence presented to demonstrate that the Company's average cash balances are unreasonable. Accordingly, we will reject Staff and RUCO's proposed $227,616 removal of the Company's average cash balances. Based on all the above, we find the Company's proposed cash working capital should be reduced by $1,293,621 with a result of ($3,807,542). ...
[Emphasis Added]

Tucson Electric Power Company
[Decision 58497; Page 26; Docket No. U-1933-93-006 et al.; January 13, 1994]
M. Cash Working Capital

TEP proposed a negative cash working capital ("CWC") in the amount of $16,389,000. Staff, RUCO, and JSA all proposed adjustments to the Company's requested CWC.

JSA recommended that if TEP is allowed to retain the net cash proceeds from its settlement agreement with Southern California Edison Company ("SCE") then TEP's CWC should be reduced by a like amount. According to JSA, this treatment should continue until ratepayers receive $27.6 million of refunds.

In response, the Company indicated this is a "non-current" cash transaction and as such should not be included as part of CWC.

We concur with the Company. As will be more fully discussed later, the Company's shareholders bore the risk and cost of pursuing the SCE litigation and should receive 100 percent of the cash benefits.

The MSR Option gain is being amortized as a credit to retail revenues. The unamortized balance of the revenues is not included as a rate base deduction since the gain was increased to allow for an implicit carrying charge to compensate for the time value of money. According to RUCO, the amortization is a non-cash transaction which is excluded from rate base. As a result, RUCO concluded that TEP's attributing $1.9 million of cash working capital to the MSR revenue was wrong and should be adjusted to zero.

In response, **the Company indicated it has excluded all "non-current" cash transactions. As a result, the Company excluded the MSR revenue credit as well as a number of "non-cash" expense debits.** According to the Company, the debits and credits should be treated consistently. We concur with the Company.

...

TEP deposits funds in a special account to match anticipated medical payments on claims in process. Once notified that payment is due on claims, the Company records the medical expense and reduces the balance in the special account. There were, on average, 19.3 days from the time funds are deposited in the special account until the Company is notified that payment is due on claims. The Company included the 19.3 days as part of its payment lag period of 66.62 days.

Staff deducted the 19.3 days from the payment lag period. According to Staff, the expense is incurred at the time medical services are provided and that is the date from which to measure the payment lag.

In response, the Company indicated that Staff was erroneously assuming that the ratepayers were providing cost free funding of medical expenses. TEP asserted it is Company funds that are being used to fund the medical expenses. As a result, TEP requested Staff's adjustment be denied.

We concur with Staff. The proper payment lag time should be measured from the date the expense is incurred.

Staff proposed to measure the expense lag used in the CWC study from the date an expense is incurred by the Company. The Company objected to Staff's approach and argued the expense lag should be based on the date the cost of service is recorded. Although TEP disputed Staff's concept, the Company indicated it could agree as long as Staff utilized the same concept for both revenue recovery and expense payment lags.

In response, Staff indicated that the revenue lag is not necessarily affected by the expense lag. According to Staff, the revenue lag is measured from the date service is provided to the customer. We concur with Staff.
[Emphasis Added]

Citizens Utilities Company
[Decision 60172; Page 19; Docket No. E-1032-95-417 et al.; May 7, 1997]
E. Cash Working Capital

Both Staff and RUCO proposed adjustments to the Company's cash working capital, a number of which were accepted by the Company, including adjustments to expense lead or lag days with salaries and wages, pumping power expense, administrative office expense, insurance, injuries and damages expense, and other taxes. **The Company also accepted inclusion of interest expense in the lead lag study at a 90-day lag** and also removed preliminary survey and investigation ("PS&I) charges from the working capital balance. Staff and RUCO agree that the revenue lag should be reduced by one day to reflect the Company's new lock box program which will allow customers to pay their bills through the bank rather than remitting them directly to the Company. Staff and the Company have agreed to certain increases to expense lags to reflect check clearing lags and have revised the pension lag expense to reflect an actual contribution made by Citizens to the pension trust. We will adopt those adjustments. RUCO recommends that, consistent with past Commission decisions, including Decisions Nos. 58360 and 58664, the Commission should exclude $83,354 in rate case and deferred TARGET: Excellence expenses from the cash working capital component. We agree with RUCO.

Staff and RUCO proposed that cash balances should be removed from the determination of cash working capital. RUCO notes that these two asset items have never been included in the calculation of cash working capital in any prior Commission decision. Staff notes that with the exception of only Sun City Sewer, there is a negative cash working capital requirement and to include a cash balance in the cash working capital requirement for these companies would grant them a return on cash when they have no cash requirement. We agree with Staff and RUCO's adjustment to remove cash balances.

We note that RUCO believes that the Company's sampling method for determining the lag for the O&M, administrative and general expense category analyzed too few invoices and does not capture the various types of expenses contained in the category. While we will not adopt RUCO's adjustment in this proceeding, we expect the Company to address the issues raised by RUCO in its next lead/lag study.
[Emphasis Added]

Utilitech, Inc.'s Second Set of Data Requests
To Arizona Public Service Company
Docket No. E-01345A-05-0816
April 24, 2006

UTI-2-100 Reference page 12 of Ms. Laura Rockenberger's direct testimony. Please provide actual PWEC A&G expenses by month for the period January 2002 through the transfer date of PWEC assets that would be comparable in composition to those considered in the development of the $20,415,000 proforma adjustment.

Response:

Note: Discussion regarding A& G components of Operating Income Pro forma is discussed at page 15 of Ms. Rockenbergers direct testimony.

Schedules of PWEC A&G expenses by month for the period January 2002 through the transfer date (July 29, 2005) of PWEC assets is attached as APS09887.

APS will be submitting a pro forma adjustment for $5,098,000 to remove out-of-period costs included in the test year with its Rebuttal testimony. See the attaché schedule of PWEC A&G expense for more information

Witness: Laura Rockenberger

Data Request
UTI 2-100
PWEC A & G Expenses by Month
January 2002 - July 2005

	2002	2003	2004	2005
January	210,678	672,542	6,910	2,457,139
February	156,533	359,476	701,426	(482,760)
March	(45,188)	215,082	750,715	2,015,992
April	170,348	382,009	662,193	869,667
May	49,358	773,148	802,273	1,559,300
June	225,285	505,151	460,094	1,313,578
July	337,586	797,506	1,292,785	1,135,373 *
August	207,157	268,534	679,627	N/A
September	1,108,456	685,559	1,445,231	N/A
October	321,307	680,198	563,024	N/A
November	(83,823)	685,496	4,496,622	N/A
December	660,491	1,242,151	4,633,754	N/A
Total	3,318,188	7,266,852	16,494,653	8,868,289

Shared Services Costs are allocated based on Pinnacle West's net equity and debt in it's Affliates in accordance with ACC Code of Conduct Policy 1. The annual increase in the allocation of costs to PWEC is associated with the construction of the PWEC units.

	2002	2003	2004	2005
PWEC Share - Corporate Allocation	19.80%	29.60%	35.00%	34.90%
PWEC Share - Corporate Governance Allocation	17.70%	27.00%	32.00%	32.30%

An adjustment for Pinnacle West's Shared Services Asset depreciation was recorded in November, 2004. The proforma adjustment should have excluded nine months of these charges as an out-of-period adjustment. We are proposing to reduce the pro forma by $2,001,367.

An adjustment for affiliate rent was recorded in December, 2004. The proforma adjustment should should have excluded nine months of these charges as an out-of-period adjustment. We are proposing to reduce the pro forma by $3,096,000.

* PWEC Assets transferred to APS effective July 29, 2005.

Utilitech, Inc.'s Tenth Set of Data Requests
To Arizona Public Service Company
Docket No. E-01345A-05-0816
Issued June 14, 2006

UTI-10-314. Reference the Company's response to UTI-2-100 addressing PWEC A&G expenses. Please provide:

a. A more detailed explanation of the proposed nine months of out-of-period costs related to Pinnacle West's Shared Services Asset depreciation recorded in November 2004. What caused or created the out-of-period entry? Did it just affect PWEC or were all the subsidiaries – including APS – affected by the entry?

b. A more detailed explanation of the proposed nine months of out-of-period costs related to Pinnacle West's Shared Services affiliate rent expense recorded in December 2004. What caused or created the out-of-period entry? Did it just affect PWEC or were all the subsidiaries – including APS – affected by the entry?

Response:

a. Shared Services costs are allocated based on Pinnacle West's net equity and debt invested in its Affiliates as defined in the policies provided in UTI-1-2(d). Shared Services costs include depreciation on Shared Services assets. From January through October, Shared Services depreciation was allocated to Depreciation Expense on Pinnacle West Energy's books and credited to Depreciation Expense on Pinnacle West Capital's books for the PWEC (as well as the affiliates) share of these costs. It was determined that Pinnacle West Energy and other affected PWCC affiliates should not record Depreciation Expense on their books for assets that were not recorded on their books. The out-of-period entry was to move the allocated Shared Service Depreciation from Depreciation Expense on the non-owning (of Shared Service assets) to A&G – Misc. General Expense. This entry affected all entities (APS, including, Power Marketing; APS Energy Services and PWCC) that receive these allocated costs.

b. Shared Services costs include rent offsets for CHQ (Corporate Headquarters) related to sub-tenant's and Pinnacle West Affiliates rent and credits for the use of certain Deer Valley facilities related to depreciation associated with Shared Services. It was discovered that these credits were incorrectly allocated throughout 2004. In order to properly state entity financial performance reports, an entry was recorded in December to ensure charges across entities were correct. This entry affected all entities (APS, including Power Marketing; APS Energy Services and PWEC) that receive these allocated costs, see LLR_WP27.

Witness: Laura Rockenberger

Pro Forma Adjustment Summary
UTI-10-314

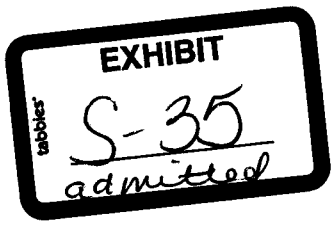
Depreciation

	FERC Account	Despcription	PWEC	APS	Total
Total Shared Services Depreciation Adjustment (11/2004)	9302	O&M	(2,446,115)	(4,060,203)	(6,506,318)
	4030-4040	Depreciation	2,446,115	4,060,203	6,506,318
			-	-	-
Proforma Adjustment (Remove nine months from TY)	9302	O&M	(2,001,367)	(3,321,984)	(5,323,351)
			UTI 2-100	*UTI 14-350 (~~UTI 10-314~~)*	Reduction to expenses

Rent

	APS	PWEC	PWCC Power Marketing	APSES	Total
Total Shared Service Affiliate Rent Adjustment (12/2004)	(4,320,000)	4,128,000	112,000	80,000	-
Proforma Adjustment (Remove nine months from TY)	(3,240,000)	3,096,000	84,000	60,000	-
	LLR_WP27	*UTI 2-100*			

Reduction in expense



IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

JOINT ACCOUNTING SCHEDULES

OF THE

ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

PUBLIC VERSION

PREPARED
BY
UTILITECH, INC.

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INDEX TO JOINT ACCOUNTING SCHEDULES

SCHEDULE NO.	DESCRIPTION	WITNESS
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Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	REFERENCE	APS PROPOSED ORIGINAL COST	APS PROPOSED FAIR VALUE	STAFF PROPOSED ORIGINAL COST	STAFF PROPOSED FAIR VALUE
	(A)	(B)	(C)	(D)	(E)	(F)
1	PROPOSED RATE BASE	Sch B	$ 4,466,697	$ 6,120,755	$ 4,401,130	$ 6,055,188
2	RATE OF RETURN	Sch D	8.73%	6.37%	8.05%	5.85%
3	OPERATING INCOME REQUIRED	Line 1 * 2	$ 389,943	$ 389,943	$ 354,291	$ 354,291
4	NET OPERATING INCOME AVAILABLE	Sch C	115,904	115,904	229,960	229,960
5	OPERATING INCOME EXCESS/DEFICIENCY	Line 3 - 4	$ 274,039	$ 274,039	$ 124,331	$ 124,331
6	REVENUE CONVERSION FACTOR	Sch A-1	1.6407	1.6407	1.6407	1.6407
7	OVERALL REVENUE REQUIREMENT	Line 5 * 6	$ 449,616	$ 449,616	$ 203,993	$ 203,993
8	ENVIRONMENTAL IMPROVEMENT CHARGE		4,315	4,315		
9	TOTAL INCREASE IN RATES	Line 7 + 8	$ 453,931	$ 453,931	$ 203,993	$ 203,993

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVENUE CONVERSION FACTOR
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	COMPANY PROPOSED
	(A)	(B)	(C)
1	Gross Jurisdictional Revenue		100.0000%
2	Less: Effective State Income Tax	APS Sch. 3	6.23%
3	Less: Effective Federal Income Tax	APS Sch. 3	32.82%
4	Operating Income % = 100% - Tax Percentage	Ln1-Ln2-Ln3	60.9500%
5	Income to Revenue Multiplier	Line 1/Line 4	1.640689
			(a) (b)

Footnote:
(a) Source: APS Schedules A-1 & C-3.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	ORIGINAL COST AS ADJUSTED BY APS	ORIGINAL COST STAFF ADJUSTMENTS	ORIGINAL COST AS ADJUSTED BY STAFF	RCND AS ADJUSTED BY APS	RCND STAFF ADJUSTMENTS	RCND AS ADJUSTED BY STAFF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Gross Utility Plant in Service	$ 9,296,308	$ -	$ 9,296,308	$ 15,219,192		$ 15,219,192
2	Less: Accumulated Depreciation & Amort.	(3,546,560)	-	(3,546,560)	(6,161,346)		(6,161,346)
3	Net Utility Plant in Service	5,749,748	-	5,749,748	9,057,846	-	9,057,846
	Deductions:						
4	Deferred Taxes	(1,064,449)	(2,018)	(1,066,467)	(1,064,432)	(2,018)	(1,066,450)
5	Investment Tax Credits	-	-	-	-	-	-
6	Customer Advances for Construction	(59,807)	-	(59,807)	(59,807)	-	(59,807)
7	Customer Deposits	(54,860)	-	(54,860)	(54,860)	-	(54,860)
8	Pension Liability	(68,699)	-	(68,699)	(68,699)	-	(68,699)
9	Liability for Asset Retirement	(260,419)	-	(260,419)	(260,419)	-	(260,419)
10	Other Deferred Credits	(109,485)	-	(109,485)	(109,485)	-	(109,485)
11	Unamortized Gain-sale of Utility Plant	(46,360)	-	(46,360)	(46,360)	-	(46,360)
12	Regulatory Liabilities	(160,744)	(3,661)	(164,405)	(160,744)	(3,661)	(164,405)
13	Total Deductions	(1,824,823)	(5,679)	(1,830,502)	(1,824,806)	(5,679)	(1,830,485)
	Additions:						
14	Regulatory Assets	64,020	(2,873)	61,147	64,020	(2,873)	61,147
15	Miscellaneous Deferred Debits	39,464	-	39,464	39,464	-	39,464
16	Depreciation Fund - Decommissioning	285,855	-	285,855	285,855	-	285,855
17	Allowance for Working Capital	152,433	(57,014)	95,419	152,433	(57,014)	95,419
18	Total Additions	541,772	(59,888)	481,884	541,772	(59,888)	481,884
19	Total Rate Base	$ 4,466,697	$ (65,567)	$ 4,401,130	$ 7,774,812	$ (65,567)	$ 7,709,245

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RATE BASE SUMMARY
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	Page Total
	(A)	(B)	(C)	(D).	(E)	(F)	(G)	(H)	(I)	(J)
1	Gross Utility Plant in Service									$ -
2	Less: Accumulated Depreciation & Amort.									-
3	Net Utility Plant in Service	-	-	-	-	-	-	-	-	-
	Deductions:									
4	Deferred Taxes			(2,018)						(2,018)
5	Investment Tax Credits									-
6	Customer Advances for Construction									-
7	Customer Deposits									-
8	Pension Liability									-
9	Liability for Asset Retirement									-
10	Other Deferred Credits									-
11	Unamortized Gain-sale of Utility Plant									-
12	Regulatory Liabilities	(3,661)								(3,661)
13	Total Deductions	(3,661)	-	(2,018)	-	-	-	-	-	(5,679)
	Additions:									
14	Regulatory Assets		(2,873)							(2,873)
15	Miscellaneous Deferred Debits									-
16	Depreciation Fund -- Decommissioning									-
17	Allowance for Working Capital				(57,014)					(57,014)
18	Total Additions	-	(2,873)	-	(57,014)	-	-	-	-	(59,888)
19	Total Rate Base	$ (3,661)	$ (2,873)	$ (2,018)	$ (57,014)	$ -	$ -	$ -	$ -	$ (65,567)

ADJUSTMENTS:

B-1 SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
B-2 CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
B-3 INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
B-4 CASH WORKING CAPITAL
B-5 **reserved**
B-6 **reserved**
B-7 **reserved**
B-8 **reserved**

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Accumulated Provision for SFAS 112 Deferred Credits		
2	Acquiesced by APS in Discovery to be Properly Included		
3	as a Rate Base Offset	UTI-10-302	$ (3,886,000)
4	Composite Retail Jurisdictional Wages & Salaries Allocator		94.212%
5	ACC Jurisdictional Adjustment to Reflect SFAS 112 Deferred		
6	Credits as a Rate Base Offset	Line 3 * Line 4	$ (3,661,453)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2 3	Proforma Rate Base Adjustment Proposed by APS to Reflect Estimated Growth in Deferred Bark Beetle Costs Between the End of the Historic Test Year and December 31, 2006	LLR_WP7, p. 2	$ 6,114,585
4	Correction Required as Noted in Response to Discovery	UTI-14-351	704,820
5 6	Eliminate Bark Beetle Cost Deferred Prior to April 1, 2005 (the Rate Effective Period Resulting from 2003 Rate Case Order)	LLR_WP17, p. 3	(1,501,069)
7 8	Corrected Before-Tax Bark Beetle Rate Base Deferral Adjustment to End of Test Year Actual Recorded Balance	Sum Lines 3 thru 6	5,318,336
9	Composite Federal and State Income Tax Rate		39.05%
10 11	Related Accumulated Deferred Income Tax Expense Properly Reflected as a Rate Base Deduction	Line 8 * Line 9	2,076,810
12 13	Correct Total Before and After Tax Adjustment to Test Year End Recorded Deferred Bark Beetle Costs	Line 8 - Line 11	3,241,526
14 15	Total Company Rate Base Adjustment for Deferred Bark Beetle Remediation Costs	Line 13 - Line 3	$ (2,873,059)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Total Amount of Investment Tax Credits Expected to be Realized As a Result of Amending Prior Year Federal Income Tax Returns	UTI-10-299	$ 6,483,389
3	Revenue Conversion Factor	Sch. A-1	1.64069
4 5	Total Revenue Requirement Savings Resulting From Amending Prior Years Tax Returns to Claim Additional ITCs	Line 2 * 3	10,637,226
6	Total Costs Incurred to Research and Claim Additional ITCs		
7	Total Contingency Charge Recorded in 2003	UTI-10-301	(2,385,468)
8	Fee for Service Charge Recorded in February 2005	UTI-10-301	(1,553,333)
9	Net Total Company Revenue Requirement Savings Realized	Lines 5+ 7 + 8	6,698,425
10	Allocate to Ratepayers		50.00%
11	Revenue Requirement Savings Allocated to Ratepayers	Line 9 * Line 10	3,349,212
12	Equivalent Total Company Rate Base Offset	Line11/Line 3	(2,041,345)
13	ACC Jurisdictional Demand Factor		98.847%
14 15	ACC Jurisdictional Adjustment to Rate Base for ITCs Allocated to Rate Payers	Line 12 * Line 13	$ (2,017,811)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION		AMOUNT	REVENUE LAG (a)	EXPENSE LAG	NET LAG (DAYS)	CWC FACTOR	CWC REQUIREMENT
	(A)		(B)	(C)	(D)	(E)	(F)	(G)
1	FUEL FOR ELECTRIC GENERATION							
2	COAL		$ 200,856,342	36.85231	32.36664	4.48567	0.01229	$ 2,468,428
3	NATURAL GAS		237,557,927	36.85231	44.25857	-7.40625	-0.02029	(4,820,311)
4	FUEL OIL		1,077,082	36.85231	32.34060	4.51172	0.01236	13,314
5	NUCLEAR:							
6	AMORTIZATION		34,445,413	0.00000	0.00000	0.00000	0.00000	0
7	SPENT FUEL		7,336,099	36.85231	76.35359	-39.50128	-0.10822	(793,932)
8	SUBTOTAL		481,272,863					(3,132,502)
9	PURCHASED POWER	(b)	471,931,131	36.85231	38.15020	-1.29789	-0.00356	(1,678,121)
10	TRANSMISSION BY OTHERS		14,391,245	36.85231	33.69389	3.15842	0.00865	124,531
11	SUBTOTAL		486,322,376					(1,553,591)
12	OTHER OPERATIONS & MAINTENANCE							
13	PAYROLL		240,714,447	36.85231	15.00192	21.85039	0.05986	14,410,153
14	INCENTIVE		8,653,091	36.85231	214.50000	-177.64769	-0.48671	(4,211,511)
15	PENSION AND OPEB		38,986,000	36.85231	77.71371	-40.86140	-0.11195	(4,364,445)
16	EMPLOYEE BENEFITS		26,995,515	36.85231	20.35895	16.49337	0.04519	1,219,855
17	PAYROLL TAXES		18,118,131	36.85231	21.78589	15.06643	0.04128	747,878
18	MATERIALS & SUPPLIES		53,466,114	36.85231	24.22000	12.63231	0.03461	1,850,413
19	FRANCHISE PAYMENTS		11,986,402	36.85231	52.83966	-15.98735	-0.04380	(525,016)
20	VEHICLE LEASE PAYMENTS		3,169,771	36.85231	7.43789	29.41442	0.08059	255,444
21	RENTS		6,776,038	36.85231	-33.48601	70.33832	0.19271	1,305,795
22	PALO VERDE LEASE	(c)	45,900,681	36.85231	103.99426	-67.14195	-0.18395	(8,443,456)
23	PALO VERDE S/L GAIN AMORT		(4,575,722)	0.00000	0.00000	0.00000	0.00000	0
24	INSURANCE		4,639,562	0.00000	0.00000	0.00000	0.00000	0
25	OTHER		119,131,971	36.85231	35.39000	1.46231	0.00401	477,283
26	SUBTOTAL		573,962,001					2,722,393
27	DEPRECIATION & AMORTIZATION		321,525,565	0.00000	0.00000	0.00000	0.00000	0
28	AMORT OF ELECTRIC PLT ACQ ADJ		0	0.00000	0.00000	0.00000	0.00000	0
29	AMORT OF PROP LOSSES & REG STUDY COSTS		(2,564,492)	0.00000	0.00000	0.00000	0.00000	0
30	SUBTOTAL		318,961,073					0
31	INCOME TAXES							
32	CURRENT-FEDERAL		59,824,326	36.85231	58.95000	-22.09769	-0.06054	(3,621,861)
33	CURRENT- STATE	(d)	16,379,288	36.85231	62.05000	-25.19769	-0.06903	(1,130,740)
34	DEFERRED		77,758,889	0.00000	0.00000	0.00000	0.00000	0
35	SUBTOTAL		153,962,503					(4,752,601)
36	OTHER TAXES							
37	PROPERTY TAXES		123,403,653	36.85231	211.94223	-175.08992	-0.47970	(59,196,535)
38	SALES TAXES		158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,194,095)
39	FRANCHISE TAXES		18,920,381	16.69615	52.83966	-36.14351	-0.09902	(1,873,559)
40	SUBTOTAL		300,564,589					(71,264,189)
41	INTEREST EXPENSE	(e)	108,267,803	36.85231	90.43103	-53.57872	-0.14679	(15,892,741)
42	SUBTOTAL		108,267,803					(15,892,741)
43	TOTALS		$ 2,423,313,208					(93,873,230)
44	APS CWC ALLOWANCE							(29,372,869)
45	STAFF CWC ADJUSTMENT -- TOTAL COMPANY							(64,500,361)
46	% ARIZONA RETAIL -- Jurisdictional Factor							0.88394
47	STAFF CWC ADJUSTMENT -- RETAIL							$ (57,014,492)

Footnotes :

(a) See Workpaper B-4, p. 1, for calculation of re-weighted revenue lag.
(b) Test year purchased power reduced by expenses incurred to facilitate unregulaged marketing and trading (see Staff Adjustment C-4).
(c) See Workpaper B-4, p. 2, for calculation of PV lease expense lag.
(d) See Workpaper B-4, p. 3, for calculation of State income tax expense lag.
(e) See Workpaper B-4, p. 4, for calculation of interest expense lag & Staff Adjustment C-19 for pro forma interest expense.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF OPERATING INCOME
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION (A)	AS ADJUSTED BY APS (B)	STAFF ADJUSTMENTS (C)	AS ADJUSTED BY STAFF (D)
1	Electric Operating Revenues	$ 3,440,590	$ (849,582)	$ 2,591,008
	Operating Expenses:			
2	Purchased Power and Fuel	2,129,741	(966,175)	1,163,566
3	Operations and Maintenance	766,212	(59,870)	706,342
4	Depreciation and Amortization	306,988	(500)	306,488
5	Income Taxes	395	64,596	64,991
6	Other Taxes	121,350	(1,689)	119,661
7	Total	3,324,686	(963,637)	2,361,049
8	Operating Income	$ 115,904	$ 114,056	$ 229,960

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ 4,907	$ 1	$ (18,924)	$ (835,566)						$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel			(124,082)	(841,833)						(965,915)
3	Operations and Maintenance		19			(8,273)	(33,483)	1,920	(437)	(7,933)	(48,187)
4	Depreciation and Amortization										-
5	Income Taxes	1,916	(7)	41,064	2,447	3,231	13,075	(750)	171	3,098	64,245
6	Other Taxes										-
7	Total	1,916	12	(83,018)	(839,386)	(5,042)	(20,408)	1,170	(267)	(4,835)	(949,857)
8	Operating Income	$ 2,991	$ (11)	$ 64,094	$ 3,820	$ 5,042	$ 20,408	$ (1,170)	$ 267	$ 4,835	$ 100,275

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:

- **C-1** REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
- **C-2** CORRECTION OF MISCELLANEOUS OTHER REVENUES
- **C-3** NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES
- **C-4** ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
- **C-5** ELIMINATE MARKETING AND TRADING O&M EXPENSES
- **C-6** PENSION EXPENSE ADJUSTMENT
- **C-7** POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
- **C-8** ELIMINATE ADDITIONAL MARKETING EXPENSES
- **C-9** ELIMINATE NON-RECURRING SHARED SERVICES COSTS

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Other Operating Expenses:										
2	Purchased Power and Fuel	(965,915)							(260)		(966,175)
3	Operations and Maintenance	(48,187)	(95)	(2,718)	(2,618)	(4,488)		(1,764)			(59,870)
4	Depreciation and Amortization	-					(500)				(500)
5	Income Taxes	64,245	37	1,062	1,022	1,752	195	689	101	659	69,764
6	Other Taxes	-								(1,689)	(1,689)
7	Total	(949,857)	(58)	(1,657)	(1,595)	(2,735)	(305)	(1,075)	(158)	(1,029)	(958,470)
8	Operating Income	$ 100,275	$ 58	$ 1,657	$ 1,595	$ 2,735	$ 305	$ 1,075	$ 158	$ 1,029	$ 108,888

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:

- **C-10** ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
- **C-11** ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
- **C-12** ELIMINATE NON-RECURRING TAX RESEARCH COSTS
- **C-13** ELIMINATE STOCK BASED INCENTIVE COMPENSATION
- **C-14** ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
- **C-15** ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
- **C-16** NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
- **C-17** ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(F)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel	(966,175)									(966,175)
3	Operations and Maintenance	(59,870)									(59,870)
4	Depreciation and Amortization	(500)									(500)
5	Income Taxes	69,764	(959)	630	(4,838)						64,596
6	Other Taxes	(1,689)									(1,689)
7	Total	(958,470)	(959)	630	(4,838)	-	-	-	-	-	(963,637)
8	Operating Income	$ 108,888	$ 959	$ (630)	$ 4,838	$ -	$ -	$ -	$ -	$ -	$ 114,056

Composite Federal and State Income Tax Rate 39.05%

C-18	PRODUCTION TAX CREDIT ADJUSTMENT	C-22
C-19	INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT	C-23
C-20	CORRECT COS INCOME TAX EXPENSE ADJUSTMENT	C-24
C-21		C-25

Witness: J. Anderson

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2 3	Adjustment to Reverse APS' Proposal to Reduce Test Year Margins Predicted to Occur as a Result of Implementing Various Demand Side Management Programs	APS Sch. C-2, Page 1, Col F	$ 4,907,000

Footnote: Adjustment is 100% Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECTION OF MISCELLANEOUS OTHER REVENUES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	REVENUE AMOUNT	EXPENSE AMOUNT
	(A)	(B)	(C)	(D)
1	APS Adjustment for Schedule 1 Rate Changes	Workpaper DJR_WP8	$ 127,000	$ (19,000)
2	APS Revised Adj. for Schedule 1 Rate Changes	UTI 13-344, 13-345	128,339	-
3	Adjustment Correcting APS Schedule 1 Rate Adjustment	Line 2 - Line 1	$ 1,339	$ 19,000
4	Jurisdictional Allocation Factor		100%	99.12%
5	Staff Retail Adjustment for Schedule 1 Rate Changes	Line 3 * Line 4	$ 1,339	$ 18,833

Witness: J. Antonuk &
J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Normalized Fuel and Purchased Power Expense Proposed by:		
2	Staff/Liberty Consulting Group (cents/kWh)		2.8942
3	APS (cents/kWh)	PME_WP6, P. 2	3.2859
4	Net Cents/kWh Reduction Proposed by Staff to be		
5	Rolled Into Base Rates	Line 2 - Line 3	(0.3917)
6	Adjusted Test Year Retail Sales	PME_WP6, P. 3	$ 26,759,478
7	Subtotal: Reduction in Fuel and Purchased Power Expense		
8	Attributable to Serving Retail Load	Line 5 * Line 6	(104,816,875)
9	**Note: This portion of fuel adjustment is 100% retail**		
10	**Proforma Off-Systems Sales Margin Adjustment:**		
11	Proforma Off-System Sales Revenues Per:		
12	Staff/Liberty Consulting Group		133,863,799
13	APS	PME_WP6, P. 5	153,098,000
14	Total Co. Adjustment Decreasing Off-System Sales Revenues	Line 12 - Line 13	(19,234,201)
15	Proforma Fuel and Purchased Power Expense Incurred to		
16	Facilitate Off-system Sales Per:		
17	Staff/Liberty Consulting Group		107,553,298
18	APS	PME_WP6, P. 5	127,134,000
19	Subtotal: Total Co. Additional Fuel and Purchased Power		
20	Expense to Facilitate Off-system Sales	Line 17 - Line 18	(19,580,702)
21	Net Total Company Decrease in Off-System Sales Margins	Line 14 - Line 20	346,501
22	Retail Jurisdictional Energy Allocator		98.389%
23	ACC Jurisdictional Adjustment Reducing Off-system		
24	Sales Revenues	Line 14 * Line 22	(18,924,319)
25	ACC Jurisdictional Adjustment Reducing Fuel/Purchased		
26	Power Expense Related to Reduced Off-system Sales	Line 20 * Line 22	(19,265,238)
27	ACC Jurisdictional Adjustment Increasing Net Margins		
28	Resulting from Reduced Off-system Sales Forecasted	Line 24 - Line 26	$ 340,919

Witness: J. Dittmer
& Liberty

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2	Unregulated Marketing and Trading Revenue Included Within the Total Company Cost of Service Study	GAAPversus FERC_ Reporting(2).xls	$ 849,248
3 4	Purchased Power Expense Incurred in Facilitating Unregulated Marketing and Trading Revenues	GAAPversus FERC_ Reporting(2).xls	(855,618)
5 6	Total Company Net Margin (Loss) on M&T Operations Exclusive of Payroll and Other Non-fuel O&M Expenses	Line 2 + Line 3	(6,370)
7	Energy Allocator		98.389%
8	ACC Retail Jurisdictional		
9	Revenues	Line 2 * Line 7	835,566
10	Purchased Power Expense	Line 4 * Line 7	(841,833)
11	Net Margin (Loss)	Line 9 + Line 10	$ (6,267)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE MARKETING AND TRADING O&M EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000S)
	(A)	(B)	(C)
1	Eliminate Unregulated Marketing and Trading		
2	Non-Purchased Power Operations and		
3	Maintenance Expenses Included Within APS'		
4	Total Company Cost of Service:		
5	Payroll	Response to	$ 6,618
6	Outside Services	UTI-10-315	1,078
7	Corporate Allocations		33
8	Miscellaneous		811
9	Corporate Allocable and Governance		241
10	Total Company Unregulated Marketing and Trading Non-		
11	Purchased Power Operations and Maintenance		
12	Expenses to be Eliminated From APS' Proposed		
13	Total Company Cost of Service	Sum Lines 5 - 9	(8,781)
14	Composite ACC Jurisdictional Allocator		94.212%
15	ACC Jurisdictional Unregulated Marketing and Trading Non-		
16	Purchased Power Operations and Maintenance		
17	Expenses to be Eliminated From APS' Proposed		
18	ACC Jurisdictional Cost of Service	Line 13 * Line 14	$ (8,273)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PENSION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2 3	Reversal of APS' Proposed Total Company Adjustment to Amortize the Unfunded Projected Benefit Obligation Over a Five Year Period	APS Exhibits Sch. C-2, page 7 Adj't No. 21	$ (43,695)
4 5	Total Company Monthly Accrual for Pension Expense in 2006	UTI-7-258	2,784
6	Annualized 2006 Total Company Pension Expense	Line 5 * 12	33,408
7	Test Year Actual Recorded Pension Expense	UTI-7-258	(23,484)
8 9	Pension Expense Adjustment Included Within APS' Payroll Annualization Adjustment	LLR_WP21, page 34	(1,769)
10	Subtotal:	Sum Lines 6 - 9	8,155
11 12	Net Total Company Adjustment to APS' Proposed Level of Pension Expense	Line 3 + Line 10	(35,540)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 12 * Line 14	$ (33,483)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2	Monthly Post Retirement Medical Benefits Expense Being Accrued in 2006	UTI-7-259	$ 1,423
3	Annualized 2006 PRMB Expense	Line 2 * 12	17,076
4	Less: Test Year Actual PRMB Expense	UTI-7-259	(14,020)
5 6 7	APS PRMB Expense Annualization Adjustment Included as Part of the Payroll Expense Annualization	LLR_WP21, page 34	(1,018)
8 9	Net Total Company PRMB Adjustment to Annualize Expenses for 2006 Actuarial Estimates	Sum Lines 3 - 7	2,038
10 11	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
12 13	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 9 * Line 11	$ 1,920

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ADDITIONAL MARKETING EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Additional Marketing and Sponsorship Costs Identified and		
2	Conceded by APS to be Excluded From Retail Cost of		
3	Service Development		
4	Eliminate Dodge Theater Sponsorship	UTI-5-240	$ (100,000)
5	Eliminate Allocated PWCC Radio and	UTI-1-17	
6	Television Advertising	(Revised)	(337,351)
7	Total Additional Marketing and Sponsorship Costs to be		
8	Eliminated from Retail Cost of Service Development	Line 4 + Line 6	$ (437,351)

Footnote: This adjustment is assigned 100% to ACC Jurisdictional Cost of Service

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING SHARED SERVICES COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Reverse Correcting Journal Entries Recorded During the		
2	Historic Test Year that Had the Impact of Overstating "On Going"		
3	Shared Services Expenses:		
4	Reverse Correcting Journal Entry Recorded in		
5	November 2004 Posted to Transfer Shared Services		
6	Costs Originally Recorded as Depreciation Expense		
7	as "A&G" Expense	UTI-10-314	$ (5,323,351)
8	Reverse a Correcting Journal Entry Recorded in		
9	December 2004 to Reallocate Rents Improperly		
10	Allocated Throughout 2004	UTI-10-314	(3,096,000)
11	Total Company Adjustment to Reverse Correcting Journal Entries		
12	Recorded During the Historic Test Year that Had the Impact of		
13	Overstating "On Going" Shared Services Expenses	Line 7 + 8	(8,419,351)
14	Composite ACC Jurisdictional Wages		
15	and Salaries Allocator		94.212%
16	ACC Jurisdictional Adjustment to Reverse Correcting Journal		
17	Entries Recorded During the Historic Test Year that Had the		
18	Impact of Overstating "On Going" Shared Services Expenses	Line 13 * 15	$ (7,932,850)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Legal Expenses Incurred in the Sale of the Unregulated Silverhawk Power Plant	UTI-14-349	$ 240,238
3 4	Silverhawk Legal Costs Already Eliminated by APS from the Test Year Cost of Service		
5 6	Total Shared Services Legal Costs Allocated to PWEC During the Historic Test Years	LLR_WP13, pages 6 & 7	1,394,011
7 8	Percentage of PWEC Legal Costs Assigned by APS to PWEC Activities	LLR_WP13, pages 6 & 7	10%
9 10	Total Company Silverhawk-related Legal Expenses Already Eliminated from the COS by APS	Line 6 * Line 8	139,401
11 12	Net Total Company Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 10 - Line 2	(100,837)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 12 * Line 14	$ (95,010)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Eliminate APS' Proposed Accrual for "Non-Routine"		
2	Maintenance or "Major" Overhaul Costs at the Sundance		
3	Power Station Not Expected to Occur For Many Years	LLR_WP14	$ (2,750,100)
4	ACC Jurisdictional Production Demand Allocator		98.847%
5	Eliminate ACC Jurisdictional Accrual for "Non-Routine"		
6	Maintenance or "Major" Overhaul Costs at the Sundance		
7	Power Station Not Expected to Occur For Many Years	Line 3 * Line 4	$ (2,718,396)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING TAX RESEARCH COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1 2 3 4	Total Company Adjustment to Eliminate a Credit Given to Joint Owners of Palo Verde During the Historic Test Year Related to a Tax Contingency Fee Recorded in 2003 That in Turn Resulted in Incremental TY Charges to Account 9302	UTI-10-296	$ (1,224,795)
5 6 7	Total Company Adjustment to Eliminate Non-recurring Tax Research Costs Incurred on a Fee for Service Basis During the Historic Test Year	UTI-10-301	(1,553,333)
8 9 10	Total Company Adjustment to Eliminate Non-Recurring Tax Research Costs/Credits Recorded During the Historic Test Year	Line 4 + Line 7	(2,778,128)
11 12	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
13 14 15	ACC Jurisdictional Adjustment to Eliminate Non-Recurring Tax Research Costs/Credits Recorded During the Historic Test Year	Line 10 * Line 12	$ (2,617,594)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE STOCK BASED INCENTIVE COMPENSATION
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Total Company Adjustment to Eliminate Above-		
2	the-Line Expense Charges for Stock Based		
3	Incentive Compensation	UTI-1-83	$ (4,762,874)
4	Composite ACC Jurisdictional Wages		
5	and Salaries Allocator		94.212%
6	ACC Jurisdictional Adjustment to Eliminate Above-		
7	the-Line Expense Charges for Stock Based		
8	Incentive Compensation	Line 3 * Line 5	$ (4,487,657)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate Bark Beetle Remediation Costs Deferred in		
2	January through March 2005 Prior to the Effective Date		
3	of Decision No. 67744 (April 1, 2005)	LLR_WP7	$ (1,501,069)
4	Amortization Period -- Years		3
5	Adjustment to Eliminate Bark Beetle Amortization Expense		
6	Related to Costs Inappropriately Deferred Prior to		
7	Effective Date of ACC's Prior Case Rate Order	Line 3 / Line 4	$ (500,356)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2 3	Federal Affairs Charged to "Governance" Activities During the Historic Test Year - Ultimately Allocated to Various PWCC Subsidiaries	UTI-6-244	$ 1,352,479
4 5	Percent of Governance Activities Allocated During the Historic Test Year to PWEC	UTI-6-244	28.930%
6 7	Federal Affairs Lobbying Costs Allocated as Corporate Governance Activities to PWEC	Line 3 * Line 17	391,272
8 9 10	Total Federal Affairs Shared Services Costs Charged to APS Above-the-Line Operating Expense in the Historic Test Year	UTI-10-305	834,125
11 12 13	Subtotal: Federal Affairs Lobbying Costs Charged Above-the-Line to APS and PWEC During the Historic Test Year	Line 7 + Line 10	1,225,397
14 15 15	Public Affairs Costs Charged Above-the-Line to APS During the Historic Test Year	UTI-10-306	595,455
16 17 18	Total Public Affairs Costs Charged to APS During the Historic Test Year	UTI-10-306	1,617,107
19 20	Percent of Public Affairs Costs Charged Above the Line During the Historic Test Year	Line 15/Line 17	36.82%
20 21	Public Affairs Costs Direct Assigned to PWEC During the Historic Test Year	UTI-6-244	139,377
22 23 23	Estimate of Public Affairs Costs Charged to PWEC Above-the-Line During the Historic Test Year	Line 19 * Line 21	51,322
24 25 25	Total Company Above-the-Line Lobbying Costs to Be Eliminated from Cost of Service Development	Line 13 +15 + 23	(1,872,174)
26 27 27	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
28 29	ACC Jurisdictional Above-the-Line Lobbying Costs to Be Eliminated from Cost of Service Development	Line 25 * Line 27	$ (1,763,994)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Yearly Amortization of Post Shutdown ISFSI Costs Based on Funding Expiration Date	LLR_WP16 Page 7	$ 108,000
3 4 5	Negative Amortization of Reduction in Post Shutdown ISFSI Costs Accrued Between September 30, 2005 and January 1, 2006	LLR_WP16 Page 8	(48,000)
6 7	Reduction in Ongoing ISFSI Costs to be Collected in Base Rates Based Upon Updated TLG Study	LLR_WP16 Page 7	(324,000)
8 9	Net Total Company Adjustment Reducing Nuclear Fuel Expense and Amortization of ISFSI Expense	Sum Lines 2 - 7	(264,000)
10	Retail Jurisdictional Energy Allocation Factor		98.389%
11 12	ACC Jurisdictional Adjustment Reducing Nuclear Fuel Expense and Amortization of ISFSI Expense	Line 9 * Line 10	$ (259,747)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate APS Proposed Inclusion of Increased PWEC	LLR_WP20	
2	Property Tax Expense Attributable to Legislative Phase-in	Pages 2 & 10	$ (1,708,338)
3	ACC Jurisdictional Production Demand Allocator		98.847%
4	Eliminate ACC Jurisdictional Portion of APS' Proposed		
5	Inclusion of Increased PWEC Property Tax Expense		
6	Attributable to Legislative Phase-in	Line 2 * Line 3	$ (1,688,644)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PRODUCTION TAX CREDIT ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	DEMAND RELATED AMOUNT (000s)	ENERGY RELATED AMOUNT (000s)	TOTAL COMPANY AMOUNT (000s)
	(A)	(B)	(C)	(D)	(E)
1	Total Company Production Rate Base	CNF_WP13, p.2	$ 2,172,190	$ 95,432	$ 2,267,622
2	Staff Proposed Weighted Cost of Common Equity	Sch. D	5.59%	5.59%	5.59%
3	After-Tax Net Income	Line 1 * Line 2	121,425	5,335	126,760
4	Revenue Conversion Factor	Sch. A-1	1.64069	1.64069	1.64069
5	Pre-Tax Net Income	Line 3 * Line 4	199,221	8,753	207,974
6	Book/Tax Differences	CNF_WP13, p.2	32,377	1,422	33,799
7	Taxable Income	Line 5 + Line 6	231,598	10,175	241,773
8	Deduction Percentage - Effective in 2006		3.00%	3.00%	3.00%
9	Additional Production Deduction	Line 7 * Line 8	6,948	305	7,253
10	Composite Income Tax Rate	Sch. A-1	39.05%	39.05%	39.05%
11	Total Company Annualized Income Tax Savings	Line 9 * Line 10	2,713	119	2,832
12	Total Company Annualized Savings per APS	CNF_WP13, p.2	1,784	78	1,862
13 14	Total Company Adjustment to APS' Original Production Tax Credit Calculation	Line 12 - Line 11	(929)	(41)	(970)
15	Jurisdictional Allocator		98.847%	98.389%	-98.828%
16 17	ACC Jurisdictional Annualized Income Tax Savings Adjustment	Line 14 * Line 15	$ (918)	$ (40)	$ (959)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	ACC Jurisdictional Rate Base Proposed by Staff	Sch. B	$ 4,401,130
2	Weighted Cost of Debt Proposed by Staff	Sch. D	2.460%
3 4 5	Annualized Interest Deduction Based Upon ACC Staff Proposed Retail Jurisdictional Rate Base and the ACC Staff' Proposed Weighted Cost of Debt	Line 1 * Line 2	108,268
6	Annualized Interest Deduction per APS		
7 8	APS Proposed As Adjusted ACC Jurisdictional Rate Based	APS Sch. B-1 Page 1, Col. F	4,466,697
9	APS Proposed Weighted Cost of Debt	APS Sch. D-1	2.460%
10 11	APS Proposed ACC Retail Jurisdictional Interest Expense Deduction	Line 8 * Line 9	109,881
12 13	Retail Jurisdictional Reduction in Annual Interest Deduction	Line 11 - Line 5	1,613
14	Composite Federal and State Income Tax Rate	Sch. A-1	39.05%
15 16 17 18	Adjustment Increasing Retail Jurisdictional Income Tax Expense to Reflect the Synchronization of the Interest Deduction with Staff's Proposed Rate Base and Cost of Capital Recommendations	Line 13 * Line 14	$ 630

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT COS INCOME TAX EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	TOTAL COMPANY AS ADJUSTED AS FILED BY APS (PER ORIGINAL UTI-3-169 & UTI-10-297) TAX EXP. $s	2006 AS ADJUSTED PERMANENT DIFFERENCES PER UPDATED UTI-10-297 TAX EXP. $s	ADDITIONAL ON GOING 2006 PER UPDATED UTI-10-297 TAX EXP. $s	ADJUSTMENT EXCLUDING PRODUCTION TAX CREDIT TAX EXP. $s
	(A)	(B)	(C)	(D)	(E)
1	Other Permanent Differences:				
2	OPEB Subsidy	$ 1,349,000			$ (1,349,000)
3	DCP & SERBP CSV	1,250,000			(1,250,000)
4	2005 vs. 2006 statutory rate	1,181,000			(1,181,000)
5	Tax exempt Interest Income	449,000			(449,000)
6	Depreciation on AFUDC	276,000		394,614	118,614
7	Officer's Compensation	83,000	70,924	27,696	(55,304)
8	Misc. tax credit true-up	28,000			(28,000)
9	Interest on tax reserve - net of tax	-			-
10	Meals & Entertainment	(102,000)	1,644,804	642,296	744,296
11	Penalties	(36,000)			36,000
12	Other	1,536,000			(1,536,000)
13	Subtotal: Other Permanent Differences	6,014,000			(4,949,394)
14	Medicare Subsidy	(3,872,000)		(3,338,429)	533,571
15	AZ State Credits	(570,000)		(482,950)	87,050
16	Amortization of FAS 109 Reg Liability			(460,435)	(460,435)
17	Depreciation on Medicare Subsidy			(49,195)	(49,195)
18	Net Add (Deduction) to Otherwise Calculated				
19	COS Income Tax Expense Based Upon "As				
20	Adjusted Book Income" Including a Deduction				
21	for Synchronized Interest Expense	$ 1,572,000		$ (3,266,403)	$ (4,838,403)

Witness: Parcell

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CAPITAL STRUCTURE & COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION (A)	AMOUNT (000'S) (B)	CAPITAL RATIO (C)	COST RATES (D)	WEIGHTED COST (E)
	APS - PROPOSED (a)				
1	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
2	Preferred Stock	-	0.00%	0.00%	0.00000%
3	Common Equity	3,083,591	54.50%	11.50%	6.27000%
4	Short-Term Debt	-	0.00%	0.00%	0.00000%
5	Total	$ 5,658,416	100%		8.73%
	ACC STAFF- PROPOSED (b)				
6	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
7	Preferred Stock	-	0.00%	0.00%	0.00000%
8	Common Equity	3,083,591	54.50%	10.25%	5.59000%
9	Short-Term Debt	-	0.00%	0.00%	0.00000%
10	Total	$ 5,658,416	100%		8.05%

Footnotes:

(a) Source: APS Schedule D-1, p. 1. Test year ended 9/30/05.
(b) Source: Staff witness Parcell, Exhibt__(DCP-1)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RECONCILIATION OF POSITIONS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Description	Amount	Difference In Pretax Return	Revenue Requirement Value
(A)	(B)	(C)	(D)
APS PROPOSED REVENUE REQUIREMENT			$ 453,931
RETURN DIFFERENCE (on APS Proposed Rate Base)	$ 4,466,697	-1.120%	(50,027)
SUBTOTAL - REVENUE REQUIREMENT			$ 403,904
		Pre-Tax Return	
RATE BASE ADJUSTMENTS			
SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT	$ (3,661)	11.63%	$ (426)
CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE	(2,873)	11.63%	(334)
INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE	(2,018)	11.63%	(235)
CASH WORKING CAPITAL	(57,014)	11.63%	(6,632)
reserved	-	11.63%	-
reserved	-	11.63%	-
reserved	-	11.63%	-
reserved	-	11.63%	-
TOTAL VALUE OF STAFF RATE BASE ADJUSTMENTS	(65,567)		$ (7,626)
STAFF RATE BASE RECOMMENDATION	$ 4,401,130		
		Revenue Conversion Multiplier	
Company Proposed Net Operating Income	$ 115,904		
NET OPERATING INCOME ADJUSTMENTS			
REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM	$ 2,991	1.6407	$ (4,907)
CORRECTION OF MISCELLANEOUS OTHER REVENUES	(11)	1.6407	17
NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES	64,094	1.6407	(105,158)
ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE	3,820	1.6407	(6,267)
ELIMINATE MARKETING AND TRADING O&M EXPENSES	5,042	1.6407	(8,273)
PENSION EXPENSE ADJUSTMENT	20,408	1.6407	(33,483)
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT	(1,170)	1.6407	1,920
ELIMINATE ADDITIONAL MARKETING EXPENSES	267	1.6407	(437)
ELIMINATE NON-RECURRING SHARED SERVICES COSTS	4,835	1.6407	(7,933)
ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES	58	1.6407	(95)
ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE	1,657	1.6407	(2,718)
ELIMINATE NON-RECURRING TAX RESEARCH COSTS	1,595	1.6407	(2,618)
ELIMINATE STOCK BASED INCENTIVE COMPENSATION	2,735	1.6407	(4,488)
ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER	305	1.6407	(500)
ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE	1,075	1.6407	(1,764)
NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT	158	1.6407	(260)
ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES	1,029	1.6407	(1,689)
PRODUCTION TAX CREDIT ADJUSTMENT	959	1.6407	(1,573)
INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT	(630)		-
CORRECT COS INCOME TAX EXPENSE ADJUSTMENT	4,838	1.6407	(7,938)
TOTAL VALUE OF STAFF NET OPERATING INCOME ADJUSTMENTS	114,056		$ (188,163)
STAFF NET OPERATING INCOME RECOMMENDATION	$ 229,960		
RECONCILED REVENUE REQUIREMENT			$ 208,115
OTHER RECONCILING ITEMS			
APS PROPOSED ENVIRONMENTAL CHARGE			(4,315)
UNRECONCILED DIFFERENCE			193
REVENUE REQUIREMENT RECOMMENDATION			$ 203,993

EXHIBIT
S-37
admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

SURREBUTTAL TESTIMONY

OF JAMES R. DITTMER

ON BEHALF OF THE
UTILITIES DIVISION STAFF

SEPTEMBER 27, 2006

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SURREBUTTAL TESTIMONY OF JAMES R. DITTMER

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SURREBUTTAL TESTIMONY
OF
JAMES R. DITTMER

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc.

Q. Have you previously presented testimony within this docket?

A. Yes. I filed direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") in this docket on August 18, 2006.

Q. On whose behalf are you providing this surrebuttal testimony?

A. Like my direct testimony, this surrebuttal testimony is being presented on behalf of the ACC Staff.

Q. What is the purpose of your surrebuttal testimony?

A. I will be responding to a number of arguments and comments offered in the rebuttal testimony of various Arizona Public Service Company ("APS" or

"Company") rebuttal witnesses. Specifically, I will be providing surrebuttal testimony addressing the following topics and responding to the following APS rebuttal witnesses:

Company Witness	Topic/Issue
Steven Wheeler	Overview of Company's Rebuttal Case
Steven Wheeler	Criticism Of Staff's "End Results" And APS' Request for an Attrition Adjustment in the Event the Commission Adopts any of Staff's or Other Intervenors' Revenue Requirement Proposals
Steven Wheeler	Staff's Recommendation Regarding Continuation Of The Interim PSA Adjustor
	Staff's Revised Recommendations Resulting From Updated, Corrected And APS-Conceded Adjustments
Don Brandt	Accelerated Recovery Of Underfunded Pension Liability
Laura Rockenberger	Deferred Bark Beetle Remediation Costs
Chris Froggatt	Investment Tax Credits As A Ratebase Offset
Fred Balluff	Cash Working Capital – Lead Lag Study Development
Peter Ewen	Sundance Operations and Maintenance Expense

I note that APS has addressed a few adjustments within its rebuttal testimony that I proposed within my direct testimony that I am not addressing with this surrebuttal testimony. The fact that I am not filing surrebuttal testimony on an issue should not be construed as acquiescence of the adjustment. Rather, in those cases, it is believed that those issues have been adequately addressed in direct testimony.

OVERVIEW OF COMPANY'S REBUTTAL CASE

Q. Please provide your overall understanding of the Company's rebuttal position regarding the Staff's revenue requirement recommendations as presented within Staff's direct testimony and exhibits filed on August 18, 2006.

A. My understanding is that APS has conceded a number of adjustments included within Staff's and the Residential Utility Consumer Office's testimony that, when considered in isolation, would have the impact of *reducing* APS' rate request as filed on January 31, 2006. However, the Company has upwardly revised its adjustment for annualized fuel and purchased power expense in an amount that is nearly identical to the sum of all other concessions that it has made. Additionally, the Company has accepted Staff's recommendation to increase the annual Environmental Improvement Charge in the amount of $4.25 million. The end result, as reflected within Attachment SMW-1RB affixed to Mr. Steven Wheeler's testimony, is that the Company is now requesting a $451.3 million increase (21.21%) in base plus adjustor rates as opposed to its January 2006 requested increase of $453.9 million (21.34%).

CRITICISM OF STAFF'S "END RESULTS" AND APS' REQUEST FOR AN ATTRITION ADJUSTMENT IN THE EVENT THE COMMISSION ADOPTS ANY OF STAFF'S OR OTHER INTERVENORS' REVENUE REQUIREMENT PROPOSALS

Q. Please summarize your understanding of APS witness Mr. Steven Wheeler's testimony as it addresses Staff's overall rate recommendations.

A. Mr. Wheeler is highly critical of Staff's overall recommendations. He indicates that financial results stemming from Staff and RUCO's revenue requirement recommendations are "clearly disturbing" and that adoption of Staff's adjustments "would represent a step backward from the level of regulatory support heretofore provided by this Commission." Further, Mr. Wheeler characterizes Staff's failure to perform "any analysis....of the likely consequences of their overall revenue requirement recommendation" as "equally disturbing."

Finally, Mr. Wheeler appears to advocate adoption of an "attrition adjustment" that would be equivalent on a dollar-for-dollar basis to the sum of all Staff, RUCO or other intervenor adjustments that this Commission might adopt that would otherwise reduce the Company's requested overall increase of approximately $450 million. Or stated more specifically, Mr. Wheeler is advocating that for each dollar of "disallowance" of the Company's requested rate increase that this Commission might adopt that it concurrently authorize a dollar of an attrition allowance adjustment that would bring the increase being granted exactly back to the level that the Company is now requesting.

The entire basis for Mr. Wheeler's request for an attrition adjustment that would offset dollar-for-dollar any "disallowance" adjustment this Commission might adopt is the Company's financial forecasts for years 2006, 2007 and 2008 that indicate that the Company *must* receive every dollar of its requested $451.2

1 million increase in order to maintain financial ratios that will allow it to retain
2 its investment grade credit rating.
3
4 Q. Has the Staff reviewed the impact of its overall revenue requirement
5 recommendation upon forecasted results?
6 A. No.
7
8 Q. Why not?
9 A. APS' currently requested increase – up until the time of filing its rebuttal
10 testimony – was based exclusively upon the adjusted historic test year ending
11 September 30, 2005. In this base rate proceeding Staff has focused its review
12 on the Company's proposed adjusted test year cost of service that, prior to the
13 rebuttal stage of this proceeding, was the sole support for its requested increase.
14
15 In the 1980s and early 1990s, as APS was undertaking its extensive construction
16 program of the three Palo Verde units, APS occasionally sought new rate
17 proposals based upon financial integrity concerns – concerns that were
18 supported in part by financial forecasts. The data in our files from those very
19 dated cases are limited. But from memory and a brief review of limited
20 testimony from files still retained, I believe in those old cases that APS was
21 requesting *within its initial direct filing of testimony and exhibits* new rate
22 proposals that were driven, in part, by cash flow and interest coverage concerns.
23 Some of the issues and rate proposals driven by cash flow/coverage concerns

were requests for full tax normalization of book/tax timing differences, requests to include construction work in progress in rate base, and the testing of the impact of phase-in plans being suggested. Additionally, in the last Palo Verde-driven rate case, the Staff was contemplating significant disallowances of the Palo Verde units based upon a prudence review as well as an excess capacity study. The Staff had concerns of what the impact of its disallowance might be upon the Company's overall financial conditions – and its ability to maintain access to capital markets at reasonable rates.

Since the last Palo Verde rate case undertaken in the early 1990s, Utilitech has not been requested to review, and has not undertaken a review of, the impact of Staff's overall revenue requirement recommendations upon forecasted operating results in any rate case in which it has been involved on behalf of the ACC Staff.

In Staff's view, this rate case has been driven primarily by significantly rising fuel and purchased power costs, and a previously-approved Power Supply Adjustor that imposed restrictions upon the timing and amounts of pass through of such costs. Accordingly, significant resources were devoted in this proceeding to assessing the reasonableness of fuel cost increases being incurred, and to revisiting the mechanics of the PSA to assess its effectiveness in passing through costs – balanced with needs to provide proper incentives to APS and to

obtain assurances that costs being passed through have been, and prospectively would be, reasonably incurred.

In summary, Staff did not undertake an analysis of the impact of its recommendations on forecasted operating results because such analyses simply have not been undertaken for a number of years – since the completion of APS' significant production construction program in the early 1990s. Additionally, there were no unique rate proposals included within APS' direct case that were specifically linked to forecasted financial ratios, similar to those that triggered forecast analyses in the 1980s and early 1990s. Further, an analysis of the Company's forecast, even at a fairly high review level, is resource intensive. This case was primarily driven by increasing fuel and purchased power costs – and Staff has directed significant resources to addressing this significant cost of service component. Without a forewarning in the Company's direct case that APS believed the revenue requirement to be granted should ultimately be driven by *financial forecasts* rather than *the adjusted historic test year cost of service,* and with competing resource requirements for other elements of the case (i.e., fuel costs and PSA modifications), the thought of undertaking a resource-intensive review of the Company's forecast was simply not considered.

Q. Mr. Wheeler is highly critical of Staff's failure to assess the impact of its recommendations upon the Company's financial integrity. Do you have any response to such criticism?

1 A. Yes. First, it has been my experience that the type of analysis that Mr. Wheeler
2 is suggesting has not been undertaken for any APS proceeding for
3 approximately 15 years. Second, to the best of my knowledge, the type of
4 analysis that Mr. Wheeler is suggesting be undertaken, and which Staff did
5 undertake during the years when APS was under going the significant
6 construction program related primarily to the Palo Verde Units, were all
7 predicated by unique rate proposals included within APS' direct case that were
8 being driven by financial integrity concerns. No such forewarning was included
9 with APS' current rate filing. Third, in old cases where forecasted financial
10 ratios were addressed, we undertook at least a high level review of the
11 Company's forecast. Even with only a "high level" review, we sometimes
12 made correcting or updating adjustments to the Company's forecast. The
13 important point being that we did not in prior cases acquiesce to, nor would we
14 recommend in the instant case, blind adherence to the Company's financial
15 forecast. Specifically, in a base rate proceeding there should be at least some
16 level of scrutiny of a Company forecast before discretionary rate decisions are
17 based upon the forecast results.
18
19 Q. Do you understand that this Commission based its decision in the APS
20 emergency proceeding held earlier this year, at least in part, based upon the
21 Company's forecasted financial results?
22 A. That is my understanding. In the context of an emergency rate proceeding there
23 typically is not adequate time or resources to analyze a Company's forecast in

1 any detail. However, importantly, the emergency or interim increase granted is
2 subject to refund. Further, the emergency increase was requested after APS had
3 filed this current base rate case, and accordingly, it was a certainty that a more
4 thorough review would be undertaken in the very near future.
5
6 Q. Given the APS-claimed dire consequences of Staff's recommendations stated
7 within Company testimony, are you or Staff recommending that the
8 Commission accept any of the forms of attrition adjustments that the Company
9 is recommending in the event any of Staff's adjustments are adopted by this
10 Commission?
11 A. No. At the outset, I would first state that I encourage the Commission to decide
12 every issue presented based upon the evidence and merits of each individual
13 issue. If the Commission adopts any Staff adjustments – as I certainly hope that
14 it does for reasons stated within the various Staff witnesses' testimony – I would
15 strongly recommend it not concurrently and blindly adopt an offsetting attrition
16 adjustment as suggested within Mr. Wheeler's testimony. As noted, Staff has
17 not reviewed APS' forecasts for years 2006, 2007 and 2008 in any meaningful
18 detail because APS had not previously based its requested rate increase upon
19 these forecasts. Staff has, obviously, reviewed the information presented by
20 APS in its rate filing – its adjusted test year cost of service – in detail. That
21 review has lead to a number of significant adjustments – many of which have
22 been agreed to by APS. Unless a reasonably detailed review of the Company's
23 forecast is undertaken, I would strongly urge rejection of attrition adjustments

based upon its results. Just as mistakes and oversights occurred in APS' preparation of its adjusted test year cost of service, it is entirely possible, and perhaps likely, that similar mistakes or oversights may have occurred in the preparation of the Company's financial forecast. Additionally, even in the absence of clear mistakes, forecasts can be prepared with results skewed toward pessimistic or optimistic results. Accordingly, before rate decisions are based upon their results, financial forecasts must be given some level of review.

Second, I would note that APS has recommended a number of "alternative" rate proposals to be adopted in the event the Commission is inclined to adopt *any* of Staff's recommendations regarding accounting issues or rate of return. Mr. Wheeler loosely lumps these alternatives together in a discussion regarding "attrition." However, it should be clearly understood that some Company proposals would offset earnings attrition, while other proposals would do very little to alleviate earnings attrition, but would nonetheless, enhance cash flow to the Company that would, in turn, improve cash flow metrics that would assist in maintaining the Company's credit ratings.

Q. Please further explain the distinction between pure "attrition adjustments" versus rate proposals that simply enhance cash flow.

A. Earnings attrition occurs when the increase in the cost of providing electric service begins to outpace the increase in margins derived from growth in sales. Relative to electric utilities nationwide, APS is experiencing – and predicts to

1 continue to experience – high growth in retail sales. The noted growth is
2 creating a demand to add transmission and distribution plant, as well as to find
3 new sources of generation capacity and energy to meet such load growth.
4 Currently, and in all likelihood for at least the next several years under the 2004
5 Settlement Agreement, APS will meet the need for generation capacity and
6 energy through additional purchased power arrangements. With the PSA APS
7 is permitted to pass through not only purchased power *energy* charges, but
8 importantly, *demand* charges. The purchased capacity being paid for through
9 demand charges included in purchased power transactions replaces the need to
10 build generating capacity otherwise required to meet growth in customer
11 electric requirements. Inclusion of demand charges in automatic fuel
12 adjustment clauses – similar to the APS PSA – does not always occur.
13 Specifically, demand charges are often excluded from automatic fuel adjustment
14 clauses inasmuch it is recognized that growth in retail sales – and attendant
15 margins above fuel costs – will be available to "pay for" incremental demand
16 costs being incurred. I am not suggesting or recommending that demand
17 charges be prospectively excluded from APS' PSA. However, I would note and
18 emphasize that the APS PSA is more beneficial to shareholders than some
19 automatic fuel adjustment clauses, and the inclusion of demand charges in the
20 PSA should be considered a huge "plus" to APS in its challenges regarding
21 attrition.
22

Because attrition for the production function cost of service is significantly alleviated with the PSA that includes recovery of demand charges, growth in retail margins *above fuel and purchased power costs that include demand charges* is available to a much larger extent to meet the cost-of-service increases attributable to return/depreciation requirements accompanying growth in distribution plant constructed to meet new load as well to simply recover increases in expense caused by ongoing inflation over time.

Returning to the various alternative rate proposals suggested by APS for the first time in rebuttal testimony, some recommendations would tend to offset earnings attrition. Specifically, of the "Additional Adjustments" reflected on Attachment SMW-2RB affixed to Mr. Wheeler's rebuttal testimony, the proposals labeled "Plant in Service," "Attrition Adjustment" and ".5% increase in ROR on Staff FVRB" are truly adjustments designed to address earnings attrition. Conversely, the proposals labeled "Depreciation" and "CWIP" would enhance cash flow and improve certain financial ratios relied upon by rating agencies, but would do relatively little to offset earnings attrition.

Q. Please further expand up the distinction you are drawing regarding the various subsets of alternative APS rate proposals, addressing first the APS recommendations that you believe address earnings attrition.

A. APS' first pure earnings attrition adjustment entitled "Plant in Service" is made to reflect additional post-test year plant additions predicted through the end of

2006 without equitably and consistently updating and reflecting growth in retail number of customers and attendant growth in revenues and margins above fuel cost. This asymmetrical proposal is purportedly recommended under the theory that growth in margins is not keeping pace with growth in plant in service and attendant return requirements.

I have not been able to observe within workpapers provided with the Company's rebuttal testimony exactly how the second alternative adjustment entitled simply "Attrition Adjustment" has been calculated. From the brief description provided in Mr. Brandt's rebuttal testimony, it would appear the Company has calculated this amount by simply determining an appropriate increase based upon 2007 and 2008 forecasted operating results. In other words, it would appear that the Company's position in proposing this alternative would be to completely ignore the massive efforts that the Company undertook in preparing an historic test year cost of service and also ignore all the other parties' discovery and analyses addressing the historic test year cost of service. Instead, with this adjustment, APS proposes within "the eleventh hour" of this proceeding to simply set rates upon a forecasted test year for which no meaningful discovery has been submitted and which – to my knowledge - no party has analyzed.

I also have not observed the actual calculations underlying the alternative entitled ".5% increase in ROR on Staff FVRB." However, it appears to simply

be some form of a rate of return allowance derived from employment of Staff's Fair Value Rate Base. Apparently this proposal represents abandonment, or at least partial abandonment, of historic test year rate making principles as has been employed in Arizona for at least the past 20 years with which I am personally familiar.

Each of the adjustments described provide the Company with additional revenues, without any change in accounting that would modify the recovery of fixed assets (i.e., depreciation or amortization expense) or reduce the amount of expenditures that would otherwise be capitalized (i.e., CWIP in rate base reducing the amount of AFUDC otherwise capitalized). Because there would be no accompanying change in accounting with these pure attrition proposals, adoption of any of these recommendations would most assuredly reduce earnings attritions above that which would be achieved by establishing rates through strict employment of an historic test year cost of service.

Q. Please expand upon the other alternatives that you indicated would improve cash flow, but which would do little to address earnings attrition.

A. As already alluded to, each of the remaining two alternatives suggested result in accompanying changes in accounting. The impacts of the changes in accounting are to accelerate the recovery period for fixed plant assets from that currently being followed even though the total amount to be ultimately recovered over time would not change.

1 Currently APS capitalizes an Allowance for Funds Used During Construction
2 ("AFUDC") whenever a plant addition has a construction period exceeding one
3 month. AFUDC consists of interest and equity return associated with funding a
4 project during construction. Capitalization of AFUDC ceases upon commercial
5 operation of the project under the theory that once the project goes into service
6 it will be useful in the provision of service, and thus contribute toward
7 facilitating sales/margins that will provide for a "cash" return on the
8 construction investment. With its "CWIP" alternative, APS is proposing to
9 include an ongoing level of CWIP in rate base and concurrently cease the
10 practice of capitalizing AFUDC during the construction phase. Under this
11 proposal rates would be raised immediately, but with the cessation of
12 capitalization of AFUDC, the ultimate in-service value of the plant will be
13 lowered from that which would have occurred with continued capitalization of
14 AFUDC. The increase in current retail rates would exactly offset the reduction
15 in AFUDC income otherwise recorded – thus resulting in no increase in
16 earnings.
17
18 Under the Company's "Depreciation" alternative the Company would increase
19 recorded depreciation expense. The increase would not be based upon detailed
20 and systematic depreciation rate studies. Further, per the Company's proposal,
21 the increase in depreciation would not necessarily be FERC-plant-account
22 specific. Rather, the Company would simply begin to record additional
23 depreciation expense and record the attendant credit to a newly created

depreciation reserve sub-account. It is not clear when or how the accelerated depreciation would eventually be considered in future rate proceedings, but presumably at some point ratepayers would be "credited" for what can essentially be considered a prepayment of depreciation expense. Because there would be an increase in the recording of depreciation expense that would be equivalent to the increase in revenues being collected, the Company would not experience any reduction in earnings attrition. However, depreciation is a "non-cash" expense. Accordingly, the recovery of depreciation expense on an accelerated basis would improve the Company's cash flow metrics.

Q. You have stated that Staff is not recommending the adoption of *any* of APS' alternative rate proposals. If the Commission were inclined to adopt any of APS' proposals over Staff's objections, do you have any recommendations as to which should be adopted?

A. First, I would reemphasize that it is Staff's recommendations that none of the APS alternative rate proposals should be adopted at this point in time. That having been stated, and at the risk of giving the impression that Staff is the least bit uncertain on this position, I would suggest that if the Commission were nonetheless inclined to adopt any of APS' proposals over Staff's objections, it should either adopt the proposal to include CWIP in rate base or to reflect accelerated depreciation. As already discussed, each of these two proposals affect the recovery period for fixed assets. Each of these two proposals result in accompanying accounting changes that would yield benefits – or reductions in

rates – for future ratepayers. The other true "attrition" adjustments have no accompanying accounting changes, and thus, the revenues collected under these proposals would flow to APS' "bottom line" resulting in increased earnings for shareholders but no direct beneficial impact to future ratepayers. Accordingly, I would recommend that if the Commission were inclined to give APS more "cash," that it do so in the form of adopting the Company's accelerated depreciation expense or CWIP-in-rate-base proposals that would at least lead to future benefits to ratepayers.

Q. Are you recommending rejection of an attrition allowance beyond this case?

A. While I am admittedly skeptical of the need for an attrition allowance at this time, my recommendation is not intended to go beyond this case. If, however, APS desires the Staff or the Commission to consider an attrition allowance, or any other unique rate proposal that is driven by forward-looking financial metrics, I would recommend that APS be required to make such request *within its initial direct filing* so that Staff and other parties are forewarned and can correspondingly allocate resources appropriately. I do not believe the Company should be permitted to make such a significant request for a radically different rate proposal *for the first time* in the rebuttal phase of the case. Staff and other parties have less than two weeks to respond in surrebuttal to comments and arguments made by APS in rebuttal. There is no time to undertake discovery or meaningful analysis of new proposals within such timeframe. In my opinion, it would be unfair and inappropriate to consider such radical new proposals in the

1 rebuttal/surrebuttal phase of a case. To borrow a characterization from Mr.
2 Wheeler, I find such a proposal in the rebuttal phase of a case to be
3 "disturbing."
4
5 Q. In your earlier answer you claimed that you were "admittedly skeptical" of the
6 need for an attrition allowance at this point in time. Can you elaborate on that
7 comment?
8 A. Yes. In the jurisdictions in which I frequently participate, I personally have not
9 observed a utility company requesting, much less a commission granting, an
10 attrition allowance for many years. Requests for attrition allowances were
11 sometimes requested, and occasionally granted, in the late-1970s-through-early-
12 1990s timeframe. In particular, in the early 1980s utilities were facing high
13 single-digit if not double-digit inflation and borrowing costs. These conditions
14 were being faced at the same time that many electric utilities were in the midst
15 of significant generation construction programs and experiencing slower-than-
16 originally-forecasted growth in sales. Today, interest rates and inflation rates are
17 but a fraction of that being experienced in the early 1980s when attrition
18 allowances were sometimes requested. Further, while APS is forecasting a need
19 for significant construction expenditures for transmission and distribution
20 facilities, it does not currently have plans to construct a new generating facility.
21 Further, pursuant to the stipulation from the 2003 rate case, APS is prohibited
22 from constructing new "self build" generating facilities with an in-service date

prior to 2015 unless it seeks and is granted permission by this Commission. (Per Proposed Settlement in Docket No. E-01345A-03-0437, paragraph IX-74)

I also note that this "base rate" increase is driven exclusively by increasing fuel and purchased power costs. In fact, after revisions discussed in later sections of this testimony, Staff is recommending an *overall* base rate increase of $191.4 million. Underlying Staff's overall base rate increase is its recommendation to increase fuel and purchased power costs by $193.5 million. Thus, absent the increase in PSA-includable fuel and purchased power costs – no increase in base rates is required at this point in time. Or in other words, other than for PSA-includable costs, APS' cost of service has been, and continues to be, adequately recovered with existing non-fuel base rates.

I also emphasize that Staff is recommending significant changes to the currently-approved PSA. If Staff's PSA recommendations are adopted, the likelihood of cash flow constraints from temporary under recovery (delay in recovery) of fuel costs should be significantly mitigated. Further, disallowances stemming from the current PSA 90% limitation on the pass through of power supply costs would also be eliminated under Staff's proposal. Thus, if Staff's PSA modifications are adopted, there should be little, if any, earnings attritions stemming from under recovery of prudently incurred fuel/purchased power costs. Further, cash flow constraints caused by the delay in the recovery of prudently incurred fuel and purchased power expense should be mitigated if, as

recommended under Staff's proposal, the annual PSA factor is based upon forecasted power supply costs.

In summary, at least based upon historic operating results, I believe any significant "attrition" that has been experienced has been resulting from the delay or disallowance of the recovery of fuel and purchased power expense. If Staff's PSA recommendations are adopted, attrition caused by delay or under recovery of prudently incurred fuel and purchased power expense should be de minimus – if it exists at all. Given current conditions of inflation, recent experience with APS' non-fuel/purchased power cost of service, as well as Staff's recommendations regarding prospective changes to the PSA, I do not believe that an attrition allowance is required at this point in time. That having been stated, I do not believe there should be any impediment to APS requesting an attrition allowance or other unique rate proposals *within its initial direct filing of its next rate case* – assuming one appears needed following the implementation of new base rates resulting from this case.

STAFF'S RECOMMENDATION REGARDING CONTINUATION OF THE INTERIM PSA ADJUSTOR

Q. Mr. Wheeler expressed confusion as to whether Staff was recommending that the interim PSA adjustor be terminated prior to the implementation of new base rates stemming from this case. He went on to specifically request the

Commission to authorize the synchronization of the expiration of the interim PSA with the implementation of new base rates resulting from this proceeding. Does Staff object to this proposal?

A. No. As stated within my direct testimony, it was assumed that new base rates would be implemented at about the time that the interim increase would expire. Staff has no objection to the continuation of the interim PSA until implementation of new base rates stemming from this proceeding.

STAFF'S REVISED RECOMMENDATIONS RESULTING FROM UPDATED, CORRECTED AND APS-CONCEDED ADJUSTMENTS

Q. Have you prepared revised Accounting Schedules that reflect needed corrections, updates and/or concessions included within APS rebuttal testimony and exhibits with which you agree?

A. Yes. I have revised Staff's original Joint Accounting Schedules to reflect updates included with APS' rebuttal testimony with which I agree. Further, APS has conceded a few issues presented by RUCO that Staff had not included within its original direct case. The updates, as well as the other APS concessions, have been included within Revised Joint Accounting Schedules filed as Staff Exhibit ___. I note that the Joint Accounting Schedules continue to post adjustments to APS' original as-adjusted retail jurisdictional cost of service filed with the Company's direct testimony in January 2006 even though APS has modified within rebuttal testimony some of its original adjustments and accepted all or portions of some of Staff and RUCO adjustments. Schedule E of the Revised Joint Accounting Schedules provides a reconciliation of issues

between Staff's revised-rebuttal position and APS' original filed position. To assist the Commission and the parties in understanding which Staff adjustments remain "at issue," I have added a column on Schedule E that identifies adjustments that remain at issue, adjustments that have been conceded by APS in concept but for which the ultimate dollar value of the issue is dependent upon other Commission determinations[1], as well as adjustments that APS has agreed to in principle and for which there should be no dispute as to the value of the adjustment.

Q. Within your direct testimony you provided a table that summarized the recommendations being proposed by APS versus Staff. Have you updated that table for APS' and Staff's revised recommendations as presented within APS' rebuttal testimony and Staff's surrebuttal testimony?

A. Yes, Table A-Rebuttal below summarizes the recommendations of APS and Staff as I understand them to be at this point in time.

[1] For instance, the ultimate revenue requirement value of a rate base issue will be dependent upon the return found reasonable by the Commission.

Table A-Rebuttal Summary of APS' Request Versus Staff's Recommendations		
	APS' Request	**Staff's Recommenda-tion**
Annual Dollar Increase in Base Rates (millions):		
Fuel/power supply increase recommended	$331.0	$193.5
Non-fuel Increase Recommended	$111.5	($2.0)
Total Overall Base Rate Increase Recommended	**$442.5**	**$191.5**
Environmental Improvement Charge	$4.5	
Incremental EPS	4.3	4.3
Paragraph 19 d Bal. Account "second step"		27.5
Total Increase – Base & Trackers	**$451.3**	**$223.3**
% Impact to Average Retail Customer:		
Fuel/power supply increase recommended	15.6%	9.1%
Non-fuel Increase (Decrease) Recommended	5.2%	(0.1%)
Total Overall Base Rate Increase Recommended	**20.8%**	**9.0%**
Environmental Improvement Charge	0.02%	–
Incremental EPS	0.02%	.2%
Paragraph 19 d Bal. Account "second step" (to be filed with Staff rate design testimony)		1.3%
Total Increase – Base & Trackers	**21.2%**	**10.5%**

As discussed in greater detail in the surrebuttal testimony of Mr. John Antonuk, the Staff is recommending that the 2007 PSA factor be based upon 2007 power supply costs as prepared and reviewed during the fourth quarter of 2006. However, for purposes of calculating the base amount of PSA costs to be included within the development of current base rates, Staff has reflected revised and updated 2006 power supply costs. The fuel/power supply costs being proposed by APS for inclusion in base rate development within its rebuttal case have been prepared in mid-2006 based on a 2007 forecast. While Table A-Rebuttal above might suggest that Staff and APS disagree significantly on the level of ongoing power supply costs to include in rates, conceptually both

1 parties are recommending reflection of forecasted 2007 power supply costs to
2 be recovered in rates starting early within calendar year 2007.
3
4 Q. Please briefly describe the updates that have been reflected within the Revised
5 Joint Accounting Schedules.
6 A. In direct testimony I proposed adjustments to update pension expense and post-
7 retirement medical benefits based upon then-available actuarial estimates for
8 those items for 2006. I recommended that these expense components be
9 updated for actual 2006 final results before the end of this proceeding. APS has
10 agreed to such update, and provided the amounts for such updates in the
11 testimony and exhibits of Ms. Laura Rockenberger. Accordingly, the original
12 Schedule Nos. C-6 and C-7 have been updated within the Revised Joint
13 Accounting Schedules to reflect the latest actuarial amounts provided within
14 APS rebuttal testimony.
15
16 Q. Please discuss the RUCO adjustments that APS has agreed to that were not
17 incorporated within Staff's original direct filing.
18 A. First, I proposed an advertising adjustment on behalf of Staff that APS has
19 agreed to. However, RUCO witnesses Ms. Marylee Diaz Cortez and Mr.
20 William Rigsby proposed additional advertising adjustments in the amounts of
21 $66,000 and $4,625, respectively, that APS has also agreed to. Accordingly,
22 Staff's original advertising adjustment found on Schedule C-8 has been revised

to include the additional concessions APS has made regarding RUCO's advertising adjustments.

Second, RUCO proposed the reflection of the post test year retirement of low pressure turbine equipment retired in conjunction with the Palo Verde 1 Steam Generator Replacement occurring in December 2005. This conceded retirement had the impact of reducing annualized depreciation expense by $262,000. On Schedule C-21 of the Revised Accounting Schedules I have reflected the noted depreciation expense adjustment that APS has conceded.

Third, RUCO proposed an adjustment to annualize interest on Customer Deposits based upon last-known interest rates being paid upon one-year treasuries. APS agreed in principle to this adjustment, but recommended that it be calculated based upon the actual 2006 rate in effect. Accordingly, I have reflected on revised Schedule C-22 the adjustment to annualize interest on Customer Deposits based upon the 2006 interest rate being paid by APS.

ACCELERATED RECOVERY OF UNDERFUNDED PENSION LIABILITY

Q. Please summarize the rebuttal comments and arguments of Mr. Donald Brandt regarding the issue of accelerated recovery of the underfunded pension liability.

A. Mr. Brandt offers the following rebuttal comments and arguments supporting the Company's continuing request for accelerated recovery of the underfunded pension liability:

- APS' pension plan did not "underperform" relative to the market
- APS' proposal will not lead to a "doubling up" of the recovery of pension costs – only the accelerated recovery of pension costs
- APS' proposal will not lead to intergenerational inequity between existing and future customers
- Corporate pension contributions have exceeded amounts charged to cost-of-service
- Accelerated cash contributions will reduce future years' pension expense that customers will enjoy via reduced cost-of-service based rates

Q. Referring to the first argument cited, do you disagree with Mr. Brandt's assertion that APS' pension trust did not "underperform" relative to the stock market?

A. No. When providing the background of events that have lead to the current "underfunded" pension trust position, I noted in my direct testimony that APS' trust balance actually declined between 2001 and 2003. However I went on to specifically state that such outcome "is not too surprising when one recalls that overall stock indexes also fell during this time frame." Thus, the basis for my opposition to the Company's accelerated recovery proposal is not that APS or its pension trustees have somehow dropped the ball when investing, and therefore APS should be "punished" by rejecting its accelerated cost recovery proposal. Rather, my direct testimony describes how projections of returns are often missed in the short run, but that *significant* "misses" in realized pension

trust returns are considered within FAS 87-determined net periodic pension costs that include an element for the "net amortization of actuarial loss." I will not reiterate all discussion and arguments on the topic of the net amortization of actuarial losses included at pages 82 and 83 of my direct testimony, but will simply summarize herein by stating that underperformance of investment returns *relative to previous projections* have been, and continue to be, considered within the development of the "net amortization of actuarial loss" component of FAS 87-determined pension expense that both APS and Staff have already considered within their cost-of-service recommendations.

Q. Please expand upon Mr. Brandt's second argument that APS' pension proposal will not lead to a "doubling up" of recovery of pension costs.

A. First, as just noted, I discussed in my direct testimony how the "amortization of net actuarial losses" already considers a portion of shortfalls in returns from earlier projections. Therefore, I argued in direct testimony that the Company's request for accelerated recovery of the underfunded pension liability would constitute at least a partial double recovery of such costs which were already being considered within the FAS 87-determined "net amortization of actuarial loss."

Q. Did Mr. Brandt address your double recovery argument?

A. No. At page 57 of his surrebuttal testimony Mr. Brandt briefly alludes to my "double recovery" argument, noting that a component of FAS 87-determined

pension expense includes the amortization of a portion of shortfalls from earlier projections – but then simply ignores the argument. Instead of offering any explanation as to why the Company's proposed accelerated recovery of the underfunded pension liability does not duplicate the impact of the "net amortization of actuarial losses" component of FAS 87-determined net periodic pension expense, he simply goes on to explain the mechanics of how, under the Company's proposal, monies collected in rates over five years targeted to fund the so-called underfunded pension liability position will be refunded to customers over the following ten-year period. The question of why monies collected within FAS 87-determined "net amortization of actuarial loss" does not duplicate – at least in part – the very same amount that APS is proposing to recover through its accelerated funding recommendation is simply ignored.

I believe there are many good arguments as to why the Company's proposal should be rejected. But in my opinion, the single strongest argument for rejection of this company proposal is that *such underfunded liability is already being considered within the FAS 87-determined pension expense* upon which rates are being set in this proceeding (under Staff's recommendations) and upon which rates have been established in prior APS rate cases for over 20 years. Mr. Brandt's total disregard for this argument does not cause it to lose its validity. *The Company's proposal will lead to at least a partial double recovery of such underfunded liability whenever there is a "net amortization of actuarial losses" component of FAS 87-determined net periodic pension cost.*

Q. Has the Company ever explained – in direct testimony, discovery, or within rebuttal testimony – the actual mechanics of how APS will refund to customers the monies that it proposes to collect on an accelerated basis?

A. No. At pages 57 and 58 of his rebuttal testimony Mr. Brandt briefly describes the *rate impact* of the Company's proposal as follows:

> As described in APS witness Rockenberger's direct testimony, the accelerated recovery over five years will reverse over the subsequent ten-year period. Pension cost recovery will not double up, but merely accelerate. Furthermore, customers in the near term would fund a liability that has already been incurred. We believe that by accelerating the recovery of underfunded pension expense over the next five years, customers would benefit over the subsequent ten years, as we amortize the balance recorded in the first five years. This lowering of revenue requirements in the future would have a stabilizing impact as the reversal partially mitigates higher costs related to infrastructure additions to serve customers' growing energy needs. (Brandt Rebuttal, pages 57 – 58)

Later in his rebuttal testimony Mr. Brandt assures this Commission that it is the Company's intention to fund the external pension trust with the incremental pension recovery that it would be collecting in rates.

Additionally, in Data Request No. UTI-7-266 (e) APS was asked to:

> [P]lease explain where the monies being collected from ratepayers on an accelerated basis in years 1 – 5 would be derived in order to facilitate a negative amortization (i.e., effectively a refund) and a return to ratepayers in years 6 – 15. Specifically state the extent to which the Company envisions the

> monies to be extracted from the external pension trust and how such extraction could legally occur.

The Company's answer was not illuminating, stating only:

> The return to ratepayers in years 6 – 15 would not come from the trust. The credit would come from the amortization of the regulatory liability.

Q. If the Company is permitted to recover in rates the presently-calculated underfunded pension liability over five years, and concurrently establishes a regulatory liability on its balance sheet that effectively represents an IOU to future ratepayers, where will the money to refund future ratepayers ultimately come from?

A. If the Company's construction program were to dramatically decline, there is a possibility that funds could be generated internally from operations (i.e., net income plus non-cash depreciation/deferred income tax expense). However, there has been nothing presented within Company testimony – direct or rebuttal – to suggest that this event is likely. To the contrary, the major theme in Mr. Steven Wheeler's as well as Mr. Brandt's rebuttal testimony is that infrastructure improvements will continue to cause the Company to borrow and spend more money on construction additions. Unless the current construction trend and the Company's prediction of future construction requirements reverse at the end of five years, the Company will have to borrow additional amounts, or issue additional equity, to come up with the monies to refund the amount sitting on its balance sheet as a regulatory liability.

1 Q. Can the Company just take the refund money out of the pension trust?

2 A. My understanding is that this is generally not possible. Even if the trust
3 becomes significantly "overfunded" in the sense that the market value of
4 pension assets exceeds the Projected Benefit Obligation, Internal Revenue Code
5 ("IRC") and/or ERISA restrictions generally prohibit the withdrawal of money
6 from the pension trust except to pay amounts owed to retirees. Accordingly,
7 based upon present APS claims of a continuing significant construction
8 program, I submit that monies that would be collected from ratepayers and
9 contributed to the pension trust over the next five years would have to be
10 borrowed or raised through equity sales in order to repay future ratepayers – at
11 the very time that the Company will likely need to go to capital markets to meet
12 its continuing construction program.

13

14 From my perspective, either the Company has not fully thought through the
15 mechanics of its proposal – the funding, refunding and accounting – or it simply
16 has not adequately explained how it can rationally, permissibly (from a tax
17 qualification standpoint) and equitably be undertaken. IRC and ERISA
18 requirements, which must be followed in order to keep a plan "qualified" and
19 thus tax efficient, simply prohibit the "withdrawal" of monies from the external
20 pension trust to facilitate customer refunds, even if past contributions had been
21 accelerated above minimum requirements for a period of time. And because of
22 these IRC/ERISA restrictions, I believe the Company's rate plan for pension

1 costs will exacerbate future cash flow challenges, while doing nothing to
2 improve the Company's current cash flow position.
3
4 Q. You have explained why the Company's proposal will likely create future cash
5 flow challenges. Why do you also state that the Company's proposal will do
6 nothing to enhance the Company's current cash flow position?
7 A. The Company is effectively committing to "fund" the external pension trust
8 with any monies it collects in rates as a result of a Commission order
9 authorizing its pension cost recovery proposal. If it meets this commitment,
10 cash flow from operations would not be improved inasmuch as "underfunded
11 pension" dollars collected in rates would go directly to the external trust fund.
12 In other parts of his rebuttal testimony Mr. Brandt discusses how the Funds
13 From Operation ("FFO") ratio is projected to be below the requirements
14 established by Standard and Poors to maintain an investment grade bond rating.
15 Both Mr. Brandt and Mr. Wheeler discuss rate alternatives that would raise
16 rates, enhance the FFO ratio, and purportedly assist the Company in maintaining
17 an investment grade bond rating. A couple of the alternatives suggested include
18 increasing depreciation expense or including Construction Work in Progress in
19 rate base. However, unlike these noted alternatives, the Company's proposal to
20 recover the underfunded pension liability on an accelerated basis will do
21 nothing to enhance cash flow, improve its FFO ratio, or assist it in maintaining
22 its bond rating. This occurs as a result of the fact that 100% of the monies
23 collected for five years (cash in-flow) will be contributed to the external trust

(cash out-flow) – resulting in no additional Funds From Operation being made available to the Company. As previously noted, following the five year accelerated recovery period, it is reasonable to expect that APS' cash flow position will be worsened as it attempts to "refund" the accelerated collections to customers over the following ten years with money it cannot retrieve from the external pension trust – and therefore would probably have to borrow.

Q. How do you respond to Mr. Brandt's claims that its proposal will not lead to intergenerational inequity?

A. Mr. Brandt rationalizes that current customers would be funding a liability that already exists – that pertains to benefits already accrued. Or in other words, Mr. Brandt is effectively arguing that current customers are already responsible for the underfunded liability. In arriving at this conclusion Mr. Brandt argues that – contrary to what I stated in direct testimony – the Projected Benefit Obligation does ***not*** consider future years of service, and accordingly, the "underfunded" pension liability truly relates to employee services provided to existing, if not previous, APS customers. Specifically, Mr. Brandt states at page 58 of his rebuttal testimony:

> Mr. Dittmer states that the PBO considers **future years of service** as well as future pay raises. Mr. Dittmer's statements have incorrectly described the PBO. In fact, the PBO does **not** consider **future years of service** (as discussed in the Company's response to one of the Staff's data requests – UTI 16-376). The PBO only considers employment service provided **prior** to the current measurement date. The PBO reflects estimated future pay

levels discounted to present-day dollars. Thus, APS does **not** request accelerated recovery of pension costs attributable to **future** employee service, but only the accelerated recovery of pension costs attributable to **prior** employee service. **(Emphasis as reflected in original testimony)**

Q. Who is correct on the matter of whether the Projected Benefit Obligation includes or excludes future years of service – you or Mr. Brandt?

A. This is a highly technical area. In my opinion, the language, guidance and definitions provided within FAS 87 are difficult even for accountants to understand. With that brief background, I sincerely submit that what we have both stated is technically correct, and that neither party has craftily undertaken "word smithing" to reach an intellectually dishonest conclusion. To the specific point, I believe that Mr. Brandt is technically correct when he states the Projected Benefit Obligation does not reflect a liability related to future employee service. But I was – and continue to be – technically correct when I state in my direct testimony that the Projected Benefit Obligation considers past pay and years of service as well as *future pay increases and years of service.* This apparent conflict can perhaps be best explained with a small example.

The actual retirement pay owed to employees (i.e., the ultimate liability) is determined for most defined benefit plans by considering years of service as well as actual pay earned during employment. In a nutshell, the longer an employee works, and the more he/she earns while employed, the more he/she will be owed upon retirement. Further, an employee typically earns more per

year the longer he/she works – achieving cost of living as well as merit/rank pay increases with the passage of time. Thus, just as a hypothetical example, a 45 year old employee with 15 years of employment making $60,000 a year may be entitled to $10,000 a year in retirement pay upon eventually reaching retirement age – based upon current pay and actual years of employment at age 45. The $10,000 retirement pay would equate to approximately 17% of his final year of pay assuming he were to terminate his employment at age 45 ($10,000 divided by $60,000 equals 16.7%). However, if the employee works for an additional 15 years – or 30 years in total – he/she could, under the hypothetical example, be making $120,000 in his final year of employment. Because of the higher, final years of pay, as well as the additional employment years that result in a higher final payout liability, he/she would be entitled to $50,000 per year upon retirement. By working an additional 15 years, not only does the nominal dollar payout increase ($50,000 per year versus $10,000 per year after 15 years of service), but the retirement payout as a percentage of final pay also increases to 42% ($50,000 divided by $120,000 equals 41.7%).

My understanding is that the calculation of the Accumulated Benefit Obligation considers only the liability, in the example given, as it would exist at the end of the first 15 years of employment (i.e., the net present value of the $10,000 payout for life upon retirement already accrued or "earned" by the employee). However, the calculation of the Projected Benefit Obligation would also consider the likelihood that the employee would continue to work for additional

1 years (i.e., future years of service) and continue to receive future pay increases.
2 In other words, the calculation of the Projected Benefit Obligation would, at the
3 end of 15 years, consider an allowance for the fact that more pension cost and
4 related liability should be recognized currently for likely additional years of
5 service and future pay increases – but not to the point of recognizing the *total*
6 Projected Benefit Obligation that will exist when the employee actually
7 completes the additional 15 years of service and receives all of the future pay
8 increases.
9
10 In summary on the issue, I continue to claim – as I stated in direct testimony –
11 that the Projected Benefit Obligations *considers* future years of service and
12 future pay raises, but I do not dispute Mr. Brandt's assertion that the Projected
13 Benefit Obligation only reflects the pension liability for employment service
14 provided prior to the current measurement date.
15
16 The important point to be gleaned from this discussion is that there are different
17 measurements of "underfunding." In the continuum of funding positions, the
18 calculation of the Accumulated Benefit Obligation measures the lowest level of
19 pension obligation, while the calculation of the Projected Benefit Obligation –
20 which considers future years of service and future pay increases – measures the
21 highest level of pension liability incurred to date. As noted on Table D included
22 within my direct testimony, the Company's calculated funding position at any
23 point in time tends to fluctuate fairly significantly. It is not unusual for the

1 pension trust to be fairly significantly over or underfunded at a particular point
2 in time.
3
4 Q. Returning to the earlier argument, do you still contend that the Company's
5 proposal will lead to intergenerational inequity?
6 A. Yes. The inclusion of the "net amortization of actuarial loss" component of
7 FAS 87-determined pension cost will tend to "make up" for past under or over
8 funding of pension costs relative to prior projections. Thus, basing rates upon
9 FAS 87-determined pension expense will eventually lead to the collection of
10 monies to meet the underfunded pension liability. Since APS' proposal will
11 duplicate the collection of the underfunded pension liability occurring with FAS
12 87-determined rates for the first five years of the APS plan, holding all other
13 elements and assumptions constant, there will likely be an over collection of the
14 "underfunded pension liability" following the first five years of APS' proposal.
15 Under the Company's proposal, a portion of the "over collection" occurring
16 during the first five years of the plan would then be refunded over the ensuing
17 ten years – clearly leading to intergenerational inequity between current and
18 future rate payers.
19
20 Q. Mr. Brandt also argues that over the past five years pension contributions have
21 actually exceeded net periodic pension costs – and that claims to the contrary
22 you made in direct testimony were ***incorrect***. How do you respond to such
23 claims?

1 A. First, apparently the contributions I reflected
2 were off by one year, and therefore were inc
3 whole discussion in my direct testimony was
4 had made contributions that were less than n
5 the Company should be expected to make
6 equivalent to net periodic pension costs bein
7 Commission allows recovery of additional u
8 accelerated basis. As one can observe fro
9 Attachment DEB-17RB, notwithstanding the
10 contributions to the external pension fund
11 cost for years 2003 and 2004. And thus,
12 testimony remains valid. I think it is reason
13 contributions to the external trust that are
14 pension costs being used to establish retail
15 recover the underfunded pension liability on
16
17 Q. How do you respond to Mr. Brandt's argum
18 contributions will reduce future years' p
19 enjoy via reduced cost-of-service based rate
20 A. All other things held constant, the accelera
21 to reductions in future years' otherwise-c
22 However, the same could be said regard
23 included in rate development. Deprec

1 pension trust to be fair
2 in time.
3
4 Q. Returning to the earlie
5 proposal will lead to int
6 A. Yes. The inclusion of
7 FAS 87-determined pen
8 funding of pension cost
9 FAS 87-determined pen
10 monies to meet the und
11 duplicate the collection c
12 87-determined rates for
13 elements and assumption
14 "underfunded pension lia
15 Under the Company's p
16 during the first five years
17 ten years – clearly leadi
18 future rate payers.
19
20 Q. Mr. Brandt also argues th
21 actually exceeded net per
22 you made in direct testin
23 claims?

1 A. First, apparently the contributions I reflected on Table C of my direct testimony
2 were off by one year, and therefore were incorrect. However, the point of the
3 whole discussion in my direct testimony was that in recent years the Company
4 had made contributions that were less than net periodic pension cost – and that
5 the Company should be expected to make contributions that were at least
6 equivalent to net periodic pension costs being reflected within rates before the
7 Commission allows recovery of additional underfunded pension liability on an
8 accelerated basis. As one can observe from values shown on Mr. Brandt's
9 Attachment DEB-17RB, notwithstanding the corrections made, the Company's
10 contributions to the external pension fund were less than net periodic pension
11 cost for years 2003 and 2004. And thus, the point I was making in direct
12 testimony remains valid. I think it is reasonable to expect the Company to make
13 contributions to the external trust that are at least equivalent to net periodic
14 pension costs being used to establish retail rates before seeking permission to
15 recover the underfunded pension liability on an accelerated basis.
16
17 Q. How do you respond to Mr. Brandt's argument that recovery of accelerated cash
18 contributions will reduce future years' pension expense that customers will
19 enjoy via reduced cost-of-service based rates?
20 A. All other things held constant, the accelerated recovery of this liability will lead
21 to reductions in future years' otherwise-calculated cost-of-service-based rates.
22 However, the same could be said regarding the recovery of any utility asset
23 included in rate development. Depreciation expense could be recovered

quicker, resulting in lower rate base values and return requirements in the future. If the Commission were inclined to attempt to "stabilize" rates by changing the recovery period of an asset or paying off a liability (something I am not advocating but nonetheless point out), I would encourage it to consider means other than the accelerated recovery of the underfunded pension liability. For specific reasons stated, I believe that accelerated recovery of the so-called underfunded pension liability will create issues and problems – particularly during the ten year period wherein ratepayers will purportedly be "refunded" for accelerated payments made during the first five years of the Company's plan.

Q. Please summarize your surrebuttal testimony regarding the Company's proposal to recover the underfunded pension liability on an accelerated basis.

A. First, this underfunded position caused by the APS pension trust not meeting prior fund projections is already being considered within the "net amortization of actuarial loss" component of FAS 87-determined net periodic pension cost. Second, while it is not desirable that the Projected Benefit Obligation become significantly over or underfunded, it is not a particularly unusual situation. Third, the Company's proposal will lead to intergenerational inequities among rate payers. And fourth, I believe such proposal will lead to future cash flow problems for the Company, while doing nothing to improve the Company's current cash flow position. For these reasons summarized, as well as other reasons set forth in greater detail within my direct testimony, I would strongly urge the Commission to reject this Company proposal.

DEFERRED BARK BEETLE REMEDIATION COSTS

Q. Does an issue continue to exist between Company and Staff regarding deferred bark beetle remediation costs?

A. Yes. I discussed within my direct testimony the propriety of an adjustment to rate base as well as amortization expense related to deferred bark beetle costs. Some of the elements of those adjustments have been conceded by APS. However, one element of my adjustment dealt with the disallowance of bark beetle remediation costs deferred prior to the effective date of the last Commission order (i.e., the period January 2005 through March 2005). APS has not agreed to this element of the adjustment reflected within Staff's direct case.

Q. What is APS' rebuttal position regarding the deferral of costs prior to the effective date of the rate order?

A. APS witness Ms. Laura Rockenberger argues that the language from the Commission's order indicates that a full year of recovery was intended. Specifically, Ms. Rockenberger quotes and relies upon the Commission's language that states:

> APS is authorized to defer for later recover the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control.

She goes on to conclude that the Company believed that the August 2004 Settlement intended that deferrals would include the entire calendar year in which the deferral became effective.

1 Q. How do you respond to Ms. Rockenberger's position?

2 A. Frankly, I do not understand how she can draw a conclusion that the agreed-
3 upon language that sets the minimum basis for a deferral amount (i.e., the prior
4 test year expense level) can somehow be interpreted to mean that deferral
5 should begin earlier within a calendar year than the effective date of the order.
6 Clearly, that was not Staff's understanding or intention when agreeing to allow
7 the Company to defer amounts "that exceed the test year levels of tree and brush
8 control." Further, in all my years of negotiating and reviewing the impact of
9 accounting deferral orders, I do not ever recall an order being applied
10 retroactively from the implementation date of the order *unless explicitly set*
11 *forth within the order.* Ultimately I suppose this Commission can inform the
12 parties of *its* intentions regarding the noted language, but I would simply
13 summarize that Staff never interpreted the stipulation language to be applied
14 prior to the effective date of the Commission's order – and that such
15 interpretation is consistent with the way I have always seen accounting authority
16 orders interpreted *absent specific language to the contrary.*

17

18 **INVESTMENT TAX CREDITS AS A RATEBASE OFFSET**

19 Q. Please briefly summarize the Company's rebuttal position regarding your
20 proposed adjustment to reduce rate base for Investment Tax Credits ("ITC")
21 being realized as a result of the Company amending prior year tax returns.

22 A. The Company claims that the majority of my proposed rate base adjustment for
23 Investment Tax Credits will result in a violation of an Internal Revenue Code

"normalization" requirement, and accordingly, it urges the rejection of the entire rate base adjustment.

Q. How do you respond to this Company rebuttal argument?

A. I would note a few items to put this adjustment into perspective. First, the total revenue requirement value of the issue is relatively small. Using Staff's proposed overall rate of return, the value of the rate base issue as presented within Staff's direct case is approximately $235,000. Staff's original adjustment was calculated by considering one-half of the ITC savings generated after allowing the Company full recovery of the cost to achieve the additional ITCs.

Second, assuming the Company's position that my rate base adjustment constitutes an IRC normalization violation is correct, the ramifications suggested by the Company will be very significant – resulting in the loss of tens of millions of dollars of previously-claimed ITCs that presumably would have to be refunded to the Internal Revenue Service.

Given that the value of the revenue requirement issue is relatively insignificant, I do not believe the Company should be exposed to a very significant disallowance by the Internal Revenue Service of previously claimed ITCs.

Q. Are you then withdrawing your ITC rate base adjustment?

1 A. Not entirely. Rather, I am proposing to modify it so that a normalization
2 violation should not occur. Specifically, the Company claims that 62% of my
3 ITC rate base adjustment will definitely result in a normalization violation.
4 Therefore, I am first reducing my original adjustment to eliminate 62% of the
5 ITCs related to property that has already been fully depreciated for tax purposes.
6 Further, the Company claims that only the unamortized balance of the
7 remaining 38% of ITCs – as calculated from the original in service date of the
8 property generating the ITC – would be allowable as a rate base offset in order
9 to be in compliance with normalization requirements. I do not know what that
10 exact "unamortized" amount would be, but for purposes of calculating a revised
11 adjustment I have assumed that one-half of the ITCs would be amortized as of
12 the end of the test year. Originally I was proposing a 50/50 sharing between
13 ratepayers and the Company of net savings resulting from all of the new ITCs
14 claimed. However, for purposes of my revised adjustment, I am proposing that
15 100% of the unamortized ITC balance related to plant *not fully depreciated* be
16 reflected as a rate base offset.
17
18 Q. Why are you now proposing that 100% of the unamortized and unrestricted-as-
19 to-rate-base adjustment amount be considered within rate base determination?
20 A. For reasons stated in my direct testimony, I believe it most equitable to credit
21 ratepayers with at least some of the savings realized by APS when amending its
22 prior years tax returns. The majority of ITC savings appear to be IRC-protected
23 from sharing with ratepayers at this point in time. Thus, it is only fair that the

1 maximum amount of savings resulting from ITCs that do not have IRC
2 restrictions be considered within the development of rates in this proceeding.
3 Further, I would note that my revised proposal provides a very generous sharing
4 of savings between APS and ratepayers. Specifically, with this calculation,
5 APS would retain 100% of the ITC savings realized from the 62% of ITCs that
6 should have already been fully amortized. Further, APS would retain one-half
7 (i.e., the unamortized portion) of the remaining 38% of ITC savings realized.
8 Thus, the total split of savings from ITCs would be 81% and 19% for APS
9 shareholders and ratepayers, respectively. This treatment is very fair and
10 generous to APS shareholders – and importantly, should not result in any
11 normalization requirements.
12
13 Q. Have you researched whether, and do you accept the Company's claim that,
14 your original adjustment will result in a normalization violation?
15 A. I asked the Company to provide the authorities that it was relying upon to reach
16 the conclusion that my adjustment would result in an IRC normalization
17 violation. The Company provided to me an Internal Revenue Service Private
18 Letter Ruling that states facts that are similar to that which exists with regard to
19 the ITC rate base adjustment I have proposed. It would appear from a read of
20 the Private Letter Ruling that the ITC rate base adjustment as I originally
21 proposed would be an IRC normalization violation. That having been stated, I
22 would note that 1) I have not attempted to independently research whether there
23 might be other rulings or decisions that are more favorable to the adjustment I

am proposing and 2) the Private Letter Ruling specifically states that "[t]his ruling is directed only to the taxpayer who requested it" – as is standard in every private letter ruling I have ever reviewed.

It is possible that upon further research a determination could be made that my original adjustment would not result in a normalization violation. However, the Private Letter Ruling appears to be pretty much on point. Given this conclusion, and the relatively small value of the issue, I would urge the Commission to adopt my much smaller revised rate base adjustment and not attempt to "test" whether a further adjustment might result in a catastrophic disallowance to the Company. Further, given the *maximum* value of the issue, it would be very difficult to justify applying significant additional resources to researching whether there is any possibility that adoption of my entire original rate base adjustment would *not* lead to an IRC normalization violation.

CASH WORKING CAPITAL – LEAD LAG STUDY DEVELOPMENT

Q. Mr. Fred Balluff has filed rebuttal testimony on behalf of APS addressing the development of a lead lag study for use in the determination of the Company's cash working capital allowance. Do you have any comments or responses to arguments presented in Mr. Balluff's rebuttal testimony?

A. I filed fairly extensive direct testimony on this topic, so my comments and responses will be limited in number and brief in length so as to not become repetitive of lengthy arguments already made within my direct testimony.

First, in my direct testimony I discussed how payments for expenditures related to recently completed construction projects closed to plant in service included in rate base would not have been fully paid for in cash as of the end of the historic test year ending September 30, 2005. This argument was made in the context of addressing why a lag for non-cash depreciation expense should ***not*** be included in the development of a properly prepared lead lag study. Mr. Balluff refers to this testimony as "speculation" and notes that I did not offer any proof of such assertion.

In response I would note that construction expenditures closed to plant include Company labor capitalized, materials and supplies, as well as payments to outside contractors used on construction projects. The lags in the payment for all these types of components are measured as they exist for "expense" categories within a lead lag study. While no separate and specific lag day calculation was prepared for such expenditure as they exist regarding construction expenditures, I believe it would be absurd to assume that similar, if not identical, lags do not occur when paying for these exact same components incurred for construction projects. Accordingly, I do not believe the "proof" calculations suggested are necessary to simply conclude that a portion of test year end recorded plant in service would not have been fully "paid for" at test year end.

1 Second, in direct testimony I provided a fairly extensive listing of Arizona cases
2 wherein this Commission has upheld the lead lag study approach that I again
3 propose in this case. At page 9 of his rebuttal, Mr. Balluff lists three state
4 jurisdictions that purportedly include "non-cash" expenses within the
5 development of lead lag studies used in working capital development. I
6 recognize that there is not complete unanimity among regulators on this issue.
7 But so as to avoid any mistaken impression that Arizona is the only jurisdiction
8 that routinely adopts the methodology that it has previously adopted – and
9 which I am again proposing in the instant case – I note that the states of Kansas,
10 Missouri and Oklahoma routinely adopt the exact same methodology that this
11 Commission has previously accepted regarding exclusion of non-cash expenses
12 and inclusion of interest expense in lead lag studies. Other states may also
13 accept such methodology, but these are three jurisdictions that I happen to be
14 personally familiar with without undertaking any research or surveys on the
15 subject.
16

17 **SUNDANCE OPERATION AND MAINTENANCE EXPENSE**

18 Q. APS rebuttal witness Mr. Peter Ewen is critical of your adjustment that rejects a
19 portion of the projected Sundance units' maintenance costs as proposed by APS.
20 Please provide your understanding of his major criticisms of your adjustment.
21 A. Mr. Ewen's objections to the Sundance O&M adjustment proposed by me are:
22 • The recommendation and adjustment for Sundance overhaul O&M
23 expense normalization is inconsistent with that proposed for other
24 plants as well as previous Commission precedent

- Adoption of the adjustment will almost certainly lead to an under recovery of Sundance costs

Q. How do you respond to Mr. Ewen's criticisms?

A. Regarding the claim of "inconsistency," it should first be understood that the overhaul maintenance expenses at issue relate to a recently constructed and acquired generating facility for which there is very little historical operating information. In this case, and in all prior APS rate cases occurring over at least the past 20 years, maintenance expense for older, mature generating units has been normalized for cost-of-service inclusion by taking a multi-year historical average of actual costs incurred after first adjusting the costs incurred for inflation experienced during the period employed in developing the average. Because the Sundance units have only recently been placed in service, multiple years of data to use in developing an historical average – as has been employed for APS' older, mature units – is not available. In the absence of historical overhaul costs for the Sundance units, APS has prepared its adjustment by considering prospective or forecasted overhaul costs. However, the forecasted overhaul costs in question will not, by the Company's own admission, begin to be incurred until many years in the future. And for that reason, I recommend that they be excluded from cost-of-service development in the instant case.

A similar situation arose in the 2003 APS rate case for the PWEC units, and still exists regarding those units in the instant case. While there is a little more historical data for some of the PWEC units than what exists for the Sundance

units, there is still insufficient data to undertake the multi-year historical average approach as is undertaken for APS' older units. In the 2003 rate case, APS proposed, and Staff consultants did not object to, the use of an average of a multi-year *projection* of PWEC overhaul costs for cost-of-service development. PWEC overhaul costs proposed by APS for cost-of-service development in the prior as well as current case were developed by considering projected future year maintenance costs. However, the methodology employed by APS in developing its PWEC overhaul expense adjustment in the previous case and current, is significantly different than what it has proposed for the Sundance units. Specifically, for the PWEC units APS proposes the use of a 12 year projected average of overhaul costs, with all costs reflected in 2004-purchasing-power dollars. A similar approach was undertaken by APS in the 2003 rate case, and not opposed by Staff consultants in that case.

To adjust for overhaul costs for the Sundance units, APS has employed an entirely different approach in this case. Specifically, the "non-routine" maintenance portion of APS' Sundance adjustment was calculated by considering the expected cost of certain major or "non-routine" maintenance activities, and dividing such projected costs into the expected number of hours of usage between such activities, to arrive at an average non-routine maintenance cost-per-hour of usage. The calculated average non-routine maintenance cost-per-hour-of-usage was then multiplied times the expected normalized annual hours usage for the Sundance units to arrive at a normalized

1 annual cost level for such non-routine maintenance activities. As previously
2 noted, the non-routine maintenance overhauls considered in the development of
3 the Company's Sundance adjustment are not projected to occur for many years
4 into the future[2]. Accordingly, the Sundance methodology proposed by APS is
5 *inconsistent* with the approach APS is proposing for the PWEC units – an
6 approach that considers an average of overhaul costs that *has already begun to*
7 *occur and that is predicted to occur in immediately ensuing years*. If APS had
8 undertaken an approach for normalizing maintenance costs for the Sundance
9 units as it did for the PWEC units, the result would have been that it would have
10 been proposing very little, if any, overhaul costs for the Sundance units. Thus in
11 summary, if any party is inconsistent in approach regarding this issue, I submit
12 it is APS.
13
14 While on the topic of PWEC O&M expenses, I note that since the 2003 rate
15 case APS has only incurred a fraction of the level of overhaul costs that was
16 included within the development of base rates in the previous APS rate case.
17 Further, I note that other intervenors are proposing downward adjustments to
18 APS' proposed level of PWEC O&M expense. While I am not attempting to
19 adopt such intervenor adjustments, I would simply note that I spent considerable
20 time reviewing historical PWEC costs incurred and attempting to ascertain the
21 reasonableness of APS' forecast and request in the instant case. I was, and
22 continue to be, somewhat uncomfortable with the high level of PWEC O&M

[2] See confidential portion of my direct testimony found at page 97 for APS' projected dates of first Sundance overhaul activities.

1 expense included within the Company's adjusted test year cost of service.
2 Ultimately I did not propose a downward adjustment to PWEC O&M expense,
3 but I would summarize by stating that I believe the level of PWEC O&M
4 expense included within Company's case (and the Staff's case in the absence of
5 any downward adjustment) should certainly be considered at the high end of
6 any reasonable range of estimated PWEC O&M costs to be incurred during the
7 period that rates in this case are likely to be in effect.
8
9 Q. How do you respond to Mr. Ewen's claim that your proposed treatment will
10 almost certainly result in an under recovery of Sundance maintenance costs?
11 A. At pages 98 and 99 of my direct testimony I provided a detailed explanation as
12 to why I believe the Company's approach to developing the overhaul portion of
13 its Sundance O&M expense adjustment will, in all likelihood, lead to an
14 *overcharge* of such costs. I will not repeat such reasoning, but simply
15 incorporate such argument by reference herein. Mr. Ewen ignores my detailed
16 argument regarding how an overcharge of such costs under the Company's
17 proposal will likely occur, but without any explanation whatsoever throws out a
18 simple *quid quo pro* statement that failure to adopt the Company's proposal
19 "will almost certainly" lead to an under recovery of Sundance costs.
20
21 Further, I note that in direct testimony I held out the possibility that Sundance
22 maintenance costs being recovered in rates today could be deferred on the
23 Company's balance sheet until such activities were undertaken – and related

1 costs incurred – at some point in the future[3]. Apparently even this alternative
2 remains undesirable to the Company inasmuch as Mr. Ewen did not even
3 address this possibility in rebuttal testimony.
4
5 In summary, I believe it is the Company that is being *inconsistent* in its
6 approach to developing Sundance overhaul expense for cost-of-service
7 inclusion, and failure to accept Staff's adjustment will, in all likelihood, lead to
8 an over collection of such costs over time.
9 Q. Does that **conclude** your direct testimony?
10 A. Yes, it does.

[3] The deferral proposal was included in direct testimony *in the event the Commission was inclined to accept the Company's level of Sundance overhaul cost* that is not projected to be incurred until many years in the future. As explained within my direct testimony, the deferral accounting alternative is not my primary recommendation, and in fact, I go on to explain that I believe such deferral accounting is unnecessary and unduly complicated for such a relatively minor level of cost incurrence.

EXHIBIT
S-38
admitted

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

REVISED JOINT ACCOUNTING SCHEDULES

OF THE

ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

FILED WITH STAFF SURREBUTTAL TESTIMONY ON SEPTEMBER 27, 2006

PUBLIC VERSION

PREPARED
BY
UTILITECH, INC.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Revised
Schedule A
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	APS PROPOSED ORIGINAL COST	APS PROPOSED FAIR VALUE	STAFF PROPOSED ORIGINAL COST	STAFF PROPOSED FAIR VALUE
	(A)	(B)	(C)	(D)	(E)	(F)
1	PROPOSED RATE BASE	Sch B	$ 4,466,697	$ 6,120,755	$ 4,402,377	$ 6,056,435
2	RATE OF RETURN	Sch D	8.73%	6.37%	8.05%	5.85%
3	OPERATING INCOME REQUIRED	Line 1 * 2	$ 389,943	$ 389,943	$ 354,391	$ 354,391
4	NET OPERATING INCOME AVAILABLE	Sch C	115,904	115,904	237,636	237,636
5	OPERATING INCOME EXCESS/DEFICIENCY	Line 3 - 4	$ 274,039	$ 274,039	$ 116,755	$ 116,755
6	REVENUE CONVERSION FACTOR	Sch A-1	1.6407	1.6407	1.6407	1.6407
7	OVERALL REVENUE REQUIREMENT	Line 5 * 6	$ 449,616	$ 449,616	$ 191,563	$ 191,563
8	ENVIRONMENTAL IMPROVEMENT CHARGE		4,315	4,315		
9	TOTAL INCREASE IN RATES	Line 7 + 8	$ 453,931	$ 453,931	$ 191,563	$ 191,563

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVENUE CONVERSION FACTOR
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	COMPANY PROPOSED
	(A)	(B)	(C)
1	Gross Jurisdictional Revenue		100.0000%
2	Less: Effective State Income Tax	APS Sch. 3	6.23%
3	Less: Effective Federal Income Tax	APS Sch. 3	32.82%
4	Operating Income % = 100% - Tax Percentage	Ln1-Ln2-Ln3	60.9500%
5	Income to Revenue Multiplier	Line 1/Line 4	1.640689
			(a) (b)

Footnote:
(a) Source: APS Schedules A-1 & C-3.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Revised
Schedule B

LINE NO.	DESCRIPTION	ORIGINAL COST AS ADJUSTED BY APS	ORIGINAL COST STAFF ADJUSTMENTS	ORIGINAL COST AS ADJUSTED BY STAFF	RCND AS ADJUSTED BY APS	RCND STAFF ADJUSTMENTS	RCND AS ADJUSTED BY STAFF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Gross Utility Plant in Service	$ 9,296,308	$ -	$ 9,296,308	$ 15,219,192		$ 15,219,192
2	Less: Accumulated Depreciation & Amort.	(3,546,560)	-	(3,546,560)	(6,161,346)		(6,161,346)
3	Net Utility Plant in Service	5,749,748	-	5,749,748	9,057,846	-	9,057,846
	Deductions:						
4	Deferred Taxes	(1,064,449)	(767)	(1,065,216)	(1,064,432)	(767)	(1,065,199)
5	Investment Tax Credits	-	-	-	-	-	-
6	Customer Advances for Construction	(59,807)	-	(59,807)	(59,807)	-	(59,807)
7	Customer Deposits	(54,860)	-	(54,860)	(54,860)	-	(54,860)
8	Pension Liability	(68,699)	-	(68,699)	(68,699)	-	(68,699)
9	Liability for Asset Retirement	(260,419)	-	(260,419)	(260,419)	-	(260,419)
10	Other Deferred Credits	(109,485)	-	(109,485)	(109,485)	-	(109,485)
11	Unamortized Gain-sale of Utility Plant	(46,360)	-	(46,360)	(46,360)	-	(46,360)
12	Regulatory Liabilities	(160,744)	(3,661)	(164,405)	(160,744)	(3,661)	(164,405)
13	Total Deductions	(1,824,823)	(4,428)	(1,829,251)	(1,824,806)	(4,428)	(1,829,234)
	Additions:						
14	Regulatory Assets	64,020	(2,873)	61,147	64,020	(2,873)	61,147
15	Miscellaneous Deferred Debits	39,464	-	39,464	39,464	-	39,464
16	Depreciation Fund - Decommissioning	285,855	-	285,855	285,855	-	285,855
17	Allowance for Working Capital	152,433	(57,018)	95,415	152,433	(57,018)	95,415
18	Total Additions	541,772	(59,891)	481,881	541,772	(59,891)	481,881
19	Total Rate Base	$ 4,466,697	$ (64,320)	$ 4,402,377	$ 7,774,812	$ (64,320)	$ 7,710,492

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RATE BASE SUMMARY
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Revised
Schedule B
Page 2 of 2

LINE NO.	DESCRIPTION	B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	Page Total
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Gross Utility Plant in Service									$ -
2	Less: Accumulated Depreciation & Amort.									-
3	Net Utility Plant in Service	-	-	-	-	-	-	-	-	-
	Deductions:									
4	Deferred Taxes			(767)						(767)
5	Investment Tax Credits									-
6	Customer Advances for Construction									-
7	Customer Deposits									-
8	Pension Liability									-
9	Liability for Asset Retirement									-
10	Other Deferred Credits									-
11	Unamortized Gain-sale of Utility Plant									-
12	Regulatory Liabilities	(3,661)								(3,661)
13	Total Deductions	(3,661)	-	(767)	-	-	-	-	-	(4,428)
	Additions:									
14	Regulatory Assets		(2,873)							(2,873)
15	Miscellaneous Deferred Debits									-
16	Depreciation Fund -- Decommissioning									-
17	Allowance for Working Capital				(57,018)					(57,018)
18	Total Additions	-	(2,873)	-	(57,018)	-	-	-	-	(59,891)
19	Total Rate Base	$ (3,661)	$ (2,873)	$ (767)	$ (57,018)	$ -	$ -	$ -	$ -	$ (64,320)

ADJUSTMENTS:

B-1 SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
B-2 CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
B-3 INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
B-4 CASH WORKING CAPITAL
B-5 **reserved**
B-6 **reserved**
B-7 **reserved**
B-8 **reserved**

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Accumulated Provision for SFAS 112 Deferred Credits		
2	Acquiesced by APS in Discovery to be Properly Included		
3	as a Rate Base Offset	UTI-10-302	$ (3,886,000)
4	Composite Retail Jurisdictional Wages & Salaries Allocator		94.212%
5	ACC Jurisdictional Adjustment to Reflect SFAS 112 Deferred		
6	Credits as a Rate Base Offset	Line 3 * Line 4	$ (3,661,453)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2 3	Proforma Rate Base Adjustment Proposed by APS to Reflect Estimated Growth in Deferred Bark Beetle Costs Between the End of the Historic Test Year and December 31, 2006	LLR_WP7, p. 2	$ 6,114,585
4	Correction Required as Noted in Response to Discovery	UTI-14-351	704,820
5 6	Eliminate Bark Beetle Cost Deferred Prior to April 1, 2005 (the Rate Effective Period Resulting from 2003 Rate Case Order)	LLR_WP17, p. 3	(1,501,069)
7 8	Corrected Before-Tax Bark Beetle Rate Base Deferral Adjustment to End of Test Year Actual Recorded Balance	Sum Lines 3 thru 6	5,318,336
9	Composite Federal and State Income Tax Rate		39.05%
10 11	Related Accumulated Deferred Income Tax Expense Properly Reflected as a Rate Base Deduction	Line 8 * Line 9	2,076,810
12 13	Correct Total Before and After Tax Adjustment to Test Year End Recorded Deferred Bark Beetle Costs	Line 8 - Line 11	3,241,526
14 15	Total Company Rate Base Adjustment for Deferred Bark Beetle Remediation Costs	Line 13 - Line 3	$ (2,873,059)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule B-3
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Total Amount of Investment Tax Credits Expected to be Realized As a Result of Amending Prior Year Federal Income Tax Returns	UTI-10-299	$ 6,483,389
3	Revenue Conversion Factor	Sch. A-1	1.64069
4 5	Total Revenue Requirement Savings Resulting From Amending Prior Years Tax Returns to Claim Additional ITCs	Line 2 * 3	10,637,226
6	Total Costs Incurred to Research and Claim Additional ITCs		
7	Total Contingency Charge Recorded in 2003	UTI-10-301	(2,385,468)
8	Fee for Service Charge Recorded in February 2005	UTI-10-301	(1,553,333)
9	Net Total Company Revenue Requirement Savings Realized	Lines 5+ 7 + 8	6,698,425
10 11	Percentage Attributable to Plant Not Yet Fully Depreciated	Froggatt Rebuttal	38.0%
12	Subtotal	Line 9 X*Line 11	2,545,401
13	Percentage Assumed to Be Depreciated @ 9/30/05		50.00%
14	Revenue Requirement Savings Allocated to Ratepayers	Line 12 * Line 13	1,272,701
15	Equivalent Total Company Rate Base Offset	Line14/Line 3	(775,711)
16	ACC Jurisdictional Demand Factor		98.847%
17 18	ACC Jurisdictional Adjustment to Rate Base for ITCs Allocated to Rate Payers	Line 12 * Line 13	$ (766,768)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION		AMOUNT	REVENUE LAG (a)	EXPENSE LAG	NET LAG (DAYS)	CWC FACTOR	CWC REQUIREMENT
	(A)		(B)	(C)	(D)	(E)	(F)	(G)
1	FUEL FOR ELECTRIC GENERATION							
2	COAL		$ 200,856,342	36.85231	32.36664	4.48567	0.01229	$ 2,468,428
3	NATURAL GAS		237,557,927	36.85231	44.25857	-7.40625	-0.02029	(4,820,311)
4	FUEL OIL		1,077,082	36.85231	32.34030	4.51172	0.01236	13,314
5	NUCLEAR:							
6	AMORTIZATION		34,445,413	0.00000	0.00000	0.00000	0.00000	0
7	SPENT FUEL		7,336,099	36.85231	76.35359	-39.50128	-0.10822	(793,932)
8	SUBTOTAL		481,272,863					(3,132,502)
9	PURCHASED POWER	(b)	471,931,131	36.85231	38.15020	-1.29789	-0.00356	(1,678,121)
10	TRANSMISSION BY OTHERS		14,391,245	36.85231	33.69389	3.15842	0.00865	124,531
11	SUBTOTAL		486,322,376					(1,553,591)
12	OTHER OPERATIONS & MAINTENANCE							
13	PAYROLL		240,714,447	36.85231	15.00192	21.85039	0.05986	14,410,153
14	INCENTIVE		8,653,091	36.85231	214.50000	-177.64769	-0.48671	(4,211,511)
15	PENSION AND OPEB		38,986,000	36.85231	77.71371	-40.86140	-0.11195	(4,364,445)
16	EMPLOYEE BENEFITS		26,995,515	36.85231	20.35895	16.49337	0.04519	1,219,855
17	PAYROLL TAXES		18,118,131	36.85231	21.78589	15.06643	0.04128	747,878
18	MATERIALS & SUPPLIES		53,466,114	36.85231	24.22000	12.63231	0.03461	1,850,413
19	FRANCHISE PAYMENTS		11,986,402	36.85231	52.83966	-15.98735	-0.04380	(525,016)
20	VEHICLE LEASE PAYMENTS		3,169,771	36.85231	7.43789	29.41442	0.08059	255,444
21	RENTS		6,776,038	36.85231	-33.48601	70.33832	0.19271	1,305,795
22	PALO VERDE LEASE	(c)	45,900,681	36.85231	103.99426	-67.14195	-0.18395	(8,443,456)
23	PALO VERDE S/L GAIN AMORT		(4,575,722)	0.00000	0.00000	0.00000	0.00000	0
24	INSURANCE		4,639,562	0.00000	0.00000	0.00000	0.00000	0
25	OTHER		119,131,971	36.85231	35.39000	1.46231	0.00401	477,283
26	SUBTOTAL		573,962,001					2,722,393
27	DEPRECIATION & AMORTIZATION		321,525,565	0.00000	0.00000	0.00000	0.00000	0
28	AMORT OF ELECTRIC PLT ACQ ADJ		0	0.00000	0.00000	0.00000	0.00000	0
29	AMORT OF PROP LOSSES & REG STUDY COSTS		(2,564,492)	0.00000	0.00000	0.00000	0.00000	0
30	SUBTOTAL		318,961,073					0
31	INCOME TAXES							
32	CURRENT-FEDERAL		59,824,326	36.85231	58.95000	-22.09769	-0.06054	(3,621,861)
33	CURRENT- STATE	(d)	16,379,288	36.85231	62.05000	-25.19769	-0.06903	(1,130,740)
34	DEFERRED		77,758,889	0.00000	0.00000	0.00000	0.00000	0
35	SUBTOTAL		153,962,503					(4,752,601)
36	OTHER TAXES							
37	PROPERTY TAXES		123,403,653	36.85231	211.94223	-175.08992	-0.47970	(59,196,535)
38	SALES TAXES		158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,194,095)
39	FRANCHISE TAXES		18,920,381	16.69615	52.83966	-36.14351	-0.09902	(1,873,559)
40	SUBTOTAL		300,564,589					(71,264,189)
41	INTEREST EXPENSE	(e)	108,298,482	36.85231	90.43103	-53.57872	-0.14679	(15,897,244)
42	SUBTOTAL		108,298,482					(15,897,244)
43	TOTALS		$ 2,423,343,887					(93,877,734)
44	APS CWC ALLOWANCE							(29,372,869)
45	STAFF CWC ADJUSTMENT -- TOTAL COMPANY							(64,504,865)
46	% ARIZONA RETAIL -- Jurisdictional Factor							0.88394
47	STAFF CWC ADJUSTMENT -- RETAIL							$ (57,018,405)

Footnotes :

(a) See Workpaper B-4, p. 1, for calculation of re-weighted revenue lag.
(b) Test year purchased power reduced by expenses incurred to facilitate unregulaged marketing and trading (see Staff Adjustment C-4).
(c) See Workpaper B-4, p. 2, for calculation of PV lease expense lag.
(d) See Workpaper B-4, p. 3, for calculation of State income tax expense lag.
(e) See Workpaper B-4, p. 4, for calculation of interest expense lag & Staff Adjustment C-19 for pro forma interest expense.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF OPERATING INCOME
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Revised
Schedule C

LINE NO.	DESCRIPTION (A)	AS ADJUSTED BY APS (B)	STAFF ADJUSTMENTS (C)	AS ADJUSTED BY STAFF (D)
1	Electric Operating Revenues	$ 3,440,590	$ (849,582)	$ 2,591,008
	Operating Expenses:			
2	Purchased Power and Fuel	2,129,741	(966,175)	1,163,566
3	Operations and Maintenance	766,212	(72,186)	694,026
4	Depreciation and Amortization	306,988	(759)	306,229
5	Income Taxes	395	69,495	69,890
6	Other Taxes	121,350	(1,689)	119,661
7	Total	3,324,686	(971,314)	2,353,372
8	Operating Income	$ 115,904	$ 121,732	$ 237,636

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	ADJUSTMENT NUMBER / SCHEDULE REFERENCE									SUBTOTAL
		C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ 4,907	$ 1	$ (18,924)	$ (835,566)						$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel			(124,082)	(841,833)						(965,915)
3	Operations and Maintenance		19			(8,273)	(40,714)	(3,965)	(508)	(7,933)	(61,374)
4	Depreciation and Amortization										-
5	Income Taxes	1,916	(7)	41,064	2,447	3,231	15,899	1,548	198	3,098	69,395
6	Other Taxes										-
7	Total	1,916	12	(83,018)	(839,386)	(5,042)	(24,815)	(2,417)	(310)	(4,835)	(957,895)
8	Operating Income	$ 2,991	$ (11)	$ 64,094	$ 3,820	$ 5,042	$ 24,815	$ 2,417	$ 310	$ 4,835	$ 108,313

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:

- **C-1** REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
- **C-2** CORRECTION OF MISCELLANEOUS OTHER REVENUES
- **C-3** NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES
- **C-4** ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
- **C-5** ELIMINATE MARKETING AND TRADING O&M EXPENSES
- **C-6** PENSION EXPENSE ADJUSTMENT
- **C-7** POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
- **C-8** ELIMINATE ADDITIONAL MARKETING EXPENSES
- **C-9** ELIMINATE NON-RECURRING SHARED SERVICES COSTS

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Other Operating Expenses:										
2	Purchased Power and Fuel	(965,915)							(260)		(966,175)
3	Operations and Maintenance	(61,374)	(95)	(2,718)	(2,618)	(4,488)		(1,764)			(73,057)
4	Depreciation and Amortization	-					(500)				(500)
5	Income Taxes	69,395	37	1,062	1,022	1,752	195	689	101	659	74,913
6	Other Taxes	-								(1,689)	(1,689)
7	Total	(957,895)	(58)	(1,657)	(1,595)	(2,735)	(305)	(1,075)	(158)	(1,029)	(966,508)
8	Operating Income	$ 108,313	$ 58	$ 1,657	$ 1,595	$ 2,735	$ 305	$ 1,075	$ 158	$ 1,029	$ 116,926

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:

- **C-10** ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
- **C-11** ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
- **C-12** ELIMINATE NON-RECURRING TAX RESEARCH COSTS
- **C-13** ELIMINATE STOCK BASED INCENTIVE COMPENSATION
- **C-14** ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
- **C-15** ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
- **C-16** NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
- **C-17** ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(F)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel	(966,175)									(966,175)
3	Operations and Maintenance	(73,057)					871				(72,186)
4	Depreciation and Amortization	(500)				(259)					(759)
5	Income Taxes	74,913	(959)	618	(4,838)	101	(340)				69,495
6	Other Taxes	(1,689)									(1,689)
7	Total	(966,508)	(959)	618	(4,838)	(158)	531	-	-	-	(971,314)
8	Operating Income	$ 116,926	$ 959	$ (618)	$ 4,838	$ 158	$ (531)	$ -	$ -	$ -	$ 121,732

Composite Federal and State Income Tax Rate 39.05%

C-18 PRODUCTION TAX CREDIT ADJUSTMENT
C-19 INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT
C-20 CORRECT COS INCOME TAX EXPENSE ADJUSTMENT
C-21 PV 1 STEAM GENERATOR DEPRECIATION EXPENSE
C-22 INTEREST ON CUSTOMER DEPOSITS
C-23
C-24
C-25

Witness: J. Anderson

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment to Reverse APS' Proposal to Reduce Test Year		
2	Margins Predicted to Occur as a Result of Implementing	APS Sch. C-2,	
3	Various Demand Side Management Programs	Page 1, Col F	$ 4,907,000

Footnote: Adjustment is 100% Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECTION OF MISCELLANEOUS OTHER REVENUES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	REVENUE AMOUNT	EXPENSE AMOUNT
	(A)	(B)	(C)	(D)
1	APS Adjustment for Schedule 1 Rate Changes	Workpaper DJR_WP8	$ 127,000	$ (19,000)
2	APS Revised Adj. for Schedule 1 Rate Changes	UTI 13-344, 13-345	128,339	-
3	Adjustment Correcting APS Schedule 1 Rate Adjustment	Line 2 - Line 1	$ 1,339	$ 19,000
4	Jurisdictional Allocation Factor		100%	99.12%
5	Staff Retail Adjustment for Schedule 1 Rate Changes	Line 3 * Line 4	$ 1,339	$ 18,833

Witness: J. Antonuk & J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Normalized Fuel and Purchased Power Expense Proposed by:		
2	Staff/Liberty Consulting Group (cents/kWh)		2.8942
3	APS (cents/kWh)	PME_WP6, P. 2	3.2859
4	Net Cents/kWh Reduction Proposed by Staff to be		
5	Rolled Into Base Rates	Line 2 - Line 3	(0.3917)
6	Adjusted Test Year Retail Sales	PME_WP6, P. 3	$ 26,759,478
7	Subtotal: Reduction in Fuel and Purchased Power Expense		
8	Attributable to Serving Retail Load	Line 5 * Line 6	(104,816,875)
9	**Note: This portion of fuel adjustment is 100% retail**		
10	**Proforma Off-Systems Sales Margin Adjustment:**		
11	Proforma Off-System Sales Revenues Per:		
12	Staff/Liberty Consulting Group		133,863,799
13	APS	PME_WP6, P. 5	153,098,000
14	Total Co. Adjustment Decreasing Off-System Sales Revenues	Line 12 - Line 13	(19,234,201)
15	Proforma Fuel and Purchased Power Expense Incurred to		
16	Facilitate Off-system Sales Per:		
17	Staff/Liberty Consulting Group		107,553,298
18	APS	PME_WP6, P. 5	127,134,000
19	Subtotal: Total Co. Additional Fuel and Purchased Power		
20	Expense to Facilitate Off-system Sales	Line 17 - Line 18	(19,580,702)
21	Net Total Company Decrease in Off-System Sales Margins	Line 14 - Line 20	346,501
22	Retail Jurisdictional Energy Allocator		98.389%
23	ACC Jurisdictional Adjustment Reducing Off-system		
24	Sales Revenues	Line 14 * Line 22	(18,924,319)
25	ACC Jurisdictional Adjustment Reducing Fuel/Purchased		
26	Power Expense Related to Reduced Off-system Sales	Line 20 * Line 22	(19,265,238)
27	ACC Jurisdictional Adjustment Increasing Net Margins		
28	Resulting from Reduced Off-system Sales Forecasted	Line 24 - Line 26	$ 340,919

Witness: J. Dittmer
& Liberty

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2	Unregulated Marketing and Trading Revenue Included Within the Total Company Cost of Service Study	GAAPversus FERC_ Reporting(2).xls	$ 849,248
3 4	Purchased Power Expense Incurred in Facilitating Unregulated Marketing and Trading Revenues	GAAPversus FERC_ Reporting(2).xls	(855,618)
5 6	Total Company Net Margin (Loss) on M&T Operations Exclusive of Payroll and Other Non-fuel O&M Expenses	Line 2 + Line 3	(6,370)
7	Energy Allocator		98.389%
8	ACC Retail Jurisdictional		
9	Revenues	Line 2 * Line 7	835,566
10	Purchased Power Expense	Line 4 * Line 7	(841,833)
11	Net Margin (Loss)	Line 9 + Line 10	$ (6,267)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE MARKETING AND TRADING O&M EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000S)
	(A)	(B)	(C)
1	Eliminate Unregulated Marketing and Trading		
2	Non-Purchased Power Operations and		
3	Maintenance Expenses Included Within APS'		
4	Total Company Cost of Service:		
5	Payroll	Response to	$ 6,618
6	Outside Services	UTI-10-315	1,078
7	Corporate Allocations		33
8	Miscellaneous		811
9	Corporate Allocable and Governance		241
10	Total Company Unregulated Marketing and Trading Non-		
11	Purchased Power Operations and Maintenance		
12	Expenses to be Eliminated From APS' Proposed		
13	Total Company Cost of Service	Sum Lines 5 - 9	(8,781)
14	Composite ACC Jurisdictional Allocator		94.212%
15	ACC Jurisdictional Unregulated Marketing and Trading Non-		
16	Purchased Power Operations and Maintenance		
17	Expenses to be Eliminated From APS' Proposed		
18	ACC Jurisdictional Cost of Service	Line 13 * Line 14	$ (8,273)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PENSION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-6
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2 3	Reversal of APS' Proposed Total Company Adjustment to Amortize the Unfunded Projected Benefit Obligation Over a Five Year Period	APS Exhibits Sch. C-2, page 7 Adj't No. 21	$ (43,695)
4 5 6 7	Company's Adjustment to Test Year Operations to Reflect Actual 2006 Pension Expense	Rockenberber Rebuttal Attachment LLR-4 -5RB	2,249
8 9	Pension Expense Adjustment Included Within APS' Payroll Annualization Adjustment	LLR_WP21, page 34	(1,769)
10	Subtotal:	Sum Lines 7 - 9	480
11 12	Net Total Company Adjustment to APS' Proposed Level of Pension Expense	Line 3 + Line 10	(43,215)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 12 * Line 14	$ (40,714)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-7
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2 3 4	Company's Adjustment to Test Year Operations to Reflect Actual 2006 PRMB Expense	Rockenberber Rebuttal Attachment LLR-4 -6RB	$ (3,191)
5 6 7	Less: APS PRMB Expense Annualization Adjustment Included as Part of the Payroll Expense Annualization	LLR_WP21, page 34	(1,018)
8 9	Net Total Company PRMB Adjustment to Annualize Expenses for 2006 Actuarial Estimates	Sum Lines 3 - 7	(4,209)
10 11	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
12 13	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 9 * Line 11	$ (3,965)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ADDITIONAL MARKETING EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-8
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Additional Marketing and Sponsorship Costs Identified and		
2	Conceded by APS to be Excluded From Retail Cost of		
3	Service Development		
4	Eliminate Dodge Theater Sponsorship	UTI-5-240	$ (100,000)
5	Eliminate Allocated PWCC Radio and	UTI-1-17	
6	Television Advertising	(Revised)	(337,351)
7	Additional Marketing Expenses Eliminated by RUCO that	Rockeberger	
8	APS Agreed to in Rebuttal Testimony	Rebuttal	(70,625)
9		Testimony, p. 24	
10	Total Additional Marketing and Sponsorship Costs to be		
11	Eliminated from Retail Cost of Service Development	Line 4 + Line 6	$ (507,976)

Footnote: This adjustment is assigned 100% to ACC Jurisdictional Cost of Service

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING SHARED SERVICES COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Reverse Correcting Journal Entries Recorded During the		
2	Historic Test Year that Had the Impact of Overstating "On Going"		
3	Shared Services Expenses:		
4	Reverse Correcting Journal Entry Recorded in		
5	November 2004 Posted to Transfer Shared Services		
6	Costs Originally Recorded as Depreciation Expense		
7	as "A&G" Expense	UTI-10-314	$ (5,323,351)
8	Reverse a Correcting Journal Entry Recorded in		
9	December 2004 to Reallocate Rents Improperly		
10	Allocated Throughout 2004	UTI-10-314	(3,096,000)
11	Total Company Adjustment to Reverse Correcting Journal Entries		
12	Recorded During the Historic Test Year that Had the Impact of		
13	Overstating "On Going" Shared Services Expenses	Line 7 + 8	(8,419,351)
14	Composite ACC Jurisdictional Wages		
15	and Salaries Allocator		94.212%
16	ACC Jurisdictional Adjustment to Reverse Correcting Journal		
17	Entries Recorded During the Historic Test Year that Had the		
18	Impact of Overstating "On Going" Shared Services Expenses	Line 13 * 15	$ (7,932,850)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Legal Expenses Incurred in the Sale of the Unregulated Silverhawk Power Plant	UTI-14-349	$ 240,238
3 4	Silverhawk Legal Costs Already Eliminated by APS from the Test Year Cost of Service		
5 6	Total Shared Services Legal Costs Allocated to PWEC During the Historic Test Years	LLR_WP13, pages 6 & 7	1,394,011
7 8	Percentage of PWEC Legal Costs Assigned by APS to PWEC Activities	LLR_WP13, pages 6 & 7	10%
9 10	Total Company Silverhawk-related Legal Expenses Already Eliminated from the COS by APS	Line 6 * Line 8	139,401
11 12	Net Total Company Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 10 - Line 2	(100,837)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 12 * Line 14	$ (95,010)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Eliminate APS' Proposed Accrual for "Non-Routine"		
2	Maintenance or "Major" Overhaul Costs at the Sundance		
3	Power Station Not Expected to Occur For Many Years	LLR_WP14	$ (2,750,100)
4	ACC Jurisdictional Production Demand Allocator		98.847%
5	Eliminate ACC Jurisdictional Accrual for "Non-Routine"		
6	Maintenance or "Major" Overhaul Costs at the Sundance		
7	Power Station Not Expected to Occur For Many Years	Line 3 * Line 4	$ (2,718,396)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING TAX RESEARCH COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1 2 3 4	Total Company Adjustment to Eliminate a Credit Given to Joint Owners of Palo Verde During the Historic Test Year Related to a Tax Contingency Fee Recorded in 2003 That in Turn Resulted in Incremental TY Charges to Account 9302	UTI-10-296	$ (1,224,795)
5 6 7	Total Company Adjustment to Eliminate Non-recurring Tax Research Costs Incurred on a Fee for Service Basis During the Historic Test Year	UTI-10-301	(1,553,333)
8 9 10	Total Company Adjustment to Eliminate Non-Recurring Tax Research Costs/Credits Recorded During the Historic Test Year	Line 4 + Line 7	(2,778,128)
11 12	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
13 14 15	ACC Jurisdictional Adjustment to Eliminate Non-Recurring Tax Research Costs/Credits Recorded During the Historic Test Year	Line 10 * Line 12	$ (2,617,594)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE STOCK BASED INCENTIVE COMPENSATION
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2 3	Total Company Adjustment to Eliminate Above-the-Line Expense Charges for Stock Based Incentive Compensation	UTI-1-83	$ (4,762,874)
4 5	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
6 7 8	ACC Jurisdictional Adjustment to Eliminate Above-the-Line Expense Charges for Stock Based Incentive Compensation	Line 3 * Line 5	$ (4,487,657)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate Bark Beetle Remediation Costs Deferred in		
2	January through March 2005 Prior to the Effective Date		
3	of Decision No. 67744 (April 1, 2005)	LLR_WP7	$ (1,501,069)
4	Amortization Period -- Years		3
5	Adjustment to Eliminate Bark Beetle Amortization Expense		
6	Related to Costs Inappropriately Deferred Prior to		
7	Effective Date of ACC's Prior Case Rate Order	Line 3 / Line 4	$ (500,356)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Federal Affairs Charged to "Governance" Activities		
2	During the Historic Test Year - Ultimately Allocated		
3	to Various PWCC Subsidiaries	UTI-6-244	$ 1,352,479
4	Percent of Governance Activities Allocated		
5	During the Historic Test Year to PWEC	UTI-6-244	28.930%
6	Federal Affairs Lobbying Costs Allocated as		
7	Corporate Governance Activities to PWEC	Line 3 * Line 17	391,272
8	Total Federal Affairs Shared Services Costs		
9	Charged to APS Above-the-Line Operating		
10	Expense in the Historic Test Year	UTI-10-305	834,125
11	Subtotal: Federal Affairs Lobbying Costs Charged		
12	Above-the-Line to APS and PWEC During the		
13	Historic Test Year	Line 7 + Line 10	1,225,397
14	Public Affairs Costs Charged Above-the-Line to		
15	APS During the Historic Test Year	UTI-10-306	595,455
15			
16	Total Public Affairs Costs Charged to		
17	APS During the Historic Test Year	UTI-10-306	1,617,107
18			
	Percent of Public Affairs Costs Charged		
19	Above the Line During the Historic Test Year	Line 15/Line 17	36.82%
20			
20	Public Affairs Costs Direct Assigned to PWEC		
21	During the Historic Test Year	UTI-6-244	139,377
22	Estimate of Public Affairs Costs Charged to PWEC		
23	Above-the-Line During the Historic Test Year	Line 19 * Line 21	51,322
23			
24	Total Company Above-the-Line Lobbying Costs to		
25	Be Eliminated from Cost of Service Development	Line 13 +15 + 23	(1,872,174)
25			
26	Composite ACC Jurisdictional Wages		
27	and Salaries Allocator		94.212%
27			
28	ACC Jurisdictional Above-the-Line Lobbying Costs to		
29	Be Eliminated from Cost of Service Development	Line 25 * Line 27	$ (1,763,994)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Yearly Amortization of Post Shutdown ISFSI Costs Based on Funding Expiration Date	LLR_WP16 Page 7	$ 108,000
3 4 5	Negative Amortization of Reduction in Post Shutdown ISFSI Costs Accrued Between September 30, 2005 and January 1, 2006	LLR_WP16 Page 8	(48,000)
6 7	Reduction in Ongoing ISFSI Costs to be Collected in Base Rates Based Upon Updated TLG Study	LLR_WP16 Page 7	(324,000)
8 9	Net Total Company Adjustment Reducing Nuclear Fuel Expense and Amortization of ISFSI Expense	Sum Lines 2 - 7	(264,000)
10	Retail Jurisdictional Energy Allocation Factor		98.389%
11 12	ACC Jurisdictional Adjustment Reducing Nuclear Fuel Expense and Amortization of ISFSI Expense	Line 9 * Line 10	$ (259,747)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate APS Proposed Inclusion of Increased PWEC	LLR_WP20	
2	Property Tax Expense Attributable to Legislative Phase-in	Pages 2 & 10	$ (1,708,338)
3	ACC Jurisdictional Production Demand Allocator		98.847%
4	Eliminate ACC Jurisdictional Portion of APS' Proposed		
5	Inclusion of Increased PWEC Property Tax Expense		
6	Attributable to Legislative Phase-in	Line 2 * Line 3	$ (1,688,644)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PRODUCTION TAX CREDIT ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	DEMAND RELATED AMOUNT (000s)	ENERGY RELATED AMOUNT (000s)	TOTAL COMPANY AMOUNT (000s)
	(A)	(B)	(C)	(D)	(E)
1	Total Company Production Rate Base	CNF_WP13, p.2	$ 2,172,190	$ 95,432	$ 2,267,622
2	Staff Proposed Weighted Cost of Common Equity	Sch. D	5.59%	5.59%	5.59%
3	After-Tax Net Income	Line 1 * Line 2	121,425	5,335	126,760
4	Revenue Conversion Factor	Sch. A-1	1.64069	1.64069	1.64069
5	Pre-Tax Net Income	Line 3 * Line 4	199,221	8,753	207,974
6	Book/Tax Differences	CNF_WP13, p.2	32,377	1,422	33,799
7	Taxable Income	Line 5 + Line 6	231,598	10,175	241,773
8	Deduction Percentage - Effective in 2006		3.00%	3.00%	3.00%
9	Additional Production Deduction	Line 7 * Line 8	6,948	305	7,253
10	Composite Income Tax Rate	Sch. A-1	39.05%	39.05%	39.05%
11	Total Company Annualized Income Tax Savings	Line 9 * Line 10	2,713	119	2,832
12	Total Company Annualized Savings per APS	CNF_WP13, p.2	1,784	78	1,862
13 14	Total Company Adjustment to APS' Original Production Tax Credit Calculation	Line 12 - Line 11	(929)	(41)	(970)
15	Jurisdictional Allocator		98.847%	98.389%	-98.828%
16 17	ACC Jurisdictional Annualized Income Tax Savings Adjustment	Line 14 * Line 15	$ (918)	$ (40)	$ (959)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-19
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	ACC Jurisdictional Rate Base Proposed by Staff	Sch. B	$ 4,402,377
2	Weighted Cost of Debt Proposed by Staff	Sch. D	2.460%
3 4 5	Annualized Interest Deduction Based Upon ACC Staff Proposed Retail Jurisdictional Rate Base and the ACC Staff' Proposed Weighted Cost of Debt	Line 1 * Line 2	108,298
6	Annualized Interest Deduction per APS		
7 8	APS Proposed As Adjusted ACC Jurisdictional Rate Based	APS Sch. B-1 Page 1, Col. F	4,466,697
9	APS Proposed Weighted Cost of Debt	APS Sch. D-1	2.460%
10 11	APS Proposed ACC Retail Jurisdictional Interest Expense Deduction	Line 8 * Line 9	109,881
12 13	Retail Jurisdictional Reduction in Annual Interest Deduction	Line 11 - Line 5	1,582
14	Composite Federal and State Income Tax Rate	Sch. A-1	39.05%
15 16 17 18	Adjustment Increasing Retail Jurisdictional Income Tax Expense to Reflect the Synchronization of the Interest Deduction with Staff's Proposed Rate Base and Cost of Capital Recommendations	Line 13 * Line 14	$ 618

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT COS INCOME TAX EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	TOTAL COMPANY AS ADJUSTED AS FILED BY APS (PER ORIGINAL UTI-3-169 & UTI-10-297) TAX EXP. $s	2006 AS ADJUSTED PERMANENT DIFFERENCES PER UPDATED UTI-10-297 TAX EXP. $s	ADDITIONAL ON GOING 2006 PER UPDATED UTI-10-297 TAX EXP. $s	ADJUSTMENT EXCLUDING PRODUCTION TAX CREDIT TAX EXP. $s
	(A)	(B)	(C)	(D)	(E)
1	Other Permanent Differences:				
2	OPEB Subsidy	$ 1,349,000			$ (1,349,000)
3	DCP & SERBP CSV	1,250,000			(1,250,000)
4	2005 vs. 2006 statutory rate	1,181,000			(1,181,000)
5	Tax exempt Interest Income	449,000			(449,000)
6	Depreciation on AFUDC	276,000		394,614	118,614
7	Officer's Compensation	83,000	70,924	27,696	(55,304)
8	Misc. tax credit true-up	28,000			(28,000)
9	Interest on tax reserve - net of tax	-			-
10	Meals & Entertainment	(102,000)	1,644,804	642,296	744,296
11	Penalties	(36,000)			36,000
12	Other	1,536,000			(1,536,000)
13	Subtotal: Other Permanent Differences	6,014,000			(4,949,394)
14	Medicare Subsidy	(3,872,000)		(3,338,429)	533,571
15	AZ State Credits	(570,000)		(482,950)	87,050
16	Amortization of FAS 109 Reg Liability			(460,435)	(460,435)
17	Depreciation on Medicare Subsidy			(49,195)	(49,195)
18	Net Add (Deduction) to Otherwise Calculated				
19	COS Income Tax Expense Based Upon "As				
20	Adjusted Book Income" Including a Deduction				
21	for Synchronized Interest Expense	$ 1,572,000		$ (3,266,403)	$ (4,838,403)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PV 1 STEAM GENERATOR DEPRECIATION EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

(a)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	Adjustment to Test Year Production Depreciation	Rockenberger	
2	Expense to Reflect Post Test Year Retirement of	Rebuttal	
3	Low Pressure Turbine Equipment Retired in	Attachment	
4	Conjunction with Palo Verde Steam Generator	LLR-4-1RB	
5	Replacement Occuring in 12/05		$ (262)
6	Retail Jurisdictional Demand Allocator		98.847%
7	Retail Adjustment to Test Year Production Depreciation		
8	Expense to Reflect Post Test Year Retirement of		
9	Low Pressure Turbine Equipment Retired in		
10	Conjunction with Palo Verde Steam Generator		
11	Replacement Occuring in 12/05	Line 5 X 6	(259)

(a) This is an adjustment originally proposed by RUCO that was not included within Staff's Original direct filing but which has been accepted by APS in rebuttal testimony

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INTEREST ON CUSTOMER DEPOSITS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

(a)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	Before-Tax Adjustment to Retail Jurisdictional	Froggatt	
2	Operating Income to Reflect Annualized Interest	Rebuttal	
3	on Customer Deposits Utilizing the 1/2/06	Attachment	
4	Treasury Interest Rate Applied to Customer Deposit	CNF-6RB	
5	Balance at 9/30/05		$ 871

Note: This adjustment is 100% ACC retail jurisdictional

(a) This is an adjustment originally proposed by RUCO that was not included within Staff's Original direct filing but which has been accepted by APS in rebuttal testimony

Witness: Parcell

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CAPITAL STRUCTURE & COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION (A)	AMOUNT (000'S) (B)	CAPITAL RATIO (C)	COST RATES (D)	WEIGHTED COST (E)
	APS - PROPOSED (a)				
1	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
2	Preferred Stock	-	0.00%	0.00%	0.00000%
3	Common Equity	3,083,591	54.50%	11.50%	6.27000%
4	Short-Term Debt	-	0.00%	0.00%	0.00000%
5	Total	$ 5,658,416	100%		8.73%
	ACC STAFF- PROPOSED (b)				
6	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
7	Preferred Stock	-	0.00%	0.00%	0.00000%
8	Common Equity	3,083,591	54.50%	10.25%	5.59000%
9	Short-Term Debt	-	0.00%	0.00%	0.00000%
10	Total	$ 5,658,416	100%		8.05%

Footnotes:

(a) Source: APS Schedule D-1, p. 1. Test year ended 9/30/05.
(b) Source: Staff witness Parcell, Exhibt__(DCP-1)

Witness:
J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RECONCILIATION OF POSITIONS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Sch/ Adj. Ref.	Description	Company Position	Amount	Difference In Pretax Return	Revenue Requirement Value
	(A)		(B)	(C)	(D)
Sch. A	**APS PROPOSED REVENUE REQUIREMENT**				$ 453,931
Sch. B	**RETURN DIFFERENCE (on APS Proposed Rate Base)**	(c)	$ 4,466,697	-1.120%	(50,027)
	SUBTOTAL - REVENUE REQUIREMENT				$ 403,904
				Pre-Tax Return	
	RATE BASE ADJUSTMENTS				
B-1	SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT	(b)	$ (3,661)	11.63%	$ (426)
B-2	CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE	(c)	(2,873)	11.63%	(334)
B-3	INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE	(c)	(767)	11.63%	(89)
B-4	CASH WORKING CAPITAL	(c)	(57,018)	11.63%	(6,632)
B-5	**reserved**		-	11.63%	-
B-6	**reserved**		-	11.63%	-
B-7	**reserved**		-	11.63%	-
B-8	**reserved**		-	11.63%	-
	TOTAL VALUE OF STAFF RATE BASE ADJUSTMENTS		(64,320)		$ (7,481)
	STAFF RATE BASE RECOMMENDATION		$ 4,402,377		
				Revenue Conversion Multiplier	
SCH. A	**Company Proposed Net Operating Income**		$ 115,904		
	NET OPERATING INCOME ADJUSTMENTS				
C-1	REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM	(c)	$ 2,991	1.6407	$ (4,907)
C-2	CORRECTION OF MISCELLANEOUS OTHER REVENUES	(a)	(11)	1.6407	17
C-3	NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALE	(c)	64,094	1.6407	(105,158)
C-4	ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE	(a)	3,820	1.6407	(6,267)
C-5	ELIMINATE MARKETING AND TRADING O&M EXPENSES	(a)	5,042	1.6407	(8,273)
C-6	PENSION EXPENSE ADJUSTMENT	(c)	24,815	1.6407	(40,714)
C-7	POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT	(c)	2,417	1.6407	(3,965)
C-8	ELIMINATE ADDITIONAL MARKETING EXPENSES	(a)	310	1.6407	(508)
C-9	ELIMINATE NON-RECURRING SHARED SERVICES COSTS	(a)	4,835	1.6407	(7,933)
C-10	ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES	(a)	58	1.6407	(95)
C-11	ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE	(c)	1,657	1.6407	(2,718)
C-12	ELIMINATE NON-RECURRING TAX RESEARCH COSTS	(a)	1,595	1.6407	(2,618)
C-13	ELIMINATE STOCK BASED INCENTIVE COMPENSATION	(c)	2,735	1.6407	(4,488)
C-14	ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER	(c)	305	1.6407	(500)
C-15	ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE	(c)	1,075	1.6407	(1,764)
C-16	NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT	(a)	158	1.6407	(260)
C-17	ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXE	(a)	1,029	1.6407	(1,689)
C-18	PRODUCTION TAX CREDIT ADJUSTMENT	(b)	959	1.6407	(1,573)
C-19	INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT	(b)	(618)		-
C-20	CORRECT COS INCOME TAX EXPENSE ADJUSTMENT	(a)	4,838	1.6407	(7,938)
C-21	PV 1 STEAM GENERATOR DEPRECIATION EXPENSE	(a)	158	1.6407	(259)
C-22	INTEREST ON CUSTOMER DEPOSITS	(a)	(531)	1.6407	871
	TOTAL VALUE OF STAFF NET OPERATING INCOME ADJUSTMENTS		121,359		$ (200,365)
SCH. A	STAFF NET OPERATING INCOME RECOMMENDATION		$ 237,263		
	RECONCILED REVENUE REQUIREMENT				$ 196,058
	OTHER RECONCILING ITEMS				
	APS PROPOSED ENVIRONMENTAL CHARGE				(4,315)
	UNRECONCILED DIFFERENCE				(180)
SCH. A	**REVENUE REQUIREMENT RECOMMENDATION**				$ 191,563

(a) Staff understands that APS agrees to adjustment in principle as well as to the value of the issue
(b) Staff understands that APS agrees to adjustment in principle but value of issue may be dependent upon other Commission determinations (i.e., rate of return authorized)
(c) Staff understands that APS does not agree with some element of, if not entire, adjustment

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
S-39
admitted

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

STAFF'S NOTICE OF FILING

Staff of the Arizona Corporation Commission hereby provides notice of filing the Supplemental Testimony and Exhibits of James R. Dittmer, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 22nd day of November, 2006.

Christopher C. Kempley

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
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BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	DOCKET NO. E-01345A-05-0816

SUPPLEMENTAL TESTIMONY

OF JAMES R. DITTMER

ON BEHALF OF THE
UTILITIES DIVISION STAFF

NOVEMBER 22, 2006

SUPPLEMENTAL TESTIMONY
OF
JAMES R. DITTMER

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc.

Q. Have you previously presented testimony within this docket?

A. Yes. I previously filed direct and surrebuttal testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. On whose behalf are you providing this supplemental testimony?

A. This supplemental testimony is being presented on behalf of the ACC Staff.

Q. What is the purpose of your supplemental testimony?

A. First, I wish to clear up some confusion on the record regarding remaining differences between Staff and Company regarding pension and post retirement medical benefits expense.

Second, I will briefly respond to Commissioner Mayes' questions regarding development of cost-of-service income tax expense based upon a "consolidated" versus "stand alone" approach.

Third, I would simply note that I am available to attempt to answer any questions that may be deferred to me by other Staff witnesses addressing the policy issues surrounding the possible implementation of hook up fees. More specifically, I am available to attempt to answer questions surrounding the impact that hook up fees could be expected to have upon the Company's construction expenditures budget as well as the financial metrics that are most heavily relied upon by the credit rating agencies.

Fourth, I wish to briefly address the Company's acknowledgement that it intends to file a transmission case with the Federal Energy Regulatory Commission ("FERC"), and how such filing can be expected to affect the Company's claim for an "attrition" allowance in this case.

REMAINING PENSION AND POST-RETIREMENT MEDICAL EXPENSE DIFFERENCES BETWEEN COMPANY AND STAFF

Q. Please provide your understanding of the remaining differences between Company and Staff with regard to the issues of pensions and post-retirement medical benefits expense.

A. My understanding is that the only difference between Company and Staff with regard to pension expense or post-retirement medical benefits expense, after one final correction to Staff's case that I am making with this Supplemental Testimony, is that Staff continues to oppose the Company's request to recover over a five-year period the underfunded Projected Benefits Obligation.

By way of background, Staff had recommended in direct testimony that APS be required to effectively true-up pension expense and post-retirement medical benefits expense based upon the 2006 actuarial study that was not available at the time Staff was preparing its direct case. APS did, in fact, reflect the recently-issued 2006 actuarial study results in rebuttal testimony, which Staff in turn, reflected within the Joint Accounting Schedules that were revised and updated in surrebuttal testimony.

In direct testimony Staff had also opposed the Company's pension and post-retirement medical benefits expense adjustment that had been included as a subcomponent of the Company's payroll adjustment. In the exhibits filed with rebuttal testimony the Company did, in fact, withdraw that element of its payroll adjustment related to pensions and post-retirement medical benefits expense – though no specific mention of this withdrawal was made in the rebuttal testimony.

A review of the workpapers supporting the Company's pensions and post-retirement medical benefits adjustments revealed an allocation error contained within Staff's Joint Accounting Schedules C-6 and C-7. Accordingly, I am filing with this Supplemental Testimony corrected Schedules C-6 and C-7. With the corrections made in the attached revised Schedules C-6 and C-7, I believe the sole remaining difference between Company and Staff on the issue of pension and post-retirement medical benefits expense lies in the Company's continuing request to collect the underfunded Projected Pension Benefits Obligation over a five-year period.

"CONSOLIDATED" VERSUS "STAND ALONE" COST-OF-SERVICE INCOME TAX EXPENSE DEVELOPMENT

Q. Commissioner Mayes has posed questions regarding the reflection of "consolidated" versus "stand alone" cost-of-service income tax expense development. Please discuss your understanding of the two approaches to cost-of-service income tax development.

A. First, as the name implies, when utilizing the "stand alone" approach to developing cost-of-service income tax expense, the tax calculation entails simply utilizing the revenues and expense from regulated "stand alone" utility operations. It has been my experience that the vast majority of regulatory jurisdictions employ the "stand alone" approach to developing cost-of-service income tax expense.

1 I have not personally observed the calculation undertaken by any jurisdiction
2 utilizing the "consolidated" tax approach. However, my understanding is that in
3 those jurisdictions that employ the "consolidated" approach, tax losses
4 stemming from unregulated business operations are considered in some fashion
5 in reducing cost-of-service income tax expense. I believe the reasoning
6 employed in adopting a *consolidated* approach is that it is unfair that ratepayers
7 continually pay "phantom" federal and state income taxes that are never paid to
8 taxing authorities, but rather, are transferred to unregulated affiliates that are
9 temporarily or continually in a tax loss position.
10
11 Q. Do you advocate employment of the "stand alone" or "consolidated" approach
12 to cost-of-service income tax development?
13 A. With perhaps one clarifying exception, I endorse employment of the "stand
14 alone" approach to cost-of-service income tax development?
15
16 Q. Why do you generally endorse employment of the "stand alone" approach to
17 cost-of-service income tax development?
18 A. This Commission as well as other regulatory commissions have taken steps to
19 ensure that regulated utility operations do not subsidize any unregulated
20 operations of the utility itself, or any affiliate of the utility. In my opinion, it
21 would be unfair to utilize the "tax losses" of unregulated operations so long as
22 all other "unregulated" operation's revenues, expenses and investment are
23 excluded from the regulated utility's cost-of-service determination.

1 Q. In an earlier answer you stated that "with perhaps one clarifying exception," you
2 endorsed the employment of the "stand alone" approach to cost-of-service
3 income tax development. Please expand upon the "clarifying exception" that
4 you noted.

5 A. In some instances, a utility subsidiary's "stand alone" common equity is, in fact,
6 financed in part by debt at the parent company level. This scenario is
7 commonly referred to as a "double leverage" situation. In situations where a
8 utility company's rate base investment is supported by additional debt at the
9 parent company level that is, in fact, being serviced by the return on common
10 equity at the "stand alone" utility subsidiary level, I believe it is fair and
11 reasonable to consider the interest at the parent company level in the cost-of-
12 service income tax development. Since utility ratepayers are indirectly paying
13 for at least a portion of interest being incurred at the parent level, it is
14 reasonable, equitable and consistent to consider such "deduction" in the cost-of-
15 service income tax calculation
16
17 Some may refer to the use of parent company interest in the cost-of-service
18 income tax calculation as a form of a "consolidated" tax approach. Without
19 getting into the semantics argument of whether use of parent company interest
20 is or is not a form of a "consolidated" income tax expense calculation, I would
21 simply summarize that to the extent that utility rate payers are indirectly paying
22 the interest cost on parent company debt, they should in turn, receive the tax
23 benefits stemming from such parent company interest cost.

IMPACT OF FERC TRANSMISSION CASE

Q. Is it your understanding that APS is intending to file a FERC transmission case?

A. In answer to a question by Administrative Law Judge Farmer, APS witness Mr. Steven Wheeler indicated that APS was planning on changing its rates at FERC, though to my knowledge no timetable was addressed in the record (Tr. Vol. II, page 351).

Q. Is the fact that APS is purportedly "under earning" on its transmission investment relevant to this proceeding?

A. Normally it would not be. However, in the rebuttal phase of this case the Company effectively abandoned its entire adjusted historic test year cost of service, and now essentially recommends that this Commission set the retail revenue requirement based upon the results of its 2007 and 2008 financial forecast. Because those forecasts which APS would now have the Commission set rates in this proceeding are based on APS' "total company" operating results – including its FERC-regulated transmission operations – the degree to which APS is "under earning" on its transmission rate base is very relevant to this proceeding.

Q. Do you know how much APS is earning on its transmission investment, or how much rate relief might be justified within a FERC transmission rate application?

1 A. I have not undertaken a detailed calculation, nor have I observed where APS or
2 other parties have calculated a "transmission" cost of service and revenue
3 deficiency. However, by subtracting out the *retail* cost of service results from
4 the "total company" APS cost of service, one can get an idea of the total
5 revenue shortfall from all of APS' unregulated operations.
6
7 Q. Have you undertaken such calculation?
8 A. Yes. On Attachment Supplemental JRD-1 I subtract out APS' originally-
9 proposed *retail* rate base from the APS originally-calculated *total company* rate
10 base. Additionally, I back out APS' originally-proposed *retail* net operating
11 income under existing rates from APS' originally-calculated *total company* net
12 operating income under existing rates. From those two noted calculations I am
13 able to derive a calculated "Required Increase in Non-Jurisdictional Revenues"
14 of slightly over $50 million.
15
16 Q. Are you suggesting that APS can justify a $50-plus million FERC-regulated
17 transmission operations rate increase?
18
19 A. No. A more refined calculation is required. Further, I note that the APS
20 amounts used in the simplified calculation undertaken on Attachment
21 Supplemental JRD-1 include components with which the APS Staff can be
22 expected to object – similar to objections being made within this retail docket.
23 Rather, this calculation simply supports a conclusion that 1) some amount of

transmission rate relief is required, and 2) part of the forecasted "total company" earnings short fall that APS would have this Commission consider in adopting its "attrition adjustment" is apparently being caused by earnings shortfall occurring with APS' operations which are not regulated by this Commission.

Q. If APS files at FERC, and receives a transmission rate increase, can such costs be passed onto retail customers outside the context of a retail rate application?

A. Pursuant to this Commission's order approving the settlement in Docket No. E-01345A-03-0437, APS was authorized to establish a transmission cost adjustor ("TCA") wherein APS may file for approval of a new TCA rate outside the context of a retail rate case so long as the change in the TCA rate exceeds the amount currently included in retail base rate development (i.e., $.000476) by five percent.

Q. If this Commission were to accept APS' proposed attrition adjustment based upon the unaudited 2007 and 2008 forecasts over the objections of Staff and other parties, would such finding have any impact on the APS FERC transmission proceeding?

A. No. Even if this Commission attempts in this case to help APS' "total company" operations out by adopting an attrition adjustment based upon "total company" forecasted results, I do not believe such facts would be relevant in a FERC proceeding. Or in other words, I do not believe the ACC or other parties to a FERC proceeding could successfully argue that any earnings shortfall for

1 transmission operations had effectively been totally or partially remedied by this
2 Commission's adoption of an attrition adjustment that had been based upon
3 APS' "total company" operations.
4
5 Q. Does this conclude your Supplemental Testimony?
6 A. Yes, except to the extent that questions regarding possible implementation of a
7 hook up fee may be deferred to me.
8

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PENSION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-6
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2 3	Reversal of APS' Proposed Total Company Adjustment to Amortize the Unfunded Projected Benefit Obligation Over a Five Year Period	APS Exhibits Sch. C-2, page 7 Adj't No. 21	$ (43,695)
4 5 6 7	Company's Adjustment to Test Year Operations to Reflect Actual 2006 Pension Expense	Rockenberber Rebuttal Attachment LLR-4 -5RB	2,249
8 9	Pension Expense Adjustment Included Within APS' Payroll Annualization Adjustment	LLR_WP21, page 34	(815)
10	Subtotal:	Sum Lines 7 - 9	1,434
11 12	Net Total Company Adjustment to APS' Proposed Level of Pension Expense	Line 3 + Line 10	(42,261)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 12 * Line 14	$ (39,815)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Revised
Schedule C-7
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1 2 3 4	Company's Adjustment to Test Year Operations to Reflect Actual 2006 PRMB Expense	Rockenberber Rebuttal Attachment LLR-4 -6RB	$ (3,191)
5 6 7	Less: APS PRMB Expense Annualization Adjustment Included as Part of the Payroll Expense Annualization	LLR_WP21, page 34	(469)
8 9	Net Total Company PRMB Adjustment to Annualize Expenses for 2006 Actuarial Estimates	Sum Lines 3 - 7	(3,660)
10 11	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
12 13	ACC Jurisdictional Adjustment to APS' Proposed ACC Jurisdictional Pension Expense	Line 9 * Line 11	$ (3,448)

EXHIBIT
S-40
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

STAFF'S NOTICE OF FILING ERRATA

On November 22, 2006, Staff of the Arizona Corporation Commission ("Staff") filed the Supplemental Testimony and Exhibits of James R. Dittmer, in the above-referenced matter. At that time Staff inadvertently omitted Attachment Supplemental JRD-1.

Staff hereby filed Attachment Supplemental JRD-1.

RESPECTFULLY SUBMITTED this 27nd day of November, 2006.

Janet Wagner

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Estimated Revenue Shortfall From APS Non-ACC Jurisdictional Operations

Line No.	Description	Amount
1	**Original Cost Rate Base: (Source: APS Sch. B-1)**	
2	Total Company Adjusted	$5,327,833
3	Less ACC Adjusted	(4,466,697)
4	Net Non-Jurisdictional (Line 2 - Line 3)	$ 861,136
5	**Adjusted Net Operating Income**	
6	Total Company (Sch C-1, p.1)	$ 154,747
7	ACC Juris (Sch C-1, p.2)	(115,904)
8	Net Non-Jurisdictional (Line 6 - Line 7)	$ 38,843
9	**Adjusted Return on Rate Base Under Existing Rates:**	
10	Total Company (Line 6 / Line 2)	2.90%
11	ACC Jurisdictional (Line 7 / Line 3)	2.59%
12	Net Non-Jurisdictional (Line 8 / Line 4)	4.51%
13	Staff Proposed ROR (Staff Joint Accounting Schedule A)	8.05%
14	Non-Jurisdictional NOI Required (Line 4 X Line 13)	$ 69,321
15	Non-Jurisdictional NOI Available (Line 8 Above)	38,843
16	Increase in Non-Jurisdictional NOI Required (Line 14 - 15)	$ 30,478
17	Tax Conversion Factor	1.6407
18 19	Required Increase in Non-Jurisdictional Revenues (Line 16 X Line 17)	$ 50,006

EXHIBIT
S-41
Submitted

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

September 28, 2006

EA 06-221

James M. Levine, Executive
Vice President, Generation
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Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: Palo Verde Nuclear Generating Station, Units 1, 2, and 3 - NRC SPECIAL INSPECTION REPORT 05000528/2006011; 05000529/2006011; 05000530/2006011

Dear Mr. Levine:

On September 26, 2006, the US Nuclear Regulatory Commission (NRC) completed a special inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3. This inspection examined your staff's response to the high intake air temperature condition identified in Emergency Diesel Generator 2B on May 17, 2006, and the fouling of safety-related heat exchangers serviced by the emergency spray pond system. The NRC's initial evaluation met both the risk criteria and several of the deterministic criteria for initiating a special inspection. The basis for initiating this special inspection is further discussed in the Charter, which is included as Attachment 2 to this report.

The enclosed special inspection report documents the inspection findings which were discussed on August 18, 2006, with Mr. C. Eubanks, Vice President, Nuclear Operations, Mr. D. Mauldin, Vice President, Engineering, and other members of your staff. A supplemental exit was conducted on September 26, 2006, with Mr. J. Levine and other members of your staff to discuss the preliminary significance determination and the characterization of the performance deficiency. The determination that the inspection would be conducted was made by the NRC on June 6, 2006, and the inspection started on June 12, 2006.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents two findings that were determined to be violations of very low safety significance. Also, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as noncited violations consistent with Section VI.A.1 of the NRC Enforcement Policy. If

you contest any noncited violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station.

In addition, the attached report discusses a finding that appears to have greater than very low safety significance. As described in Section 5.1 of this report, the failure to recognize that improperly implemented chemistry controls for the emergency spray pond systems in all three units caused degraded performance in all emergency diesel generators and emergency cooling water systems over a period of years. This finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process (SDP) and was preliminarily determined to be a Greater Than Green Finding. The final resolution of this finding will convey the increment in the importance to safety by assigning the corresponding color i.e., [(white) a finding with some increased importance to safety, which may require additional NRC inspection; (yellow) a finding with substantial importance to safety that will result in additional NRC inspection and potentially other NRC action; (red) a finding of high importance to safety that will result in increased NRC inspection and other NRC action]. This finding has a preliminary greater than very low safety significance because it has been estimated that in Unit 2, Train B of essential cooling water was incapable of performing its safety function for 6.8 months in 2003, based on extrapolation of performance data for this heat exchanger. Accident sequences that would cause high pond temperatures, primarily loss-of-coolant accidents, could challenge this system to the point where the essential chiller would fail, causing a loss of room cooling to important mitigating systems. In addition, there is uncertainty associated with the amount of scaling that could occur on any of the affected heat exchangers for all three units during 24 hours of an accident scenario.

Due to the complexity of this issue, there was insufficient information for a number of important aspects to complete a final Phase 3 significance determination evaluation in a timely manner. During the inspection process, it was apparent that your staff is working to develop the information and calculations needed to complete an accurate assessment. Therefore, the preliminary significance was based on a Phase 2 evaluation in accordance with Inspection Manual Chapter 0609. In order to complete a final significance determination, additional information is needed. The specific information needed is described in the assessment portion of Section 5.1.

This finding does not represent an immediate safety concern because of the immediate and long term corrective actions that have been implemented to reduce chemical addition, remove excess impurities from the ponds, clean all the affected heat exchangers, and adjust control limits appropriately. You are also in the process of removing sediment and sludge from the ponds.

There are five apparent violations associated with this finding being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's web site at http://www.nrc.gov/reading-rm/adams.html.

In accordance with Inspection Manual Chapter 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of this letter.

The significance determination process encourages an open dialog between the staff and the licensee, however the dialogue should not impact the timeliness of the staffs final determination. Before we make a final decision on this matter, we are providing you an opportunity (1) to present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least 1 week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Linda J. Smith at (817) 860-8137 within 10 business days of the date of this receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Dwight D. Chamberlain, Director
Division of Reactor Safety

Dockets: 50-528; 50-529; 50-530
Licenses: NPF-41; NPF-51; NPF-74

Enclosure:
Inspection Report 05000528/2006011; 05000529/2006011; 05000530/2006011
w/Attachment: Supplemental Information

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SUNSI Review Completed: LJS ADAMS: ■ Yes ☐ No Initials: LJS
■ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ■ Non-Sensitive
R:_REACTORS_PV\2006\PV2006011rp-nfo.wpd

EB2/TL	EB2	NRR	NRR	SRA	EB2/BC
CFO'Keefe/lar	PAGoldberg	YDiaz-Castillo	KParczewiski	MFRunyan	LJSmith
/RA/	**/RA/**	**T=CFO**	**T=CFO**	**DPL for**	**/RA/**
09/26/06	09/27/06	09/26/06	09/26/06	09/28/06	09/28/06

PBD/BC	ACES	OE	NRR	EB2/BC	D:DRS
TPruett	MSHaire	RFretz	MTschiltz	LJSmith	DDChamberlain
T=CFO	**T=CFO**	**T=CFO**	**E=CFO**	**/RA/**	**/RA/**
09/27/06	09/27/06	09/27/06	09/28/06	09/28/06	09/28/06

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528; 50-529; 50-530
Licenses:	NPF-41; NPF-51; NPF-74
Report No.:	05000528/2006011; 05000529/2006011; 05000530/2006011
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	June 6 through September 26, 2006
Inspectors:	N. O'Keefe, Team Leader P Goldberg, Reactor Inspector, Engineering Branch 1 Y. Diaz-Castillo, Chemical Engineer, Office of Nuclear Reactor Regulation (NRR) K. Parczewiski, Senior Chemical Engineer, NRR M. Runyan, Senior Reactor Analyst
Approved By:	Dwight D. Chamberlain, Director Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000528/2006011; 05000529/2006011; 05000530/2006011; 6/6-9/26/2006; Palo Verde Nuclear Generating Station, Units 1, 2, and 3: Special Inspection, 50.59, Operability Evaluations, Design Control, Corrective Actions, Biennial Heat Sink, Test Control.

The report covered a 3-month period of inspection by two region-based inspectors and two chemistry subject matter experts from headquarters. In addition to performing a special inspection, this report includes the results of the announced biennial heat sink inspection, which was performed concurrently. One finding was identified with five apparent violations, which were determined to have potential safety significance greater than very low safety significance. Additionally, two NRC-identified noncited violations and one licensee-identified noncited violation with very low safety significance were identified. The significance of most findings is indicated by its color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Summary of Event and Inspection Results

The NRC conducted a special inspection to better understand the circumstances surrounding the heat exchanger fouling at Palo Verde Nuclear Generating Station. The fouling came to the NRC's attention as a result of unusual temperatures noted during a surveillance test of Emergency Diesel Generator 2B conducted on May 17, 2006. After 2 days, it was determined that this potentially impacted the ability of this safety-related system to perform its safety function during a design basis accident. It also became apparent that the fouling that was experienced had existed for a long period of time. The cause of the fouling was not fully understood, and affected other equipment in all trains of all three units. In accordance with NRC Management Directive 8.3, it was determined that this event had sufficient risk significance and met several deterministic criteria to warrant a special inspection.

This inspection identified a pattern of behavior where heat exchanger performance data and internal inspection results were not understood, entered into the corrective action program, or adequately assessed for operability impact. When the degradation increased and the appearance of the foulant changed, this did not cause an increased response, other than to clean heat exchangers more frequently. The chemistry control credited to prevent fouling was determined to have no mechanism to actively monitor fouling. Further, the chemistry control limits were changed over time to actually promote fouling and increase the potential for scaling during design basis accidents. This pattern of behavior existed for the last 10 years.

A. NRC-Identified and Self Revealing Findings

Cornerstone: Mitigating Systems

- TBD. A finding with five apparent violations was identified associated with fouling of safety-related heat exchangers cooled by the emergency spray pond system. Between 1995 and May, 2006, the licensee failed to recognize that

improperly implemented chemistry controls for the emergency spray pond system caused a significant condition adverse to quality which degraded the performance of all emergency diesel generators and emergency cooling water systems. The degraded performance was primarily due to heat exchanger fouling caused by adding excessive amounts of chemicals. The conditions that existed also had the potential to cause scaling after an accident starts. In one instance, it is estimated that this resulted in degrading the performance of Emergency Cooling Water Heat Exchanger 2B to the point where it would not have been capable of performing its intended safety function for approximately 6.8 months in 2003.

An apparent violation of Technical Specification 3.7.7 was identified because Train A of the Essential Cooling Water System in Unit 2 was not capable of performing its safety function for approximately 6.8 months ending on September 27, 2003.

An apparent violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," was identified because the two procedures that were performed to measure essential cooling water heat exchanger performance were implemented in a way that was inadequate to ensure the timely determination that the requirements and acceptance limits contained in applicable design documents were met.

An apparent violation of 10 CFR 50.59 was identified for making nine revisions to Procedure 74DP-9CY04, "System Chemistry Specification," a procedure described in the Updated Final Safety Analysis Report, between 1998 and 2004 without performing evaluations of the potential impact of the changes on the safety-related components in the spray pond system; the changes revised spray pond chemistry parameter limits which were subsequently determined to have contributed to heat exchanger fouling.

An apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," was identified. On March 19, 2002, performance testing for Essential Cooling Water Heat Exchanger 2B indicated that the system would not be capable of performing its design function, but this significant condition adverse to quality was not promptly identified, the cause determined, or corrective actions taken to restore the required heat exchanger performance. The failure to correct this degraded performance contributed to the continued degradation and eventual loss of function for an estimated period of 6.8 months.

An apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified for failure to correctly evaluate the scaling potential of the safety-related heat exchangers cooled by the emergency spray pond during a design basis accident. An error in the SEQUIL calculation caused the licensee to incorrectly conclude that scaling would not occur under the conditions established in the chemistry control program.

The performance deficiency associated with these apparent violations was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone objective to maintain the availability and reliability of systems needed to mitigate accidents. Specifically, Essential Cooling Water (EW) Train B in Unit 2 was estimated to have been incapable of performing its function under existing conditions for approximately 6.8 months. A Phase 2 significance determination process concluded that this finding has potential safety significance greater than very low safety significance because some accident sequences, notably loss of coolant accidents, were expected to elevate the ultimate heat sink temperature to the point where the degraded essential cooling water heat exchanger would be challenged. This was expected to cause failure of the essential chiller, and the resulting loss of room cooling to safety-related equipment increased the plant risk. In addition, there is uncertainty associated with the amount of scaling that could occur on any of the affected heat exchangers for all three units during 24 hours of an accident scenario. Additional information was needed to perform a final Phase 3 assessment, due to the complexity of the issue. (Section 5.1)

Cornerstone: Mitigating Systems

- Green. Two examples of a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," were identified involving the failure to adequately translate the design basis of the spray ponds into procedures. Design Calculation 13-MC-SP-0307, "SP/EW System Thermal Performance Design Basis Analysis," Revision 7, which demonstrated that the spray pond system could adequately limit spray pond temperature during a design basis accident did not account for any reduced heat capacity caused by sediment buildup. However, this fact was not translated into procedures, so approximately 400 cubic yards of sediment had built up in each of the six spray ponds when the team questioned the impact to the heat removal function. Also, the same calculation demonstrated that sufficient water was available to provide adequate cooling during a design basis accident, but did not account for any leakage from the ponds. The team determined that the licensee did not translate this into a procedure to ensure that the condition of the spray pond was maintained such that leakage did not occur. Procedure 81DP-0ZZ01, "Civil System, Structure, and Component Monitoring Program," Revision 11, was used to monitor the condition of the pond structures. The team identified that it examined only the exposed concrete surfaces, which constituted about 7 percent of the surface area and almost none of the water-containing volume. Cracks had been identified and repaired in this area, but the inspections were not expanded to the underwater surfaces. This issue was documented in Condition Report/Disposition Requests 2906671 and 2910912.

  Failure to adequately translate the design basis of the spray ponds into procedures was a performance deficiency. This finding was determined to be more than minor because, if left uncorrected, the finding could become a more significant safety concern. This finding affected the Mitigating Systems Cornerstone. This performance deficiency screened as having very low safety

significance in a Phase 1 significance determination process because the licensee was able to demonstrate that the sediment would not have resulted in a loss of safety function, and that significant leakage did not exist. The licensee was able to revise the calculation to take credit for heat absorption by the concrete walls, and scheduled inspections by divers of underwater portions of the ponds to follow sediment removal. (Section 5.2)

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," with multiple examples was identified for failure to adequately assess the impact to operability of degraded heat exchangers in the emergency diesel generators and essential cooling water system. Specifically, the licensee failed to follow Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 16, in assessing indications of degraded heat exchanger performance, an activity affecting quality. Key support organizations were not always involving operations personnel with questions that had a potential to affect the operability of safety-related equipment, or were informing operators only after the support organization had fully evaluated the condition, delaying actions that were required to be prompt. Also, operations personnel did not always insist on a rigorous evaluation. This issue was documented in Condition Report/Disposition Requests 2918892, 2901815, and 2898237.

  Failure to adequately implement the operability assessment process was a performance deficiency. This finding was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone objective to maintain the availability and reliability of systems needed to mitigate accidents. This finding screened as having very low safety significance in a Phase 1 significance determination process, because the examples used for this violation were confirmed not to involve any loss of safety function. This finding had cross-cutting aspects in the area of human performance because the licensee did not follow their systematic process for operability decision making when information was not brought to the right decision makers. (Section 5.3)

B. Licensee-Identified Findings

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

1.0 SPECIAL INSPECTION SCOPE

The NRC conducted this special inspection to better understand the circumstances surrounding the heat exchanger fouling at Palo Verde Nuclear Generating Station. The fouling came to the NRC's attention as a result of unusual temperatures noted during a surveillance test of Emergency Diesel Generator (EDG) 2B on May 17, 2006. Over the following several days, it was determined that this potentially impacted the ability of this safety-related system to perform its safety function during a design basis accident. It also became apparent that the fouling that was experienced had existed for a long period of time. The cause of the fouling was not fully understood, and affected other equipment in all trains of all three units. In accordance with NRC Management Directive 8.3, it was determined that this event had sufficient risk significance and met several deterministic criteria to warrant a special inspection.

The team used NRC Inspection Procedure 93812, "Special Inspection Procedure," to conduct the inspection. The special inspection team reviewed procedures, corrective action documents, and design and maintenance records for the equipment of concern. The team interviewed key station personnel regarding the event, the root cause analysis, and corrective actions. A list of specific documents reviewed is provided in Attachment 1. The charter for the special inspection effort is provided as Attachment 2.

2.0 SYSTEM AND EVENT DESCRIPTION

2.1 Event Summary

On May 17, 2006, Palo Verde Nuclear Generating Station noted elevated temperatures in the intake air for EDG 2B while the engine was running for a surveillance test. The engine intake air is compressed and heated by the turbocharger, and is then cooled by two parallel intercoolers before entering the engine. The elevated temperatures were noted at the outlet of the intercoolers, which was indicative of inadequate cooling in the intercoolers.

The elevated temperatures were discussed among operations and engineering personnel, and it was concluded that this condition did not affect operability. Emergency Diesel Generator 2B was returned to service, and the following day the EDG Train A and essential cooling water (EW) heat exchanger were removed from service for approximately 23 hours. On May 19, following the return to service of Train A, the operability of EDG 2B was revisited. An immediate operability determination was completed at 9:55 a.m. which concluded EDG 2B was operable. After additional review, at 5:54 p.m., it was concluded that EDG 2B was not operable, and Technical Specification 3.8.1 was entered. Because the condition was potentially a common mode failure concern for the EDGs, all EDGs were run to assess the performance of the intercoolers in accordance with Technical Specification 3.8.1.2.

The licensee inspected the EDG 2B intercoolers and found they were fouled on the cooling water (spray pond system) side. The emergency spray pond system (SP)

provides the cooling water to both the EDG coolers (two intercoolers, a jacket water cooler, and a lube oil cooler), as well as cooling the large EW heat exchanger. The intercoolers' water side had a white slimy substance which was apparently reducing the ability to transfer heat.

That same week, the licensee had taken each of the Unit 2 EW heat exchangers out of service for tube cleaning. This was in response to earlier heat transfer degradation which was judged to be degrading fast enough that the Unit 2 EW heat exchangers would not remain operable through the full operating cycle and needed to be cleaned before summer. The degradation was not fully understood, but was suspected to be related to a similar white slimy substance.

As NRC inspectors got involved and asked key questions related to the operability of these components, it became apparent that the scope of the problem was more than just EDG 2B.

2.2 System Descriptions

The spray pond system for each unit is comprised of two trains. Each train has a concrete lined spray pond of 6.2 million gallons of water, which serves as the ultimate heat sink. The ponds are 345 feet by 172 feet, and are 15.5 feet deep. The spray pump for each train takes a suction on one corner of the pond, at a level 6 feet below the bottom of the main portion of the pond. The pump delivers 16,300 gpm through buried piping to the EW heat exchanger and the EDG coolers. The water then returns to the pond through over 300 spray nozzles spaced around the pond above the surface. The spray nozzles atomize the water, allowing for evaporative cooling. The spray pond system is normally in a standby condition with no flow. The spray pond piping was made of carbon steel with a protective coating on the inside surfaces.

Each EDG has five coolers which have heat removed by the spray pond system: the jacket water cooler; lube oil cooler: fuel oil cooler, and a pair of turbocharger intercoolers. While the EDG is normally in standby, the jacket water system and lube oil system continue to circulate and heat their process fluids. The fuel oil cooler has a very small flow, and is not required for the EDG to function. The intercoolers function at the highest temperature, approximately 290F air inlet temperature.

The EW heat exchangers transfer heat from the systems it cools to the spray pond system. The loads supplied are the essential chillers, shutdown cooling heat exchanger, and spent fuel pool cooling system. The essential chillers provide cooling to the control room ventilation, safety-related switchgear rooms, and emergency core cooling pump rooms. The shutdown cooling heat load during an accident constitutes over 94 percent of the total EW heat load.

The spray ponds were provided with a filtering system. Pond water was pumped through a pair of sand filters to remove larger impurities at 600 gpm each (1200 gpm total). The sand filters were backwashed to remove the impurities about once per day under normal conditions.

3.0 CHEMISTRY DESCRIPTION

3.1 Fouling Mechanisms

The degraded heat transfer capabilities in the EDG coolers and the EW heat exchangers occurred in all trains in all units. The degree of degradation varied somewhat among the units. The EDG intercoolers and the EW heat exchangers were observed to have fouled the most, while the jacket water and lube oil coolers fouling was minor and had no impact to operation.

The team determined that the licensee did not take photographs or have samples of the substances found in these heat exchangers analyzed. When the May 2006 event occurred, samples were analyzed, but the exact substances could not be determined because it was an amorphous mix of a number of substances. The major constituents were determined to be zinc (38 percent), phosphorous (29 percent), and calcium (32 percent).

Two different substances have been found in the heat exchangers, though this was not recognized. In earlier years, a thin coating that turned white as it dried was observed in heat exchanger inspections. This is now believed to be zinc hydroxide. In more recent years, a thicker coating that has been described as white, slimy, and lotion-like was observed. It was believed for years that the coating was zinc hydroxide which the chemistry control program was intentionally trying to deposit on the system piping, so it was largely accepted. The team noted that the licensee did not reassess what the material was when the appearance began to change.

The licensee's root cause assessment concluded that improper chemical control resulted initially in excessive zinc hydroxide precipitating out of solution, which is a heat transfer foulant. Later, zinc phosphate precipitated as a thicker mix. This precipitant then provided a localized seed site for other chemicals to also precipitate out of solution. The combined effect was an amorphous lotion-like substance that coated heat exchanger tubes and degraded heat transfer by interrupting cooling water flow at the tube wall. Specifically, the fluffy film caused a low flow zone near the tube wall and forced the turbulent flow away from the tube wall; since efficient convective heat transfer required strong turbulent flow at the tube wall, heat transfer was significantly impacted even though the film was fluffy and not tightly adherent.

It should be noted that the above fouling mechanisms were different than scaling. Scaling involved hard mineral deposits, such as calcium carbonate and calcium phosphate which occur at high temperatures. Scaling concerns are addressed in Section 5.1.5.

3.2 The Intended Chemistry Control Program

The licensee's program was intended to meet two goals: minimize corrosion in the spray pond piping and components, and minimize fouling. The team determined that the Palo Verde Nuclear Generating Station program was similar to that used in cooling water systems in the electric power industry, both nuclear and non-nuclear. Though complex, this type of program is typically effective. When initially implemented, the spray pond

chemistry control program used the chemical supply vendor's recommended limits; however, over time these limits were changed numerous times, eventually departing from these recommendations.

The Palo Verde Nuclear Generating Station program treated the two parts of the spray pond system separately. The spray ponds were treated only to prevent gross biological fouling. The spray pond system piping and components were treated with a complicated combination of chemicals to meet the goals stated above. Chemicals were added at the pump suction during pump runs for piping treatment, and pond chemicals were added at the same location but were not effectively dispersed through the pond.

The carbon steel piping was protected from corrosion by adding zinc and phosphoric acid. This combination was intended to form a very thin layer (a few molecules thick) of zinc, with phosphate in solution to protect any active corrosion sites. The root cause assessment team concluded that this film should not be thick enough to be visible on the piping. The zinc coating must be replaced periodically, so extra zinc is added to stay in solution to be available as replacement if needed. However, zinc has a low solubility and will precipitate out of solution unless the conditions are carefully managed.

The makeup water for the system has a relatively high alkalinity and some potentially scale-forming impurities (such as calcium). Scale is more likely to form at higher temperatures (such as those expected in heat exchangers), and under higher pH values. The alkalinity from makeup water and evaporating of water caused pH to naturally increase. Therefore, the licensee added sulphuric acid to lower pH and improve the solubility conditions.

Dispersant was added to keep the impurities and the chemicals that were intentionally added in solution and avoid precipitation and fouling. The dispersant was very important to control solubility and avoid fouling and scaling. However, the team determined that the dispersant in use at the time of the event could not be measured directly, and the method used to estimate dispersant concentration was no longer reflecting the actual conditions.

Finally, the licensee added biocide and hypochlorite to control biological growth. The piping was treated during pump runs; pond treatments were started during pump runs, but continued for hours after the pump was secured. All chemicals were added to the ponds near the pumps.

The team identified that the chemistry program objectives to minimize fouling was not being monitored. The effectiveness of fouling prevention was not being tracked by chemistry personnel.

3.3 How The Chemistry Control Was Actually Implemented

A summary of the chemistry control program and changes made over time is provided in Section 6.1.

The team determined that the chemistry control program was being implemented in a way that caused fouling of safety-related heat exchangers. Chemical additives (zinc and

phosphate) were being added in excess of what was needed and above the solubility limits for the existing conditions. The pH was also being maintained too high, reducing the solubility limits. Also, dispersant was not being accurately being monitored, and as a result, was not being added in sufficient quantities to effectively control the solubility of the existing chemicals. These conditions combined to cause the fouling.

The team reached the following conclusions about the actual implementation of the spray pond chemistry control program:

> The Chemistry personnel implementing the program did not fully understand how the spray pond chemistry control program was supposed to work. As a result, they made a series of inappropriate changes to chemistry limits which negatively impacted solubility without assessing or understanding the potential impacts.
>
> The specified pH band was too high to maintain zinc hydroxide in solution, so it precipitated out of solution and formed a foulant.
>
> The zinc control band was too high, resulting in injecting too much and precipitating significant quantities out of solution. The precipitate collected in the EW heat exchangers and intercoolers, and may have also precipitated into the sediment at the bottom of the ponds. The ideal control concentration was determined to be about 0.5 ppm by the root cause team, while the actual control band was 1.0 - 3.0 ppm at the time of the event.
>
> Excess phosphate was being added, contributing to the precipitation problems. Phosphoric acid was added in a 4:1 ratio with the zinc; zinc was constantly removed from solution, while phosphate built up in the pond and piping. The ideal phosphate level was determined by the root cause team to be about 4.0 ppm, while at times, samples recorded over 20 ppm phosphates in Unit 2. The high phosphate levels exceeded the maximum solubility for the bulk water conditions, and precipitated out of solution in the EW heat exchangers and intercoolers, and probably also precipitated into the sediment at the bottom of the ponds.
>
> Calcium and other impurities from makeup water were allowed to concentrate excessively over time, and under the relatively high pH conditions they contributed to precipitation problems. The root cause team concluded that the zinc phosphate precipitant provided a seed site for other compounds containing zinc, calcium, and phosphate to attach.

Dispersant was intended to improve the solubility conditions, but there was too little dispersant present to be effective. The dispersant in use could not be measured directly, so a "tag" chemical (molybdate) which could be measured was added in a known proportion to the dispersant. The licensee did not recognize that this tag chemical was not subject to the same loss and use mechanisms as the dispersant. As a result, the tag chemical analyses registered incorrectly high results. The team determined that Chemistry personnel reduced or stopped adding dispersant for long

periods of time because the molybdate concentrations indicated dispersant levels were high. Contributing to this, the tag chemical was only checked once per month. Also, when the licensee allowed the high levels of impurities to build up, they did not recognize that this should have required raising the amount of dispersant to maintain the same effectiveness.

The team identified that the chemistry control practices for this system were not typical of other plant systems with the same importance. Chemicals were added based on thumbrules and past additions, rather than basing them on recent sample results. Also, many key samples were taken only once per month, but the associated chemical additions were made several times per week. Some important samples had no controls associated with undesirable levels. For example calcium, an impurity, which is a scale-forming concern, had no action level to trigger action to reduce the concentration. The spray pond system was a concentrator for chemicals, so as calcium levels accumulated over the years, Chemistry raised the limits to stay ahead of the actual levels, rather than reducing the existing concentrations. When sample results indicated that molybdate levels were high and it was presumed that this meant dispersant levels were high, dispersant additions were stopped. The molybdate samples were taken monthly, but the analyses were sometimes delayed by up to 2 to 3 weeks (Condition Report/ Disposition Request (CRDR) 2800653). This created an untimely feedback mechanism for adjusting the chemical addition.

The team identified that chemistry personal had focused on treating the pipes and did not effectively manage the chemistry condition in bulk pond water. This approach was viewed as economical, and is a common industrial practice. However, this did not account for the unique nature of the spray ponds at Palo Verde Nuclear Generating Station. Unlike typical systems, the spray pond system was not designed or operated in a way that regular water turnover occurred, such that chemicals and impurities would be removed. It was not recognized that the chemistry control program in use typically involved a system that ran continuously and had a much higher water turnover. The turnover should result in removal of impurities and cause the tag chemicals to more closely reflect dispersant concentrations. The continual buildup of chemicals and impurities at Palo Verde Nuclear Generating Station caused a departure from the conditions assumed when the vendor recommendation for dispersant levels was made.

Most sampling was done during pump runs by taking samples from the pipes, with very little sampling of the bulk water in the ponds. As a result, the ponds were allowed to accumulate chemicals and impurities. This was further complicated by allowing sediment to accumulate at the bottom of the ponds, where precipitants could be concealed but still affect water chemistry.

Biological fouling in the ponds was not being effectively controlled. The team concluded that the biocide treatments and monitoring of the ponds were ineffective. During the onsite portion of the inspection, contract divers began vacuuming sediment from the Unit 1 ponds. Condition Report/Disposition Request 2905162 was written on June 21, 2006, to document that the diving operations were dislodging "sheets" of algae from the spray pond walls. The licensee was unaware that algae existed in the ponds prior to this time. The team reviewed the pond treatment practices and concluded that the biocide addition point was in one corner of the ponds, insufficient mixing was provided to

distribute the chemicals. This was, in part, because much of the biocide chemicals were added after securing the spray pond pumps. The licensee's evaluation concluded that the existing algae would not impact operability, and the team concluded that this was a reasonable conclusion.

Finally, the water chemistry control program being used was challenged by the licensee's practice of leaving the systems idle, without constant flow, for most of the time. Typical cooling water systems run pumps continuously, which have the benefits for flushing pipes and heat exchangers out and mixing the chemicals. The Palo Verde Nuclear Generating Station spray pond systems were normally run only for chemistry control (adding chemicals 3 times per week), infrequent testing, and during plant outages. This resulted in the system having no flow most of the time.

The team noted that the chemistry control program documents stated that dispersant additions were intended to be based on makeup water addition. However, that had never been the actual practice. The team identified that the licensee did not track makeup water additions to the spray ponds, and had no way of measuring the quantity of water flowing to any one pond. In an idle pond, evaporative losses ranged from 2,200 to 10,000 gallons per day. When the system was run, evaporation was much higher, and "drift" losses occurred when water droplets were carried out of the pond berm by wind. Despite these large and highly variable losses which required makeup and caused loss of dispersant, the team identified that the licensee had stopped adding dispersant for long periods, in part because they were not adding dispersant based on makeup water addition.

The team identified that the chemical supply vendor site representative visited the site several times per month, but this source of expertise was not utilized. The vendor was not asked to assess the performance of the program, and was not asked to observe heat exchanger foulant or analyze the material. The site representative was involved in trying to identify the lotion-like substance found in the spray pond sand filters, though he was not provided with a sample as a basis for the discussion.

The team concluded that the licensee was no longer maintaining the spray pond chemistry control program within the bounds that were originally intended. They had made changes without understanding the effect the changes would have on the conditions and without understanding the complex interactions that existed. As a result, the fouling was self-induced by the chemistry control program.

4.0 HEAT EXCHANGER PERFORMANCE MONITORING

4.1 Essential Cooling Water (EW) Heat Exchanger Performance Testing

The licensee committed to conducting heat exchanger performance testing on the EW heat exchangers. This was typically done for one train at the beginning of each refueling outage during the primary plant cooldown, when decay heat load allowed enough heat load to be able to get accurate results. Later, the licensee began to also conduct EW heat exchanger performance testing during the primary plant heatup at the end of refueling outages. These tests had a much lower heat loading, so the accuracy

of the results was potentially lower, but the results would still be expected to provide an indication of the relative effectiveness of any tube cleaning during that outage.

The team performed a detailed review of the licensee's performance testing methods and results, including internal inspections and cleaning practices. This included reviewing documented results since 2001. This is further discussed in Section 1R07.

The results of the performance testing conducted on the EW heat exchangers is summarized in Attachment 3. It can be seen that the data for any one heat exchanger is very limited, since it might be tested only once every three years. It can also be seen that significant reductions in heat exchanger performance were indicated by test results, yet very few instances were found where this degradation was documented in the corrective action program. This is further discussed in Section 5.4.

4.2 Emergency Diesel Generator (EDG) Performance Testing

The licensee did not conduct performance testing of any of the EDG heat exchangers. The primary reasons are briefly summarized:

Lube oil coolers and jacket water coolers: The shell side fluids (lube oil and jacket water) have automatically controlled flows that adjust to the conditions to maintain a constant temperature. The thermostatic control valves cannot be manually overridden or their positions measured. Also, the systems do not have installed flow measurement devices, and the pipe configuration prevents an accurate flow measurement using an external device.

Intercoolers: These heat exchangers have a relatively small heat load, and use air as a working fluid. Both these facts make it difficult to accurately measure heat exchanger performance.

Instead of performance testing, Palo Verde Nuclear Generating Station's commitment in their Generic Letter 89-13 response was to regularly clean and inspect these heat exchangers to ensure there was not excessive fouling. Since these inspections identified that the intercoolers in each unit experienced fouling, the licensee was trending the relative performance of the intercoolers during EDG surveillance testing. This was done by assessing the difference between air outlet temperature and water inlet temperature over time. Cleanings were scheduled when this difference became high, but the condition was documented as a degraded condition in the corrective action program only once, although the degraded condition occurred on numerous occasions. This is further discussed in Section 5.3.

5.0 FINDINGS

5.1 Performance Deficiencies that Directly Related to Fouling to the Point of Inoperability

a. Description.

In 1994, Palo Verde Nuclear Generating Station implemented a new chemistry control program for the emergency spray pond system to control corrosion and prevent fouling of the safety-related components. This system provides the ultimate heat sink function. Throughout the period of 1994 through May 2006, the licensee made a series of changes to this program which created a chemical environment that was progressively more conducive to fouling of the heat exchangers which were relied upon to transfer heat from the reactor, containment, EDGs, and safety-related equipment rooms to the ultimate heat sink. The foulant was determined to be a buildup of excess chemicals which were added as part of the chemistry control program, but which were subsequently determined to have exceeded the limitations of solubility. Despite years of test results which showed degraded heat exchanger performance, numerous heat exchanger inspections which documented chemical buildup, and an increasing need to clean the heat exchangers more frequently, the licensee failed to recognize the safety significance of the problem or determine and correct the cause. Degraded performance was observed in all trains in all three units. Because of significant inherent design margins, only one example was identified where fouling may have been sufficient to cause a loss of safety function. Specifically, the Unit 2 Train B EW heat exchanger was potentially inoperable between about April and October 2003.

Also, during the inspection it was recognized that calculations which demonstrated that heat exchangers cooled by the spray pond system would not be subject to scaling during a design basis accident contained an error. When re-performed, the calculations indicated that scaling was possible. This would have the effect of further reducing the heat transfer capability of these heat exchangers during certain accident scenarios. This had the potential to affect components cooled by the spray pond in all units.

The team reviewed the degraded performance and the remaining capabilities of these components over the period 1994 through 2006. The licensee performed computer modeling and analysis that adequately demonstrated that the EDG systems were capable of performing under the degraded conditions. This was due to considerable margins inherent in the design, and because it could be shown that the fouling in EDG 2B that triggered this inspection was clearly the worst case that had been experienced. For the EW heat exchangers, the team identified the following four periods where the EW heat exchangers had less than the design basis heat removal capability, a degraded condition which constituted a significant condition adverse to quality. Of these, it appears that only 2B was incapable of performing its function under the existing, less challenging conditions in 2003.

EW HX 1B was possibly as low as -20.8 percent margin entering 1R11 in 2004.

EW HX 2B was possibly as low as -49.78 percent margin entering 2R11 in 2003.

EW HX 3B was possibly as low as -14.4% percent margin entering a midcycle outage in 2004. .

EW HX 3A was measured at -22 percent margin entering 3R10 in 2003.

These estimates do not include the possible effect due to scaling discussed in subsection (5) below. The impact due to fouling will be reassessed in all units during the final significance determination.

Note that throughout this report, heat exchanger capacity is discussed in terms of "percent margin." This term is meant to refer to margin above or below the design capacity of a heat exchanger. In this context, "0 percent margin" means the heat exchanger would have exactly the capacity required to transfer the design heat load under limiting design conditions. Positive or negative margin expresses how much more or less than that capability actually existed. This was used to be consistent with licensee documentation.

b. Statement of the Performance Deficiency.

Between 1995 and May, 2006, the licensee failed to recognize that improperly implemented chemistry controls for the emergency spray pond system caused a significant condition adverse to quality which degraded the performance of all emergency diesel generators and emergency cooling water systems. The degraded performance was because of heat exchanger fouling from chemical additives, and potentially because of scaling after an accident starts. This resulted in degrading the performance of EW Heat Exchanger 2B to the point where it would not have been capable of performing its intended safety function for approximately 6.8 months in 2003. In addition, there is uncertainty associated with the amount of scaling that could occur on any of the affected heat exchangers for all three units during 24 hours of an accident scenario.

c. Enforcement.

(1) Technical Specification 3.7.7 requires that two trains of essential cooling water be operable in Mode 1, with an allowed outage time for one train of 72 hours. Contrary to this, Train A of the EW system in Unit 2 was not capable of performing its safety function for approximately 6.8 months ending on September 27, 2003, when the plant shut down for Refueling Outage 11. This will be treated as an apparent violation pending a final significance determination: AV 05000529/2006011-01, EW Train 2B Inoperable Longer than Allowed Outage Time. This issue was entered into the licensee's corrective action program under CRDR 2905161.

The period during which the train was incapable of performing its intended safety function was determined through straight-line extrapolation of the two prior heat exchanger performance tests for this train. The minimum acceptable performance was determined by licensee calculation dated June 22, 2006, which revised Design Basis Calculation 13-MC-SP-307 to remove all known margins. The minimum acceptable performance was 204 Btu/hr-ft2-F, or about -35 percent margin compared to the full design basis value. This calculation included the most limiting values for spray pond

temperature and air temperature actually recorded during the exposure period, and accounted for the existing number of tubes with plugs installed. The team reviewed this calculation and determined that appropriate values and assumptions were used for the purpose of determining heat exchanger performance capability.

The licensee showed documentation that indicated that eddy current testing of this heat exchanger was performed during 2R10 in March, 2002. The licensee stated that the probes were known to push out the majority of the foulant and improve heat exchanger performance. The team acknowledged this fact, but could not quantify any potential improvement because no data existed to quantify this for Unit 2 EW heat exchangers. The Unit 2 EW heat exchangers were the only ones with sleeves at each end; the sleeves necessitated using a smaller probe than was used in the other units, and thus had a bigger gap between the probe and the majority of the tube wall length. This fact precluded using test data which was available for the other units, particularly because the heat transfer characteristics of the foulant were not known.

(2) Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XI, "Test Control," requires that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Test results are required to be documented and evaluated to assure that test requirements have been satisfied. Test Procedure 70TI-9EW01, "Thermal Performance Testing of Essential Cooling Water Heat Exchangers," contained instructions for conducting performance testing. Procedure 73DP-9ZZ10, "Guidelines for Heat Exchanger Thermal Performance Analysis," contained instructions for calculating the results of EW heat exchanger performance testing and verifying them against the design basis requirements in Calculation 13-MC-SP-0307, "SP/EW System Performance Design Bases Analysis," Revision 007. Contrary to this, the results of performance testing for EW Heat Exchanger 2B conducted on March 19, 2002, did not meet the design basis requirements, but this was not correctly evaluated to determine whether the system would be capable of performing its design function until August 22, 2002. As a result, Unit 2 was allowed to restart and run an entire operating cycle without correcting the degraded performance. This will be treated as an apparent violation pending final significance determination: AV 05000528; 05000529; 05000530/2006011-02, Inadequate Test Control to Promptly Identify Unacceptable Performance Test Results. This issue has been entered into the licensee's corrective action program under CRDR 2928230.

The team determined that the performance test was scheduled and conducted under a maintenance order. However, the calculation of the results and comparison to acceptance criteria was not scheduled. Further, the test results were not administratively tracked to ensure that the unit was not restarted before acceptable performance was documented. As a result, the March 19, 2002, test results were determined after Unit 2 started up from Refueling Outage 2R10. The test results were unexpectedly low, but this was determined to involve a calculation error. When the error was corrected with results, which indicated low performance, the test method was evaluated. On August 22, 2002, the test package was completed and verified to

demonstrate -9.5 percent capability. This untimely determination of unacceptable performance did not trigger a review of operability, nor was continued degradation considered. As a result, this component continued to degrade for 18 months after demonstrating unacceptable performance. Had this determination been made prior to the end of the outage, corrective actions could have been taken to clean the tubes. Technical Specifications require that both trains be operable prior to making plant mode changes, so the unit should not have be restarted with this condition, had it been identified.

(3) Part 50.59 of Title 10 of the Code of Federal Regulations allows licensees to make changes to procedures as described in the Updated Final Safety Analysis Report without obtaining a license amendment only if the change satisfies the criteria in 50.59.c. It goes on to specify that changes made to procedures must include written evaluations which provide the bases for the determination that the change does not require a license amendment.

The Palo Verde Nuclear Generating Station Updated Final Safety Analysis Report, Section 9.2.1.2.F, specified that the spray pond system would be protected from organic fouling and inorganic buildup by proper water treatment. Procedure 74DP-9CY04, "System Chemistry Specification," implemented the licensee's program, including chemical limits and addition frequencies, in order to control corrosion and fouling in the emergency spray pond system.

Contrary to the above, between 1998 and 2004, the licensee made multiple changes to the chemistry control program specified in Procedure 74DP-9CY04, "System Chemistry Specification," without adequately assessing the impact to the safety-related systems affected by the changes. Revisions 3, 6, 8, 10, 12, 24, 28, 32, and 36 to Procedure 74DP-9CY04 made changes between March 1998 and February 2006, which affected spray pond chemistry parameter limits which were subsequently determined to contribute to heat exchanger fouling. Specifically:

- Revisions 3, 6, 8, 12, 24, 28, and 32 were made without any documented 50.59 review. The team determined that these revisions contained changes to chemistry limits in the spray pond which had the potential to negatively impact fouling, and therefore were required to be evaluated per 50.59. These included changing pH, phosphate, and zinc limits, and instructions on the frequency of dispersant additions.

- The screening performed for Revision 10 was determined to be inadequate because the revision increased the maximum allowable pH in Unit 1, but the screening dated 6/30/99 did not evaluate this aspect of the revision. This limit had been lowered in Revision 6 to account for the decision to use well water as the makeup source for the Unit 2 spray pond. This water source had a significantly higher alkalinity, and the lower pH was determined to be necessary to avoid scaling at the time the modification was implemented. However, this aspect of the change was not evaluated in this screening.

- The screening performed for Revision 36 was determined to be inadequate because the revision increased the maximum allowable zinc concentration by a factor of two, but Screening Number S-06-0049, Revision 1, did not address this aspect of the revision. Excessive zinc additions were subsequently determined to be a primary cause of fouling.

This will be treated as an apparent violation pending final significance determination: AV 05000528; 05000529; 05000530/2006011-03, 50.59 Reviews Not Performed or Inadequate for Multiple Changes to Spray Pond Chemistry Control Procedure.

This issue was documented in CRDR 2902498. The team concluded that there were two prior opportunities to have identified that chemistry limit changes were being made without 50.59 reviews which did not identify this set of examples (CRDRs 2683642 and 2864575); these are further discussed in Section 4OA7.

(4) Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI, "Corrective Actions," requires that significant conditions adverse to quality shall be promptly identified, and that the cause shall be determined and corrective action shall be taken to preclude repetition. Contrary to this, on March 19, 2002, performance testing for EW Heat Exchanger 2B indicated that the system would not be capable of performing its design function, but this significant condition adverse to quality was not promptly identified, the cause determined, or corrective actions taken to restore the required heat exchanger performance. Specifically, the unacceptable performance was not promptly identified, because the test results were not correctly calculated until August 22, 2002, which was after operating mode changes and returning the unit to power following the outage. When the test results were finalized, the fact that the design basis capability was not met was not recognized or entered into the corrective action program. These failures to correct this degraded performance contributed to the continued degradation and eventual loss of function for a period of approximately 6.8 months. This will be treated as an apparent violation pending final significance determination: AV 05000528; 05000529; 05000530/2006011-04, Inadequate Identification and Corrective Action for Degraded EW Heat Exchanger Performance. This issue was entered into the corrective action program under CRDR 2897810.

(5) Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, requires that design control measures be established to verify the adequacy of design of structures, systems and components. A SEQUIL calculation was intended to demonstrate that the heat exchangers cooled by the emergency spray pond system would be capable of transferring the required heat load to the spray pond because scaling would not occur during a design basis accident. Contrary to this, the calculation used an improper setting which caused the calculated result to incorrectly show that scaling would not occur. This issue was documented in CRDR 2913430. This violation has the potential to increase the exposure time when EW Heat Exchanger 2B was incapable of performing its safety function, since the 6.8 month exposure time did not

account for any impact because of scaling. There is uncertainty associated with the amount of scaling that could occur on any of the affected heat exchangers for all three units during 24 hours of an accident scenario. This will be treated as an apparent violation pending final significance determination: AV 05000528; 05000529; 05000530/2006011-05, Inadequate Design Control to Ensure No EW Heat Exchanger Scaling.

This finding does not represent an immediate safety concern because immediate and long term corrective actions that have been implemented to reduce chemical addition, remove excess impurities from the ponds, clean all the affected heat exchangers, and adjust control limits appropriately. The licensee was also in the process of removing sediment and sludge from the ponds.

d. Assessment.

The performance deficiency associated with these violations was more than minor because it impacted the equipment performance attribute of the Mitigating Systems cornerstone objective to maintain the availability and reliability of systems needed to mitigate accidents. Specifically, EW Train B in Unit 2 was estimated to have been incapable of performing its function under existing conditions for approximately 6.8 months. This was determined through straight-line extrapolation of heat exchanger performance test data. The minimum required performance for the EW heat exchanger was determined by the licensee by modifying the design basis calculation to credit the use of all known margin and evaluated the condition for the worst case pond temperature known to exist during the period of concern.

This performance deficiency affected the Mitigating Systems functions of short-term primary heat removal (high and low pressure safety injection) and long-term heat removal (emergency core cooling system recirculation). Because this performance deficiency involved the loss of function for a single train for longer than its Technical Specification allowed outage time, Phase 1 of the significance determination process required a Phase 2 evaluation.

To challenge the safety function of the EW heat exchanger, it was determined that there must be both a high heat load and a high pond temperature. The sequences of concern were determined to be small, medium and large break loss-of-coolant accidents, loss-of-offsite power, plus, stuck open primary relief valve sequences. Loss of dc Bus B was also evaluated as a consequential failure.

The performance deficiency was assumed to cause a loss of function of the EW heat exchanger. As a consequence, this has the following assumed impacts:

Loss of cooling to shutdown heat exchanger - reduced containment heat removal function credit from multi-train to single train.

Loss of cooling to the essential chiller, which fails and causes loss of room cooling and eventual failure of the following equipment:

Motor driven auxiliary feedwater pump - reduced credit from multi-train to single train

Containment spray pump - reduced credit from multi-train to single train

High pressure safety injection pump - reduced credit from multi-train to single train

Low pressure safety injection pump - reduced credit from multi-train to Single Train

EW pump - reduced credit from multi-train to single train

Control room complex - no Phase 2 impact because of redundant train and non-safety cooling supply

Direct current equipment room - required evaluation of the loss of dc Bus B special initiator

Recovery credit was considered for the EW heat exchanger, because the condition was a degradation in capability, not a complete loss of function. The requirements in Manual Chapter 0609 for recovery credit were not explicitly met, but it was judged that normal operator training and procedures would be sufficient to maintain containment/core heat removal.

Recovery credit was considered for mitigating the effects of loss of room cooling. The licensee had procedure steps to open doors for the affected rooms, and meet the requirements for recovery credit. It was uncertain whether this action would be effective, so this is an area where additional information is needed to make a final significance determination.

Manual Chapter 0609 directs that findings of this type be evaluated for large early release frequency (LERF) contribution. For large, dry type containment buildings (e.g., Palo Verde Nuclear Generating Station) Appendix H and associated basis document indicates that Type A findings at pressurized-water reactors that affect containment heat removal do not contribute to LERF, because they involve late containment failure probability only. Therefore, the risk of this performance deficiency is best represented by ΔCDF.

The results of the Phase 2 SDP determined that this condition represented a risk that was potentially greater than very low risk significance (potentially greater than Green). The Phase 2 results and assumptions were reviewed by Senior Risk Analysts from Region IV and Headquarters.

A preliminary Phase 3 SDP analysis was performed. However, it was determined that several important aspects and assumptions contained considerable uncertainty or could not yet be verified. While the licensee was working on a number of evaluations and calculations to resolve the uncertainty, these were not complete. The preliminary Phase 3 analysis and modified Phase 2 using the same assumptions as the Phase 3 analysis indicated that the risk could be lower than the Phase 2 analysis, but the results were highly dependent on the uncertainty of some of the information.

In accordance with Manual Chapter 0609, NRC senior management determined that the preliminary significance would be based on the Phase 2 SDP results, pending a final significance determination which would account for additional information to be provided by the licensee. This was intended to improve the timeliness of regulatory decision-making in situations where the complexity of the significance determination would otherwise cause an excessive delay.

Information on the following aspects was still needed from the licensee in order to complete a final significance determination:

> The effect on heat exchanger heat transfer capability that scaling may have played in the first 24 hours of a design basis loss-of-coolant accident for the worst chemistry conditions that existed in each of the six spray ponds. Also, whether this impact would cause other periods of degraded performance because of fouling to challenge the capability of the system.
>
> Whether the peak spray pond temperature would be significantly lower for loss-of-coolant accident break sizes less than analyzed in the large break design basis accident. If so, what would the resulting limiting overall heat transfer coefficient values be for medium and small break sizes given the lower peak pond temperatures.
>
> Best available calculations (technical basis and results) for room temperature profiles during loss-of-coolant accidents with loss of room cooling to safety-related equipment because of a failed essential chiller. Also, best available information of the failure probability and basis associated with the safety related pumps affected by the loss of room cooling.
>
> An assessment of human error probabilities for important operator actions under the specific conditions expected to be present if operator action is to be credited in reducing the risk estimation. Specifically, if the licensee plans to credit controlling EW flow through the shutdown cooling heat exchanger as a way of delaying or eliminating a loss of the essential chiller.
>
> The technical basis for any "inadvertent cleaning" effect the licensee intends to credit. This should include an analysis of how the any test data to be used relates to the geometry and conditions in the Unit 2 EW heat exchangers (i.e. eddy current probe size, the heat exchanger tube sleeves, normal tube diameter, thermal conductivity of remaining precipitant, etc.).

An analysis of the contribution to risk for external events associated with this issue.

5.2 Design Control Issues

Three examples of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," were identified. The example related to scaling calculations is discussed in Section 5.1.5.

(1) **Spray Pond Allowed to Build Up Sediment**

Introduction. An example of a noncited violation of Criterion III was identified for failure to adequately translate the design basis of the spray ponds into procedures. The design basis calculation that demonstrated that the spray pond system could adequately limit spray pond temperature during a design basis accident did not account for reduced heat capacity caused by sediment. However, this was not translated into procedures to ensure that sediment did not build up in the spray ponds.

Description. During early discussions of the design and condition of the spray ponds, it became apparent that the spray ponds had sediment along most of the bottom of each pond. It was also determined that the licensee had never drained or cleaned the ponds, nor did they monitor or quantify the sediment. The team questioned the impact the sediment had on the ponds' ability to perform their intended functions.

Engineering and chemistry personnel initially stated that the ponds needed 18 inches of at the bottom of the pond to assure adequate spray pond system pump net positive suction head. This was therefore an unusable water volume. By this reasoning, this volume of water could be replaced by sediment with no impact, since sediment did not affect the net-positive suction head (NPSH). Informal reports from contract divers had indicated that sediment was about 4 inches thick on average, and did not exist near the pump suctions.

The licensee determined that a preventive maintenance basis document from the early 1990s had specified that a preventive maintenance item should be created to verify that sediment did not accumulate and impact system capability. However, this was never implemented.

Additionally, engineering personnel reviewed Calculation 13-MC-SP-0307, "SP/EW System Thermal Performance Design Basis Analysis," Revision 7, and determined that this calculation relied on both the usable and unusable water volume contained in the ponds to absorb the heat rejected during a design basis accident. Using the entire water volume yielded the result that under limiting conditions, the maximum pond temperature was maintained just below the maximum allowable temperature of 110F. Further, the heat capacity of the sediment was about 40 percent compared to that of the water that it displaced. Therefore, the team concluded that the spray ponds were all outside the analyzed condition of the design basis.

Engineering revised the calculation to account for the quantity of sediment believed to exist in each pond. In doing so, it was necessary to credit heat transfer to the concrete in the spray pond walls, which was not previously credited. The team reviewed the calculation and determined that it used reasonable assumptions and demonstrated adequate margin.

As part of the corrective actions, the licensee began a campaign to remove and quantify the sediment from each spray pond. By the time of this report, three of the six spray ponds had been vacuumed, removing approximately 400 cubic yards of sediment from each pond. This was within the volume assumed in the calculation.

Analysis. Failure to adequately translate the design basis of the spray ponds into procedures was a performance deficiency. This finding was determined to be more than minor because, if left uncorrected, the finding could become a more significant safety concern. This finding affected the Mitigating Systems cornerstone. This performance deficiency screened as having very low safety significance (Green) in a Phase 1 SDP because the licensee was able to demonstrate that the sediment would not have resulted in a loss-of-safety function.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, requires that design control measures be established to ensure that design basis information is translated into instructions, procedures, and drawings. The Calculation 13-MC-SP-0307 was intended to demonstrate that the heat exchangers cooled by the emergency spray pond system would be capable of transfering the required heat load to the spray pond because scaling would not occur during a design basis accident. This calculation relied upon the entire volume of water available at the Technical Specification minimum water level to demonstrate that the pond could perform its intended safety function. Contrary to this, the licensee did not ensure that the water volume was maintained as assumed in the calculation through instructions, procedures, or drawings. This issue was documented in CRDR 2906671. This example of a violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2006011-05a, Inadequate Design Control to Ensure Spray Pond Sediment Would Not Impact Operability.

(2) **Spray Pond Integrity**

Introduction. An example of a noncited violation of Criterion III was identified for failure to adequately translate the design basis of the spray ponds into procedures. The design basis calculation, which demonstrated that sufficient water was available to provide adequate cooling during a design basis accident did not account for any leakage from the ponds. The team determined that the licensee did not translate this into a procedure to ensure that the condition of the spray pond was maintained such that leakage did not occur.

Discussion. The team reviewed all CRDRs associated with the spray pond system initiated since 2000. In CRDRs 114987, and 2886930, and CORs 00-1-001, 00-2-001, and 00-3-001, the licensee documented cracks that were observed in the accessible portions of the spray pond walls. In some instances, minor weepage through the wall was observed. The conditions were repaired.

The team reviewed the licensee's treatment of the system within their maintenance rule program, and determined that it was subject to condition monitoring. Condition monitoring was performed using Procedure 81DP-0ZZ01, "Civil System, Structure, and Component Monitoring Program, Revision 11. At Palo Verde Nuclear Generating Station, structural monitoring was performed in one unit every 10 years, rather than in each unit. The program required that if problems were identified in one unit's structure, the similar structures in the other units would be inspected.

The team was concerned that licensee's Maintenance Rule Program only required inspections of the accessible portions of the pond structures. The licensee considered that the pond bottom and inner walls were inaccessible because of the presence of water. The team concluded that the portions of the spray pond liners considered by the licensee to be accessible represented a small fraction of the structure (less than seven percent). Almost the entire portion that was subject to inspections was above the water line, were structural integrity was not needed, whereas the uninspected portion was critical to the safety function.

The team identified that the licensee had never drained any the spray ponds or conducted formal or complete inspections using divers. Further, the pond bottom constituted the majority of the pond liner surface, and this could not be inspected because the licensee had allowed approximately 4 inches of sediment to buildup on the pond bottom. Also, the licensee was not able to measure spray pond makeup, nor were they able to estimate spray pond water loss because of the large daily evaporative losses, which were highly variable. The licensee calculated that there was sufficient water maintained above the Technical Specification minimum water level to be able to tolerate a 5 gpm leak, which was small compared to the daily losses.

The licensee acknowledged the need to inspect the pond liners. This was scheduled as part of CRDR 2901589 to be performed by divers trained to perform this inspection upon completion of vacuuming in each pond. Inspections of the three completed ponds indicated no integrity problems.

The licensee performed an assessment which concluded that no significant leakage existed. This was based largely on the judgement that the geology and hydrology of the site would cause significant leakage to be observable on the surface, and no such indication had ever been observed. This was supported by recent efforts to identify the source of detectable tritium in ground water, which included drilling some holes in the vicinity of the spray ponds. Many of the holes collected no water, and none of the water that was collected had chemical results which would indicate that it included spray pond water. Also, the construction methods ensured that there were no joints that could provide leakage paths through the walls or bottom. The observed cracking was judged to be too tight to allow significant leakage.

The team reviewed the photographs from the inspections, the design and construction of the liner, and the results of ground water studies, and concluded that it was reasonable to conclude that no significant leakage existed.

Analysis. Failure to adequately translate the design basis of the spray ponds into procedures was a performance deficiency. This finding was determined to be more than minor because, if left uncorrected, this finding would be a more significant safety concern. This finding affected the Mitigating Systems cornerstone. This performance deficiency screened as having very low safety significance (Green) in a Phase 1 SDP because it did not result in a loss-of-safety function.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, requires that design control measures be established to ensure that design basis information is translated into instructions, procedures, and drawings. Calculation 13-MC-SP-0307, "SP/EW System Thermal Performance Design Basis Analysis," Revision 7, which demonstrated that the system contained sufficient water to provide adequate cooling during a design basis accident did not provide any margin for leakage from the ponds. Contrary to this, the team determined that the licensee did not translate this information into an instruction, procedure or drawing to ensure that the condition of the spray pond was maintained such that leakage did not occur. This issue was documented in CRDR 2910912. This example of a violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2006011-06b, Inadequate Design Control to Ensure Spray Pond Integrity.

5.3 Inadequate Implementation Of Operability Assessment Process

Introduction. A Green noncited violation with multiple examples was identified for failure to follow Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 16. Key support organizations were not always involving operations personnel with questions that had a potential to affect operability of safety-related equipment, or were informing operators only after the support organization had fully evaluated the condition, delaying actions that were required to be prompt by days or weeks. Also, operations personnel did not always insist on a rigorous evaluation. This violation was determined to be of very low safety significance because it was determined to not involve a loss-of-safety function in a Phase 1 SDP evaluation. This finding has Human Performance Cross-cutting aspects associated with decision making.

Description. Charter Item 7 required a review of operability evaluations associated with heat exchanger fouling and an assessment of the compensatory actions and initial corrective actions to address the issues.

During this review, the team noted a number of examples where the assessment of operability did not meet the NRC's expectations as delineated in Regulatory Issue Summary 2005-20 or follow the operability assessment process in Procedure 40DP-9OP26, "Operability Determination and Functional Assessment." More specifically, the team concluded that key support organizations (engineering, chemistry, and maintenance) were not always involving operations personnel with questions that had a potential to affect operability. In a few cases, operations was

informed only after the support organization had fully evaluated the condition, delaying actions that were required to be prompt by days or weeks. In a larger number of cases, support organizations decided not to involve operations. Also, operations personnel became involved but did not always insist on a rigorous evaluation. The following are the more significant examples that illustrate these conclusions:

- During a surveillance test of EDG 2B on May 17, 2006, high out of specification intercooler air temperatures were noted. The licensee failed to adequately assess this degraded condition or formally enter the operability determination process until May 19. Emergency diesel generator operability was informally discussed. The EDG system engineer assured the operations shift manager that the emergency diesel was operable based on a call with a consultant to the Cooper-Bessemer Owners Group (inappropriately represented as a representative of the vendor). The team determined that the scope of the discussions had been limited to the impact to the engine and had failed to evaluate other aspects, such as the effect of higher exhaust temperatures on turbocharger blade creep, increased fuel consumption, and load control. While these were eventually addressed after NRC inspector involvement, this initial informal and undocumented operability assessment allowed the licensee to remove the opposite train from service when EDG 2B was degraded and the impact was not properly understood. When operability was properly addressed on May 19, it was decided that EDG 2B should not have been considered to have a reasonable expectation of operability.

- On May 19, 2006, Work Order 2896333 was initiated to inspect and clean the EDG 2B intercoolers. During review of this work order following EDG 2A restoration, the on-shift operators determined the high temperatures warranted an operability determination. Condition Report/Disposition Report 2896661 initially concluded that the condition was isolated to EDG 2B. The NRC inspectors identified that this ignored fouling in both EW heat exchangers on the common spray pond system side that had necessitated cleaning that same week to be able to assure operability through the coming hot summer months. However, the team noted that operations did correctly decide to run all EDGs in accordance with Technical Specification Surveillance Requirement 3.8.1.2 to assess their operability. Additionally, the inspectors noted that the initial evaluation assessed performance using the existing pond and air temperatures, rather than using the more limiting design basis conditions; when this was included, the degradation was shown to potentially exceed the design basis temperature limit during accident conditions in two additional EDGs. Following prompting from NRC inspectors, on May 24, 2006, the licensee appropriately expanded the scope of their evaluation. Additionally, the team noted that the licensee initiated CRDR 2898120 that states, in part, "It appears that trending and monitoring and/or extent of condition considerations of the essential water heat exchanger fouling condition should have provided for identification of the intercooler fouling condition and prevented the emergent condition discovered on May 17, 2006."

- The Prompt Operability Determination that was issued on June 3, 2006, concluded that heat exchangers were adversely affected by a low temperature fouling mechanism that was already known. The team concluded that this initial conclusion was based on an incorrect understanding of the situation that dated back to 2003, and was the basis of the decision to stop adding dispersant to the spray ponds. This was eventually shown to be an inappropriate compensatory action. However, when a technical evaluation of facts progressed, the cause assessment correctly triggered a reassessment of operability and more appropriate compensatory measures.

- On June 10, 2006, the licensee identified the failure to implement routine preventative maintenance tasks to remove biological fouling agents, corrosion products, and sedimentation from the essential water cooling spray ponds. The concern was documented in CRDR 2901737 and was determined to not meet the procedural requirements for contacting the control room operators as an operability concern based on the incorrect conclusion that the failure to implement this task only affected the preventative maintenance process, even though it was known that the ponds had several inches of sediment buildup. This issue should have been reviewed by the control room operators in accordance with procedural requirements because the failure to remove debris from the ponds could adversely affect the safety function of the ultimate heat sink based on water displacement and heat transfer considerations. The team concluded that the reviewers of this CRDR prevented a timely review of operability. This technical issue is further discussed in Attachment 4.

- On June 10, 2006, the NRC inspectors discussed with the licensee concerns that sedimentation buildup of the essential water spray ponds could potentially affect operability of the ultimate heat sink. On June 21, 2006, licensee engineering personnel provided the inspectors a calculation revision demonstrating that any sedimentation accumulation had placed the ultimate heat sink outside its analyzed condition for assuring the peak pond temperature limits could be met. The inspectors noted that engineering should have recognized that all three units were outside their analyzed condition, but chose to evaluate the condition before discussing the operability concern with operations (CRDR 2906487 was written with June 28 listed as the discovery date, and CRDR 2906671 was written for the untimely identification of the issue). The team concluded that site personnel lacked a questioning attitude and technical rigor while evaluating this degraded condition since the accumulation of sedimentation had been known for years at the site without documenting or evaluating the possible impact to operability until questioned by the NRC.

- The team questioned whether the spray ponds had leakage which could challenge their ability to maintain enough water to perform their intended safety function during a design basis accident. This question was raised when it was identified that there was a history of cracking in the ponds' concrete liners, and that the ponds were receiving inadequate inspection and monitoring (see Section 4.2.3). The team concluded that an operability assessment was required by the licensee's procedure for this condition. The licensee wrote CRDR 2910912 and documented many of the points which would have been

required in an operability assessment, although a discovery checklist was inexplicably used to make the case that an operability determination was not required. This document reiterated the conclusion of a 2000 assessment in addressing the structural integrity function of the concrete, rather than the specific concern raised by the NRC team, which was water loss. The team was told by the engineering supervisor that performed the evaluation that a hole of considerable size would be required to allow enough leakage to cause a loss of operability, so his evaluation had not addressed this aspect. The team noted that this evaluation was based on engineering judgement, was not complete in addressing the functions affected, and was based on a perception of lack of evidence of leakage, rather than a solid body of facts. The team found that operations had exhibited a questioning attitude, and when it was noted that the evaluation had not addressed the leakage aspect, and operations had performed their own calculation to show that only 5.3 gpm leakage could be tolerated without losing operability, and this small margin was made possible by crediting the amount of water normally maintained above the Technical Specification minimum water level. The team noted that this practice was reasonable for an operability assessment, but did not address the design problem of having no design margin reserved for realistic leakage values.

Assessment. Failure to adequately implement the operability assessment process was a performance deficiency. This finding was more than minor because it impacted the equipment performance attribute of the Mitigating Systems cornerstone objective to maintain the availability and reliability of systems needed to mitigate accidents. This finding screened as having very low safety significance in a Phase 1 SDP, since it was confirmed not to involve any loss-of-safety function. This finding had cross-cutting aspects in the area of human performance because the licensee did not follow their systematic process for operability decision making when information was not brought to the right decision makers.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings, and shall be accomplished in accordance with those instructions, procedures, and drawings. The assessment of operability of safety-related equipmnet needed to mitigate accidents was an activity affecting quality, and was implemented by Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 16. Failure to follow Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 16, to properly and promptly evaluate operability constituted a violation of Criterion V. This issue was documented in CRDRs 2918892, 2901815, and 2898237. This violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2006011-07, Multiple Examples of Failure to Properly Implement Operability Assessment Process.

5.4 Examples of Inadequate Response Under the Corrective Action Program

Introduction. Section 5.1.4 briefly discusses an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." This section provides more details and specific examples which demonstrate a pattern of behavior which did not recognize and

address degraded heat exchanger performance between 1995 and May, 2006. Fouling and degradation of these heat exchangers and cracking in the spray pond structure was apparent from inspections, performance tests, and surveillance tests, but the licensee failed to enter most instances into the corrective action program. Of the instances that were documented, the licensee failed to recognize that some instances constituted a significant condition adverse to quality, failed to determine the cause, and failed to implement corrective actions to prevent recurrence.

Description. The Palo Verde Nuclear Generating Station corrective actions program is documented in Procedure 90DP-0IP10, "Condition Reporting," with Revision 28 being the current revision at the time of the inspection. Section 5.1.4 documented examples where the licensee failed to properly implement the corrective action program that directly contributed to a loss of safety function in one train that had potentially greater than very low safety significance. The team identified the following additional examples of a violation where the safety significance was determined to be very low.

Specific examples where the licensee's corrective action program was ineffective include:

- Emergency diesel generator intercooler degradation was evident from available documentation starting in 1995, but was not recognized until January, 1999 when it was documented in CRDR 36287. After that, the team identified no other problem reporting in the corrective action program associated with this ongoing EDG intercooler fouling until May, 2006. Instead, engineering attempted to manage the problem outside the corrective action program by repeatedly scheduling cleanings when degradation reached a threshold which was not formally established. This was determined to be an example of inadequate problem identification for a condition adverse to quality.

- Problem reporting for EW heat exchanger fouling was incomplete and appears to have been based on a relative departure from "expected fouling" instead of from an absolute reference. In the early years after implementing the zinc-phosphate chemistry control program, the team noted that EW heat exchanger performance tests measured up to 75 percent excess capacity, and on paper, these components had more than 100 percent excess capacity. By 2004, engineering was considering 30 percent excess capacity to be "expected." This amounted to tolerating significant performance loss without reporting it into the corrective action program. The following examples associated with the EW heat exchangers' degraded performance illustrate this performance deficiency:

Date	Heat Exchanger	Performance Margin	Comments
4/96	2B	3.2%	Untimely identification (CRDR 80645 initiated 4 months after test).
9/02	1B	3.6%	No CRDR written.

4/03	3A	-22.0%	Condition Report/Disposition Request 2598216 failed to identifying that this was a significant condition adverse to quality, address the cause, or implement corrective actions to preclude repetition.
10/03	2A	1.0%	Condition Report/Disposition Request 2653867 addressed fouling and the informally attempted to determine the cause, but failed to conclude it was a significant condition adverse to quality when it was recognized that the problem affected multiple systems in all trains and all units.
2/04	1B	-17%	No CRDR written, no cleaning or corrective action, so condition was allowed to further degrade until refueling outage in 5/04 This constituted a significant condition adverse to quality that was not entered into the corrective action program, corrected, or a cause determined.
3/04	2A	28.6%	No CRDR written. This constituted a condition adverse to quality, if considered individually.
5/04	1A	9.9%	No CRDR written. This constituted a condition adverse to quality, if considered individually.
4/05	2B	25.8%	No CRDR written. This constituted a condition adverse to quality, if considered individually.
5/05	2A	29%	No CRDR written. This constituted a condition adverse to quality, if considered individually.
10/05	2B	11.1%	No CRDR written. This constituted a condition adverse to quality, if considered individually.
10/05	3B	19.3%	No CRDR written. This constituted a condition adverse to quality, if considered individually.

10/05	1B	1.4%	Condition Report/Disposition Request 2835865 written. In 11/05, CRDR 2860763 was written and took 3 months to address EW heat exchanger fouling in all units. Not classified as significant condition, and did not consider EDG impact. Operability Determination performed for performance test results in 10/05 was not completed until 1/06.

Note that 30 percent margin was used as the threshold by the team in assessing when sufficient degradation had occurred to constitute a condition adverse to quality, to be consistent with the licensee's stated expectations. It could be argued that a higher threshold could be used, since no degradation should be present if the chemistry control program was performing as intended. However, it was considered sufficient to document the above examples to illustrate the extensive pattern of behavior that is being addressed in this violation.

- In June, 2006, engineering personnel reviewed historical performance testing results and noted that EW Heat Exchanger 2B may have been significantly degraded in 2002-2003. This was not entered into the corrective action program for a week, and not until the team asked. Condition Report/Disposition Request 2905161 was written to document this issue.

- The corrective action process was ineffective in determining the significance of the fouling. The team determined that there was enough evidence to have recognized that the fouling problems affected both trains and all units as early as 1999, which should have raised the issue to a "significant" classification, but this did not occur because the licensee did not adequately consider the extent of condition or identify the cause.

- In December 2005, when it was recognized that the fouling was occurring faster in EW heat exchangers to the point where their capacity would be assured only during cooler weather, some of these heat exchangers were taken out of service while the associated plant was on line to perform midcycle cleanings. However, the fact that the EDG coolers should also be expected to be experiencing the same degradation was not considered. The worsening of the degradation rate did not trigger a reassessment of the cause or significance.

- In May 2005, chemistry wrote CRDR 2800653 to report that molybdenum analyses yielded erratic results. They concluded that the analysis method was not sufficiently accurate (actual accuracy was estimated at 30-50 percent) to maintain it in the desired control band (225 - 270 PPB). Chemistry began to question whether the molybdenum tag was accomplishing what they wanted it to and requested an evaluation of alternatives. The licensee also identified that samples were untimely because of lack of qualified analysts (would sometimes wait 2 to 3 weeks to analyze samples). The CRDR also documented that they had stopped adding dispersant in November 2005, but still recorded increases in molybdenum or other unexpected results in over half of the samples. The team

concluded that this represented a missed opportunity to recognize that they were not adding dispersant, and that dispersant concentration was no longer coupled with the tag chemical. The evaluation of alternatives considered other tag chemicals, but did not consider other dispersants which could be measured. The team noted that this CRDR was closed with the only change being to qualify more analysts to perform the molybdate analysis.

Assessment. The significance of this finding will be assessed as part of the final significance determination. See Section 5.1 for the assessment of this finding.

Enforcement. See Section 5.1.4 for the enforcement discussion associated with this finding.

6.0 ADDITIONAL INFORMATION

6.1 Summary of Chemistry Control Changes

There were three distinct periods of interest in this inspection. From 1994 to 2001, the licensee used Nalco (later bought by Calgon) chemicals. In 2001, the Arizona Public Service corporate system changed to Betz chemicals. Palo Verde Nuclear Generating Station changed to what was believed to be equivalent chemicals, but maintained essentially the same chemistry control program for the spray ponds. In 2004, the dispersant was changed because it was thought that the dispersant was reacting with the biocide and forming an acrylic polymer and fouling heat exchangers.

The licensee implemented zinc-phosphate chemistry control in the SP systems in 1994. The proprietary specialty chemicals used were:

Dispersant:	CALGON PCL-401 (AA/AMPS)
Corrosion inhibitor:	CALGON MSW-109 (zinc chloride in phosphoric acid (3:1)
Biocide:	BULAB 6002
Chemical supplier:	NALCO/CALGON

Initially, zinc limits were 1.0 - 1.5 ppm, the pH band was 7.6-8.2, and dispersant was added three times per week.

Between 1995 and 1999, some degraded performance was noted in EDG intercooler outlet temperatures. This was not documented until 1999. Also, in 1995, the spray pond system began to have corrosion problems where localized corrosion nodules formed and broke off, blocking heat exchanger tubes.

On 4/24/96, the pH band was lowered from 7.6 - 8.2 to 7.4 - 8.0.

In 1997, the licensee attempted to chemically passivate spray pond piping by significantly lowering pH to remove corrosion products, then reestablish a protective zinc layer. This was unsuccessful.

On 3/3/98, pH specification was raised from 7.4 - 8.0 to 7.6 - 8.6. On 8/13/98, the dispersant addition time was increased from 2.5 to 3 hours.

On 9/18/98, the licensee split the requirements so that Unit 1 had different limits, since they were changing Unit 1 so makeup water came from wells. Since this water had higher alkalinity and thus a higher scaling potential, Unit 1 was given a lower pH band to improve solubility and avoid scaling. Unit 1 had a pH specification of 7.8 - 8.2, while Units 2 and 3 had 8.0 - 8.4. However, on 7/6/99, this was reversed, and all units had a pH specification of 8.0 - 8.4. No explanation was given why the increased potential for scaling was acceptable.

On 7/11/00, the upper zinc specification was changed from 1.0 to 1.5 ppm.

In 2001, the corporate chemistry group for Arizona Public Service changed chemical supply companies. On 5/30/01, the licensee began adding the following new chemicals:

Dispersant:	BETZ PY5200 (AA/HPS-1)
Corrosion inhibitor:	BETZ MS-6209 (zinc oxide in phosphoric acid in 4:1 ratio)
Biocide:	BULAB 6002
Chemical supplier:	BETZ

In October 2003, the licensee performed the first EW heat exchanger tube cleaning in 2R11 in response to fouling. Since then, 100 percent of the EW heat exchanger tubes are cleaned every refueling outage.

On 1/29/04, the licensee concluded from informal lab testing that EW heat exchanger fouling was being caused by an undesirable interaction between the dispersant and the biocide. This was based on discussions with the chemical supplier's site representative, and included informal lab tests which showed that a white substance could be formed by mixing the chemicals, although the conditions of this test were not documented and the substance formed was not analyzed. The team noted that the conclusions drawn from this informal test dominated the licensee's response through June, 2006.

In March 2004, the dispersant was changed to address EW heat exchanger fouling. The chemicals were now:

Dispersant:	BETZ DN2317 (AA/APES)
Corrosion inhibitor:	BETZ MS-6209 (zinc oxide in phosphoric acid in 4:1 ratio)
Biocide:	BULAB 6002
Chemical supplier:	BETZ

The target dispersant concentration was 12.5 - 15 ppm. The previous dispersant was not removed from the ponds through feed and bleed, but was expected to continue to react and be removed by spray pond sand filters. There was no evaluation of adding a new dispersant with the previous dispersant still present, or an analysis of the acceptability fo the new dispersant for the system (LIST CRDR). Also, the zinc specification was doubled from 0.5 - 1.5 ppm to 1.0 - 3.0 ppm.

In November 2004, a white "lotion-like" substance identified in Spray Pond 2C sand filter. The cause was believed to be having the old dispersant and the new dispersant, polymerizing and coagulating into larger particles (essentially doing what they were supposed to do, but at a higher rate). It was not believed to be a problem for heat

exchangers because of the mobility of the substance and most recent EW heat exchanger performance test showed improving trend (the team noted that this was actually after a midcycle cleaning with only 6 months of operation, so it was not useful to consider this data). The licensee implemented more frequent backwashing of spray pond sand filters, believing that this would remove the problem chemical. Chemistry explained that this took 10 months to happen after changing dispersants by saying it was because of cooler temperatures in the pond. However, the team noted that this did not take into consideration that the dispersant change took place in January when the ponds were also cold.

In May 2005, chemistry wrote CRDR 2800653 to report that molybdenum analyses yielded erratic results. They concluded that the analysis method was not sufficiently accurate (actual accuracy was estimated at 30-50 percent) to maintain it in the desired control band (225 - 270 PPB). Chemistry began to question whether molybdenum tag was accomplishing what they wanted it to and requested an evaluation of alternatives. The licensee also identified that samples were untimely because of lack of qualified analysts (would sometimes wait 2 to 3 weeks to analyze samples). The CRDR also documented that they had stopped adding dispersant in November 2005, but still recorded increases in molybdenum or other unexpected results in over half of the samples. The team concluded that this represented a missed opportunity to recognize that they were not adding dispersant, and that dispersant concentration was no longer coupled with the tag chemical. The evaluation of alternatives considered other tag chemicals, but did not consider other dispersants which could be measured. The team noted that this CRDR was closed with the only real change being to qualify more analysts to perform the molybdate analysis.

On 10/17/05, the pH specification was changed from 8.0 - 8.4 to 7.8 - 8.4 in order to improve chlorine effectiveness and zinc solubility.

The team noted that between October 2005 and May 2006, both spray ponds in Units 2 and 3 had molybdate results that were above the target level of 200-300 ppb almost continuously, even though dispersant was largely not being added. The validity of these results was not questioned. The team considered that this was imprudent, since evaporation required adding 2,200 to 10,000 gallons of makeup water per day if the pond was idle, more if the sprays were run. Of note, Unit 1 spray ponds were maintained within the target band during most of this period. The team reviewed the dispersant usage by assessing tank levels in each unit. Between October 2004 and August 2005 little or no dispersant was added to any of the ponds. From August 2005 until May 2006, dispersant was added fairly regularly in Unit 1, less regularly in Unit 3, and infrequently in Unit 2. This was known to the chemistry line organization, but not to management or the root cause team until the inspection team requested the information. The team also compared the recent dispersant usage to earlier usage. Since changing to the latest dispersant in March 2004, the total dispersant used in 27 months was about equal to the annual used in years prior to that change. The lack of regular additions coupled with rising concentrations of other chemicals tended to indicate that there was increasingly insufficient dispersant to prevent loss of solubility in the spray pond systems.

The team assessed the history of differences in chemistry parameters between the units. The team noted that Unit 2 consistently had the highest levels of phosphates, and the pH was above 8.2 for long periods of time compared to the other units. Unit 1 had roughly double the calcium compared to the other units; this was known to be because of using well water in this unit.

7.0 SUMMARY OF HOW THE TEAM ADDRESSED THE CHARTER SCOPE

1. Sequence of Events

This topic is documented in Attachment 4.

2. Operating Experience

Personnel from the Operating Experience Branch of NRR supported the team by performing searches of operating experience databases and other sources. The intent was to identify operating experience report of similar problems and other relevant information, both within and outside the nuclear industry. Palo Verde Nuclear Generating Station had one instance of tube blockage, which was documented in Licensee Event Report 50-528/95-005-00, "Corrosion Nodules Blocking EDG 1B Jacket Water Cooler Tubes." This involved chemistry challenges in the spray pond system, but did not involve precipitation or scaling. Only two reports of problems with similar circumstances were identified, although the causes were different. It was noted, however, that outside the nuclear industry, this type of condition would probably not be considered to be serious. However, these searches identified information that indicated that zinc-phosphate chemistry control programs similar to the one used by Palo Verde Nuclear Generating Station were in common use in similar systems, and were used effectively.

3. Generic Issues

The chemical control program in use in the Palo Verde Nuclear Generating Station spray ponds and associated systems were generally compatible when used together in a coordinated program. This type of program was in common use and effectively employed in similar applications. However, the unique design of the spray pond system and the unique operating practices were not adequately reviewed to ensure compatibility.

The only generic issue identified was that AA/HPS-1 type dispersant is know to interact with polyquat amine-type biocide and form an acrylic polymer that can cause water problems, including possibly fouling. The acrylic acid in this product has a strong negative charge compared to other dispersants, and will combine with the biocide.

4. Corrective Actions

During this inspection, the licensee corrected the limits for the spray pond in the chemistry control program, and restored the ponds to within the new limits by blowing down the ponds. They were also evaluating changing the dispersant to regain the ability to monitor it. The ponds were being vacuumed and inspected to remove chemical

sludge and sediment, and to verify pond integrity. Part 50.59 reviews were planned for past changes to chemistry procedures. Emergency diesel generator intercoolers were promptly cleaned, and increased frequency monitoring of performance was implemented while chemistry improvements were being identified and implemented.

5. Root Cause Determination.

The licensee's determination of the cause was broad and thorough in assessing the problems and the history. This effort included looking at both the technical issues and the organizational aspects, which was appropriate. Adequate resources were devoted this effort, including obtaining several sources of outside expertise in a number of important aspects of the evaluation. The draft report, although awaiting some technical information, thoroughly documented the facts available, the process used, the possible causes considered, and the conclusions. This effort also identified a number of peripheral issues that were entered into the corrective action program.

6. Design Basis and Technical Specifications Compliance

A number of problems were identified with the design basis and Technical Specification compliance. These are discussed in the Findings section.

7. Operability Assessments and Compensatory Measures

A number of problems were identified with operability assessments. These are discussed in the Operability Assessment section. The compensatory measures and initial corrective actions implemented by the licensee were appropriate and timely, with the exception of stopping dispersant additions. In retrospect, this was inappropriate based on the later understanding of the cause of the fouling; however, from the perspective of what was known at the time, this was not unreasonable. Dispersant additions were resumed in a prompt manner when the cause was better understood.

8. Heat Exchanger Testing

The test methodology was reviewed along with several years worth of test results. The methodology was in accordance with industry standards, although the calculations provided results which were not typical. Specifically, the heat exchanger performance was calculated for the existing conditions, and the acceptance criteria (reflecting design basis conditions) were extrapolated to the existing condition results. The normal practice is to extrapolate the results from the existing conditions to design basis conditions. The team concluded that, while the licensee's practice made comparison of results technically awkward, this did not affect the ability to demonstrate proper performance. The team also identified that the licensee's practice of having the test and the calculation as separate activities contributed to having untimely results from the performance tests in at least one case, and possibly others.

9. Risk Analysis

Information was gathered to support a preliminary risk assessment. However, key information was still needed to be able to perform a final risk analysis. This is further discussed in the Findings section under the Analysis heading.

10. Methods of Heat Exchanger Protection

The team assessed the chemistry control program design and implementation, operating practices, inspection and cleaning methods and results, and the cathodic protection used in portions of the system. As discussed in various parts of this report, the chemistry control program was changed over time in ways that created heat exchanger fouling. Corrosion control was being effectively implemented, however.

11. Effectiveness of Heat Exchanger Performance Monitoring

As discussed in various parts of this report, performance monitoring was not effective in identifying and correcting heat exchanger degradation. The tests and inspections were being done according to commitments, but the results that indicated increasing amounts of chemical residue, and the need for increasing frequent cleanings, were not followed up to determine and correct the cause. This was an organizational problem, rather than a problem with the monitoring methods or frequencies.

1R07 Biennial Heat Sink Performance (71111.07B)

a. Inspection Scope

The team reviewed design documents (e.g., calculations and performance specifications), program documents, implementing documents (e.g., test procedures, maintenance procedures, and actual data), and corrective action documents. The team interviewed chemistry personnel, maintenance personnel, engineers, and program managers.

The team verified whether testing, inspection and maintenance, or the biotic fouling monitoring program provided sufficient controls to ensure proper heat transfer. Specifically, the inspectors reviewed heat exchanger test methods, test results from performance testing, inspection results, and chemical controls to limit fouling.

For the ultimate heat sink and its subcomponents, the team reviewed the heat sink to determine if it was free from clogging because of macrofouling and provided sufficient controls to ensure proper heat transfer. The inspectors reviewed; (1) heat exchanger test methods and test results from performance tests, (2) heat exchanger inspection and cleaning methods and results, and (3) chemical treatment for the spray ponds to control fouling. The team selected the following heat exchangers for this inspection:

- Essential cooling water heat exchanger
- Emergency diesel generator jacket water heat exchanger
- Emergency diesel generator inter-cooler

The team completed 3 of the 2 to 3 required samples.

b. Findings

An apparent violation of Criterion XI, "Test Control," associated with EW heat exchanger testing was discussed in Section 5.1.2. A minor violation of 10 CFR Part 50, Appendix B, Criterion III, was identified for using an inappropriate fouling factor in design documents for the EDG intercoolers. The team identified that fouling factors for clean water (0.0005) was used on both sides of these heat exchangers, where fouling factors of 0.002 was appropriate for the application. The latter value was correctly used in the other EDH heat exchangers. This was determined to be minor because the team calculated that this had a small impact (4 percent) to the point at which these heat exchangers would not be able to perform their intended function, compared to the large margins available in the EDG system. This minor issue was entered into the corrective action program as Action Request 051201123.

4OA6 Meetings, Including Exit

On August 18, 2006, the inspectors presented the inspection results to Mr. C. Eubanks, Vice President, Nuclear Operations, and Mr. D. Mauldin, Vice President, Engineering, and other members of his staff, who acknowledged the findings.

An additional exit was conducted on September 26, 2006, to provide the results of preliminary significance determination and to change the characterization of the associated issues to Apparent Violations. The findings were discussed with Mr J. Levine and members of his staff, who acknowledged the findings.

The inspectors confirmed that proprietary information that was examined during this inspection was properly handled in accordance with NRC policy.

4OA7 Licensee-Identified Violation

The following violation of very low safety significance (Green) was identified by the licensee and was a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Part 50,59 of Title 10 Code of Federal Regulations allows licensees to make changes to procedures described in the Updated Final Safety Analysis Report without prior NRC approval provided that the change satisfies the criteria in Part 50.59.c. Contrary to this, Revisions 2, 6, 7, 8, and 9 to Procedure 74DP-0CY01, "Specification for Bulk Chemicals," were made between 1997 and 2004 without 50.59 reviews. This was identified in the licensees corrective action program under CRDRs 2864575 and 2683642. This violation is of very low safety significance because it did not actually impede the regulatory process or contribute to degraded heat exchanger performance.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Andrews, Department Leader, System Engineering
P. Borchert, Director, Operations
D. Breckenridge, Consulting Engineer, Arizona Public Service
P. Carpenter, Unit Department Leader, Operations
C. Churchman, Director, Engineering
A. Dave, Senior Engineer, Design Engineering
C. Eubanks, Vice President, Nuclear Operations
T. Green, Team Leader, Chemistry
D. Hautala, Senior Compliance Engineer
P. Heinstein, Chemical Vendor Site Representative, GE Betz
J. Hughey, Senior Engineer, System Engineering
H. Hurley, Root Cause Team Sponsor
R. Jenkins, Senior Chemist, Chemistry
D. Kanitz, Senior Compliance Engineer
M. Karbasian, Department Leader, Design Mechanical Engineering
J. Levine, Executive Vice President, Generation
D. Mauldin, Vice President, Engineering
J. Proctor, Section Leader, Regulatory Affairs - Compliance
M. Radspinner, Section Leader, System Engineering
C. Seaman, General Manager, Regulatory Affairs and Performance Improvement
T. Selby, Chemistry Consultant
G. Sowers, Section Leader, PRA
D. Straka, Senior Consultant, Regulatory Affairs
D. Vogt, Section Leader, Operations/STA

NRC personnel

J. Melfi, Resident Inspector, Palo Verde Nuclear Generating Station
E. Owen, Reactor Inspector, Region IV
N. Sieller, Operations Experience Branch, NRR
W. Sifre, Senior Reactor Inspector, Region IV
R. Telson, Operations Experience Branch, NRR and Acting Resident Inspector, PVNGS
S. Unikewicz, Senior Engineer, NRR
G. Warnick, Senior Resident Inpspector, Palo Verde Nuclear Generating Station
G. Werner, Senior Project Engineer, RIV

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000529/2006011-01,	AV	EW Train 2B Inoperable Longer than Allowed Outage Time (Section 5.1.1)
05000528; 05000529; 05000530/2006011-02	AV	Inadequate Test Control to Promptly Identify Unacceptable Performance Test Results (Section 5.1.2)
05000528; 05000529; 05000530/2006011-03	AV	50.59 Reviews Not Performed or Inadequate for Multiple Changes to Spray Pond Chemistry Control Procedure (Section 5.1.3)
05000528; 05000529; 05000530/2006011-04	AV	Inadequate Identification and Corrective Action for Degraded EW Heat Exchanger Performance (Section 5.1.4)
05000528; 05000529; 05000530/2006011-05	AV	Inadequate Design Control to Ensure No EW Heat Exchanger Scaling.(Section 5.1.5)

Opened and Closed

05000528; 05000529; 05000530/2006011-06	NCV	Two Examples of Failure to Translate Spray Pond Design Assumptions Into Plant Procedures Control (Section 5.2)
05000528; 05000529; 05000530/2006011-07	NCV	Multiple Examples of Inadequate Operability Assessments for Heat Exchanger Degradation (Section 5.3)

LIST OF DOCUMENTS REVIEWED

Procedures

30DP-9MP08, Preventive Maintenance Program, Revision 12

40OP-9SP01, Essential Spray Pond Train A, Revision 35

40DP-9OP26, Operability Determination and Functional Assessment, Revision 16

70TI-9EW01, Thermal Performance testing of Essential Cooling Water Heat Exchangers, Revision 5

70DP-9SP01, Monitoring of ESPS Piping Integrity, Revision 3

73DP-9ZZ10, Guidelines for Heat Exchanger Thermal Performance Analysis, Revision 4

73DP-9ZZ11, Heat Exchanger Condition Monitoring, Revision 4

74DP-9CY04, Systems Chemistry Specifications, Revision 37 (other revisions were also reviewed)

90DP-0IP10, Condition Reporting, Revision 28

Corrective Action Documents

2474313	2683642	2824865	2864575	2896661	2904101
2484639	2699739	2825469	2870799	2901500	2905161
2521395	2748191	2828929	2886930	2901737	2905162
2591826	2750856	2835865	2896661	2901815	2906671
2598216	2789993	2837696	2897810	2902498	2908351
2653867	2819671	2859430	2898120	2902504	2987810
2654231	2824784	2860763	2898237		

Work Orders

2537300	2723819	2805526	2897078	2897130
2723814	2724390	2886543	2897080	2898676
2723815	2724394	2886547	2897128	2898679
2723818	2805525	2896333		

Deficiency Work Orders

2564416
2700286

50.59 Documents

Screening S-06-0049, Revision 1, "Add Boron-10 Specifications to 74DP-9CY04 (Rev 36)," dated 2/15/06

Calculations

13-MC-DG-206,"Corrosion Allowance For DG Inter-cooler Water Boxes End Plates, dated January 15, 1991

13-MC-DG-411, "DG Heat Exchanger Minimum Flow Rate vs. Inlet SP Water Temperature," dated may 7, 1996

13-MC-DG-410, "Spray Pond Minimum Flow Rates To Diesel Generator Heat Exchangers," Revision 1

13-MC-DG-206, "Corrosion allowance For DG Inter-cooler Water Boxes End Plates," dated January 15, 1991

13-MC-DG-403, "Diesel Intake Exhaust and Drain Pipe P/T," Revision 0

13-MC-SP-0307, "SP/EW System Performance Design Bases Analysis," Revision 007

13-NS-B098, At-power PRA Study for the HVAC Room Coolers, Revision 2

Miscellaneous

GE Betz Memo, "SEM/EDXA Analysis of Deposit Samples from Arizona Public Service - Palo Verde Nuclear Generating Station," Dated December 1, 2003

Preventive Maintenance Basis Document 248948

Updated Final Safety Analysis Report Section 9.2, Cooling Water Systems, and Section 9.5.5, Diesel Generator Cooling Water System, Revision 13

Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," Revision 2
VTD-P162-0002, "Perfex Industrial Products Data Sheets and Drawings for Diesel Generator Inter-Coolers" Revision 1

13-NS-C076, "MSPI Data," Revision 00

RCTS 010359, IEC 78-13 Perform Periodic Inspection of Spray Pond Intake Structure for Sand/Silt Buildup dated 6/22/90.

LDCP Number 2LM-EW-036, Sleeving of Unit 2 Trains A and B Essential Cooling Water Heat Exchangers, 9/9/93

PVNGS Design Basis Manuals

Auxiliary Building HVAC System, Revision 13

Control Building HVAC System, Revision 13

Essential Cooling Water System, Revision 18

Essential Chilled Water System, Revision 10

Essential Spray Pond System, Revision 15

Diesel Generator, Class 1E Standby Generation, Fuel Oil Storage and Transfer System, Revision 016

Operating Experience

Palo Verde Nuclear Generating Station Licensee Event Report 50-528/95-005-00, Corrosion Nodules Blocking EDG 1B Jacket Water Cooler Tubes

Braidwood Operating Event Report, "Lake Chemistry Trend, Calcium Carbonate Issue," dated 2/17/04

Braidwood Operating Event Report on Calcium Carbonate Precipitation on the Non-essential Service Water Strainers, dated 4/18/02

NRC Information Notice 94-79, Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping, 11/23/94

NRC IE Circular 78-13, Inoperability of Multiple Service Water Pumps, 7/6/78Regulatory Commitment Tracking System Number 010359, Perform Periodic Inspection of Spray Pond Intake Structure for San/Silt Buildup

ATTACHMENT 2

SPECIAL INSPECTION CHARTER

June 7, 2006

MEMORANDUM TO: Neil O'Keefe, Senior Reactor Inspector
Engineering Branch 2
Division of Reactor Safety

FROM: Dwight D. Chamberlain, Director
Division of Reactor Safety

SUBJECT: SPECIAL INSPECTION CHARTER TO EVALUATE PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 HEAT EXCHANGER FOULING

You are hereby designated as the Special Inspection Team leader. Your team members are Paula Goldberg, Yamir Diaz-Castillo, Krzysztof Parczewiski, and Mike Runyan.

A Special Inspection Team is being chartered in response to the discovery of fouling of the emergency diesel generator (EDG) intercooler heat exchangers and essential cooling water heat exchangers. Fouling of each of the heat exchangers cooled by this system could lead to a failure of the EDGs to supply rated electrical power to safety-related components and a reduction in cooling to essential chilled water (room cooling for emergency core cooling system components), shutdown cooling, fuel pool cooling, and nuclear cooling water. The licensee implemented actions to inspect and clean the affected heat exchangers in order to restore margin for safety system operability.

A. Basis

On May 17, 2006, during surveillance testing of the Unit 2 B Train EDG, the licensee observed an abnormal increase in turbocharger air temperature. The cause of the increase is associated with fouling of the EDG intercooler heat exchanger. On May 19, during a review of the increased turbocharger air temperature, the licensee determined that a reasonable expectation of operability no longer existed and declared the EDG inoperable. The licensee subsequently cleaned the intercooler heat exchanger and declared the EDG operable. The licensee also initiated work packages to clean and inspect the remaining five EDG intercooler heat exchangers. Each of the EDG intercooler heat exchangers had experienced an increase in turbocharger air temperature, but not to the same magnitude as the Unit 2 Train B EDG.

On May 25, 2006, a teleconference was conducted with the licensee to discuss the extent of the condition and cause of the intercooler heat exchanger fouling. The licensee indicated that in 2001, a chemical additive (dispersant) to the spray pond reacted with a biocide to create the chemical substance that was found on the EDG intercooler heat exchangers and the essential cooling water heat exchangers in all three units. Dispersant is used to prevent ions (e.g., iron) from plating out on spray pond system surfaces. The dispersant coats the ions and aids in the filtration of the ions from the spray pond system. The licensee indicated that the fouling of the heat exchangers was initially discovered in 2003.

In March 2004, the licensee changed the type of dispersant and implemented more frequent (once per refueling outage) inspections and cleaning of the essential cooling water heat exchangers. The licensee indicated that heat exchanger fouling decreased following the decision to change the type of dispersant. However, recent performance testing of the essential cooling water heat exchangers, EDG testing, and heat exchanger inspections have shown that the rate of fouling of the heat exchangers is increasing.

The licensee indicated that degradation of the EDG intercooler heat exchanger would now be detected during surveillance testing. The resident inspectors noted that the Unit 2 Train B EDG had operated at higher temperatures for several months without being questioned by the licensee. The licensee also indicated that a performance test of the essential cooling water heat exchanger is performed whenever they initiate shutdown cooling operations and that the essential cooling water heat exchangers are cleaned every 18 months. However, the inspectors noted that the rate of fouling of the essential cooling water heat exchangers may result in a reduction of essential cooling water heat exchanger performance to below design margins during the operating cycle. The inspectors also noted that the licensee's actions were focused on cleaning degraded heat exchangers and not on eliminating the source of the chemical fouling.

The preliminary risk assessment for this condition determined that the increase in conditional core damage probability was 1E-6. The risk assessment assumed that the fouling of the EDG intercooler heat exchangers and essential cooling water heat exchangers may affect the reliability of the following components, either directly or through a loss of room cooling:

- emergency diesel generators
- motor and turbine-driven auxiliary feedwater pumps
- high pressure injection pumps
- low pressure injection pumps
- containment spray pumps
- shutdown cooling heat exchangers

To assess the risk of the condition, the analyst performed a sensitivity analysis to determine the amount of change in unreliability of these components that would cause a change in core damage probability of 1.0E-6, considering an exposure period of 1 year.

Using the Palo Verde Nuclear Generating Station SPAR model, Revision 3.2.1, and assuming average test and maintenance, the analyst determined that an increase in unreliability of 30 percent of all affected components would result in an increase in core damage probability of 1.0E-6. To attain this result, the fail-to-run individual and common cause basic events were adjusted by the same amount for all components except for the shutdown cooling heat exchangers (a basic failure event was adjusted in this case).

B. Scope

The team is expected to address the following:

1. Develop a complete sequence of events related to the discovery of the chemical fouling of the EDG and essential cooling water heat exchangers.

2. Compare operating experience involving fouling of heat exchangers to the identified issues at Palo Verde Nuclear Generating Station.

3. Determine if there are any generic issues related to the use of multiple chemicals and their subsequent impact on operating systems. Promptly communicate any potential generic issues to regional management.

4. Review the extent of condition determination for this condition and whether the licensee's previous and planned corrective actions are comprehensive.

5. Review the licensee's determination of the cause of any deficiencies and/or operating practices that allowed the chemical fouling to occur and continue. Independently verify key assumptions and facts. If available, determine if the licensee's root cause analyses and corrective actions have addressed the extent of condition.

6. Determine if the design basis and technical specifications were met for the effected systems.

7. Determine if the operability assessments, supporting analyses, and compensatory measures for heat exchanger fouling were made in accordance with RIS 2005-20.

8. Evaluate the adequacy of heat exchanger testing and calculations that were performed to evaluate the effect of heat exchanger fouling.

9. Collect data necessary to support a risk analysis. Specifically obtain information associated with the degree to which the EDG and essential cooling water systems would be affected during an event.

10. Assess the method(s) used by the licensee to protect the heat exchangers from corrosion, scale formation, fouling, and other biological impacts.

11. Assess the effectiveness and appropriateness of the tests and inspections used to determine heat exchanger performance and capability, including frequency and acceptance criteria.

C. Guidance

Inspection Procedure 93812, "Special Inspection," provides additional guidance to be used by the Special Inspection Team. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the

circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance, and begin inspection no later than June 19, 2006. While on site, you will provide daily status briefings to Region IV management, who will coordinate with the Office of Nuclear Reactor Regulation, to ensure that all other parties are kept informed. A report documenting the results of the inspection should be issued within 45 days of the completion of the inspection.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact me at (817) 860-8180.

ATTACHMENT 3

SUMMARY OF HEAT EXCHANGER PERFORMANCE TEST RESULTS

EW 1A	EW 1B	EW 2A	EW 2B	EW 3A	EW 3B
	3/92 1R2; tube leak identified	All tubes sleeved in 12/93 (8" at inlet and outlet) becasue of cracking in 2R4	All tubes sleeved in 12/93, (8" at inlet and outlet) because of cracking in 2R4		4/94, 3R4: Perf test 54.1% margin
12/94 Began Zinc-Phosphate chemistry control program.	12/94 Began Zinc-Phosphate chemistry control program.	12/94 Began Zinc-Phosphate chemistry control program.	4/94 Unit 2B pond begins trial use of Zinc-Phosphate chemistry control program.	12/94 Began Zinc-Phosphate chemistry control program.	12/94 Began Zinc-Phosphate chemistry control program.
4/95, 1R4: perf test 56% and 33.8% margin at outage beginning and end.	4/95, 1R4 perf test 39.8% margin	2/95, 2R5: perf test 56% margin.	3/95, 2R5: perf test 41.9% margin.	11/95, 3R5; end of outage perf test 24.9% margin.	10/95, 3R5; beginning of outage perf test 42.8% margin.
10/96, 1R6; end of outage perf test 34.3% margin.	9/96, 1R6; early outage perf test 55.7% margin.	2R6 - No test or cleaning.	4/96, 2R6; beginning of outage perf test 3.2% margin. No cleaning, CRDR written 4 months later.	3R6 - No test or cleaning.	3/97, 3R6; early outage perf test 37.1% margin.

EW 1A	EW 1B	EW 2A	EW 2B	EW 3A	EW 3B
3/98, 1R7; early outage perf test 58.7% margin.	4/98, 1R7; end of outage perf test 43.5% margin.	9/97, 2R7; early outage perf test 37.8% margin.	10/97, 2R7; chemical passivation (cleaning). End of outage perf test 38.6% margin.	10/98, 3R7; beginning of outage perf test 55.5% margin.	10/98, 3R7; end of outage perf test 71.7% margin
10/99, 1R8 - No test or cleaning.	10/99, 1R8; beginning of outage perf test 37.8% margin.	4/99, 2R8; early outage perf test 72.6% margin.	4/99, 2R8; late outage perf test 64.7 % margin.	4/00, 3R8; early outage perf test 40.8% margin.	4/00, 3R8 - No test or cleaning.
4/01, 1R9; early outage perf test 31.5% margin.	1R9 - No test or cleaning.	10/00, 2R9; early outage perf test 27.6% margin.	10/00, 2R9 - No test or cleaning.	3R9 - No test or cleaning.	10/01, 3R9; early outage perf test 24% margin.
9/02, 1R10 - No test or cleaning.	9/02, 1R10; early outage perf test 3.6% margin. No CRDR written, no cleaning.	9/02, 2R10 - No test or cleaning.	3/02, 2R10; early outage perf test -9.5% margin. No cleaning.	4/03, 3R10; early outage perf test -22.0% margin before cleaning, 26.8% after. All tubes inspected with boroscope.	4/03, 3R10 - No test or cleaning.
		10/03, 2R11; early outage perf test 1.0% margin. Post-cleaning margin 32.8%.	10/03, 2R11; EW HX 2B was cleaned but not tested.		
CRDR 2653867 ACE concluded dispersant was interacting with biocide in Jan 04. Changed dispersant starting with a batch add to each pond in 2/04.					

EW 1A	EW 1B	EW 2A	EW 2B	EW 3A	EW 3B
	2/04, midcycle outage perf test -17.1% margin.	3/04, midcycle outage perf test 28.6% before cleaning.	3/04, midcycle outage, cleaning performed but no test.	3/04, midcycle outage; cleaning performed but no test.	3/04, midcycle outage; cleaning performed but no test.
5/04, 1R11; 9.9% margin before cleaning, 34.5% after.	5/04, 1R11 - EW HX 1B cleaned but not tested.			10/04, 3R11 EW HX 3A cleaned but not tested.	10/04, 3R11; 34.6% margin before cleaning, 26.8% after.
"Lotion-like" substance reported in water from Unit 2 sand filter. CRDR 2750856.					
		5/05, 2R12; post-cleaning margin 29%.	4/05, 2R12; margin 25.8% before cleaning.		
1R12 - EW HX 1A cleaned but not tested. Fouling present.	10/05, 1R12; 1.4% margin before cleaning, 41.4% after. Fouling present.		10/05, midcycle outage; perf test 11.1% margin. No cleaning performed.		10/05, midcycle outage; perf test 19.3% margin. No cleaning performed.
6/06, midcycle outage; perf test 28.6% before cleaning, 36.3% after.	3/06, midcycle outage; perf test 32.9% margin before cleaning.	5/06 - midcycle cleaning performed.	5/06 - midcycle cleaning performed.	4/06, 3R12; 30.3% margin before cleaning, 36.3% after.	3R12; cleaned but not tested.

ATTACHMENT 4

SEQUENCE OF EVENTS

1994	Licensee implemented zinc-phosphate chemistry control program for spray pond system.
1995	Preventive Maintenance Basis for spray ponds revised to specify removing sediment every two cycles. No preventive maintenance item was ever written to implement this.
4/96	Essential Cooling Water 2B performance measured 3.2 percent margin. CRDR 80645 written 8/27/96.
9/98	Unit 1 spray pond makeup source changed to well water. Lower pH range specified for Unit 1 to account for higher alkalinity to avoid scaling.
1/99	Degraded performance in EDG intercoolers first noted. It was later determined to have been evident from records starting in 1995. Condition Report/Disposition Request 36287 written.
7/99	Unit 1-specific pH specification removed, so it was effectively raised without evaluating the increased scaling potential.
10/00	Essential cooling water heat exchanger performance begins to show performance results below 30 percent margin. Prior to this, results were typically 40 to 70 percent margin.
5/01	Licensee changed chemical vendors for water treatment of spray ponds.
3/02	Essential Cooling Water 2B performance measured significant negative margin. Condition Report/Disposition Request 2521395 written 5/30/02 to evaluate calculational problems. Revised 7/10/02 when another calculation error identified. September 2002 finally concluded -9.5 percent margin was the correct result. No corrective action for degraded equipment performance.
9/02	Essential Cooling Water 1B performance measured at 3.6 percent margin. No CRDR written.

4/03	Upper zinc specification raised to 1.5 ppm.
4/03	Essential Cooling Water 3A performance measured at -22 percent margin. The heat exchanger was cleaned to restore performance. Condition Report/Disposition Request 2598216 written.
10/03	Essential Cooling Water 2A performance measured at 1.0 percent margin. Both trains' heat exchangers cleaned, and routine cleanings were initiated.
11/03	Declining performance trend identified in EW heat exchangers in all units. Condition Report/Disposition Request 2653867 written. Also recognized EDG intercoolers had experienced similar fouling since 1995. Zinc precipitation identified as "the primary factor." Operability determination completed that showed this and the 4/03 result in 3A were both capable of performing its safety function under existing conditions (but not under the more limiting design basis conditions). Compensatory measure established to monitor spray pond temperature to ensure continued operability.
1/04	Apparent cause for CRDR 2653867 concluded that dispersant was combining with biocide, forming sticky substance that was coating tubes.
2/04	Essential Cooling Water 2B perfromance measured at -17.1 percent. No CRDR written. Operability was considered to be bounded by a previous operability determination.
2/04	Self-assessment identified that chemistry changed spray pond chemical evndor and chemicals without evaluating impact. Condition Report/Disposition Request 2683642 written.
3/04	Changed dispersant. No action taken to remove old dispersant through feeding and bleeding the ponds.
3/04	Mid-cycle cleaning performed for Unit 3 EW heat exchangers.
4/04	Essential Cooling Water 1A performance measured at 9.9 percent margin.
10/04	Upper zinc specification doubled to 3.0 ppm.

11/04	White lotion-like substance identified in Unit 2 sand filter, CRDR 2750856 written. It was concluded that this was the old dispersant reacting and being removed by sand filter, which would help remove the remaining old dispersant.
10/05	Essential Cooling Water 1B performance measured at 1.4 percent margin.
10/05	Units 2 and 3 entered unscheduled outages. Essential Cooling Water 2B performance measured at 11.1 percent and 3B measured at 19.3 percent margin.
11/05	Condition Report/Disposition Report 2860763 written to address loss of performance of Unit 1 EW heat exchangers.
1/06	The operability determination for CRDR 2860763 completed.
1/06	Condition Report/Disposition Report 2835865 written to address degraded performance in all three units' EW heat exchangers in 10/05 tests. This was the first time that licensee addressed continuing degradation and need for cleaning to assure heat exchangers would remain operable through end of the cycle. Unit 3 was expected to be operable until cleaning in spring outage. Unit 1 was cleaned in 10/05. Unit 2 was scheduled for mid-cycle cleanings before summer (5/06).
4/06	Unit 3 EW heat exchangers cleaned.
5/17/06	Essential Cooling Water 2B cleaned. Emergency Diesel Generator 2B intercooler fouling noted during surveillance run, when air intake temperature jumped up 29F from last test to 145F.
5/18/06	Unit 2 Train B removed from service for EW cleaning.
5/19/06	Train B returned to service. Operability of EDG 2B revisited. Concluded that there was not a reasonable expectation of operability, so it was declared inoperable. All other EDGs run to check performance to comply with Technical Specification 3.8.1, Action B.3.2. Emergency Diesel Generator 2B intercoolers cleaning initiated, CRDR 2896661.
5/20/06	At 7:40 p.m., engineering issued a white paper that set a 160F limit of confidence that EDGs would remain operable if they knew air temp would stay below this level.

5/23/06	Operations lifted compensatory measure of monitoring pond temperatures based on having completed cleaning in all EW heat exchangers.
5/24/06	Condition Report/Disposition Request 2897810 written to document significant condition of fouling caused by incompatible chemicals. This reiterated the earlier conclusion from CRDR 2653867 in 2003. Root cause assigned.
5/20/06	EDG 2B declared operable following cooler cleaning and surveillance testing. New cleaning method used brushes and significantly improved HX performance over previous method of chemical cleaning.
5/22/06	Inspectors point out that the promptly operability determination concluded EDGs would remain operable at least up to 160F intercooler outlet temperature, but used existing pond temperature plus the temperature increase observed in last surveillance, rather than the maximum pond temperature. By doing so, EDG 3B would have 162F intercooler outlet temp, and EDG 3A would be 158F. Condition Report/Disposition Request 2897266 written.
5/23/06	White paper written at 8:42 p.m. to describe a method for adjusting as-found spray pond temperatures to design basis accident conditions in the spray pond and show that EDGs were currently operable.
5/23/06	Inspectors pointed out that the discovery checklist was not created for this issue in CRDR 2896661 as specified in procedures. Checklist was created, but it had errors that under-rated the significance.
5/24/06	Inspectors determine that the licensee's transportability review concluded that only EDG 2B was affected, but all EDGs' intercoolers showed elevated delta-T's during previous monthly runs. Following this, the licensee decided to re-evaluate the operability determination, assess whether both Unit 2 EDGs were inoperable at the same time on May 18, and evaluate the potential for fouling in other EDGs. Significant CRDR 2897810 written on chemical incompatibilities in the spray pond system, based on 6-train impact.
5/25/06	Conference call between NRC Region IV and licensee about the condition and cause of the EDG 2B issue. Condition Report/Disposition Request 2899237 written on apparent delay in making an immediate operability determination for the elevated temperatures seen in EDG 2B on May 17. Condition Report/Disposition Request 2898120 written to document that EDG intercooler HX's were not considered in extent of condition review for previous EW heat exchanger fouling.

5/25/06	Licensee began increased frequency testing and trending on all EDGs as compensatory measure for fouling mechanism.
6/22/06	NRC questioned the impact of the accumulated sediment in the spray ponds on the design basis accident capabilities of the pond. Licensee calculated that it reduced the ability to accept heat rejected, and no longer met the design basis for the pond. A revision to the design basis calc was prepared which took credit for rejecting heat to the concrete pond liner which demonstrated operability, but no CRDR or operability determination was written. Condition Report/Disposition Request 2906671 was written on 6/29 when the team asked why there was no CRDR.

EXHIBIT
S-42
~~Document~~

Staff Response to Commissioner Mayes' October 2, 2006 Request
Rate Impact Analysis for E-12 at 800 kWh
Arizona Public Service
Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827

E-12 at 800 kWh	Summer: Rates Prior to Decision No. 67744	Summer: Rates Resulting from Decision No. 67744	Summer: Rates Resulting from Decision No. 68685	Summer: Staff Proposed Rates	Winter: Rates Prior to Decision No. 67744	Winter: Rates Resulting from Decision No. 67744	Winter: Rates Resulting from Decision No. 68685	Winter: Staff Proposed Rates
Base Rate	$ 78.13	$ 80.35	$ 80.35	$ 86.78	$ 66.65	$ 66.73	$ 66.73	$ 71.85
Environmental Portfolio Surcharge Adjustor [1]	$ 0.35	$ 0.35	$ 0.35	$ 0.56	$ 0.35	$ 0.35	$ 0.35	$ 0.56
Competition Rules Compliance Charge [2]	$ -	$ 0.27	$ 0.27	$ 0.27	$ -	$ 0.27	$ 0.27	$ 0.27
Power Supply Adjustor Rate [3]	$ -	$ 3.20	$ 3.20	$ 2.39	$ -	$ 3.20	$ 3.20	$ 2.39
Interim Adjustor Rate [4]	$ -	$ -	$ 5.60	$ -	$ -	$ -	$ 5.60	$ -
Surcharge 1 [5]	$ -	$ -	$ 0.44	$ 0.44	$ -	$ -	$ 0.44	$ 0.44
Surcharge 2 [6]	$ -	$ -	$ -	$ 0.82	$ -	$ -	$ -	$ 0.82
DSM Adjustor [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Cost Adjustor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franchise Fee [8]	$ -	$ 1.21	$ 1.30	$ 1.29	$ -	$ 1.02	$ 1.10	$ 1.08
Total Bill [9]	$ 78.48	$ 85.38	$ 91.51	$ 92.56	$ 67.00	$ 71.57	$ 77.69	$ 77.42
Increase in Bill per Period		$ 6.90	$ 6.13	$ 1.05		$4.57	$ 6.12	$ (0.27)
Percent Increase in Bill per Period		8.79%	7.18%	1.15%		6.82%	8.56%	-0.35%
Total Increase in Bill over Entire Period				$ 14.08				$ 10.42
Percent Increase in Bill over Entire Period				17.94%				15.55%

Notes

[1] Environmental Portfolio Surcharge Adjustor of $0.001392 for Staff proposed rates per the rate design testimony of Staff witness Barbara Keene.

[2] Competition Rules Compliance Charge of $0.000338 per Commission Decision No. 67744.

[3] Projected Power Supply Adjustor rate of $0.002993 for Staff proposed rates based on APS estimates. Staff has not verified the accuracy of APS' forecasted costs. If the forecast is not verified by the Commission the adjustor rate should be set to zero, consistent with the surebuttal testimony of Staff witness John Antonuk. The Power Supply Adjustor rate of $0.004 is used for other periods.

[4] Interim Adjustor rate of $0.007 per Commission Decision No. 68685.

[5] Surcharge 1 of $0.000554 per Commission Decision No. 68646.

[6] Surcharge 2 of $0.001029 per the rate design testimony of witness Barbara Keene.

[7] DSM Adjustor will not go into effect until APS spends more than $10 million on DSM in a calendar year.

[8] Average franchise fee rate of 1.41% is used for Staff proposed rates based on APS calculation for the test year. Average franchise fee rate of 1.44% used for other periods.

[9] Bills do not include regulatory assessment or taxes.

Staff Response to Commissioner Mayes' October 2, 2006 Request
Rate Impact Analysis for E-12 at 800 kWh
Arizona Public Service
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	Summer				Winter			
E-12 at 800 kWh	Rates Prior to Decision No. 67744	Rates Resulting from Decision No. 67744	Rates Resulting from Decision No. 68685	Staff Proposed Rates	Rates Prior to Decision No. 67744	Rates Resulting from Decision No. 67744	Rates Resulting from Decision No. 68685	Staff Proposed Rates
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Competition Rules Compliance Charge [2]	$ -	$ 0.27	$ 0.27	$ 0.27	$ -	$ 0.27	$ 0.27	$ 0.27
Power Supply Adjustor Rate [3]	$ -	$ 3.20	$ 3.20	$ 2.39	$ -	$ 3.20	$ 3.20	$ 2.39
Interim Adjustor Rate [4]	$ -	$ -	$ 5.60	$ -	$ -	$ -	$ 5.60	$ -
Surcharge 1 [5]	$ -	$ -	$ 0.44	$ 0.44	$ -	$ -	$ 0.44	$ 0.44
Surcharge 2 [6]	$ -	$ -	$ -	$ 0.82	$ -	$ -	$ -	$ 0.82
DSM Adjustor [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Cost Adjustor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franchise Fee [8]	$ -	$ 1.21	$ 1.30	$ 1.29	$ -	$ 1.02	$ 1.10	$ 1.08
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Total Increase in Bill over Entire Period				$ 14.08				$ 10.42
Percent Increase in Bill over Entire Period				17.94%				15.55%

Notes

[1] Environmental Portfolio Surcharge Adjustor of $0.001392 for Staff proposed rates per the rate design testimony of Staff witness Barbara Keene.

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[7] DSM Adjustor will not go into effect until APS spends more than $10 million on DSM in a calendar year.

[8] Average franchise fee rate of 1.41% is used for Staff proposed rates based on APS calculation for the test year. Average franchise fee rate of 1.44% used for other periods.

[9] Bills do not include regulatory assessment or taxes.

EXHIBIT
S-43
Admitted

Staff Response to Commissioner Mayes' October 2, 2006 Request
***REVISED* Rate Impact Analysis for E-12 at 800 kWh**
Arizona Public Service
Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827

E-12 at 800 kWh	Summer: Rates Prior to Decision No. 67744	Summer: Rates Resulting from Decision No. 67744	Summer: Rates Resulting from Decision No. 68685	Summer: Staff Proposed Rates	Winter: Rates Prior to Decision No. 67744	Winter: Rates Resulting from Decision No. 67744	Winter: Rates Resulting from Decision No. 68685	Winter: Staff Proposed Rates
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Competition Rules Compliance Charge [2]	$ -	$ 0.27	$ 0.27	$ 0.27	$ -	$ 0.27	$ 0.27	$ 0.27
Power Supply Adjustor Rate [3]	$ -	$ 3.20	$ 3.20	$ -	$ -	$ 3.20	$ 3.20	$ -
Power Supply Adjustor Forward Component [4]	$ -	$ -	$ -	$ 3.61	$ -	$ -	$ -	$ 3.61
Power Supply Adjustor Transition Component [5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interim Adjustor Rate [6]	$ -	$ -	$ 5.60	$ -	$ -	$ -	$ 5.60	$ -
Surcharge 1 [7]	$ -	$ -	$ 0.44	$ 0.44	$ -	$ -	$ 0.44	$ 0.44
Surcharge 2 [8]	$ -	$ -	$ -	$ 0.82	$ -	$ -	$ -	$ 0.82
DSM Adjustor [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Cost Adjustor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franchise Fee [10]	$ -	$ 1.21	$ 1.30	$ 1.33	$ -	$ 1.02	$ 1.10	$ 1.12
Total Bill [11]	$ 78.48	$ 85.38	$ 91.51	$ 93.82	$ 67.00	$ 71.57	$ 77.69	$ 78.68
Increase in Bill per Period		$ 6.90	$ 6.13	$ 2.31		$4.57	$ 6.12	$ 0.99
Percent Increase in Bill per Period		8.79%	7.18%	2.52%		6.82%	8.56%	1.27%
Total Increase in Bill over Entire Period				$ 15.34				$ 11.68
Percent Increase in Bill over Entire Period				19.55%				17.43%

Notes

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[4] Forward Component of $.004516 to recover estimated 2007 fuel and purchased power costs consistent with the testimony of Staff witness John Antonuk.
[5] The Transition Component is unknown at this time. The Transition Component would include any leftover balances of 2006 costs and the portion of 2007 costs that predate the effective date of a decision in this matter.
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Surcharge 1 [7]	$ -	$ -	$ 0.44	$ 0.44	$ -	$ -	$ 0.44	$ 0.44
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DSM Adjustor [9]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Cost Adjustor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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[11] Bills do not include regulatory assessment or taxes.

EXHIBIT
S-44.
Admitted

STAFF'S SURVEY OF THE LINE EXTENSION AND HOOK-UP FEE POLICIES OF OTHER STATES

States to which surveys were sent	States that responded to the surveys
Alabama	X
Arkansas	
California	
Colorado	X
Connecticut	
Delaware	
District of Columbia	
Florida	X
Georgia	
Idaho	X
Illinois	X
Indiana	X
Iowa	X
Kansas	X
Kentucky	X
Louisiana	
Maine	
Maryland	
Michigan	X
Minnesota	
Missouri	
Montana	X
Nebraska	
Nevada	X
New Hampshire	
New Mexico	
New York	X
North Dakota	
Ohio	X
Oklahoma	X
Oregon	X
Pennsylvania	
Rhode Island	
South Carolina	
Tennessee	
Vermont	X
Virginia	
Washington	X
West Virginia	
Wisconsin	X
Wyoming	

STAFF'S SURVEY OF THE LINE EXTENSION AND HOOK-UP FEE POLICIES OF OTHER STATES

States to which surveys were sent	States that responded to the surveys
Alabama	X
Arkansas	
California	
Colorado	X
Connecticut	
Delaware	
District of Columbia	
Florida	X
Georgia	
Idaho	X
Illinois	X
Indiana	X
Iowa	X
Kansas	X
Kentucky	X
Louisiana	
Maine	
Maryland	
Michigan	X
Minnesota	
Missouri	
Montana	X
Nebraska	
Nevada	X
New Hampshire	
New Mexico	
New York	X
North Dakota	
Ohio	X
Oklahoma	X
Oregon	X
Pennsylvania	
Rhode Island	
South Carolina	
Tennessee	
Vermont	X
Virginia	
Washington	X
West Virginia	
Wisconsin	X
Wyoming	

EXHIBIT
S-45
~~Admitted~~

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826

REPORT OF

GDS ASSOCIATES, INC.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

PUBLIC VERSION
REDACTED

August 17, 2006

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ATTACHMENTS

Attachment 1	Palo Verde Nuclear Generating Station Performance Improvement Plan, October 15, 2005
Attachment 2	NRC Reactor Oversight Process Action Matrix Summary, 4Q/2005
Attachment 3	NRC Letter from Bruce Mallet, NRC Regional Administrator to James Levine, APS Executive Vice President, Generation dated January 27, 2006 Subj: Palo Verde Nuclear Generating Station – NRC Supplemental Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012
Attachment 4	NRC Annual Assessment Letter to Mr. Gregg R. Overbeck dated March 2, 2005
Attachment 5	NRC Annual Assessment Letter to Mr. James M. Levine dated March 2, 2006
Attachment 6	Palo Verde CRDR Number 2780273, NRC Crosscutting Issue Human Performance dated September 16, 2005, pages 1-23.
Attachment 7	Palo Verde CRDR 2780286, Rev. 1 Crosscutting Issue with Problem Identification and Resolution dated September 22, 2005
Attachment 8	Significant Root Cause Investigation Report 2775015
Attachment 9	CRDR Number 2777226 Upper Oil Seal O-Ring Failure, pages 25-48
Attachment 10	CRDR Number 2782680 Emergency Diesel Generator 1A Failure to Attain Rated Voltage/Frequency, Rev. 0, pages 1-17
Attachment 11	CRDR Number 2825485, Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup, pages 1-15
Attachment 12	CRDR Number 2824258, U-2 3.03 Shutdown Due to CPC Software dated 11/30/2005, pages 1-18
Attachment 13	CRDR 2835132 Evaluation of RWT Suction Behavior during SIS and CSS Transition to RAS and Related Design Interface Criteria, page 161
Attachment 14	CRDR 2809138 Pressurizer Heater Failures at Palo Verde and Waterford Root Cause Investigation Report dated October 4, 2005, pages 61-89

Attachment 15 Palo Verde 2005 Replacement Power Costs

Attachment 16 Estimated Impact Off-System Sales Margins Due to Imprudent Forced Outages

Attachment 17 Adjustment to APS Interest on Fuel Under-Recovery Balances Due to Imprudent Outages

Attachment 18 Summary of Cost Disallowances for Imprudent Outages

ACRONYMS

ACC: Arizona Corporation Commission
AFI: Areas for Improvement
APS: Arizona Public Service Company
AVR: Automatic Voltage Regulator
CPC: Core Protection Calculators
CRAI: Condition Report Action Item
CRDR: Condition Report Disposition Request
ECCS: Emergency Core Cooling System
EDG: Emergency Diesel Generator
EFOR: Effective Forced Outage Rate
ESI: Engine Systems Incorporated
GDS: GDS Associates
INPO: Institute of Nuclear Power Operations
LCO: Limiting Condition for Operation
LER: Licensee Event Report
NRC: Nuclear Regulatory Commission
PDA: Primary Disconnect Assembly
PIP: Performance Improvement Plan
PSA: Power Supply Adjustor
PVNGS: Palo Verde Nuclear Generating Station
RAS: Recirculation Actuation Signal
RCI: Root Cause Investigation
RCP: Reactor Coolant Pump
RFO: Refueling Outage
RWT: Refueling Water Tank

PUBLIC VERSION
REDACTED
REVIEW OF PALO VERDE 2005 OUTAGES
FINAL REPORT
8/17/06

EXECUTIVE SUMMARY

Palo Verde Performance

Performance of the Palo Verde Nuclear Generating Station ("Palo Verde" or "Plant") in 2005 was poor by almost any measure. Generation and capacity factors were low and production costs were high compared to historical performance. The NRC ranked Palo Verde in the next to the lowest regulatory category and the Institute of Nuclear Power Operations ("INPO") [redacted]. In addition to two refueling outages, Palo Verde experienced eight unplanned outages and one planned outage in 2005. Because the capital cost of Palo Verde embedded in base rates is high, the Plant must operate well to take advantage of the relatively low fuel and variable costs of the Plant. As a result of this poor performance, the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") retained GDS Associates, Inc. of Marietta, Georgia to investigate the reasons for Palo Verde's poor performance, to make recommendations to improve performance, and to reduce the likelihood of future unplanned outages. GDS conducted this investigation by reviewing documents, such as APS' root cause evaluations and NRC inspection reports. GDS also visited the Palo Verde site, conducted interviews of APS officials at the senior management level, and attended meetings between APS and the NRC.

While the operating and regulatory performance of Palo Verde during 2005 was poor, GDS has not found any evidence or indication that operation of the plant has compromised safety. None of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shutdown the plant when any safety concerns were identified. Palo Verde was safely operated throughout 2005.

APS has implemented an aggressive Performance Improvement Plan to return Palo Verde performance to the desired level of excellence. While it is too early to know

with certainty if the plan will succeed, the plan is comprehensive and APS has committed substantial management and financial resources to ensure success. Based on our experience with similar plans at other nuclear plants, GDS is optimistic that APS will be successful in achieving improved performance at Palo Verde.

Palo Verde Outages

GDS determined that, of the eleven 2005 outages, four were avoidable and the result of imprudent actions by APS, three were the result of faulty or defective vendor supplied equipment, and one cannot be completely evaluated at this time. GDS did not identify any imprudence related to the remaining three outages. As shown in Table 3 in this report, APS' estimate of the net replacement power cost is $16.269 million for the four imprudently incurred outages in 2005 of which $14.944 million was incurred during the period of April through December when the Power Supply Adjustor ("PSA")was in effect. APS' request for $44.564 million for recovery of replacement power costs for 2005 Palo Verde forced outages should be reduced by $14.944 million.[1] Attachment 18 provides Staff's quantification of the total cost impact of these imprudent outages including lost opportunity costs and claimed interest expense. This amount is $18.996[2] million for the imprudently incurred outages.

Conclusions

1. Performance of the Palo Verde Plant has declined significantly over the past three years.
2. The number of outages in 2005 was much higher than normal and the capacity factor and generation were lower than should be expected.

[1] See Section VI of this report for a detailed explanation of the minor adjustment needed to account for the forced outage replacement power costs included in the PSA base rate.
[2] $17.373 million from page 1 of Attachment 18 for outages for the period April through December 2005 plus $1.623 million from page 2 of Attachment 18 for outages for the period prior to PSA implementation (January through March 2005).

3. APS acknowledges the decline in performance and has implemented an aggressive Performance Improvement Plan ("PIP") to return the Plant to its former levels of performance.
4. Four of the 2005 outages were avoidable and the result of imprudence.
5. Some of the unplanned Palo Verde outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent.
6. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem, which continued into 2006. Additional investigation will be needed to determine the cause of and responsibility for this outage.
7. Although APS received a yellow finding from NRC in 2004 regarding safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

Recommendations

1. The Commission should disallow the additional costs resulting from outages identified as avoidable and imprudent in this report. The resulting disallowance is $17.373 million (see Table 5). The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.
2. An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the

pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' action.

3. The Commission should establish a Nuclear Performance Standard that would establish minimum acceptable levels of performance for Palo Verde and penalties for periods during which the performance of Palo Verde falls below the minimum levels. The Nuclear Performance Standard should be considered in APS' pending rate case.
4. The Commission should order APS to submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO, and providing details of corrective actions taken. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.
5. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.
6. The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to

improve receipt inspection and pre-installation verification of parts at Palo Verde.

I. INTRODUCTION

Palo Verde is a vital component of Arizona Public Service Company's ("APS") generation resources, providing 17.9% of APS' total generating capacity. During 2005, Palo Verde experienced more outages than normal. Both capacity factor and generation were lower than expected. Because of this, the Commission Staff issued a Request for Proposals for a qualified firm to investigate the reasons for this lower level of performance at Palo Verde, to make recommendations to improve performance, and to reduce the likelihood of future unplanned outages. In January 2006, the Staff selected GDS Associates ("GDS") of Marietta, Georgia to conduct this investigation.

Operating performance of Palo Verde is of great interest to the Commission and to APS ratepayers. Nuclear power plants have the highest capital costs of any central power station. This high capital cost is embedded in base rates and APS ratepayers pay for this high capital cost whether or not the plant is in operation. Nuclear power is an economic source of electrical generation because the high capital cost of a nuclear power plant is offset by low fuel and low variable costs. However, low operating costs are sufficient to offset the high capital costs only when the plant is operated at a high capacity factor. Such high capital cost plants must be operated at a high capacity factor for the ratepayers to receive proportionate economic benefits. In addition, when the Palo Verde plant is out of service, the lost generation must be replaced by higher cost generation. If an outage is the result of imprudent operations or management, APS should be held responsible for the additional costs incurred.

II. DESCRIPTION OF WORK

GDS initiated the investigation of Palo Verde's 2005 performance by reviewing the publicly available documents on the Nuclear Regulatory Commission ("NRC") website. At the same time, GDS submitted an extensive request for information concerning all aspects of Palo Verde's operation. Following this initial activity, additional tasks as stated below have been accomplished:

- Reviewed NRC inspection reports, licensee event reports and other relevant documents;
- Reviewed APS responses to GDS' data requests;
- Developed additional data requests as needed to evaluate each outage;
- Conducted a preliminary review and evaluation of each forced and planned outage at Palo Verde in 2005;
- Attended meetings with the ACC Staff;
- Attended the Open Meeting with the ACC Commissioners and NRC Region 4 management;
- Conducted an inspection of the Palo Verde site;
- Interviewed the Palo Verde senior management team;
- Reviewed confidential reports of plant evaluations conducted by the Institute of Nuclear Power Operation ("INPO").
- Conducted an interview of the NRC Senior Resident Inspector.
- Conducted follow-up interviews of Palo Verde managers.
- Attended by telephone APS' presentation of the Performance Improvement Plan at NRC Regional office in Arlington, Texas.
- Attended the NRC Annual Assessment meeting in Tonopah, Arizona.

GDS' evaluation and analysis of the information gathered through the activities described above is provided in the following report.

III. PALO VERDE PERFORMANCE

By almost any measure, the performance of Palo Verde in 2005 was poor. Nuclear generation, capacity factors and production costs for each Palo Verde unit for the past 5 years are shown in the table below:

Table 1. Palo Verde Performance Metrics 2001 to 2005[3]

Metric	Year				
Net Capacity Factor (%)	**2001**	**2002**	**2003**	**2004**	**2005**
PV1	88	89	97	85	66
PV2	93	92	78	91	82
PV3	84	102[4]	88	75	84
Total Plant	**88**	**94**	**87**	**84**	**77**
Net Generation APS Share (MWH)	**2001**	**2002**	**2003**	**2004**	**2005**
PV1	2,781,838	2,824,162	3,080,847	2,687,616	2,098,779
PV2	2,934,303	2,915,578	2,455,817	3,102,661	2,743,327
PV3	2,668,583	3,241,073	2,778,048	2,392,985	2,666,717
Total	**8,384,724**	**8,980,813**	**8,314,712**	**8,183,262**	**7,508,822**
Production Cost ($/MWh)	**2001**	**2002**	**2003**	**2004**	**2005**
Total Plant	**13.10**	**12.94**	**13.03**	**14.50**	**16.94**

[3] APS response to Data Request PB 4.7

[4] Capacity factor may be greater than 100 percent if the plant operates at a generating capacity greater than that assumed in the capacity factor calculation for some periods during the year. For example, during the winter months, the generating capacity will be significantly greater than the Maximum Dependable Capacity ("MDC") which is determined during the hottest summer months. If the capacity factor is based on the MDC, a capacity factor greater than 100 percent is possible.

As seen in this Table, the capacity factor and nuclear generation declined significantly in the past two years. Palo Verde generated 1,051,261 million (APS share) fewer megawatt-hours in 2005 than were generated on average in the years 2001 thru 2003. From 2002 to 2005, Production Costs have increased over 30% from 12.94 $/MWH to 16.94 $/MWH. Other plant metrics including Effective Forced Outage Rate ("EFOR") and the INPO Performance Indicator Index show a similar decline in performance.

It is useful to put Palo Verde's performance in perspective by comparison to the performance of other nuclear plants in the United States. A recent article in Nuclear News[5], a publication of the American Nuclear Society, provides comparisons of the capacity factors achieved by all U.S. nuclear plants. Table I of this article provides the Net Capacity Factor based on Design Electric Rating of the 104 individual nuclear units in the United States for the period 2003 through 2005[6]. For this period, the Net Capacity Factor of Palo Verde 3 ranked 99th, Palo Verde 1 ranked 97th and Palo Verde 2 ranked 93rd of all 104 U.S. nuclear plants. Since Browns Ferry 1 was not in operation, only 4 nuclear plants had a lower Net Capacity Factor than Palo Verde 1 for this period. Table II in the article ranked nuclear plants based on the change in capacity factor from the 2000-2002 period to the 2003-2005 period. In this comparison, Palo Verde 3 ranked 104th of 104 (greatest decrease in capacity factor of all U.S. nuclear plants), Palo Verde 1 ranked 100th and Palo Verde 2 ranked 93rd. Finally, Table III provided the Net Capacity Factor for all multi-reactor sites. The Palo Verde site ranked 35th of 36 multi-reactor sites in the United States. The performance of Palo Verde during the 2003 to 2005 period was at the bottom of the U.S. nuclear industry.

[5] "U.S. Capacity Factors: Leveled off at last", Nuclear News, May 2006
[6] A two year rolling average is used to normalize the effect of refueling outages.

On October 15, 2005, APS issued the Palo Verde Performance Improvement Plan. The intent of this plan is to provide a strategic overview of Palo Verde performance improvement activities and to provide tactical actions to achieve improved performance. Section 1 of the PIP presents the following discussion of the decline of performance at Palo Verde.

> In late 2002 or early 2003 performance indicators at Palo Verde began a downward trend relative to the sustained high performance levels in previous years. A cause of this trend appears to have been the realignment of key site leadership that in turn caused the team to be more focused on day-to-day tactical matters, and less focused on strategic planning, standards and accountability. Additionally, in 2004, two significant events occurred at Palo Verde. They are the three unit trip in June 2004 that resulted from a grid disturbance and, the discovery, in July 2004, of the absence of water in portions of Emergency Core Coolant System piping ("RAS[7] Sump Event"). These events also revealed issues with regard to various Palo Verde programs and processes that are in need of improvement.[8]

APS' Performance Improvement Plan also states that Palo Verde site leadership did not fully accept that Palo Verde performance indicators reflected actual declining performance until mid-2005 in part because of ten previous years of good performance. In response to the recognition in mid-2005 of declining performance, APS management initiated the Performance Improvement Plan to return Palo Verde to a higher level of performance. At this time, it is too early for the effectiveness of the PIP to be known. However, the PIP is a comprehensive plan with substantial resources and the full backing and commitment of APS management. Palo Verde management is acutely aware of the need to improve performance at Palo Verde and has involved personnel at all levels of the plant organization in development and implementation of the PIP. While the results

[7] "RAS" stands for Recirculation Actuation Signal, the signal that allows the Emergency Core Cooling Systems to take suction from the Containment Sump during a Loss of Coolant Accident.
[8] Palo Verde Nuclear Generating Station Performance Improvement Plan, October 15, 2005, page 1 (Attachment 1)

of the PIP cannot be predicted with total certainty, GDS is optimistic that the PIP will be successful in improving the performance of Palo Verde to the desired level.

Regulatory Performance

Regulatory performance at Palo Verde has also declined. In 2004, the NRC issued a yellow finding to Palo Verde for failure to maintain certain safety-related piping full of water. A yellow finding is a finding with substantial importance to safety. At the end of 2005, only one other plant in the United States (Kewaunee Nuclear Power Plant) had an open yellow finding. Based on this yellow finding and the NRC's evaluation of overall plant performance, Palo Verde is rated in the third column of the NRC's Reactor Oversight Process Action Matrix[9] as a plant with a "degraded cornerstone." Only the Kewaunee Nuclear plant shares this rating along with two plants that are in the 4th column, the Multiple/Repetitive Degraded Cornerstone column. While APS officials attempt to minimize this rating, stating that Palo Verde is in the 3rd column only because of the yellow finding, the NRC clearly states on Attachment 2 that the Action Matrix Summary "reflects overall plant performance and is updated regularly to reflect inputs from the most recent performance indicators and inspection findings." In addition, the NRC has conducted a follow-up inspection and, based on the results of this inspection, has declined to close the yellow finding. In the cover letter for the follow-up inspection, the NRC states:

> However, the NRC also concluded that, while you performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the

[9] NRC Reactor Oversight Process Action Matrix Summary (Attachment 2)

> implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or follow-up, to ensure that corrective actions were effective in improving performance in the affected areas.[10]

Thus, the yellow finding will remain open until the NRC is convinced that the corrective actions are broad enough to resolve the problems and that the corrective actions have been effectively implemented.

In addition to the open yellow finding, in its Annual Assessment Letter dated March 2, 2005, the NRC has identified substantive cross-cutting issues in the areas of human performance and problem identification and resolution. Substantive cross-cutting issues indicate an NRC concern that the nuclear plant operator has had multiple performance deficiencies that had commonality in the central cross-cutting areas of human performance, problem identification and resolution, and/or safety conscious work environment.

The NRC stated that the adverse trend in human performance issues indicated that Palo Verde had not effectively addressed the underlying causes associated with this substantive crosscutting area. The NRC further stated that the adverse trend in problem identification and resolution indicates that Palo Verde had not addressed the underlying causes associated with this substantive crosscutting issue.[11] These issues were addressed again in the NRC's Annual Assessment Letter dated March 2, 2006. In this letter the NRC states:

> During this assessment period, we continue to identify findings with the same cause and common themes in both

[10] NRC Letter from Bruce Mallet, NRC Regional Administrator to James Levine, APS Executive Vice President, Generation dated January 27, 2006 Subj: Palo Verde Nuclear Generating Station – NRC Supplemental Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012 (Cover letter and NRC Inspection Report are provided as Attachment 3)
[11] NRC Annual Assessment Letter to Mr. Gregg R. Overbeck dated March 2, 2005 (Attachment 4)

> cross-cutting areas. There were 16 Green findings with cross-cutting aspects in the areas of human performance. Our assessment indicates that your actions to date have not completely corrected the root causes associated with procedural compliance, procedural adequacy, and the interactions between engineering and operations personnel when assessing degraded and nonconforming conditions. Additionally, there were 12 Green and Severity Level IV findings with cross-cutting aspects in the area of problem identification and resolution. Our assessment indicates that your actions to date have not completely corrected the root causes associated with the identification of non-conforming conditions, the evaluation of conditions adverse to quality, particularly engineering and operations personnel and the implementation of effective corrective actions for deficient conditions.[12]

APS' corrective actions in the areas of human performance and problem identification and resolution were ineffective in resolving the NRC's concerns in these areas.

APS conducted root cause evaluations of these cross-cutting issues and reached the following conclusions:

> Root Cause of the Human Performance Cross-Cutting Issue[13]
>
> The Palo Verde organization does not demonstrate ownership and leadership of the human performance culture. Since the entire organization demonstrates a weakness in human performance culture, the culpability for station behavior lies with the highest levels of management.
>
> - Palo Verde Management does not emphasize that excellence in human performance will result in excellence in plant performance.
> - Leaders sometimes model behaviors inconsistent with site expectations.

[12] NRC Annual Assessment Letter to Mr. James M. Levine dated March 2, 2006 (Attachment 5)
[13] Palo Verde CRDR Number 2780273, NRC Crosscutting Issue Human Performance dated September 16, 2005. Note that CRDR stands for Condition Report Disposition Request. It is the mechanism to report and track problems in Palo Verde's Corrective Action Program (Attachment 6)

- There are little apparent negative consequences to HP[14] events, especially when compared to plant performance (accountability).
- Palo Verde often rewards heroic actions. This was pointed out in the September 2004 self-assessment on Supervisory Effectiveness.
- There are numerous daily meetings focused on plant performance and plant concerns and few, if any, focused on human performance.
- CRDRs are sometimes not generated as expected (additional details can be found in CRDR 2780286, NRC Crosscutting Issue with Problem identification and resolution).
- Corrective actions seem to be aimed at closing CRDRs and not at fixing problems (see CRDR 2780286 for additional details).

Root Cause of the Problem Identification and Resolution Crosscutting Issue[15]

The root cause of a workforce that does not effectively use the corrective action program to improve performance is the result of ineffective management behaviors, such as accepting substandard performance regarding the Corrective Action Program. Regardless of intent, management behaviors have devalued the CAP and diminished people's ability to effectively use the corrective action program as the cornerstone to a continuous improvement culture.

Contributing Causes:

- Continuous Improvement Culture not Anchored – Management behaviors have not promoted a continuous improvement culture, which is essential to the resolution of the Problem Identification and Resolution crosscutting issue.
- Failed to Address Personnel's Frustration with the Corrective Action Program.
- Station Vision is not Globally Understood – the site management team has not motivated the staff with a site-wide vision.
- Mismatched Management Styles – Some of the management team members have not been able to achieve high standards for the corrective action program because of their inflexible management style.
- Lack of Mentoring and Coaching in Leadership Development.

[14] HP - Human Performance
[15] Palo Verde CRDR 2780286, Rev. 1 Crosscutting Issue with Problem Identification and Resolution dated September 22, 2005 (Attachment 7)

APS' evaluation of the crosscutting issues in Human Performance and Problem Identification and Resolution laid the blame squarely on Palo Verde management.

INPO Evaluation Results

In addition to the NRC, a private nuclear industry organization called the Institute of Nuclear Power Operation ("INPO") closely monitors and evaluates the operation of all nuclear power plants in the United States. INPO was established by the nuclear utility industry following the accident at Three Mile Island. INPO's mission is to promote excellence in the operation of nuclear power plants and it is supported by dues paid by all nuclear plant operators. INPO conducts periodic inspections of each nuclear power plant and also provides assistance when requested by the plant operator. A typical INPO evaluation consists of a team of 15 to 20 experienced evaluators on site for a period of 2 weeks. Following the evaluation, INPO provides a report which identifies strengths and areas for improvement ("AFI"). In addition, INPO provides a rating for the plant based on its findings. [redacted]. Finally, each nuclear plant tracks key performance indicators identified by INPO and uses these performance indicators to develop an INPO Performance Index for the plant.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Safety

While the operating and regulatory performance of Palo Verde during 2005 was poor, GDS has not found any evidence or indication that operation of the plant has compromised safety. Palo Verde managers stress nuclear safety as a top priority and all decisions consider nuclear safety. GDS found the decisions of APS management to be conservative and the plant Technical Specifications that govern plant operation were strictly followed. None of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shutdown the plant when any safety concerns were identified. Palo Verde was safely operated throughout 2005.

IV. PRUDENCE STANDARD

In our analysis, we have evaluated APS' performance by comparison to the reasonable decisions and actions of a qualified and experienced utility manager given what was known or should have been known at the time without the benefit of hindsight. Thus, the actions and decisions of Palo Verde personnel must be judged on what they knew, or reasonably should have known, at the time the action was taken or the decision was made without benefit of hindsight.

V. REVIEW OF 2005 PALO VERDE OUTAGES

The following is a summary of the 2005 Palo Verde outages including a description of the cause of each outage, APS' estimate of the replacement power cost associated with each outage, a determination of whether or not the outage was avoidable, and a determination of whether or not the outage was the result of imprudent actions or decisions by APS.

Unit 1 Outages

A. Unit 1 13.8 kV Bus Failure and Reactor Coolant Pump ("RCP")-1B Upper Oil Seal Failure

Date: 02/09/ - 02/19/05

Type: Unplanned

At 10:19 PM on 2/06/05 with Unit 1 operating at 100% power, a 'B' train loss of power occurred in Unit 1 when an electrical fault within cubicle 1E-NAN-S06J resulted in circuit breaker 1E-NAN-S06H tripping open on over-current. The Train "B" Emergency Diesel Generator ("EDG") started as a result of under-voltage and loaded the emergency bus as designed. This event resulted in entry into Technical Specification Limiting Condition for Operation ("LCO") 3.8.1 which required that the bus be restored to operable condition or the plant be shutdown within 72 hours. Unit 1 began a shutdown in the early morning of 2/9/05. During the startup on 2/16/05 at 0110, RCP-1B experienced failure of the upper oil seal. This seal failure delayed the startup until 2/19/05.

Cause:

As discussed in APS' Significant Root Cause Investigation Report 2775015,[16] the direct cause of the bus 1E-NAN-S06 failure was an electrical fault in cubicle 'J' within the line side primary disconnect assembly (rosette) compartment above the circuit

[16] Significant Root Cause Investigation Report 2775015. (Attachment 8)

breaker. The electrical fault and resulting explosion completely destroyed the bus side rosettes and upper portions of the primary circuit breaker bushings. APS found that the root cause of this event was indeterminate due to the extent of damage. However, APS determined that the most probable root cause was that the 'C' Primary Disconnect Assembly ("PDA") was damaged as a result of an electrical three-phase fault in the rear of switchgear cubicle 1ENANS06J that occurred in 1992. A possible contributing cause was the lack of inspection of the switchgear cubicle and line PDAs anytime following the 1992 electrical fault event.

During startup from this unplanned outage, excessive oil leakage from the RCP-1B thrust bearing upper seal was observed. The cause of the leakage was determined to be an O-ring of incompatible material that had been installed in the seal.[17]

Net Replacement Power Cost: $[redacted]

Net Replacement Power Cost due to O-ring delay: $[redacted]

References:

Significant Root Cause Investigation Report 2775015

CRDR 2777226 Upper Oil Seal O-Ring Failure

Analysis:

The Root Cause Investigation ("RCI")speculates that the bus failure could have been caused by damage to the PDA which occurred in a prior electrical fault in 1992. However, due to the extent of damage, this could not be confirmed. No inspection was performed following the 1992 event. However, there is no assurance that an inspection would have revealed a fault that took some 13 years to cause failure. The bus failure that initiated this outage could not have been foreseen and was unavoidable. Concerning the RCP oil seal failure, the receipt inspection and the inspection prior to installation did not identify that the O-ring provided by the vendor was made of the incorrect material. The

[17] Condition Report / Disposition Request (CRDR) 2777226 Upper Oil Seal O-Ring Failure. (Attachment 9)

delay in startup caused by the RCP oil seal failure was avoidable by a more diligent effort and attention to detail, including a more comprehensive receipt inspection and verification of the proper O-ring material prior to installation as is now being conducted. This view is supported by APS' analysis of the event in CRDR 2777226 which states "...it would be most beneficial to ensure the TB Seal O-rings were composed of the correct material before they are installed, and preferably at the receipt inspection stage of the procurement process." However, APS' response to PB-5.1(b) states:

> The incorrect O-ring materials were shipped as the result of factory error. The correct material was ordered; however, the factory shipped the wrong O-rings to Palo Verde with documentation for the "correct" O-rings. The incorrect O-rings received had the same size and appearance as the "correct" O-rings but were designed for water application and not oil.

Based on this explanation, and without prior similar events, APS' prior inspection practices were reasonable. Therefore, this outage extension is found to be the result of vendor error.

B. Unit 1 Emergency Diesel Generator 'A' Governor Failure

Date: **03/18 - 03/21/05**

Type: **Unplanned**

On March 17, 2005 Emergency Diesel Generator 'A' failed to start during a post maintenance retest. The EDG reached approximately 100 RPM for 15 seconds and then tripped. It was determined that the failure to start was due to a governor failure. The faulty governor was replaced. Re-testing of the EDG involved a load rejection test which required that the unit be shutdown to perform in accordance with the Plant Technical Specifications.

Cause:

APS conducted a Root Cause Investigation of this failure as reported in CRDR 2782680. A sample of the governor lube oil was taken and the faulty governor was sent to the vendor, Engine Systems Incorporated ("ESI"), for testing. The oil sample was found to contain very high levels of water (5159 ppm vs an upper limit of 1500 ppm). Normal water content is in the 100-200 ppm range with new oil required to be less than 500 ppm. An internal inspection revealed rust in the oil seal retainer area, on the base, and on the accumulator springs. The RCI concluded that the direct cause of the governor failure was oil contamination inside the governor actuator. No root cause could be found for this event. However, the RCI identified three most probable causes of water introduction into the actuator lube oil sump:

1. Water was introduced at the Woodward Governor Company during refurbishment of the governor in June 2000 and never completely drained.
2. The governor was stored in the Palo Verde warehouse drained of oil for 9 months creating prime conditions for rust formation.
3. Water may have been introduced during an oil change in April 2004. This was deemed a lesser probability based on a walk down of the oil change procedure with no obvious discrepancies found.

Net Replacement Power Cost: **$**[redacted]

References:

Root Cause Investigation in CRDR 2782680

NRC Inspection Report IR 2005002

Licensee Event Report ("LER") 2005-006-00

Analysis:

The cause of the governor failure was water and rust in the lubricating oil. APS identified several possibilities of the cause of the water in the lube oil but could not identify the cause with certainty. Storage of the governor drained of oil in a warehouse that was not climate controlled is not a good practice. APS now requires that oil be added to governors when they are received in the warehouse to minimize the possibility

of rust formation. The Woodward Governor Technical Manual states "*oil contamination is the major cause of actuator troubles*" and "*Particles of dirt and water in the oil are the greatest causes of governor and actuator failures.*"[18] This outage was the result of imprudence and was avoidable by ensuring that the storage conditions and pre-installation inspection of the re-furbished governor were commensurate with the importance of this equipment.

C. Unit 1 Emergency Diesel Generator 'B' Voltage Regulator Failure and Reactor Trip due to Operator Error

Date: **08/11-08/28/05**

Type: **Unplanned**

On August 9, 2005, EDG 'B' failed to maintain proper steady state output voltage during performance of a routine monthly surveillance test. Maintenance personnel were unable to correct the problem within the 72 hours allowed by the plant Technical Specifications and Unit 1 was shutdown on August 12, 2005. EDG 'B' was returned to operable status on 8/14. However, the startup was delayed due to several equipment problems including an oil leak on Reactor Coolant Pump ("RCP") "1A". On 8/26 during startup, the unit tripped due to an operator error in controlling the feedwater to the Steam Generator.

Cause:

The problem with EDG 'B' was a failed diode in the automatic voltage regulator ("AVR"). Several RCPs at Palo Verde have experienced the leaking oil seal problem. This problem is discussed in detail in connection with a forced outage of Unit 3 in July for the same problem. The cause of the August 26, 2005 trip during startup included individual and crew failures to implement expected requirements and good practices

[18] CRDR Number 2782680 Emergency Diesel Generator 1A Failure to Attain Rated Voltage/Frequency, Rev. 0, page 12 of 54 (Attachment 10)

prescribed by their training and procedures. The Root Cause Investigation of this event identified the following direct, root and contributing causes:[19]

> **Direct Cause #1:** The assigned dayshift licensed operator for Steam Generator feedwater control failed to request CRS[20] concurrence when placing the digital feedwater control system in manual when level was lower than desired under automatic control. This communication failure isolated the individual from supervisory oversight and the crew's ability to assess the overall plant condition. Subsequently, feedwater flow was increased by operator action at a rate in excess of the rate required to compensate for the steaming rate at that power level and resulted in a high steam generator level and subsequent MSIS[21] and reactor trip.
>
> **Direct Cause #2:** Crew members failed to provide the team support needed to ensure individual errors are promptly identified and corrected.
>
> **Root Cause #1**: Consistent standards of performance by Unit 1 Operations Crew C were not sufficiently anchored.
>
> **Root Cause #2**: Feedwater control system performance issues at low power levels have not been effectively resolved since the digital upgrade. This has led to acceptance of operational strategies to cope with system instability at low power levels.
>
> **Contributing Cause #1**: Procedures 40DP-9FT01&02, *Feedwater Pump Turbine A(B)* are not sufficiently human factored for all users, making them susceptible to performance error and resultant system perturbations.

[19] CRDR Number 2825485, Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup. Attachment 11)
[20] CRS - Control Room Supervisor
[21] MSIS – Main Steam Isolation Signal

Contributing Cause #2: Common belief existed among licensed operators that the DFWCS[22] cannot reliably control SG[23] level well at low power. This belief was not based on actual performance data and led to acceptance of the condition and mitigating strategies.

Contributing Cause #3: Training was not commensurate with the unidentified difficulty of putting the DFWCS into auto operation given the current procedure detail and system design. This has resulted in mis-operation of DFWCS components while in single element control.

Net Replacement Power Cost: $[redacted]

Net Replacement Power Cost due to 8/28 Reactor Trip: $[redacted]

References:

NRC IR 2005004

LER 2005-004-00

LER 2005-005-00

CRDR 2821210

CRDR 2811543

CRDR 2825485

Analysis:

The initiating event of this outage, failure of the Automatic Voltage Regulator diode, could not have reasonably been foreseen and was unavoidable. As will be discussed later, the extension of the outage due to the RCP seal oil leakage was avoidable but not the result of imprudent actions by APS. The 8/26/05 reactor trip and resulting outage extension would have been avoided with prudent operation and management. This reactor trip and outage extension exemplify the human performance problems at Palo Verde. The operator failed to follow procedures and failed to communicate his actions with shift management as required by the procedure. It is closely related to the

[22] DFWCS – Digital Feedwater Control System
[23] SG – Steam Generator

findings of the INPO evaluation including lack of consistent standards, lack of accountability and a willingness to accept longstanding equipment problems. This outage also is a consequence of the lack of effective problem resolution as identified in Root Cause #2 and in the NRC substantive cross-cutting issue in problem identification and resolution. In addition, even though the concern with the ability of the digital feedwater control system to maintain steam generator level at low power was well known in the operations department, training of the operators was not commensurate with the difficulty encountered putting the control into automatic mode. For these reasons, the delay in completion of this outage and resulting cost due to the reactor trip on August 26 is due to imprudence.

D. Unit 1 Refueling outage and Steam Generator Replacement

Date: **10/8-12/27/05**

Type: **U1 Refueling**

This planned refueling outage included refueling Unit 1 and replacement of the Steam Generators. The outage was planned for 75 days and the actual duration was 77 days, 1 hour and 44 minutes.

Cause:

Planned refueling and Steam Generator Replacement

Cost: NA

References:

APS07243

Analysis:

The actual duration of 77 days, 1 hour and 44 minutes is very fast for a Steam Generator replacement outage. Radiation exposure was very low and costs were within budget. This was a complex outage that was well planned and executed.

E. Unit 1 Shutdown Cooling Line Vibration

Date: **12/27-12/31/05**

Type: **Reduced Power Operation**

Unit 1 operated at a reduced power level of 25 to 30% since startup from the fall 2005 refueling outage through the end of 2005 because of excessive vibrations in the Shutdown Cooling Line. Vibration levels trended upward during the prior operating cycle. Modifications were installed during the refueling outage. However, upon return to service, higher vibration levels were experienced. This outage continued into 2006.

Cause:

As of the end of 2005, the cause of the high vibration levels had not been determined.

Cost: $[redacted]

References:

APS presentation to ACC

Interviews at Palo Verde site

Analysis:

This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem. Additional investigation will be needed to determine the cause of and responsibility for this outage.

Unit 2 Outages

F. Unit 2 Refueling Outage

Date: **04/02-05/20/05**

Type: **Planned Refueling**

This outage was a standard refueling outage ("RFO") for Unit 2. It was scheduled for 35 days and the actual duration was 48 days, 21 hours and 50 minutes. The duration of this outage was approximately 14 days longer than scheduled.

Cause:

Completion of the refueling outage was delayed due to a number of equipment problems including problems with the refueling machine and spent fuel handling machine.

Net Replacement Power Cost: $[redacted]

References:

APS response to PB 1.9

Interviews with Peter Borchert and Bill Chapin

APS Response to PB 5.5

Analysis:

APS had numerous problems with the refueling equipment that delayed the completion of this outage. It appears that some of these problems had occurred previously while others were experienced for the first time during this RFO. APS outage managers reviewed each of the outage delays with GDS personnel. APS conducted extensive maintenance on the fuel handling equipment prior to the outage. However, the refueling equipment is old and prone to failure even with extensive pre-outage maintenance. APS is planning to replace the refueling equipment prior to the next refueling outage. GDS concludes based on interviews with APS outage management personnel and review of documentation that APS' preparations for the April refueling outage were reasonable because of the extensive pre-outage maintenance to eliminate known problems, the efforts to minimize delays when problems were found and the emphasis on safety during the outage. The outage delays were not the result of imprudence.

G. Unit 2 Core Protection Calculators ("CPC") Inoperable

Date: **08/22-08/26**

Type: **Unplanned**

On August 22, 2005, Unit 2 was shutdown when all four channels of the Core Protection Calculators were declared inoperable. The CPCs consist of four separate,

redundant channels. Each channel is a computer system that continuously calculates thermal conditions and thermal limits within the reactor. The CPC system is an integral part of the plant protective system in that it provides two trips to the reactor protection system. On August 22, 2005, control room personnel declared all four channels of the CPCs inoperable and the unit was shutdown in accordance with Technical Specifications.

Cause:

On May 18, 2005, Westinghouse personnel became aware of a potential problem with the version of the CPC software installed in Unit 2. It was discovered that the installed version of the CPC software was not consistent with the system requirements regarding the system response to analog input module errors. In other words, the CPC would not trip the plant when required under all conditions. Due to errors in the installed software, the CPCs would not generate a trip as required when both analog input modules within a CPC channel indicated an error. On August 18, Westinghouse completed an apparent cause analysis and concluded that the issue was a nuclear safety concern. Palo Verde personnel were alerted to this problem during an August 22 conference call. After performing a test in the shop that confirmed the problem, Palo Verde personnel notified the Unit 2 Shift Manager and the decision was made to shutdown the unit. The direct cause of the issue was a 2002 revision of the software requirements specification that led to an inconsistency with the system requirements specification. APS found that the root cause of this inconsistency was that no formal communication plan existed with the internal Westinghouse "downstream" users of the reactor trip.

Net Replacement Power Cost: $[redacted]

References:

LER 2005-005-00

CRDR2835132

Analysis:

As described in CRDR Number 2824258,[24] this outage was the result of flawed software provided by the vendor, Westinghouse. Westinghouse's internal communication in development of this software was inadequate. This outage could not have reasonably been foreseen by APS.

H. Unit 2 Refueling Water Tank Inoperable

Date: **10/11-10/20/05**

Type: **Unplanned**

On October 11, 2005 with Palo Verde Units 2 and 3 at 100% power, both trains of Emergency Core Cooling System ("ECCS") and Containment Spray were declared inoperable in both units because the Refueling Water Tanks ("RWT") for both units were declared inoperable. The RWT provides suction to the safety injection pumps and the containment spray pumps in the event of a loss of coolant accident. With both trains of ECCS and Containment Spray inoperable, the plants were shutdown in accordance with the Technical Specifications.

Cause:

During a supplemental NRC inspection resulting from the yellow finding in 2004 (which also dealt with a concern that air entrainment could endanger the operability of the ECCS and Containment Spray pumps), NRC inspectors raised a question concerning the possibility that air would be entrained in the suction from the RWT under certain postulated conditions. The concern was that a large amount of entrained air could damage the critical safety pumps and render them inoperable. APS was unable to demonstrate that air entrainment from the RWT was not a concern and the plant was shutdown while APS conducted the necessary analysis. APS ultimately concluded and demonstrated to the NRC that air entrainment from the RWT was not a safety issue.

Net Replacement Power Cost: $[redacted]

References:

[24] CRDR Number 2824258, U-2 3.03 Shutdown Due to CPC Software dated 11/30/2005. (Attachment 12)

LER 2005-005-00

CRDR2835132[25]

Analysis:

The RWT air entrainment issue was identified by the NRC during the NRC's 95002 Supplemental Inspection in the fall of 2005. This inspection was a part of the additional oversight that resulted from the yellow findings in 2004 due to containment sump piping being left empty. The RWT air entrainment issue is closely related to the 2004 yellow finding in that the fundamental concern of both issues is the possible damage to safety-related pumps due to air entrainment either from the empty sump piping or from the drain down of the RWT. Numerous evaluations of Palo Verde described above in this report have identified problems with Palo Verde's Corrective Action Program including the crosscutting issues in Problem Identification and Resolution. One of the problems identified is that the analyses of problems have been too narrow. Even though the RWT was within the boundary of the evaluation of the yellow finding event, and the primary concern was the potential for damage to safety related pumps due to air entrainment, APS personnel did not identify the RWT concern until it was pointed out by NRC inspectors during the 95002 inspection in October 2005. A more comprehensive root cause evaluation with a broader focus should have identified this concern in 2004. For these reasons, this 2005 outage was avoidable.

This outage was discussed with Palo Verde's NRC Senior Resident Inspector Mr. Greg Warnick on March 28, 2006. Mr. Warnick stated that he believed this outage to be avoidable and referenced the NRC's conclusions found in Inspection Report 200512 dated January 27, 2006 which presents the results of the 95002 Supplemental Inspection. Section 4OA5.1 of this report addressed the RWT air entrainment issue. In its report, the NRC states

[25] CRDR 2835132 pages 16 through 162, Evaluation of RWT Suction Behavior during SIS and CSS Transition to RAS and Related Design Interface Criteria (Attachment 13)

> During preparation of this inspection, the inspectors reviewed the transportability analysis included in the Condition Report/Disposition Request (CRDR) 2726509, "ECCS Sump Suction Piping Discovered in an Unanalyzed Condition," Revision 1. This report included extent of condition and extent of cause evaluations for the ECCS sump issue (event date July 29, 2004). The inspectors noted this report included the RWT in its scope, but did not address the RWT as a potential source of air entrainment into the ECCS. The inspectors also noted that the PVNGS design did not include automatic closure of the RWT isolations valves with a recirculation actuation signal (RAS). The inspectors noted that the licensee did not fully understand the plant design basis and the dynamic of the system at the time of a RAS. Based on these observations, the inspectors questioned licensee personnel further on the potential of air entrainment from the RWT into the ECCS.[26]

A full and complete understanding of the plant design basis is critical to safe operation of a nuclear power plant. The NRC also concluded that Palo Verde personnel's "attention to detail was lacking and there was poor inter- and intra-group coordination" as described in more detail in the NRC inspection report below[27]:

- The inspectors determined that the licensee extent of cause and extent of condition reviews were narrowly focused. The licensee defined very extensive design criteria and features that could be pertinent to the original (Yellow) violation. However, if some design document or interface document addressed the design criteria, the licensee performed no further review. There was not a thorough effort by the licensee to validate the design criteria. This was clearly demonstrated in the RWT voiding issue. Examples included the licensee's misunderstanding of the maximum RWT Temperature, and their reliance on a Combustion Engineering interface requirement, for piping elevations, to meet all dynamic thermal-hydraulic design criteria for ECCS piping.

- The licensee also noted, in other ongoing programs at the facility, that design basis information was not handled with appropriate attention to detail. Examples

[26] Palo Verde Nuclear Station – NRC Supplemental Inspection Report 05000528/200512; 05000529/200512; 05000530/200512 dated January 26, 2006, pages 7 - 8. (Attachment 3)
[27] Palo Verde Nuclear Station – NRC Supplemental Inspection Report 05000528/200512; 05000529/200512; 05000530/200512 dated January 26, 2006, pages 10 - 12. (Attachment 3)

included the licensee's evaluation statements that their UFSAR[28] validation process, under 10 CFR 50.54(f), was shallow; quality assurance reviews indicated that engineers did not verify reference values or conditions for design calculations; and various design organizations did not interface well with each other for multi-disciplinary issues.

- The inspectors determined that the licensee's evaluation of technical issues was iterative, which demonstrated a lack of thoroughness in reviews. The inspectors noted that engineering personnel would address one particular aspect or consideration when a design problem was presented. However, when questioned by the inspectors or engineering management, more discrepancies would be identified by the engineering personnel. The inspectors determined that design engineering personnel were making broad assumptions of criteria in their reviews, and in several cases, were using unverified or unstated assumptions from other groups. An example was the stroke times of the containment sump isolation valves used by design engineers in their RWT required volume calculations. There was no stated basis for the times used, and design engineers could not explain to the inspectors where the values came from. Additionally, other engineering personnel were not challenging these assumptions in peer or supervisory reviews. These organizational and human performance issues caused the inspectors to question the appropriateness of the extent of cause review for the (Yellow) Design Control violation.

- The inspectors noted a lack of communication between organizations, and a lack of attention to detail when coordinating critical design evaluations between organizations. During discussions of this RWT voiding issue, engineering personnel inappropriately described system operation to operators while discussing the operability of ECCS (see Section 4OA5.1). One shift test engineer informed an inspector that on October 8, 2005, he was told by the operator he was relieving, that "I believe we may be in 3.0.3,"[29] based on the emergent RWT voiding issue. The individual apparently did not address this to his crew supervision because he had not had time to reconcile his own questions. Subsequently, the operations crew and the lead shift test engineer reviewed the RWT information, without consulting engineering, and concluded the previous operator's questions were not of concern. The inspectors were concerned that this demonstrated problem resolution by isolated groups, and did not look across organizational boundaries.

[28] UFSAR – Updated Final Safety Analysis Report
[29] Technical Specification 3.0.3 requires that the plant be shutdown when the condition of the plant is found to be outside the plant's design basis.

- The inspectors determined that the licensee had a very limited use of operating experience for the RWT issue. The licensee previously identified that ineffective use of operating experience was a contributor to the (Yellow) ECCS violation. The licensee also had several self-identified findings of ineffective operating experience use in the last year, following reviews of their substantive crosscutting problem identification and resolution issue and their engineering program review. However, during the review of the RWT issue, the licensee did not consider all relevant operating experience. The inspectors brought to the licensee's attention a similar finding in 2003 at the Brunswick Nuclear Power Station, and a specific American Society of Mechanical Engineers' study for uncovering the RWT vortex breaker at the Donald C. Cook facility in 2001. This study not only included detailed flow modeling of the same system, it partly refuted the original operability determination that the licensee performed under OD 301 by stating air would enter the suction piping.

- The inspectors determined that the schedule for effectiveness reviews did not ensure a timely review of the adequacy of corrective actions. Two root causes, and one of the contributing causes, were addressed by a condition report action item (CRAI) 2825679, which at the time of the inspection was already closed. This corrective action included all-hands communications from senior management to communicate the need for effective questioning attitudes and technical rigor. This corrective action was closed on September 9, 2005, after such meetings were conducted to "emphasize that it is essential that all employees have a strong and effective questioning attitude and technical rigor, and to challenge assumptions and/or any situations which do not seem safe, or per design, or per procedure, or per expectation, or in general do not seem appropriate". The licensee stated this was placed in effectiveness review process, but that specific review of effectiveness of these actions was not planned until 2006. The inspectors determined that the effectiveness review was untimely in that unacceptable performance continued without additional corrective actions being implemented.

Based on these findings by the NRC and the documented poor performance in the area of Problem Identification and Resolution and deficiencies in the Corrective Action Program, GDS concludes that the RWT outages for units 2 and 3 in August 2005 were avoidable and imprudent.

Unit 3 Outages

I. Unit 3 Pressurizer Heater Replacement and Reactor Coolant Pump Seal Oil Leak

Date: **05/22-06/24/05**

Type: **Planned**

Pressurizer heaters are cylindrical heaters that are used to assist in controlling the pressure in the reactor coolant system. Water in the pressurizer is heated to increase the saturation pressure of water in the pressurizer and thus increase the pressure in the reactor coolant system. In the fall 2004 refueling outage, Unit 3's pressurizer heaters were replaced with heaters supplied by [redacted]. The new [redacted] heaters began failing shortly after startup in November 2004. On May 22, 2005, Unit 3 was shutdown for reactor coolant pump maintenance and to replace nine heaters. During startup from this outage, five more [redacted] supplied heaters failed. APS decided to replace all of the [redacted] heaters with heaters from a different manufacturer, and of the original design.

Cause:

[redacted]

[30] CRDR 2809138, page 61 – 87, Pressurizer Heater Failures at Palo Verde and Waterford Root Cause Investigation Report dated October 4, 2005. (Attachment 14)

5. [redacted]

Net Replacement Power Cost: $[redacted]

References:

NRC Inspection Report IR2005003

CRDR2809138

CRDR2805701

Analysis:

This outage was caused by faulty or defective vendor supplied equipment. The equipment supplier was imprudent in [redacted]. A review of the facts associated with this outage indicate that APS could not have reasonably foreseen the [redacted], and APS' decision to replace the remaining suspect heaters prior to the summer season was prudent.

J. Unit 3 Reactor Coolant Pump Seal Oil Leak

Date: **07/06-07/13/05 and 10/02-10/07/05**

Type: **Unplanned**

Unit 3 was shutdown in July 2005 and again in October 2005 to replace leaking Reactor Coolant Pump thrust bearing oil seals. Oil was leaking past the upper thrust

bearing and being collected in the lower thrust bearing at which time it would be pumped back to the upper thrust bearing. While this was not a nuclear safety problem, the oil lift pump was not designed for the near continuous duty required, and APS was concerned that failure of the oil lift pump would result in a plant outage. In addition, other outages were extended or impacted due to RCP seal oil leakage including the Unit 1 Diesel Generator outage in August 2005 and the Unit 3 pressurizer heater outage in May 2005.

Cause:

Oil leakage from the RCP upper thrust bearing seal has been a recurring problem at Palo Verde but had not caused a plant outage prior to 2004. In 2004, Palo Verde personnel began a program to implement modifications to the oil seals to reduce leakage to a more acceptable level. In the words of Palo Verde Director of Nuclear Engineering, Carl Churchman, these modifications "took the problem from chronic to acute." In other words, APS' attempts to resolve the problem in fact made it worse. Westinghouse has completed a root cause analysis of the leakage problem and APS is in the process of developing a comprehensive root cause analysis. In addition, APS is conducting a program to develop a new seal design to eliminate the leakage problem.

Net Replacement Power Cost: $[redacted] for July outage and $[redacted] for Oct. outage

References:

CRDR 2808859

CRDR 2811543

Interviews with Carl Churchman

Analysis:

Problems with the RCP upper thrust bearing oil seal were identified during the early days of operation at Palo Verde. While the leakage was not enough to cause an outage, it was greater than the desired level and was thought to be a potential fire hazard in containment. In 2004, Palo Verde personnel initiated an engineering program to attempt to reduce the leakage past the oil seals. While the modifications were not

successful, and in fact made the leakage worse, the actions were a proactive attempt to improve a problem in the plant. While the RCP oil seal outages could perhaps have been avoided by a more measured approach to the seal modifications, or by doing nothing, the actions taken to improve the seal oil leakage were reasonable and prudent. It should be noted, however, that the success of the current actions to develop and install a newly designed seal will not be known for some time to come. If the oil leakage is eliminated or reduced to the desired level and no future outages are experienced due to this problem then the actions taken will have been successful. While the actions taken to date have been reasonable and prudent, no final conclusions regarding their effectiveness can be made at this time.

K. Unit 3 Refueling Water Tank Inoperable

Date: **10/11-10/20/05**

Type: **Unplanned**

Note: This is the same as the RWT Unit 2 Outage.

On October 11, 2005 with Palo Verde Units 2 and 3 at 100% power, both trains of Emergency Core Cooling System and Containment Spray were declared inoperable in both units because the Refueling Water Tanks in both units were declared inoperable. The RWT provides suction to the safety injection pumps and the containment spray pumps in the event of a loss of coolant accident. With both trains of ECCS and containment spray inoperable, the plants were shutdown in accordance with the Technical Specifications.

Cause:

During a supplemental NRC inspection resulting from the yellow finding in 2004, NRC inspectors raised a question concerning the possibility that air would be entrained in the suction from the RWT under certain postulated conditions. The concern was that a large amount of entrained air could damage the critical safety pumps and render them inoperable. APS was unable to demonstrate that air entrainment from the RWT was not a

concern and the plant was shutdown while APS conducted the necessary analysis. APS ultimately concluded and demonstrated to the NRC that air entrainment from the RWT was not a safety issue.

Net Replacement Power Cost: $7.672 million

References:

LER 2005-005-00

CRDR2835132

Analysis:

See the Unit 2 Refueling Water Tank Inoperable outage for a detailed analysis of this outage. As stated in the analysis of the Unit 2 RWT outage, based on these findings by the NRC and the documented poor performance in the area of Problem Identification and Resolution and deficiencies in the Corrective Action Program, the RWT outages for units 2 and 3 in August 2005 were avoidable and imprudent.

Summary of Imprudent 2005 Palo Verde Outages

The following table presents a summary of the outages or outage extensions that were the result of imprudence and does not include additional disallowances for lost margins and interest costs.

Table 3. SUMMARY OF IMPRUDENT PALO VERDE OUTAGES 2005

OUTAGES OR OUTAGE DELAYS DUE TO IMPRUDENCE			
Description	**Date**	**Cause**	**Cost**[31]
Unit 1 – Diesel Generator Governor Failure	3/18 – 3/21/05	Oil and rust in governor	[redacted]
Pre-PSA Amount			[redacted]
Unit 1 – Outage extension due to reactor trip on high steam generator level	8/26 – 8/28/05	Reactor trip due to operator error	[redacted]
Unit 2 – RWT inoperable	10/11-10/20/05	RWT declared inoperable	[redacted]
Unit 3 – RWT inoperable	10/11-10/20/05	RWT declared inoperable	[redacted]
Post PSA Amount			[redacted]
Total Replacement Power Cost Due to Imprudence			**$16.269 million**

[31] Costs shown in this table present APS' estimates of replacement power only and reflect the 90/10 split for outages after April 1, 2005. Staff's quantification of the total cost impact of the imprudent outages is addressed in Section VI of this report.

VI. TREATMENT OF COSTS ASSOCIATED WITH PALO VERDE OUTAGES

As part of the Settlement in Docket No. E-01345A-03-0437, APS was allowed to implement a Power Supply Adjustor ("PSA") to allow for the recovery of changes in fuel and purchased power costs. The fuel and purchased power costs recoverable under the PSA are subject to a prudency review by the Commission and may be disallowed if it is found that "the costs were not prudently incurred." The PSA provision also includes an incentive mechanism that only allows 90% of the increased costs or savings to be passed through to customers.

This Report addresses Palo Verde's unplanned outages for all of 2005. However, the PSA provision became effective on April 1, 2005. Any power replacement costs for unplanned Palo Verde outages from January 1, 2005 through March 31, 2005 cannot be recovered under the PSA. Since power replacement costs for imprudent Palo Verde outages from January 1, 2005 through March 31, 2005 fall within the test year in APS' pending rate case, these costs should be addressed in that proceeding. Power replacement costs for imprudent Palo Verde outages from April 1, 2005 through December 31, 2005 can be addressed in APS' upcoming rate case or another proceeding. This Report identifies the costs associated with imprudent Palo Verde outages for January-March of 2005; April-December of 2005, and the total for 2005.

A. APS' Replacement Power Cost Analysis

APS has developed a Statistical Analysis System (SAS) model to estimate the replacement power costs during the 2005 unplanned Palo Verde outages. The SAS model first determines the amount of nuclear energy that was lost as a result of the unplanned outage, i.e., the amount of replacement energy that was needed for each outage. Second, the cost of the replacement power or energy is determined by the model. Based upon APS' analysis, the replacement energy is provided from: (1) increased generation at APS

power stations and (2) purchases of power from other utilities. Next, APS estimates the amount of nuclear fuel expense that was not incurred, or was "avoided" as a result of each unplanned outage, i.e., the portion of nuclear fuel expense that would be recovered in base rates but was not incurred due to the unplanned outage. To determine the amount of replacement power costs that should be recovered in the PSA, APS then reduces the total replacement power cost by the nuclear fuel costs that were not incurred due to the outage but were included in the PSA base cost of fuel and purchased power. A monthly summary of the results of this APS' analysis was provided in response to data request number 1-7(k).

Next, APS further reduces the monthly amount of replacement power costs for unplanned Palo Verde outages by the monthly amount of replacement power costs included in the PSA base cost for a "normal" level of unplanned outages based upon an assumed forced outage rate. APS' analysis presumes that these "normal" replacement power costs included in the PSA base cost should be subtracted from the total replacement power costs for actual unplanned outages since APS claims those costs have already been recovered in base rates. This presumption assumes that all of the actual unplanned outages were prudent.

The following Table 4 summarizes the results of APS' analysis of replacement power costs due to Palo Verde unplanned outages since the PSA provision became effective:

Table 4. SUMMARY OF APS' CLAIMED REPLACEMENT POWER COSTS FOR PALO VERDE FORCED OUTAGES

Month of 2005	APS' Gross Estimated Replacement Power Cost ($ x 1,000)	Nuclear Fuel Expense Avoided ($ x 1,000)	APS' Claimed Replacement Power Cost Less Avoided Fuel ($ x 1,000)	"Normal" Replacement Power Costs in PSA Base Cost ($ x 1,000)	APS' Claimed Net Replacement Power Costs ($ x 1,000)
April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**$ 60,790**	**$3,868**	**$56,922**	**$7,407**	**$49,516**
			Less	**10%(1)**	**$4,952**
Net Total					**$44,564**

Note: (1) 10% reduction stems from the 90/10 sharing between APS and the ratepayers.

Based upon the PSA provisions, APS is only allowed to recover 90% of the total amount of net replacement power costs. Accordingly, APS is claiming that 90% of $49,516,000, or $44,564,000 should be recoverable under the PSA. Again, APS's claim assumes that all of the unplanned outages were prudent.

B. Results of Analysis of Cost Impacts of Imprudent Palo Verde Outages

GDS reviewed the results of the SAS model used by APS, including the inputs used by APS and other information provided by APS. Based upon our review and

analysis of APS' replacement power cost calculation, two revisions need to be made to APS' methodology. In addition, once these two revisions are made, then the amount of interest on the balance of fuel and purchased power cost under-recoveries needs to be recalculated. Each of these revisions and adjustments is explained below.

1. Netting the PSA base cost amount from the total replacement power cost amount.

As discussed in section VI. A. above, APS' analysis reduces the monthly amount of replacement power cost for unplanned Palo Verde outages by the amount included in the PSA base cost for assumed "normal" levels of unplanned outages. In other words, for any amount of replacement power costs disallowed for imprudence, APS' analysis would reduce that disallowed amount by the amount of replacement power cost for unplanned outages included in the PSA's base cost. While this adjustment may be an appropriate assumption for outages not due to imprudence, the adjustment should not be made to reduce disallowed fuel costs related to imprudent Palo Verde outages. If the outage is imprudent, the Commission should disallow all of the replacement power costs. Accordingly, any replacement power costs related to Palo Verde outages determined to be caused by imprudence should be disallowed in their entirety and should not be off-set by any amounts included in the PSA base cost.

Page 1 of Attachment 15 to this report provides a quantification of the replacement power costs due to imprudent Palo Verde outages to be disallowed from recovery in the PSA. Column (c) on page 1 of Attachment 15 provides APS' monthly amount of replacement power costs for all unplanned Palo Verde outages in 2005 after implementation of the PSA. Column (d) is the portion of replacement power costs in column (c) related to imprudence. The recommended disallowance amounts are shown in column (e) which are the replacement power cost amounts in column (d) reduced by the 90/10 recovery ratio provided for in the PSA. Page 2 of Attachment 15 provides the

2005 replacement power costs for imprudent outages prior to the implementation of the PSA, or prior to April 1, 2005. Page 3 of Attachment 15 provides the replacement power costs both for forced outages due to faulty equipment and for all other forced outages not found to be imprudent.

2. Palo Verde outage impacts on off-system sales margins

APS regularly makes off-system sales into the wholesale power markets from available excess generation. The margins earned on these off-system sales are used to reduce the amount of fuel and purchased power expenses recoverable through the PSA. When the excess generation is needed to replace Palo Verde generation due to an unplanned outage, then APS has fewer opportunities to make off-system sales. In response to Staff Data Request 2.19, which asks whether APS' replacement power cost analysis considered lost opportunity sales due to the unplanned outages, APS states that:

> The replacement power cost methodology captures only realized costs incurred in serving native load customers and does not attempt to measure lost opportunity sales. Such a calculation would necessarily require the use of some spot market price index to serve as the basis for assigning value to a sale that did not happen, which would correspondingly require significant assumptions about the availability and depth of the market at any point in time relative to that market index. Additionally, assessments of which generating units would truly be available to make such sales would require that operating constraints on the transmission system and spinning and non-spinning reserves be adequately accounted for.

It is clear that reduced levels of nuclear generation due to unplanned outages at Palo Verde would result in lost off-system opportunity sales. The margins on such lost opportunity sales would have been used to offset the fuel and purchased power expenses that APS is seeking to recover through the PSA. APS' failure to quantify the impact due to such lost opportunity sales will reduce the cost impact of any imprudent unplanned

outages, and thereby overstates the amount of any claimed fuel cost under-recovery. APS' claim that this quantification is complex should not be an excuse that results in increased costs to customers. APS has the data, western regional power market experience, and resources to do the analyses. GDS does not have access to the same market information available to APS and does not have APS' day-to-day western regional power market experience. Ideally, the APS analysis should determine both the additional net margins for the off-system sales that were lost and the reduced margins on the off-system sales that did occur.

In addition to lost opportunity sales, the unplanned outages at Palo Verde also reduce the margins on the off-system sales that were made during the outage. As shown on APS' Power Supply Adjustor report for December 2005, several of APS' off-system sales actually had negative margins. Also, in that same report, APS states that "due to unplanned unit forced outages, those sales were supplied out of higher cost generation units than anticipated." In other words, APS committed to the off-system sales assuming the Palo Verde units were running. When the unplanned outages occurred, those off-system sales were either less profitable or made at a loss. The result is that the net margins on off-system sales were less than "anticipated." These reduced margins must be considered as part of the cost impact of the imprudent outages at Palo Verde.

GDS estimates the impact of lost off-system sales opportunities and reduced margins on off-system sales due to imprudent Palo Verde outages to be $2,103,169 (Attachment 16, Column e, Line 11). The calculation of this amount is provided on Attachment 16. As shown in Attachment 16, the estimated amount is determined by multiplying the average margin amount per MWh for off-system sales from April through December 2005 times the MWh reduction in nuclear generation due to each imprudent Palo Verde outage. If APS does not provide an analysis of the reduced margins, then these estimated amounts should be used to reduce any amount of fuel and purchased

power cost under-recovery to be flowed through the PSA. If APS does provide an analysis of off-system sales margins, we would be glad to review the reasonableness of that analysis.

3. Interest

As shown on its monthly Power Supply Adjustor reports, APS is seeking to collect interest on under-recovered fuel and purchased power expenses. Should the Commission disallow the recovery of any APS claimed fuel and purchased power expense under-recoveries, the amount of APS' claimed interest needs to be reduced as well. Based on the recommended disallowances in this report for imprudent Palo Verde outages, the interest amount should be reduced by $85,539 (Attachment 17, Column f, Line 10) through the end of 2005. The calculation of this interest adjustment is provided on Attachment 17. If the interest adjustment calculation is carried through to July 1, 2006, the reduction should be $325,934 (Attachment 17, Column f, Line 18). Also, for each month beyond June 2006, the additional reduction in interest per month is approximately $40,000 (Attachment 17, Column f, Lines 11-16). We have generally used the interest calculation methodology shown on APS' Power Supply Adjustor reports.

C. Summary

In Section V above and in this section, the unplanned outages at Palo Verde that were due to imprudence are identified and the amount of replacement power costs related to these outages is provided. For the 2005 imprudent outages that occurred after implementation of the PSA (April 1, 2005 through December 31, 2005), the recovery of the related replacement power costs through the PSA should be disallowed.

In addition to the replacement power cost impact of the imprudent Palo Verde outages, APS experienced reduced margins on off-system sales and lost opportunity sales due to the imprudent Palo Verde outages. Margins on off-system sales are used to offset fuel and purchased power costs recovered through the PSA. The reduced margins caused by the imprudent outages should be adjusted (increased) to exclude the impacts of these outages, i.e., APS' fuel expenses should be reduced by the adjusted (increased) margin amount. Also, the amount of interest APS is allowed to recover on its under-recovered fuel and purchased power expense balances should be reduced to reflect the disallowed costs and lost margins related to the imprudent Palo Verde outages.

The total cost impact for imprudent Palo Verde outages for 2005 is $18.996 million, including replacement power cost, lost opportunity sales, and interest through June 2006. For the period April 1, 2005 through December 31, 2005 (the period that the PSA was in effect), the recommended disallowance is $17,373,103 (Attachment 18, Page 2, Column f, Line 18). The following table summarizes the components of this disallowance:

Table 5. RECOMMENDED PSA DISALLOWANCES

Component	Amount ($ x 1,000,000)
Imprudent Replacement Power Costs	$14.944
Margins on Lost Opportunity Sales	2.103
Total Interest Adjustment(1)	0.326
TOTAL DISALLOWANCE	$17.373

Note: (1) Includes Interest Adjustment through June 2006.

A more detailed schedule of the recommended disallowances is provided as Attachment 18. The portion of the recommended $14.944 million disallowance for replacement

power costs that is related to APS' claim of $44.564 million for recovery of replacement power costs for 2005 Palo Verde forced outages is $14.401 million.[32] If APS' claim for replacement power costs is adjusted to exclude the portion that was related to imprudent unplanned outages, the remaining amount would be $30.163 million ($44.564 million less $14.401 million).

The Commission should consider how to treat the cost of imprudent unplanned outages at Palo Verde in APS' pending rate case.

[32] The reason that the $14.401 million amount is lower than the recommended disallowance of replacement power costs is that APS reduces its claim for replacement power costs by the amount of replacement power costs for "normal" forced outage levels recovered in the PSA base cost (See Section VI.A.1 above). The $0.543 million is the amount included in the next to last column of Table 4 that is related to imprudent forced outages.

VII. CONCLUSIONS

GDS' investigation of Palo Verde's performance during 2005 has resulted in the following conclusions:

1. Performance of the Palo Verde plant declined significantly over the past three years by almost any measure of performance.
2. The number of outages during 2005 was much higher than normal and the generation and capacity factors were lower than should be expected.
3. APS acknowledges the decline in performance and has implemented a comprehensive and aggressive Performance Improvement Plan to return the plant to its former levels of performance. APS has changed the Palo Verde organization to allow greater focus by the senior management team members on their areas of responsibility. It is too early to assess the effectiveness of the performance improvement plan or the new Palo Verde organization. However, GDS is optimistic that PIP, the new Palo Verde organization, and the commitment of Palo Verde's senior management team will be successful in returning performance at Palo Verde to the desired level.
4. As described in Section V of this report, GDS identified outages and outage extensions during 2005 that were avoidable and were the result of imprudence.
5. Some of the unplanned Palo Verde outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent
6. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem. Additional investigation will be needed to determine the cause of and responsibility for this outage once.

7. Although APS received a yellow finding from NRC in 2004 regarding safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

VIII. RECOMMENDATIONS

1. Ratepayers should not be required to pay for additional costs resulting from imprudent outages or outage extensions. The Commission should disallow all costs resulting from the imprudent outages as presented in Section VI of this report. The amount of $17.373 million incurred after the PSA mechanism was in place, April 1, 2005, should be expressly disallowed from recovery under the PSA mechanism. The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.
2. An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' actions.
3. The Commission should establish a Nuclear Performance Standard that would establish a minimum level of performance for Palo Verde and provide penalties if Palo Verde performance fails to meet this minimum level. Only when Palo Verde is operated at a high capacity factor do APS ratepayers receive the economic benefit of the high capital cost of Palo Verde. A Nuclear Performance Standard would ensure that ratepayers do not suffer economic harm if the performance of Palo Verde is below acceptable levels. Establishment of a Nuclear Performance Standard should be considered during the pending APS rate case.

4. The Commission should order APS to file a semi-annual report with the Commission's Docket Control, describing the plant performance levels, explaining any negative reporting by NRC and INPO Inspectors, and, finally, providing details of the corrective actions taken by the utility. This report should also include information on the replacement cost of power resulting from forced outages of the Palo Verde units. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.
5. Effective programs must be developed to deal with aging equipment issues. The Palo Verde units are now 20 years old and age related problems will become more numerous. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.
6. Procedures for 1) receipt inspection of materials and 2) verification of materials and equipment prior to installation should be improved. Two of the 2005 outages could have been avoided with better inspection of parts and components prior to installation. The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.