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OPEN MEETING ITEM

ERNEST G. JOHNSON
Executive Director

ARIZONA CORPORATION COMMISSION

DATE: NOVEMBER 17, 2009

DOCKET NO.: E-01345A-08-0172

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Lyn Farmer. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA PUBLIC SERVICE COMPANY
(PERMANENT RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

NOVEMBER 27, 2009

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

DECEMBER 7, 2009

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602)542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

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ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

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.	DOCKET NO. E-01345A-08-0172 DECISION NO. ____________ **(PERMANENT RATES)** **OPINION AND ORDER**

DATES OF HEARING:	August 14, (Pre-Hearing Conference), August 19, 20, 21, 24, 27, 28, September 10, 11, 14, 16, 17, and 18, 2009
PUBLIC COMMENTS:	March 30 (Phoenix); August 3 (Flagstaff); August 6 (Prescott) and September 29, 2009 (Yuma)
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Lyn Farmer
IN ATTENDANCE:	Kristin K. Mayes, Chairman Gary Pierce, Commissioner Paul Newman, Commissioner Sandra D. Kennedy, Commissioner Bob Stump, Commissioner
APPEARANCES:	Mr. Thomas L. Mumaw and Ms. Meghan H. Grabel, PINNACLE WEST CAPITAL CORPORATION LAW DEPARTMENT, on behalf of Arizona Public Service Company; Mr. Daniel Pozefsky, Chief Counsel, on behalf of the Residential Utility Consumer Office; Mr. Michael M. Grant, GALLAGHER & KENNEDY, P.A., on behalf of the Arizona Investment Council; Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of Freeport-McMoRan and Arizonans for Electric Choice and Competition; Mr. Lawrence V. Robertson, Jr., on behalf of Mesquite Power, LLC; Southwestern Power Group II, LLC; and

Bowie Power Station, LLC;

Ms. Barbara Wyllie-Pecora, Intervenor, in propria persona;

Mr. Timothy H. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Western Resource Advocates, Southwest Energy Efficiency Project, Arizona School Boards Association, and Arizona Association of School Business Officials;

Ms. Cynthia Zwick, Intervenor, in propria persona;

Ms. Karen S. White, AIR FORCE UTILITY LITIGATION & NEGOTIATION TEAM, on behalf in the Department of Defense;

Mr. Nicholas J. Enoch and Mr. Jarrett Hasadovec, LUBIN & ENOCH, P.C., on behalf of the International Brotherhood of Electrical Workers Locals 387, 640 and 769;

Mr. Kurt J. Boehm, BOEHM, KURTZ & LOWRY, on behalf of The Kroger Company;

Mr. Douglas V. Fant, LAW OFFICE OF DOUGLAS V. FANT, on behalf of Interwest Energy Alliance; and

Ms. Maureen Scott, Ms. Janet Wagner, and Mr. Charles H. Hains, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On March 24, 2008, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase. The application sought a $371.7 million permanent base rate increase which included $252.6 million in non-fuel base rates and $119.1 million in fuel-related increases.[1] The $252.6 million requested increase included an $86 million attrition allowance, $53 million of which APS proposed to collect through new "hook-up" or "impact" fees.

On June 2, 2008, APS filed an amended application, seeking a $448.2 million permanent base rate increase consisting of a $264.3 million increase in non-fuel base rates and $183.9 million in fuel-related costs.[2] The amended application included a $79.3 million attrition adjustment and APS proposed to collect up to $53 million of that through its proposed impact fee.

On June 6, 2008, APS filed a Motion for Approval of Interim Rates and Preliminary Order.

On July 2, 2008, the Commission's Utilities Division Staff ("Staff") filed its Sufficiency Letter, indicating that APS' amended application had met the sufficiency requirements of A.A.C. R14-2-103.

By Procedural Order issued on July 16, 2008, the hearing on the Motion for Interim Rates was scheduled to commence on September 15, 2008.

By Procedural Order issued July 29, 2008, the hearing on the permanent rate application was scheduled to commence on April 2, 2009.

The hearing on the Motion for Interim Rates commenced as scheduled on September 15 and concluded on September 19, 2008.

On December 24, 2008, the Commission issued Decision No. 70667 which granted APS an emergency interim base rate surcharge of $0.00226 per kwh.

Intervention has been granted to The Kroger Company ("Kroger"); Freeport-McMoRan Copper & Gold, Inc. and Arizonans for Electric Choice and Competition (together, "AECC"); Mesquite Power, L.L.C., Southwestern Power Group II, L.L.C., and Bowie Power Station, L.L.C.

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[1] After reclassifying the Power Supply Adjustor ("PSA") revenues as base fuel revenues, the net increase to base rates would be $265.5 million.

[2] After reclassifying PSA revenues as base fuel revenues, the net increase to base rates would be $278.2 million.

(collectively, "Mesquite Group"); the Town of Wickenburg; Western Resource Advocates ("WRA"); Southwest Energy Efficiency Project ("SWEEP"); the Residential Utility Consumer Office ("RUCO"); the Arizona Investment Council ("AIC"); the Hopi Tribe; Cynthia Zwick; Local Union 387, International Brotherhood of Electric Workers, AFL-CIO, CLC, Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC, and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC (collectively, "IBEW"); the Federal Executive Agencies ("FEA"); the Arizona School Boards Association ("ASBA"); the Arizona Association of School Business Officials ("AASBO"); the Az-Ag Group; Interwest Energy Alliance; Ms. Barbara Wyllie-Pecora ("Ms. Pecora"); Catalyst Paper (Snowflake) Inc.; and SCA Tissue North America.

On January 23, 2009, APS filed a Notice of Settlement Discussions.

On January 30, 2009, APS filed a Motion to Suspend Procedural Schedule.

On February 4, 2009, a Procedural Order was issued which granted a 30 day extension and ordered that the parties make a filing prior to the end of the 30 day suspension period.

On March 5, 2009, APS filed a Motion to Further Suspend the Procedural Schedule and by Procedural Order dated March 9, 2009, the procedural schedule was suspended.

By Procedural Order issued March 19, 2009, the March 25, 2009 procedural conference and the April 2, 2009, hearing date were vacated, and a procedural conference was scheduled for April 7, 2009 to discuss the status of the settlement discussions and the procedural schedule in this matter.

The April 7, 2009, procedural conference was held as scheduled and the parties reported that discussions were continuing and requested another procedural conference in two weeks.

On April 21, 2009, a procedural conference was held to update the Commission as to the status of settlement discussions in this matter. During the procedural conference, the Settling Parties[3] indicated that there was an agreement in principle on revenue requirement issues and that substantial agreement had been reached on other issues. The Settling Parties agreed to file a Term Sheet containing the major provisions of the Settlement Agreement on May 4, 2009.

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[3] Settling Parties include: APS, RUCO, Staff, SWEEP, AECC, AIC, Az-Ag Group, Cynthia Zwick, IBEW, Bowie Power Station, L.L.C., Freeport-McMoRan Copper & Gold, Inc., Mesquite Power, L.L.C., Southwestern Power Group II, Western Resources Advocates, the Kroger Company, FEA, AASBO, ASBA, Interwest Energy Alliance, and the Town of Wickenburg.

On May 4, 2009, the Term Sheet containing the major provisions of the Settlement Agreement was filed along with a Request for Procedural Order which proposed a procedural schedule for filing testimony and a hearing date on the contemplated Settlement Agreement.

On May 11, 2009, a Procedural Order was issued establishing procedural dates and setting the matter for hearing to commence on August 19, 2009. The Procedural Order also directed the Settling Parties to file a joint proposed form of notice.

On June 12, 2009, the Proposed Settlement Agreement ("Settlement Agreement") and the Joint Form of Proposed Notice were docketed.

On July 15, 2009, APS filed its Request for Approval of 2010 Energy Efficiency Implementation Plan, as required by the Settlement Agreement.

Public notice of the hearing on the Settlement Agreement was published in the *Arizona Republic* on July 18 and 25, 2009, and was included as a bill insert in customers' monthly bills during July, 2009.

Public comment sessions were held in Phoenix on March 30 and August 12, 2009; in Flagstaff on August 3, 2009; in Prescott on August 6, 2009; and in Yuma on September 29, 2009. Numerous written public comments were received by the Commission and Consumer Services and were filed in the docket.

Hearing on the Settlement Agreement began on August 19, 2009, and continued to August 20, 21, 24, 27, 28, 2009, and September 10, 11, 14, 16, 17, and 18, 2009. Testimony was taken from numerous witnesses, including Jeffrey Guldner, David Rumolo, Daniel Froetscher, Peter Ewen, Barbara Lockwood, James Wontor, and James Hatfield for APS; Dr. Ben Johnson and Jodi Jerich for RUCO; Kevin Higgins for AECC; Cynthia Zwick; Dr. David Berry for WRA; Jeff Schlegel for SWEEP; Robert Rice for ASBA; Chuck Essigs for AASBO; Amanda Ormond for Interwest Energy Alliance; Sam Elliott Hoover II for IBEW Locals; Gary Yaquinto for AIC; Ms. Pecora and Joel Lawson, Carl Faulkner, Gary Nelson, Ian Campbell, Bobby Miller, and Rick Merritt; and Elijah Abinah, Ralph Smith, Frank Radigan, Barbara Keene, and William Michael Lewis (for Kenneth Strobl) for Staff. Written pre-filed testimony from Kroger's witness, Stephen Baron; from the FEA's witness, Dr. Larry Blank; and from the Mesquite Group's witness, Leesa Nayudu, were admitted without cross-examination or objection.

Initial Closing Briefs were filed on October 9, 2009, by APS, AIC, AECC, Mesquite Group, IBEW, Ms. Zwick, WRA/SWEEP/ASBA/AASBO, FEA, and RUCO, and by Staff and Ms. Pecora on October 16, 2009.

Reply Briefs were filed by APS, AIC, AECC, IBEW, RUCO, and Staff on October 23, 2009.

DISCUSSION

APS' current base rates were implemented pursuant to Commission Decision No. 69663 (June 28, 2007) based upon a test year ending September 30, 2005. Decision No. 69663 granted APS an increase of $321,723,000, a 12.33 percent increase over test year revenues.

Pursuant to Commission Decision No. 70667 (December 24, 2008), APS is also collecting an emergency interim base rate surcharge of $0.00226 per kwh, which will terminate upon issuance of this Decision.

APS' amended application sought a $448.2 million permanent base rate increase, including $264.3 million in non-fuel base rates and $183.9 million in fuel-related costs.[4] APS also proposed to collect up to $53 million of its $79.3 million attrition adjustment through an impact fee.

In direct testimony filed in December 2008, Staff recommended a base rate increase of approximately $307 million[5]; RUCO recommended an increase of approximately $157 million[6]; and AECC recommended adjustments that would result in an increase of $346.7 million.

Settlement Agreement

The Settlement Agreement is supported by twenty-two of the twenty-four parties to this proceeding. The Hopi Tribe has taken no position on the Settlement Agreement[7] and intervenor Ms. Pecora is the only party to oppose a provision of the Settlement Agreement (Section 10, Treatment of Schedule 3). According to the witnesses' testimony and statements of attorneys, all parties were

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[4] After reclassifying PSA revenues as base fuel revenues, this results in a net increase to base rates of $278.2 million.

[5] Staff proposed two alternatives – Staff Alternative 1 recommended a $255.3 million increase and Alternative 2 recommended the $306.6 million increase. Both alternatives included $140 million in fuel costs, and after reclassifying PSA revenues as base fuel revenues, result in a net increase to base rates of $115.2 million with Alternative 1, and $166.5 million with Alternative 2.

[6] However, after reclassifying PSA revenues as base fuel revenues, RUCO's recommendation was no net increase or decrease in base rates.

[7] Staff Post-Hearing Brief at 7.

invited to attend and participate in the settlement discussions which occurred over several months. The range of interests represented by the Settling Parties is broad – it includes the interests of residential ratepayers, school business officials and boards, renewables and energy efficiencies advocates, agriculture, organized labor, retail electric customers favoring competition in the electric industry, industrial and commercial customers, the federal government and large military bases, merchant power plant owners, Arizona debt and equity investors, and advocates for low-income customers. By all accounts, the negotiations were intense, extensive, detailed, time-consuming, and often contentious. The Settling Parties believe that the result is an integrated Settlement Agreement that is a "package deal" reflecting the significant give and take by all parties. The Settling Parties described the Settlement Agreement as more than just a resolution of a rate case. RUCO's attorney stated that the "settlement provides a road map . . . that will move the company towards financial health, and in return provide ratepayers with rate stability and comfort in knowing that there's a comprehensive plan in place to secure Arizona's energy future."[8] APS characterizes the Settlement Agreement as initiating "a sustainable course toward Arizona's energy future – a future of less frequent and more predictable rate cases, of higher levels of energy efficiency and renewable energy, of heightened protections for the Company's most vulnerable customers, of more transparent accountability and of greater financial stability for APS – and it specifically charts the first five years in the direction of that goal."[9]

The Settling Parties believe that the Settlement Agreement results in just and reasonable rates and is in the public interest, and recommend its approval.

Terms and Conditions of the Settlement Agreement

The Settlement Agreement contains approximately 40 pages of text describing the terms and conditions of the negotiated settlement. The major Sections of the Settlement Agreement are as follows:[10]

I. Recitals

II. Rate Case Stability Provisions – This Section includes (A) General Rate Case Filing Plan

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[8] Tr at 173.
[9] APS Initial Post-Hearing Brief at 2.
[10] This is a summary of some, but not all of the provisions contained in the Settlement Agreement.

which includes two scheduled general base rate cases covering January 1, 2010 through December 31, 2014 ("Plan Term"), and a description of efforts to process those cases; and (B) Accelerated Power Supply Adjustor Reset which provides that if at the time new rates are implemented, the PSA is over-collected, the reset would be accelerated to partially offset the increase to base rates.

III. Rate Increase – APS will receive a total rate increase of $344.7 million which is comprised of: a non-fuel base rate increase of $196.3 million (which includes the $65.2 million interim increase); a fuel-related base rate increase of $11.2 million; and $137.2 million of base fuel costs (currently collected via the PSA).[11] The rationale for the base rate increase includes providing for a return on and of post-test year plant through June 30, 2009 (eighteen months beyond the test year) and the Settling Parties' desire to enhance APS' ability to retain and improve its current investment-grade rating so that APS will be able to attract capital at a reasonable cost, optimize its operational flexibility, and thereby be better positioned to meet customers' future energy service needs. The fair value of APS' jurisdictional rate base for the test year ending December 31, 2007, is $7,665,727,000. This Section recognizes that in addition to the base rate increase, various provisions relating to fuel and purchased power costs, renewable energy, and energy efficiency may affect the amount collected from customers through established adjustor mechanisms. This Section states that the Settling Parties acknowledge that certain provisions do not have a rate impact in this case, but will have an impact in future APS rate cases.[12] This Section provides that the $10 million of Demand Side Management ("DSM") costs currently recovered in base rates will continue to be collected in base rates for this case, and the issue of the appropriate method of collecting such DSM costs (though base rates or through the DSM adjustor) will be analyzed in the next rate case.

IV. Cost of Capital – This Section adopts a capital structure of 46.21 percent debt and 53.79 percent common equity for ratemaking purposes; adopts a return on common equity of 11.06 percent and an embedded cost of debt of 5.77 percent; and adopts a fair value rate of return of 6.65 percent.[13]

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[11] When adjusted for both the interim increase and the $11.2 million associated with establishing new base fuel levels, the Settlement Agreement represents an approximate 7.9 percent increase in base revenue.

[12] Those provisions include recording Schedule 3 proceeds as revenue instead of Contributions-in-Aid-of-Construction ("CIAC"), the treatment of limited pension and other post-retirement benefits ("OPEB"), treatment of an anticipated Palo Verde depreciation rate change, and the rate impacts from $150 million in expense reductions.

[13] The fair value rate of return includes a fair value increment.

V. Depreciation – This Section adopts APS' proposed depreciation rates for ratemaking purposes, except for Account No. 370.01 which retains its current rate, and makes special provision for depreciation rates associated with a Palo Verde Licenses Extension.

VI. Fuel and Power Supply Adjustment Provisions - This Section provides for the continuation of the 90/10 sharing provision in the PSA; adopts a Base Cost of Fuel and Power of $0.037571 per kWh; provides that gains on SO2 Allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million will be recovered/refunded through the PSA; and provides that the PSA Plan of Administration is amended to reflect the terms of the Settlement Agreement and shall be approved concurrent with the Settlement Agreement.

VII. APS Expense Reduction Commitment - This Section sets out APS' renewed commitment to reduce its expenses by an average of $30 million per year beginning in 2010 and continuing during the Plan Term, for a total expense reduction of $150 million. APS will not make any expense reductions in costs necessary to preserve safe and reliable electric service and will report annually on its expense reductions.

VIII. Equity Infusions To Be Made by APS - This Section requires APS to complete equity infusions of at least $700 million between June 1, 2009 and December 31, 2014. APS agrees to use its best efforts to maintain investment grade financial ratios, a balanced capital structure that optimizes benefits to ratepayers, to work to improve its existing financial metrics and ratings, and to strive to achieve a capital structure with no more than 52 percent debt/total capital, as calculated by the credit rating agencies, by December 31, 2012. APS is also required to prepare and submit to the Commission and the Settling Parties, a plan that details the steps it will take to maintain and improve its financial ratings with the credit rating agencies.

IX. Pension and OPEB Deferrals – This Section provides that APS is allowed to defer for future recovery, in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, a portion of its annual Pension and OPEB costs above/below the test year level in years 2011 and 2012, subject to the stated maximum amounts each year.

X. Treatment of Schedule 3 - This Section provides that APS is authorized to record the proceeds from its line extension policy ("Schedule 3") as revenue during the period from January 1, 2010 through either the earlier of December 31, 2012, or the conclusion of APS' next rate case. Thereafter, the Schedule 3 receipts will be recorded as CIAC unless the Commission orders otherwise. The income from the revenue treatment of Schedule 3 proceeds is material to the Settlement Agreement and APS estimates that Schedule 3 revenues will be $23 million in 2010, $25 million in 2011, and $49 million in 2012. This Section maintains the Commission's current policy regarding customer payments for line extensions and provides that if the Commission were to modify Schedule 3, offsetting revenue changes should also be ordered so that the modification is revenue neutral. APS is required to submit a revised Schedule 3 that includes a clarified definition of Local Facilities; a Schedule of Charges; a statement that quotes provided to customers will be itemized; procedures for refunding amounts to customers when additional customers connect to the line extension; and that shall expressly permit customers to hire contractors for trenching, conduit, and backfill necessary for the extension.

<u>XI. Adjustment of Depreciation Rates for Palo Verde License Extension</u> - This Section provides that upon the later date of receiving Nuclear Regulatory Commission approval for the Palo Verde license extension or January 1, 2012, APS is authorized to adjust depreciation rates used for recording depreciation expense on the Palo Verde generating unit to reflect such license extension, and APS shall file a request to adjust the System Benefit Charge ("SBC") to reflect the corresponding reduction in the decommissioning trust funding obligations. APS is also required to provide a depreciation rate study in its next rate case.

<u>XII. Limit on Recovery of Annual Cash Incentive Compensation for APS Executives</u> - This Section provides that the annual cash incentive compensation of APS executives paid for 2010, 2011, and 2012 shall not exceed the test year level unless APS has met all the components of the Performance Measurements for that year, has received a Hardship Waiver from the Commission, or the excess is absorbed by the shareholders.

<u>XIII. Periodic Evaluation</u> – (A) Performance Measurements – this Section lists ten performance measurements, including the schools renewable program; compliance with the Commission-approved Implementation Plan designed to meet the energy efficiency goals set forth in Section XIV and the goals in the Renewable Energy Standard and Tariff ("REST") Rules; compliance

with the renewable energy goals in Section XV; the expense reductions in Section VII; APS efforts to achieve a capital structure of no more than 52 percent total debt as calculated by the credit rating agencies, by December 31, 2012; submission of the plan to maintain investment grade financial ratios and to improve financial metrics; completion of equity infusions of $700 million per Section VIII; compliance with annual reporting of financial and customer service criteria per Section XII.B; and APS' cooperation with Staff concerning the Benchmarking Study. (B) Reporting Requirements – This Section requires APS to annually file a report with a detailed list of customer service, reliability, safety, and financial information, including the frequency and duration of unplanned outages and major unplanned equipment outages/downtime; number of customer calls and level of customer satisfaction on call handling; information on the levels of enrollment in DSM, Demand Response, Low-Income, and RES programs; information regarding the frequency and severity of employee injuries; and information about changes to APS' employee counts. The annual report must also include financial reporting, including information about APS' earned return on equity, its Funds from Operations ("FFO") to Debt ratio, FFO/Interest ratio, and Total Debt/Capital ratio; information about Pinnacle West Capital Corporation's ("PNW") stock price, net book value, and relationship of the stock price to net book value; information about the status of all shelf registrations for debt and equity issuances of APS and PNW; information about any long-term debt issuances and related impacts to capital structure and FFO/Debt ratio; information about any equity infusions and related impact on capital structure, the price per share at issuance, any dilution to existing shares, and the estimated impact on APS' FFO/Debt ratio; information regarding the criteria used to measure achieved performance under the Annual Cash Incentive Compensation Plan; information regarding management expenses; information pertaining to the Dividend Payout Ratio and changes from earlier years; information pertaining to Operations and Maintenance expense and Customer and Sales expense, and any significant changes from year to year; and information regarding APS' level of major capital expenditures, and its consideration of available alternatives in connection with such capital expenditures for generation facilities. (C) Benchmarking Study of APS Operations and Cost Performance - This Section provides that by March 31, 2010, Staff shall select a benchmarking firm to conduct a benchmarking analysis of APS' operational and cost performance relative to a peer group of at least 30 other investor-owned electric-only utility operating companies. The analysis shall focus on the following areas at a minimum: Operational Performance (Safety, Customer Satisfaction, Delivery Reliability, Base Load Power Plant Performance, Sustainability Performance); Cost Performance (Non-Fuel Operating Expense per Customer, Distribution Additions to Plant per New Customer, Capital Expenditures, Hedging, Management of Expense); and Financial Health of Company (Debt/Equity Ratio, Dividend Payout Ratio, Return on Average Assets, Return on Average Equity, FFO/Debt, Debt Ratings, Earnings per share (PNW) Stock Performance (PNW)). This Section provides that APS shall pay all costs of the benchmarking study, which costs will be capped at $500,000, and which will not be recoverable in rates. The Benchmarking Study Report shall be filed with the Commission no later than December 31, 2010.

XIV. Demand Side Management – This Section establishes Energy Efficiency goals, defined as annual energy savings of 1.0 percent in 2010, 1.25 percent in 2011, and 1.5 percent in 2012, expressed as a percent of total energy resources needed to meet retail load. If the Commission adopts higher goals for those years, then the higher goals supersede the goals in the Settlement Agreement. This Section provides that the existing performance incentive for energy efficiency programs is modified to be a tiered performance incentive as a percentage of net benefits, capped at a tiered percentage of program costs. This Section provides that "Self Direction" of DSM charges is allowed for large commercial or large industrial customers who use more than 40 million kWh per calendar year. (Attachment C to the Settlement Agreement contains the Self Direction Provisions which have the specific parameters for Self Direction.) This Section provides that the settling parties agree that it is reasonable for APS' Demand Side Management Account Clause ("DSMAC") to be modified to achieve more current recovery of program costs. New DSMAC rates will be set by the Commission as part of its consideration of APS' Implementation Plan. The total amount to be recovered by the DSMAC would be calculated by projecting DSM costs for the next year, adjusted by the previous year's over- or under-collection, and adding revenue to be recovered from the DSMAC performance incentive. This Section provides that the DSM Plan of Administration will be amended as necessary to reflect the Settlement Agreement and shall be approved concurrent with the Settlement Agreement. This Section also provides that APS shall apply interest whenever an over-collected balance results in a refund to customers; that APS shall not request recovery of fixed costs as a component of DSM program costs until its next general rate case; that APS shall apply for approval of annual Energy Efficiency Implementation Plans for 2010, 2011, and 2012, with new and/or expanded programs/elements necessary to achieve the efficiency goals; and that by July 15, 2009, APS shall file for Commission approval, the 2010 Energy Efficiency Implementation Plan which Staff shall review and provide recommendations to the Commission in sufficient time so that the Commission may consider the matter at its regular November Open Meeting, so that the Commission takes action on the Implementation Plan on or before the date its takes action on the Settlement Agreement.[14] This Section lists in detail the minimal requirements to be included in the 2010 Implementation Plan.

XV. Renewable Energy - This Section provides that APS shall make its best efforts to acquire new renewable energy resources with annual generation or savings of 1,700,000 MWh to be in-service by December 31, 2015, which new resources shall be in addition to existing resources or commitments as of the end of 2008. These renewable acquisitions, in combination with existing renewable commitments, are currently estimated to be approximately 10 percent of retail sales by the end of 2015. "Renewable resources" are those defined in A.A.C. R14-2-1802. This Section requires APS to obtain a mix of new distributed and non-distributed renewable energy resources and to report to the Commission on its plans for and progress toward acquiring the new resources. This Section requires APS to issue a new request for proposals for in-state wind generation within 90 days of Commission approval of the Settlement Agreement. After evaluating potential projects, APS must file a request for Commission approval of one or more projects, within 180 days. This Section requires APS to file, within 120 days of the Commission's order approving the Settlement Agreement, a plan implementing a utility scale photovoltaic generation project, which will have a construction initiation date not later than 18 months from the date of filing. This requirement is in addition to the Concentrated Solar Power projects already under consideration or previously approved by the Commission. APS must initiate a competitive procurement that complies with its certified Renewable Energy Competitive Procurement Procedure. This Section provides that following the Biennial Transmission Assessment

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[14] APS filed its Request for Approval of 2010 Energy Efficiency Implementation Plan, as required by the Settlement Agreement.

Report prioritizing transmission projects that will facilitate interconnection of renewable resources, APS is required to commence permitting, design, engineering, right of way acquisition, regulatory authorization and line siting for one or more new transmission lines or upgrades designed to facilitate delivery of solar and other renewable resources to the APS system, and APS is required to expeditiously pursue permitting and authorizations and shall construct such transmission line(s) or upgrade(s) after satisfactory permitting and authorizations are obtained. This Section provides that within 120 days of the Commission's Order approving the Settlement Agreement, APS shall file a new program for on-site solar energy including photovoltaics, solar water heating and daylighting, at grades K through 12 public (including charter) schools in its service territory that eliminates up-front customer costs. The program goal is installation of projects resulting in 50,000 MWh of annual energy generation or savings within 36 months of program approval by the Commission. APS is required to collaborate with the School Facilities Board in determining the priority of projects. This Section requires APS to file within 120 days of the Commission's Order approving the Settlement Agreement, a new program for governmental institutions for distributed solar energy, including photovoltaics, solar water heating and daylighting, to substantially reduce or eliminate up-front customer cost. This Section provides that all reasonable and prudent expenses incurred by APS pursuant to this Section shall be recoverable through the Power Supply Adjustor, a renewable energy adjustment mechanism, or the Transmission Cost Adjustor, as appropriate. To encourage least cost renewable resources to benefit customers, these expenses will include the capital carrying costs of any capital investments made by APS in renewable energy projects, and APS cannot recover Construction-Work-In-Progress ("CWIP") related to any of the renewable projects required in this Section.

<u>XVI. Low Income Programs</u> - This Section provides that the increase in base rates will not apply to the existing low income schedules (E-3 and E-4); that eligibility for low-income schedules will be set at 150 percent of the Federal Poverty Income Guidelines ("Guidelines"); that APS shall augment its current bill assistance program to offer identical assistance to customers whose incomes exceed 150 percent of the Guidelines but are less than or equal to 200 percent of the Guidelines and shall be funded by APS in the amount of $5 million during the Plan Term; that APS will waive the collection of an additional security deposit from customers on low-income schedules under certain

specified circumstances; and that treatment of qualifying low-income customers by exempting them from the DSMAC is consistent with Decision No. 70961.

XVII. Revenue Spread - This Section provides that each retail schedule will receive an equal percentage total base rate increase and within E-32, the percentage increase is differentiated such that E-32 (402 + kW) has an increase that is 2.5 percent below average for the group, E-32 (101 – 400 kW) has the group average increase, E-32 (21 -100 kW) has an increase that is 1 percent above the group average, and E-32 (0 – 20 kW) has an increase that is above the group average by the necessary residual amount (approximately 2.8 percent).

XVIII. Rate Design - This Section provides that the voltage discount for E-35 customers taking service at transmission voltage will be equal to the current discount as adjusted by the overall percentage increase; that the third-party transmission charge for Rates E-34 and -35 as proposed by APS is not adopted; and that the rate increase for Rates E-34, -35, and -32 includes APS' proposed customer charge with an equal percentage increase in the demand and energy charges.

XIX. Interruptible Rate Schedules and Other Demand Reduction Programs - This Section provides that within 180 days of Commission approval of the Settlement Agreement, APS will (in consultation with Staff and interested stakeholders) file an Interruptible Rate Rider ("IRR") for customers with load over three megawatts. The IRR will provide a range of options and may include both short term and long term customer commitments.

XX. Demand Response - This Section defines APS' demand response programs broadly to include time-of-use rates, super peak and critical peak pricing rates as well as other programs designed to influence the timing of a customer's energy use. This Section requires APS to offer and market its demand response programs jointly with its energy efficiency programs and states that a new demand response super peak time-of-use rate for residential customers should be approved. APS' proposed critical peak pricing rate CPP-GS will be implemented on a pilot basis and APS must make a good faith effort to obtain at least 200 customers to participate. This Section provides that APS will implement a residential critical peak pricing rate pilot program and make a good faith effort to obtain at least 300 residential customers to participate. APS is required to prepare a study on the super peak and critical peak pricing programs' impact on the mix of power generation resources, air emissions, and energy use. The study must identify methods to better integrate demand response programs and energy efficiency programs and must analyze the benefits of the demand response programs. APS must file the study within two years of the Commission's Decision in this docket.

XXI. Other Rate Schedule Matters – This Section provides APS shall unfreeze the existing Rate Schedule E-20 – House of Worship tariff for a period of 12 months to allow for additional customer participation and, within 90 days for approval of the Settlement Agreement, APS will file a new optional time-of-use rate for K-12 schools designed to provide daily and seasonal price signals to encourage load reductions during peak periods.

XXIII. Commission Evaluation of Proposed Settlement – this Section provides that if the Commission fails to issue an order adopting all material terms of the Settlement Agreement, any or all of the Settling Parties may withdraw from the agreement and pursue without prejudice their respective remedies at law. This Section provides that for purposes of the Settlement Agreement, whether a term is material is in the discretion of the Settling Party choosing to withdraw from the Settlement Agreement. This Section provides that within ten days after the Commission issues an order, APS shall file compliance schedules for Staff's review and that subject to that review, the schedules will become effective on January 1, 2010.

Benefits of the Settlement Agreement as Identified by the Parties

APS

APS describes the Settlement Agreement as not just the resolution of a rate case, but as a way to "promote Arizona's energy future and provide other tangible benefits to APS customers with as little financial impact to them as possible."[15] APS believes that the Settlement Agreement promotes the public interest and should be approved. It cites the following positive benefits that it believes will balance the proposed rate increase:

- Rate Stability – A key benefit of the Settlement Agreement is base rate stability which is achieved through a Rate Case Filing Plan that governs rate applications until December 31, 2014, and through the accelerated reset of the PSA to correspond with the effective date of new rates.[16]

[15] APS Initial Post-Hearing Brief at 5.

[16] If the PSA reset is coordinated with the implementation of the rates in the Settlement Agreement, the average residential customer bill will decrease slightly in January and the increase will likely show up in customer bills beginning in May.

- Increased Transparency in APS' Accountability – APS characterized a central theme of the settlement negotiations as the transparency of its own internal efforts to improve its financial condition. The Settlement Agreement has four provisions designed to increase this accountability: APS must eliminate annual expenses by an average of $30 million each year ($150 million total) and annually report the nature and level of the reductions to the Commission; APS must fund a comprehensive benchmarking analysis of its operations (including cost and operational performance and a comparison to a peer group); APS must undergo periodic performance evaluations related to a detailed list of Performance Measurements and recovery of incentive compensation paid to APS executives is limited to test year levels[17] if any one of the Performance Measurements is not achieved; and APS must comply with extensive reporting requirements concerning customer service, reliability, safety, and financial information.

- Establishment of Ambitious Energy Efficiency Measures – According to APS, a significant benefit of the Settlement Agreement is the establishment of the first energy efficiency standard for an Arizona utility, one that "will place APS among the nation's leaders in energy efficiency deployment."[18] The programs are designed not only to allow customers to save money now, but they could also reduce the need for new generation in the long run and thereby produce savings for all APS customers. The Settlement Agreement requires APS to develop and implement innovative demand response rate programs that will allow customers to control their costs by shifting usage to avoid high load peaks. APS is also required to prepare and file a study that analyzes the programs' effects on the Company's resource portfolio, air emissions, and program participant energy use.

- Requirement of Large-Scale Renewable Resource Investments – The Settlement Agreement requires APS to make considerable additional investment in renewable energy,[19] so that by 2015, an estimated 10 percent of APS' retail sales will come from renewable resources. APS is

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The net annual rate increase during 2010 will be less than one percent, which APS characterizes as a "smooth transition during difficult economic times." APS Initial Post-Hearing Brief at 6-7, Ex. APS-37.

[17] The Test Year officer incentive compensation level was $4.374 million. Tr at 1259-60.

[18] APS Initial Post-Hearing Brief at 11.

[19] Although we note that the Settlement Agreement § 15.1 states that "APS shall make its best efforts to acquire new renewable energy resources . . ." APS' Initial Post-Hearing Brief at 13 characterizes this language as "the Agreement *requires* APS to make considerable investments in renewable energy . . . ." (emphasis added).

required to include a project for in-state wind generation, a plan for a utility-scale photovoltaic generation project, a renewable transmission project, and solar programs for Arizona schools and governmental institutions.

- Protection of APS' "Most Vulnerable Customers" – APS recognizes that its low-income customers are particularly vulnerable to even very modest rate increases and the Settlement Agreement includes several measures to address this issue, such as: excluding Schedules E-3 and E-3 from the rate increase; continuing the exemption from the DSMAC; APS' donation of $5 million to the bill assistance program for the benefit of customers whose incomes are between 150 and 200 percent of the federal poverty level; and APS' waiver of an additional security deposit from E-3 and E-4 Schedule customers under specific conditions.

- Creation of Green Jobs – APS believes that the Settlement Agreement brings important benefits to the State of Arizona in the form of creating about "425 new green jobs."[20]

- Right Price Signals Sent to Customers – According to APS, the Settlement Agreement recognizes that the prices that customers pay for electricity today do not accurately reflect the costs incurred to provide service to them. The increase will send customers a more accurate message about the cost of the energy they use, giving them an incentive to use the energy efficiency programs required in the Settlement Agreement.

- Enhancement of APS' Financial Condition – APS believes that the Settlement Agreement "takes critical steps toward improving the Company's financial health, thus enabling APS to continue to provide reliable electric service and promote the energy future the Agreement envisions."[21] APS expects that during the next five years its customer base will grow, it will need to finance improvements to maintain its aging electric system, and it will need to make the investments necessary to achieve the policy goals in the Settlement Agreement. APS' financial condition and its actual earned returns will affect its ability to acquire needed capital at reasonable rates. APS cites four key provisions that are designed to improve APS' financial metrics and its ability to compete for capital: the base rate increase, which will allow APS to maintain investment grade ratings and begin

[20] APS Initial Post-Hearing Brief at 16.
[21] Id. at 17.

to implement the energy efficiency and renewable energy provisions; the elimination of $150 million of expenses; the obligation to "'use its best efforts to improve its financial metrics and bond ratings, by completing timely equity infusions and taking other measures to strive to achieve a capital structure with no more than 52% debt/total capital as calculated by the rating agencies, by December 31, 2012,' and specifically requires equity infusions totaling at least $700 million by year-end 2014;"[22] and by providing "additional earnings support in three innovative forms: the revenue treatment of APS line extension proceeds, the deferral of a portion of the Company's increasing pension and OPEB costs, and an adjustment to the depreciation rates applied to Palo Verde reflecting a potential license extension."[23] Mr. Hatfield testified that if the Commission approves the Settlement Agreement, he is confident that APS will be able to improve its financial health.[24]

<u>Staff</u>

Staff believes that "[e]xtraordinary circumstances call for extraordinary measures."[25] Because APS' financial position has not improved despite all the measures the Commission has taken in recent years and because APS provides electric service to over 1 million customers, Staff believed that it was "critical to use this opportunity to structure a comprehensive package that addressed the Company's underlying problems as well as other issues of importance."[26] Staff believes that the Settlement Agreement balances APS' rate increase with benefits for its customers.

Staff identified the benefits as follows:[27]

<u>Investments in Arizona's Energy Future</u>

- Establishment of energy efficiency goals and the creation of tiered performance incentives to encourage meeting those goals;
- At least 100 schools served by DSM programs and at least 1,000 customers in existing homes served by the Home Performance enhanced program element by December 31, 2010;
- Placement of renewable energy projects at Arizona schools and government institutions;

[22] APS Initial Post-Hearing Brief at 20.
[23] Id.
[24] Tr at 2551.
[25] Staff Post-Hearing Brief at 1.
[26] Id.
[27] Staff Post-Hearing Brief at 2-3, and Settlement Agreement at 8-10.

- A plan for utility scale photovoltaic generation and an RFP for in-state wind generation;
- Additional renewable energy projects to be in place by 2015 which, in combination with existing renewable commitments, will result in approximately 10% of APS' retail sales coming from renewable resources; and
- Construction of one or more renewable energy transmission facilities.

Commitments Benefiting Low-Income Customers

- Continued rate discounts for low income ratepayers, holding these ratepayers harmless from the rate increase;
- Creation of a new bill assistance program to benefit customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines, funded by APS; and,
- Waiving additional security deposits for low income ratepayers.

Rate Stability Provisions

- An increase in rate stability, including an extended period without base rate increases and a scheduled plan for future rate cases, resulting in greater administrative efficiency and reduced uncertainty for both APS and ratepayers.

Rate Related Benefits

- An improvement in APS' ability to attract capital, maintain reliability and sustain growth;
- A limit on recovery through rates of executive incentive compensation based upon performance;
- A sustained reduction of expenses of at least $30 million per year, which will reduce the need for future rate increases;
- An infusion of at least $700 million of additional equity and an improvement in APS' financial metrics, strengthening its bond rating and reducing future debt costs;
- A plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics;
- An acceleration of the refund of any over-collected amounts in the PSA account, resulting in a lower adjustor rate that will partially offset the base rate increase;
- A reduced Systems Benefits Charge in 2012 if a Palo Verde license extension is approved before the conclusion of the next rate case; and
- Continued 90/10 sharing of the PSA.

Creation of Performance Measures for APS

New Rate Design Options

- Creation of an optional super-peak tariff for residential customers and other critical peak pricing rates;

- Twelve month reopening of the E-20 House of Worship tariff;
- Development of Interruptible Rate Schedules and other Demand Response Programs for large customers; and,
- A new optional time of use rate for schools.

RUCO

Jodi Jerich, the Director of RUCO, testified in support of the Settlement Agreement and urged the Commission to adopt it in its entirety. Ms. Jerich identified the benefits to the residential consumer as follows:

- Rates frozen for approximately 2 ½ years (no new rates before July 1, 2012).
- Accelerated reset of PSA to offset a portion of the rate increase.
- Maintain 90/10 sharing of PSA.
- APS will strive to achieve a capital structure with no more than 52% total debt by December 31, 2012.
- Equity infusions of $700 million which are designed to improve APS' financial metrics by strengthening APS' credit rating and reducing APS' future debt costs.
- $150 million reduction of APS expenses over the next five years forcing APS to operate more efficiently.
- Restrictions on executive cash incentive compensation.
- Periodic evaluation of APS through the use of Performance Measures with a meaningful consequence for failure to meet these Measures.
- Increased transparency in APS operations through annual and quarterly reporting on its financial health, credit ratings, earned ROE, FFO/debt ratio, management expenses, O&M expenses and dividend payout ratio.
- Benchmarking study comparing APS to other similarly situated utilities across the nation.
- Revenue spread agreement that requires all rate schedules to absorb equal amounts of the total rate increase even though the cost of service studies indicate the residential class's increase should be higher than the increase for commercial or industrial classes.
- Renewable energy projects at schools that serve to reduce school utility bills allowing schools to shift funds from utility bills into the classroom, or possibly resulting in lower property taxes.
- Energy efficiency program establishing efficiency goals through 2012, a new customer financing plan to encourage participation, and a prohibition to seek unrecovered fixed costs until APS' next general rate case.

- Time of Use, super peak and critical peak pricing demand response programs.

- Corresponding decreases to the PSA and SBC (Systems Benefit Charge) upon the granting of the Palo Verde Life Extension.

- More timely recovery of DSMAC program costs to eliminate interest expense paid by ratepayers under the delayed DSMAC recovery program.[28]

According to RUCO, the benefits to APS are:

- Non-fuel rate increase of $196.3 million (this *includes* the $65 million interim rate increase previously approved in Decision No. 70667.)[29]

- A roadmap to better financial health that should improve APS' credit ratings, make APS more attractive to investors, allow APS to borrow money on more favorable terms and stop the cycle of constant rate case litigation.

- A clear signal to investors and Wall Street that, in the Plan Terms set forth in the Settlement Agreement, APS has a defined path toward reduced expenses, a meaningful rate of return, increased equity and a plan for renewable energy projects.

- Continuation of the PSA.

- An authorized return on equity of 11.0%.

- Adoption of APS' proposed depreciation rates.

- Adjustment of depreciation rates for Palo Verde License Extension.

- Deferral of a portion of APS pension and OPEB costs up to $42.5 million.

- Ability to treat Schedule 3 proceeds as revenue.

- Tiered incentives to meet energy efficiency goals.

- More timely recovery of DSMAC program costs.

- Recovery of capital carrying costs for renewable energy projects to encourage utility-owned renewable energy generation instead of merely purchasing renewable energy from other – possibly out of state – sources (this also serves to encourage least cost renewable resources for the benefit of the customer).

- A commitment of a good faith effort to process future rate cases within 12 months of a sufficiency finding.[30]

[28] Ex. RUCO-1 at 6-7 (Direct Settlement Testimony of Jodi Jerich).

[29] The Settlement Agreement also increases the amount of fuel costs recovered in base rates, shifting these revenues currently recovered through the PSA. Since the PSA has a 90/10 sharing mechanism that is not recognized when fuel costs are recovered in base rates, an additional $11.2 million is retained by the Company. This is the amount that would have gone to the ratepayers had those fuel costs been recovered through the PSA.

Ms. Jerich testified that from RUCO's perspective, the Settlement Agreement serves the public interest by providing a framework and comprehensive strategy to improve APS' financial condition (including its financial metrics and credit ratings) in both the short and long term. RUCO is concerned with APS' marginal credit ratings despite past rate relief and the effect on ratepayers if the credit rating is downgraded to noninvestment grade. Ms. Jerich explained that although RUCO's original position in the rate case was no increase in base rate, RUCO's witness, Dr. Ben Johnson, provided an appendix to his testimony that discussed the attrition issue and an "alternative approach to attrition compensation which is not based on a series of arbitrary adjustments to the historical test year."[31] RUCO agreed to the provisions that allow APS to increase its earnings (deferred pension and OPEB expenses, Schedule 3 proceeds treated as revenue, and adjusted depreciation rates for Palo Verde license extension) because they allow APS to improve its revenues without increasing rates at this time.[32]

RUCO also recognizes that the cause of APS' strained financial condition may be due to more than just the capital costs of growth, but may be the "result of poor business practices and management decisions"[33] Therefore, the provisions of the Settlement Agreement that require APS to reduce its expenses by $150 million, meet specific performance goals and limit its executive cash incentive compensation if the goals are not met, improve its capital structure by reducing the debt percentage and making equity infusions, and that require a benchmarking study, address these possible causes of lost profitability that are within APS' ownership and management's control. Given these provisions and its desire to align the interests of stockholders and ratepayers, RUCO finds that the Settlement Agreement is more likely to address the root of APS' weak financial position than repeated incremental rate increases, and is therefore in the public interest.

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[30] Ex. RUCO-1 at 8-9.
[31] Id. at 18, citing Johnson Direct Testimony at 33.
[32] Id. at 20-21.
[33] Id. at 19.

AIC

AIC's interest in intervening in APS' rate case is based upon its desire for APS to be fiscally strong and able to access capital on reasonable terms so that APS can fund its operations and build the infrastructure necessary to meet customer demand. AIC supports the Settlement Agreement because the non-fuel base rate increase of approximately $196 million "appears adequate to meet the Company's near-term debt/equity market and financial challenges;"[34] the Settlement Agreement promotes earnings stability by scheduling future rates cases and adopting procedures designed to reduce regulatory lag; and because the Settlement Agreement is supported by Staff, RUCO and intervenors representing diverse interests, it is a positive signal to the markets. AIC identified specific provisions of the Settlement Agreement that it believes are important, including the flexibility in the timing of the new $700 million equity infusion, the requirement that APS submit a plan detailing the steps it will take to maintain and improve its financial ratings with the credit rating agencies, the treatment of Schedule 3 proceeds as revenues, APS' ability to defer a portion of pension and other post-retirement benefit increases in 2011 and 2012, the potential depreciation expense treatment that would be associated with an extension of the Palo Verde license, and the requirement for APS to reduce its expenses by $150 over the next five years.

Mesquite Group

The Mesquite Group is composed of actual and prospective vendors in the competitive wholesale power supply market in Arizona. Each of the companies in the Mesquite Group signed the Settlement Agreement. They believe that APS' financial stability and creditworthiness are essential to the successful functioning and viability of the market. The Mesquite Group points out that the credit ratings directly impact APS' "ability to raise capital on favorable terms for capital expenditures, and its ability to obtain credit on favorable terms from vendors as a purchaser in the competitive wholesale market."[35] Specific provisions of the Settlement Agreement that are important to the Mesquite Group include: periods of revenue stability; the requirement of an equity infusion and APS' responsibility to develop a plan and to use its best efforts to maintain investment grade financial ratios and a balanced

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[34] Ex. AIC-1 at 4 (Settlement Direct Testimony of Gary Yaquinto).
[35] Ex. Mesquite-1 at 4 (Settlement Direct Testimony of Leesa Naydu).

capital structure, and to improve its existing ratings; the $150 million reduction in expenses and the financial reporting requirement; the capital expenditure reporting requirement which will allow the Commission and interested entities, such as the Mesquite Group, to examine APS' resource acquisition decisions and compliance with the Commission's Recommended Best Practices for Procurement, the RES rules and APS' Renewable Energy Competitive Procurement Procedure; and the provisions requiring APS to acquire additional new renewable energy resources and to file a plan for a utility scale photovoltaic generation project through a competitive procurement.

Arizona School Boards Association

The Arizona School Boards Association intervened in this matter to advance the interests of Arizona public schools and their governing boards, so that through energy management, there would be more funds to devote to classroom learning. The ASBA believes that this has been accomplished in the Settlement Agreement and its President, Robert Rice, testified that the Settlement Agreement "greatly assists our member school districts in their efforts to conserve energy, reduce their utility demand and ultimately reduce the energy expenses and is strongly supported by our organization."[36]

Arizona Association of School Business Officials

The Arizona Association of School Business Officials provides services such as conferences and training classes to school district employees and provides information to school district members on the laws and regulations that affect their business operations. The AASBO intervened in this matter to help develop "solutions that allow schools to reduce demand and to reduce utility costs."[37] AASBO's Director of Governmental Relations, Chuck Essigs, testified that the AASBO supports the Settlement Agreement because it will help the schools pay for energy efficiency projects, implement an optional rate plan for schools, and the schedule for rate cases will allow schools to plan for future rate increases.

Ms. Zwick

Ms. Zwick is an individual employed as a low-income advocate who has intervened in this and several other rate cases to express the interests and the impact of rate increases on low-income utility

[36] Ex. ASBA-1 at 3 (Settlement Testimony of Robert Rice).
[37] Ex. AASBO-1 at 3 (Settlement Testimony of Chuck Essigs).

customers. She supports the Settlement Agreement and although her participation in this case was limited to issues affecting low-income ratepayers, she believes that the elements in the Settlement Agreement are beneficial not only to low-income customers, but also to APS and other ratepayers. The benefits to low-income customers include: no increase in base rates and continuation of the current rate discounts, expanded eligibility for the low-income schedule to 150 percent of the Federal Poverty Income Guidelines, augmentation of APS' current bill assistance program, waiver of collection of additional security deposits under certain conditions, and the continued exemption of low-income customers from the DSMAC.

Ms. Zwick testified that:

> It is my belief that low-income customers are extremely vulnerable to high utility bills at this particular time as unemployment rates in Arizona continue to rise, as the number of families without health insurance increase daily, and seniors living on fixed incomes continue to have to make difficult choices about which bills to pay. Providing families one option for staying healthy, safe and in their homes reduces greater community costs, reduces costs the Company may have to incur due to disconnections, collections or accidents occurring. Additionally, these provisions ensure that many more customers will be able to receive assistance in the event of a crisis, or are now able to maintain current accounts, which is also beneficial to the entire community.[38]

SWEEP

Southwest Energy Efficiency Project is a public interest organization whose purpose is to promote economic prosperity and environmental protection by advancing energy efficiency in six western states. SWEEP's witness, Jeff Schlegel, testified that the Settlement Agreement contains initiatives aimed at increasing energy efficiency for all of APS' customer classes. He testified that:

> Increasing energy efficiency will provide significant and cost-effective benefits for APS customers (residential consumers and businesses), the electric system, the economy, and the environment. Increasing energy efficiency will save money for consumers and businesses through lower electric bills, resulting in lower costs for customers. Increasing energy efficiency will also reduce load growth, diversify energy resources, enhance the reliability of the electricity grid, reduce the amount of water used for power generation, reduce air pollution and carbon emissions, and create jobs and improve the economy. In addition, meeting a portion of load growth through increased energy efficiency can help to relieve system constraints in load pockets.[39]

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[38] Ex. Zwick-2 at 3 (Settlement Testimony of Cynthia Zwick).
[39] Ex. SWEEP-2 at 3 (Jeff Schlegel Settlement Testimony).

SWEEP believes that the energy efficiency provisions in the Settlement Agreement "are a *major* step forward for cost-effective energy efficiency in Arizona and are in the public interest."[40] Those provisions include establishing energy efficiency goals for 2010 to 2012, modifying the existing performance incentive to encourage APS to meet or exceed the goals, requiring APS to file an annual Energy Efficiency Implementation Plan that includes new and/or expanded programs/elements for the Commission's approval, allowing large commercial or large industrial customers to "self direct" DSM program funding, and modifying the DSMAC to better match expenditures and cost recovery. The energy efficiency goals are defined as annual energy savings of 1 percent in 2010, 1.25 percent in 2011, and 1.5 percent in 2012. The cumulative effect of meeting these goals would be annual energy savings of approximately 3.75 percent of total energy resources needed to meet retail load in 2012. If the Commission adopts higher goals or performance incentives in another docket, then those higher goals/incentives would supersede the Settlement Agreement. Many of the new programs/elements will implement energy efficiency measures for schools, municipalities, residential and low-income customers. They include: Residential High Performance New Homes; Residential Existing Home Performance (targeted to serve 1,000 homes by the end of 2010); Low-Income Weatherization Enhancements; Non-Residential High Performance Construction; Non-Residential Customer Repayment Financing; Schools Program Target (100 schools by end of 2010) and the Large Customer Self-Direction Program.

WRA

Western Resource Advocates is a non-profit environmental law and policy organization founded in 1989. Its purpose is to restore and protect the natural environment of the Interior American West. WRA witness, Dr. David Berry, testified that he believes that the Settlement Agreement is in the public interest and it "specifies actions for advancing renewable energy and energy efficiency and for moving Arizona toward a new energy economy."[41] Dr. Berry testified that the important benefits of renewable resources include fixed or stable costs that provide a hedge against volatile fossil fuel

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[40] Id. at 6.
[41] Ex. WRA-2 at 12 (Settlement Testimony of David Berry).

prices for natural gas or coal-fired power plants; little or no air emissions thereby reducing air pollution and avoiding the costs of controlling emissions; and lower costs than conventional generation. The Settlement Agreement requires that APS obtain 10 percent of its energy needs from renewable resources by 2015, which approximately doubles the Renewable Energy Standard requirement of 5 percent of retail sales obtained from renewable resources. APS must use its best efforts to acquire new renewable energy resources with annual generation or savings of 1,700,000 MWh to be in service by the end of 2015.[42] These renewable resources are to be a mix of distributed and non-distributed resources. The Settlement Agreement specifies some of the types of renewable resources that APS will seek to acquire, including in-state wind generation, a utility scale photovoltaic generation project, a solar energy program for on-site projects at grades K though 12 public (including charter) schools in its service territory that eliminates up-front customer costs, a new program for governmental institutions for distributed solar energy, including photovoltaics, solar water heating and daylighting to substantially reduce or eliminate up-front customer costs. APS is required to report to the Commission on its plans and progress in acquiring these new resources. Following the Biennial Transmission Assessment report and after obtaining the required permits and authorizations, APS is also required to construct one or more transmission lines or upgrades to facilitate the delivery of solar and other renewable resources to the APS system. The reasonable and prudent expenses (including capital carrying costs of APS' capital investment in renewable energy projects) of complying with these requirements are recoverable through the PSA, a renewable energy adjustment mechanism, or the Transmission Cost Adjustor.

Dr. Berry testified that the Settlement Agreement adopts WRA's recommendation on demand response programs.[43] It requires that demand response programs be offered and marketed jointly with the energy efficiency programs so that participants are more likely to save energy. APS will offer a new demand response super peak time-of-use rate for residential customers and new critical peak pricing rates for residential and non-residential customers. The Settlement Agreement also requires

[42] In addition to resources APS had in place at the end of 2008 as well as resources APS had committed to be the end of 2008.
[43] Ex. WRA-2 at 7.

APS to prepare a study on the impacts of demand rates on the mix of power generation sources, on air emissions, and on energy use by program participants.

Interwest Energy Alliance

Interwest Energy Alliance is a trade association that represents the interests of non-governmental organizations and renewable energy developers and product manufacturers, mainly wind and solar. Amanda Ormond, a consultant to Interwest, testified that it supports the Settlement Agreement and that it will provide long-term benefits for APS and its customers.[44] Ms. Ormond testified that the amount of the new renewable energy (1.7 million megawatt hours) is consistent with the voluntary Resource Plan Report APS filed in January 2009. She testified that Interwest supported the requirement for renewable projects because they "represent a diversity of technologies and applications, and will demonstrate proven technology."[45] She believes that they will also provide educational benefits for customers. Interwest recommends that it is appropriate that the $10 million currently in base rates should be maintained in base rates, as demand side management, energy efficiency, and renewable resources continue to become mainstream and insures a fixed amount of funds for projects. Interwest recommends that in the future, capital costs for clean energy projects should be recovered in base rates, with minimal amounts collected through adjustor mechanism.

IBEW

IBEW Local 387 is a labor organization which primarily represents non-managerial utility workers throughout most of Arizona. It is the elected and recognized exclusive bargaining agent for approximately 2,300 APS employees. IBEW 640 is a sister local of IBEW 387 whose primary interest in this matter is as the supplier of highly-skilled employees to the Palo Verde Nuclear Generating Station and to a task force assisting in underground construction in residential housing developments. IBEW 769 is also a sister local that represents non-managerial utility workers in Arizona and is the exclusive bargaining agent for all IBEW outside line workers in Arizona. The IBEW's witness, Samuel Elliott Hoover II testified that the Settlement Agreement has the "Union's unqualified support."[46] The IBEW are proponents of the statement in the Settlement Agreement

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[44] Ex. Interwest-1 at 4 (Settlement Testimony Amanda Ormond).
[45] Id. at 6.
[46] Ex. IBEW-3 at 2 (Settlement Testimony of Samuel Elliott Hoover II).

recognizing the importance of public service employees and the requirement that APS shall not make expense reductions in costs necessary to preserve safe and reliable electric service. IBEW also negotiated a reporting requirement whereby APS will annually file information addressing changes to APS' employee counts, including those employees represented by the labor unions with collective bargaining agreements with APS. IBEW also stand to benefit from the proposed renewable and transmission construction projects.

Mr. Hoover testified that although IBEW would have preferred that APS received more rate relief than the Settlement Agreement provides, they "recognize that the consummation of a comprehensive Settlement Agreement amongst nearly two dozen different parties with often disparate and competing interests is no small feat. It is for that reason that we fully and strongly support the Commission's adoption of the proposed Settlement Agreement *in toto*."[47]

<u>Opposition to the Settlement Agreement (Schedule 3)</u>

<u>Background</u>

APS' Schedule 3 establishes the terms and conditions under which the Company will extend, relocate, or upgrade facilities in order to provide service to a customer. In Decision No. 69663 (June 28, 2007), the Commission found that a generic docket should be used to gather information to evaluate the feasibility of hook-up fees for electric and gas utilities, but stated that in "the interim, we find that, in view of the unprecedented growth in APS' service territory, granting APS variances to A.A.C. R14-2-207.C.1 and C.2, which require a company to provide a specified footage of distribution line at no charge, is a necessary and appropriate measure to shift the burden of rising distribution infrastructure costs away from the current customer base to growth."[48] Decision No. 69663 required APS to file revised line extension tariffs to eliminate any free footage or free allowance and to remove any requirement for an economic feasibility analysis. APS filed its revised Schedule 3 on July 27, 2007, and then filed an amended version of its proposed Schedule 3 on October 24, 2007. Staff recommended adoption of the Company's proposed tariff filed on October 24, 2007, with the exception that Staff did not agree with the Company's proposal to treat the

[47] Id. at 7.
[48] Decision No. 69663 at 97.

payments as revenues, and Staff recommended that they should be treated as CIAC. In Decision No. 70185 (February 27, 2008), the Commission ordered APS to record all Schedule 3 fees as CIAC. Decision No. 70185 also found that the new Schedule 3 would have a "detrimental effect on the electrification of the [Hopi] reservation" and because of "the special circumstances and the remote nature of Native American territories," determined that it was "appropriate to additionally 'grandfather' residential customers on Native American reservations served by APS into the Schedule 3 in effect prior to July 1, 2007."[49]

The Settlement Agreement maintains the Commission's current policy that customers pay for line extensions but authorizes APS to record the proceeds from Schedule 3 as revenue during the period from January 1, 2010 through either the earlier of December 31, 2012, or the conclusion of APS' next general rate case. The Settlement Agreement provides that the income resulting from the revenue treatment of Schedule 3 proceeds is material to the Settlement Agreement and that if the Commission were to decide to modify Schedule 3, then offsetting revenue changes should be ordered to make the modifications revenue neutral to the provisions of the Settlement Agreement.

Intervenor Ms. Pecora

Ms. Pecora is a mortgage broker, a real estate broker, and a vacant land owner who intervened in this case after hearing that the Commission had removed the 1,000 ft. free electric extension.[50] She sponsored testimony from several individuals who testified about the elimination of the free footage allowance (Schedule 3).[51]

In her Post-Hearing Brief, Ms. Pecora discussed the accounting treatment of the Schedule 3 proceeds, stating "treatment of Schedule 3 in the proposed settlement agreement is an illusion of current revenue for which future APS rate payers will suffer the consequences of increased APS rates – and for which current Arizona property owners and the counties tax revenues will suffer immediately."[52] She believes that there would not have been a settlement agreement without this

[49] Decision No. 70185 at 3.
[50] Ex. Pecora-3.
[51] The Schedule 3 that was in effect prior to Decision No. 69663 (June 28, 2007) is referred to as "Version 8" and the Schedule 3 that resulted from that decision is referred to as "Version 10" and is the Schedule 3 currently in effect.
[52] Pecora Post-Hearing Brief at 1.

"unusual, unique, uncommon accounting procedure."[53] She requests the Commission to reinstate the Schedule 3 Revision 8 residential line extension, stating that the projected cost to do so would be $6 million in 2010, $6.9 million in 2011, and $10 million in 2012.[54] Ms. Pecora states that these costs could be paid either through a small increase in bills or by using overpayment of fuel costs or part of APS' $150 million cost cutting during the next five years. Ms. Pecora stated that Section 10.7 of the Settlement Agreement does not address her "gold plating" concerns and can be eliminated from the Settlement Agreement.[55] She believes that at the time that the Commission voted to eliminate the free footage, the Commission did not understand all the consequences of that decision. Ms. Pecora believes that elimination of the free footage allowance has had a devastating effect on rural Arizona. She believes that property has been devalued and "Arizona stands to lose billions of dollars in property value" and therefore, counties will be losing millions of dollars in tax revenue.[56]

Ms. Pecora presented a limited impact analysis of the recently modified policies of APS, Tucson Electric Power ("TEP"), and UniSource Energy Services ("UniSource") to eliminate "no-cost" electrical service extensions to residential lots and subdivisions prepared by Elliott D. Pollack & Company.[57] The report concluded that "there could be both economic and fiscal impacts to governmental entities if residential development was indeed stifled by the electrical service extension policy."[58] The report included a description of a contact with an assessor for La Paz county, and stated that his opinion that "the recent devaluation of most vacant property within the county was significantly related to the elimination of the free footage allowance."[59] According to the report, "[h]e stated that it is difficult to separate the effect of the downturn in the economy from the APS policy change. However, based on interactions with landowners and realtors, the consensus was that the policy change was driving down the price of land and discouraging potential buyers from purchasing

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[53] Id. at 3.

[54] Id. at 4, citing to Staff's August 14, 2009 Notice of Errata attached to Ms. Pecora's Initial Post-Hearing Brief as Attachment A.

[55] Section 10.7 requires APS to submit a revised Schedule 3 which clarified the definition of "Local Facilities," and that included a schedule of charges, a statement that charges provided to customers will be itemized, and procedures for refunding amounts to the customers when additional customers connect to the line extension. Staff filed the final version of Schedule 3 on November 3, 2009, and it is attached to this Decision as Exhibit B.

[56] Pecora Initial Post-Hearing Brief at 8.

[57] Ex. Pecora-2.

[58] Id. at 31.

[59] Id. at 22.

land that does not have electrical lines to the property."[60] Mr. Ian Campbell is a Real Estate Agent who testified that APS' policy change is causing anti-growth and is having a huge impact on property values where the property does not have power. He believes that as a result, "the land market has been adversely affected and this has been unfair to the land owners."[61] Although he recognized the market has affected his business, he believes that the policy change has had a "huge impact on his normal business practices."[62] Mr. Carl Faulkner is a general contractor and land developer from Douglas, Arizona who has been in construction for nearly 40 years. He testified that he opposes APS' Schedule 3 policy because it limits growth by harming land development and new construction and adversely impacts rural Arizona because of poor market conditions, sparse population, and distances from electric power service.[63] He also believes that costs will increase when APS does not have to pay for the facilities and that it is not fair for APS to receive its facilities for free.[64]

In her Post-Hearing Brief, Ms. Pecora argues that the Commission did not provide notice and an opportunity to provide input on the change to the Schedule 3 policy in the 2007 rate case, thereby depriving the affected public of due process.[65] Also in her Post-Hearing Brief, Ms. Pecora seems to argue that by exempting Native American Reservations from the provisions of Schedule 3, the Commission has discriminated against counties with high poverty rates.[66]

Ms. Pecora recommends that the Commission put the previous Schedule 3, Revision 8 line extension policy back into effect, then use the next three years to review, hold meetings and notify all property owners of possible changes.

Settling Parties' Response to Objection

APS states that the Settlement Agreement does not change the fundamental philosophy underlying the policy that has been adopted by the Commission in several recent decisions, that new applicants for service should pay the full cost. APS also notes that the Settlement Agreement does not change the amount of money that applicants for new service will be required to pay. The change

[60] Id.
[61] Ex. Pecora-1 at 1.
[62] Id.
[63] Tr at 557.
[64] Tr at 561.
[65] Ms. Pecora acknowledged that she has had due process in this case. Pecora Initial Post-Hearing Brief at 15.
[66] Pecora Initial Brief at 15-17.

to Schedule 3 is the revenue treatment of those proceeds, and according to APS, "represents a considerable compromise compared to what APS sought in its original application."[67] APS had proposed a System Facilities charge that it estimated would have added another $6.6 – $12 million and an impact fee that that would have averaged about $1500 per residential applicant and higher for commercial and industrial applicants, but the Settlement Agreement requires APS to withdraw those proposals.

The other changes to Schedule 3 are designed to address inquiries and complaints concerning line extensions. In response to concerns about the lack of price transparency and price consistency, the Settlement Agreement requires Schedule 3 to include a schedule of charges and a statement that quotes will be itemized. In response to complaints about the lack of refunds, the Settlement Agreement requires Schedule 3 to permit refunds under specified circumstances. In response to the issue of allowing third-party contractors to construct all or part of a line extension, with the facilities then owned and maintained by APS, APS noted that the Settlement Agreement confirms that currently an applicant can provide non-electrical work such as trenching, conduit, and backfill. However, as related to the electric work, APS recommends that the Commission schedule workshop(s) to determine the parameters and conditions related to third-party construction.

APS emphasizes that the revenue it projects it will receive from Schedule 3 is a critical component of the Settlement Agreement, and it is a "material" provision that if changed, would require other modifications to the Settlement Agreement to make such change revenue neutral. APS identified two "clear benefits" to the revenue treatment of Schedule 3 proceeds: "(1) it directly reduces the size of the base rate increase needed from existing APS customers in this case; and (2) it enables the Company to agree to a 'stay out' of two-and-a-half years and abide by the other terms of the rate case schedule . . . ."[68] APS disputes the argument that the revenue treatment of Schedule 3 proceeds require customers to pay for the same asset twice because the customers "do not pay the actual cost of the facilities, but the estimated cost of the extension pursuant to a pre-established

[67] APS Initial Post-Hearing Brief at 28.
[68] Id. at 33-34.

schedule of charges" and the "identical amount of revenue from customers reduced dollar-for-dollar the revenue requirement that was necessary for APS to agree to the settlement."[69]

APS acknowledged that although there is concern that from a long-term perspective, the revenue treatment is less beneficial to customers than the CIAC treatment, the Settling Parties believe that "reducing the base rate increase in this proceeding and the overall present value benefit to APS customers more than offset this potential for higher future revenue requirements in 2012, when hopefully the economy has recovered."[70] APS prepared Exhibits 17 and 26 to show the dollar impacts if the Commission were to modify Schedule 3.

In its Reply Brief, APS acknowledges that "what was admittedly a long-standing subsidy to developers and other land owners created and will continue to create individual hardships to some who purchased property with the intent to build personal residences" but disagrees with Ms. Pecora's "unsubstantiated claims of widespread devastation of the Arizona real estate market and shrinking tax bases for state and local government supposedly attributable to the current version of APS Schedule 3." [71]

APS argued that Ms. Pecora presented no evidence that the current line extension policy was having a significant impact on overall property values or property tax receipts; that there was no evidence by a licensed appraiser showing a difference in appraisals for a property before and after the change in Schedule 3; that no comparison was made between property values in APS' service area and in areas still allowing free footages; and that even assuming proximity to existing electric facilities is related to land values, there is no reason to believe that the diminished value of distant parcels are not offset by the increased value of parcels close to electric facilities. APS noted that Ms. Pecora's witness testified that "we have an oversupply of housing right now that is the major cause for the decline in housing values"[72] and the others acknowledged oversupply and little demand. APS argues that "the solution to an overbuilt real estate market is not to subsidize more building,

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[69] Id. at 34 (emphasis omitted).
[70] Id. at 36.
[71] APS Reply Brief at 4.
[72] Tr at 399 (Merritt Testimony).

especially in areas further away from existing infrastructure" and states that Ms. Pecora's witness conceded that point in his deposition.[73]

APS disagrees with Ms. Pecora's suggestion that a return to a free footage allowance could be accomplished without a higher base rate increase, noting that there would still be a subsidy from current customers to landowners and that APS has already factored in the reduction in expenses and the anticipated revenues from Schedule 3 when negotiating the Settlement Agreement. APS responded to Ms. Pecora's claim of "gold plating," stating that the Settlement Agreement's requirement of a set schedule of charges which is overseen and regulated by the Commission will completely eliminate the possibility of overcharging for line extensions.

In response to Ms. Pecora's argument about discrimination, APS states that Ms. Pecora did not provide legal authority for the argument that exempting reservation lands from provisions of state law otherwise applicable off-reservation violates the 14th amendment to the United States Constitution or Article 2 § 13 of the Arizona Constitution. APS also criticizes Ms. Pecora's failure to "recognize the unique regulatory status of Native American reservations under state and federal law" and points to Decision No. 54663 (August 22, 1985) where "the Commission found that its ability to regulate utility service on at least the Navajo Reservation was at the sufferance of the Navajo Nation."[74]

APS accepted all of Staff's changes in Staff Exhibit 19 – Schedule 3 as revised by Staff, and requests that the Commission approved the Revised Schedule 3 in this Decision. The final, non-redlined version was docketed by Staff on November 3, 2009 and is attached to this Decision as Exhibit B.

Staff believes that Ms. Pecora's allegations that APS' current line extension tariff is limiting Arizona's economic growth and that reinstating the previous policy is necessary to address the economic downturn, are exaggerated and not supported by the record. Staff argued that the Elliott D. Pollack & Company study sponsored by Ms. Pecora "does not purport to evaluate whether the change in line extension policy *has actually* resulted in fewer homes being built" but instead focuses on "quantifying the economic impacts (in terms of job loss, diminished economic activity, and

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[73] Ex. APS-16 (Ewen Reply Testimony, Attachment 1-S at 50).
[74] APS Reply Brief at 9.

unrealized government revenues) of the failure to construct one hundred (100) homes."[75] Staff argues that the witness who testified about the study acknowledged that study did not identify how may homes may not be built due to the cost of line extensions, did not establish that the line extension policy is the cause of the economic downturn, and did not establish that the changes to Schedule 3 have impacted the value of land.

Staff acknowledges that the issue of whether to provide a free footage allowance is a policy question that involves determining whether a social interest or regulatory policy would warrant a subsidy. Staff points out that recently the Commission has eliminated the free footage allowance for many electric service providers, including TEP, UniSource, TRICO, Sulphur Springs Valley and Graham County Electric, in order to more closely assign the costs of growth to those responsible for the growth. Although Staff surveyed practices in other states and recognizes that a compromise approach is possible, Staff supports the Settlement Agreement as proposed. Staff believes that changing the Settlement Agreement in even a nominal way may undermine the provisions of the Settlement Agreement that allowed a settlement to be reached. Staff does not recommend an increase of more than $344 million, and understands that APS would not have agreed to that amount of a base rate increase without a mechanism such as treatment of the Schedule 3 proceeds as revenue. Staff is also concerned that a reversion to a free footage policy would have significant ratemaking consequences – meaning higher rates to ratepayers from a revenue increase or declines in APS' financial condition if there is no corresponding revenue increase. Staff notes that restoration of the free footage allowance "would likely increase the base rate revenue requirement provided for in the Agreement by approximately $6 million in 2010, $6.8 million in 2011, and $10 million in 2012."[76] Staff believes that if the Commission wanted to reconsider the current line extension, it could retain the current policy for purposes of resolving the rate case by adopting the Settlement Agreement, but begin workshops to study the issues and continue to develop a policy in a more comprehensive manner. According to Staff, the workshop process could be completed and incorporated into APS' next rate case.

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[75] Staff Post-Hearing Brief at 21 (emphasis original).
[76] Id. at 25.

Although Staff recognizes that treating the Schedule 3 accounting treatment may place upward pressures on rates in future rate cases, and generally believes that CIAC is the better treatment over the long-term, Staff believes that treating Schedule 3 receipts as revenues is a reasonable outcome in the context of the significant regulatory challenges that APS presents. Staff identified two main considerations that addressed its concerns: "1) rate cases typically present a variety of issues, and there are likely to be certain downward pressures on rates as well; and 2) most important of all, there are broad and continuing concerns about APS' financial health that the Proposed Agreement takes affirmative steps to address."[77] Staff notes that the elimination of the free footage allowance could be viewed as positive by the credit rating agencies and if the Commission were to readopt a free footage allowance, it could be viewed negatively and harm APS' financial position. Staff argues that Ms. Pecora fails to acknowledge the significant benefits for individuals with real estate interests that are in the Settlement Agreement, such as APS' withdrawal of its request for a system facilities charge and for an impact fee; and the revisions to Schedule 3, including a clarified definition of local facilities, a schedule of charges, a provision that quotes to customers will be itemized, and refund procedures.

Staff responded to Ms. Pecora's allegations that Commission Decision No. 69663 did not comply with due process requirements. Staff noted that as part of that rate application, APS included testimony requesting the Commission to re-evaluate its line extension tariff and included APS' proposal to eliminate the footage basis and move to a dollar-based allowance. APS was required to and did, mail and publish notice of its application. Staff states that the due process allegations are related to the previous Commission decision and appear to be a collateral attack that is not appropriate in this subsequent rate case. Staff notes that Ms. Pecora has not alleged any due process issues in this proceeding. Staff was unclear about Ms. Pecora's discrimination discussion in her Post-Hearing Brief and could not tell whether Ms. Pecora claimed the grandfathering of the Native American reservations was discriminatory or whether Ms. Pecora was proposing another "means" test exemption to Schedule 3. Staff objected to the late introduction of new issues after the record was

[77] Id. at 27.

closed, but would "wholeheartedly support including this issue among the many issues that could be addressed at workshops designed to consider the policy issues associated with line extensions."[78]

In its Reply Brief, IBEW responded to Ms. Pecora's "gold plating" assertions stating that they are "merely based upon conjecture, surmise, and several unwarranted and unproven assumptions as to APS' incentive structures and behavior."[79] IBEW cited to testimony that APS prices out work to be done on a "minimum cost to serve" basis using current cost of material and equipment and labor[80] and notes that the Settlement Agreement requires Schedule 3 to include a clarified definition of Local Facilities, a Schedule of Charges, a statement that quotes provided to customers will be itemized, and procedures for refunding when additional customers connect to the line extension. IBEW believes that these provisions would help address the concerns raised by Ms. Pecora.

Analysis of Objections to Settlement Agreement

The Schedule 3 issue raises two questions: 1) Should the Commission continue its policy of no free footage; and 2) How should the proceeds from Schedule 3 be treated from an accounting perspective.

Continuation of Existing Line Extension Policy

Our determination in Decision No. 69663 to eliminate the free footage allowance was based upon the belief that it was appropriate to shift the burden of rising distribution infrastructure costs away from the current customer base to growth. By making those responsible for the growth pay for the costs, the existing customers are not subsidizing the growth. We have subsequently applied this same policy in cases involving other electric utilities in Arizona. Since the summer of 2007 when we issued Decision No. 69663, the nation's economy has gone into a recession. Like the rest of the country, and probably to a greater extent, the Arizona real estate market has suffered.

Ms. Pecora is a mortgage broker, a real estate broker and a vacant land owner who believes that the Commission should not have eliminated the free footage allowance. She offered anecdotal testimony from witnesses to support her belief that the elimination of the free footage allowance has stopped growth, especially in the rural areas of Arizona. Numerous public comment letters, including

[78] Staff Reply Brief at 9.
[79] IBEW Reply Brief at 2.
[80] Tr at 666-7.

many from government officials, have been filed in the docket requesting the Commission reverse its policy and allow free footage for line extensions.

Ms. Pecora's expert witness only testified to the effects of no growth, not to the reason for the lack of growth or development. Therefore, no economic analysis or evidence was presented to support Ms. Pecora's opinion that the Schedule 3 change was the reason for the decline in the Arizona real estate market. The fact that growth has slowed may be a reflection of the general economic conditions and a recognition of the true costs of accessing electric service. To the extent that the elimination of the free footage allowance has contributed to the lack of growth, the conclusion that could be drawn is that the growth (cost of construction and connection) was not economically feasible to the landowner. Ms. Pecora's arguments in support of her position to require current customers to pay for such new growth include her belief that others have benefitted from the old policy and that it would not cost current customers very much on their monthly bills.

Our responsibility is to weigh the effects on current customers if we were to readopt a policy that encourages new customers to access APS' electric service at the current customers' expense. Arizona and the country have been experiencing an economic downturn that has affected all residents, not just landowners. Many current APS customers struggle to pay their monthly electric bills today and to force them to subsidize landowners' new connections by increasing their monthly bills raises serious equity concerns. We note that Ms. Pecora did not counter the argument that although some property values may decline due to the change to Schedule 3, other properties would increase in value due to the change.

The parties to the Settlement Agreement have made it clear that pursuant to the terms of the Settlement Agreement, a change to Schedule 3 would be material, and would require offsetting revenue impacts to customers.

Ms. Pecora has presented no evidence to convince us that the policy that we adopted in the last APS rate case, as well as in subsequent cases involving other electric utilities, should be abandoned or modified in this rate case. We find no reason from the evidence presented in this case to modify our policy that current customers should not be subsidizing new growth, and therefore decline to modify Schedule 3 as requested by Ms. Pecora. However, we believe that the issue of line extension policies should be considered in a broader context and find that Staff should open or use an existing generic docket and conduct one or more workshops to evaluate, with input from stakeholders across the state, whether to modify our policy on line extensions, and if so, how, with the goal of incorporating that outcome into APS' next general rate case. Ms. Pecora will have the opportunity to participate in the workshop process and provide input and recommendations concerning the line extension policy.

We believe that the Settlement Agreement's required revisions to Schedule 3 will address the concerns about "gold plating" and will provide price transparency and consistency for customers and allow the Commission to monitor APS' compliance. We also find that Staff should open or use an existing generic docket and conduct one or more workshops to study and discuss the parameters and conditions related to allowing third-party construction of electric facilities related to line extensions.

Accounting Treatment of Schedule 3 Proceeds

The issue of the accounting treatment of Schedule 3 proceeds generated significant discussion during the evidentiary hearing. Staff and other parties have stated that the preferred regulatory treatment of such proceeds is CIAC, yet the Settlement Agreement adopts a treatment as revenues. The parties have articulated their reasons for agreeing to the revenue treatment and they also underscore the temporary nature of this provision. It seems counter-intuitive that APS should collect funds from its new customers to build facilities to connect the customer to APS' system, and then be allowed to earn a return when those funds are recognized in rate base. APS' explanation that the fees collected are not funding a portion of the Company's infrastructure but rather paying a portion of the overall revenue requirement is not particularly convincing. However, it is clear that the treatment of Schedule 3 proceeds as revenue was a significant concession that allowed the parties to settle the rate case without additional increases in base rates. Given that we have already adopted a policy that requires new customers to pay their costs to connect with APS' facilities as well as the temporary nature of the accounting treatment, the accounting treatment of those payments has little effect on the new customers, other than to reduce the amount of the rate increase in this case. They, like all APS customers, may eventually pay a return on any Schedule 3 revenues that become part of rate base in the future.

Accordingly, we find that the accounting treatment of Schedule 3 proceeds as revenues for a short period of time is not unreasonable in the context of this case and the ongoing economic situation in the country. It will accommodate the interests of the parties who want to limit the amount of the increase to base rates and the interest of APS to enhance revenues during the latter years of its stay-out period. The treatment was critical to the parties' ability to settle the rate case and implement new programs that will produce benefits for APS customers and Arizona in the future. We recognize that some aspects of the Settlement Agreement, including the treatment of Schedule 3 revenues, may have a future rate impact, but believe that other aspects of the Settlement Agreement will result in benefits that balance that possibility. We emphasize that our decision to allow Schedule 3 proceeds to be recorded as revenues for accounting purposes is limited to the specific facts of this case and the unique circumstances presented by the comprehensive Settlement Agreement. *We want to make clear that we expect APS to use this unique opportunity to finally address and resolve the concerns related to its financial metrics and condition, and will closely scrutinize the Company's compliance with the terms of the Settlement Agreement.*

Conclusion

The parties to this case have many different perspectives and interests. They have expended a substantial amount of time, energy, and funds negotiating this Settlement Agreement. As set forth in the discussion above, they have achieved a resolution of many significant, complex, and conflicting issues and have identified benefits to all stakeholders. As with every settlement, the give and take nature of negotiations ends up with a product that no one party initially proposed. The key question when deciding whether to approve such a Settlement Agreement is whether the end result resolves the important issues fairly and reasonably when taken together as a whole, and in such a way that will promote the public interest. So while we may not have determined or resolved individual issues the same way if this matter had been litigated, taken as a whole, we find that the Settlement Agreement reasonably resolves the rate application and sets out a plan that includes the requirements, responsibilities, and opportunity for APS to achieve a financial condition that will bring long-term benefits to its customers while comprehensively addressing issues of energy policy affecting APS customers and the State of Arizona. Accordingly, we find that adoption of the Settlement Agreement is in the public interest.

Bill Impact

Staff's May 15, 2009, Settlement Agreement Bill Impact Analysis discusses the methods used to allocate revenue responsibility and to design rates. The Settlement Agreement provides that all customer classes would incur roughly the same percentage increase to the 2007 Test Year base rates, or approximately 13.07 percent.[81] There were four elements the parties used that affected the base rate increase and the bill impact analysis in this case:

- Designing rates such that E-3 and E-4 low income customers are held harmless, by spreading those costs across customer classes on a per kWh basis;
- Moving a portion of fuel and purchased power costs from the PSA to base rates;
- Eliminating the separate interim base rate surcharge and incorporating that charge into base rates; and
- Including the non-fuel increase necessary to bring base rates to the agreed upon 13.07 percent customer class average increase.[82]

According to Staff's May 15, 2009, Bill Impact Summary, a residential customer using an average of 1,169 kWh per month would experience a $6.32 increase, from $130.97 to $137.29, or 4.83 percent.[83]

During the course of the hearing, APS updated the bill impact statement to include the effects of more recent adjustor charges, as well as the effect of resetting the PSA concurrently with the implementation of rates from the Settlement Agreement. APS Exhibit 37 contains a preliminary estimated bill impact of the Settlement Agreement with these changes. As set forth in that exhibit, APS estimates that the net effect of the base rate increase under the Settlement Agreement and the reduction to the PSA would result in an overall minimal increase in rates. APS Exhibit 37 indicates that a residential customer using an average of 1,177 kWh per month would experience a $1.22 increase, from $132.87 to $134.09, or 0.92 percent[84] when the effects of the base rate increase and the

[81] This includes the amount that is already being collected as interim rates.
[82] Staff May 15, 2009 Bill Impact Statement at 1-2.
[83] This is an average, the summer monthly bill would increase by $8.98 and the winter bill would increase by $3.67.
[84] This is an average, the summer monthly bill would increase by $2.83 and the winter bill would decrease by $0.35.

PSA decrease are taken into account. This reflects the resetting of the PSA and results in a lower bill for at least one year until the over-collected PSA is refunded.

APS Bill Format

Several public comments addressed the issue of confusion relating to APS customer bills. The parties were directed to brief the issue of APS' billing format, in order to address the stated concerns. In its Initial Post-Hearing Brief, APS stated that the Commission rules requiring unbundled billing include A.A.C. R14-2-1612(O) ("Rule 1612") and A.A.C. R14-2-210(B)(k) ("Rule 210"). According to APS, Rule 1612 was ruled to be invalid in the *Phelps Dodge* decision[85] due to lack of certification by the Attorney General of Arizona, and thereby, non-compliance with the provisions of the Arizona Administrative Procedures Act. APS points out that Rule 210 was enacted by the same Commission order as Rule 1612 but was not the subject of a challenge in the *Phelps Dodge* case. APS concludes that the amendments to Rule 210 were also not certified by the Attorney General but have not been invalidated by any court. APS believes that to be cautious, the Commission should probably waive compliance with Rule 210 if it wants APS to stop issuing unbundled bills. RUCO agrees with APS that APS' compliance with Rule 210 would need to be waived in order for APS to stop issuing unbundled bills.

AECC recommends that APS bills should continue to retain the existing information related to the unbundled service elements required by the Retail Electric Competition Rules (A.A.C. R14-2-1601.44) and also include information related to adjustor clauses, because this information provides greater transparency and more information to consumers. In its Post-Hearing Reply Brief, AECC asserts that an A.R.S. § 40-252 proceeding would be necessary. In addition, AECC points out that in another pending matter, the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Services,[86] Staff is required to submit a report by December 31, 2009 as to whether retail electric competition is in the public interest and should be implemented in Arizona. AECC believes that that it would be premature and prejudicial and that its due process rights would be violated if the Commission decided in this case to change APS' billing

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[85] *Phelps Dodge Corp. v. Arizona Elec. Power Coop., Inc.*, 207 Ariz. 95, 83 P.3d 573 (Ariz. App. Div. 1 2004), review denied (2005).
[86] Docket No. E-03964A-06-0168.

format. AECC asserts that good public policy supports the inclusion of more information for customers so they can make informed choices to manage costs, and it would oppose the grant of a waiver or amendment to the Rules.

Staff does not object to APS changing its bill format, and states that Rule 1612 remains uncertified by the Attorney General. Staff does note that some Commission decisions address APS' bill format and states that it is possible that A.R.S. § 40-252 may be implicated. Staff stated that because retail electric competition, at least as contemplated by the Commission's electric competition rules, has not been implemented to date, the specific bill formatting requirements of the rules may no longer serve the purpose for which they were designed.

Although we share the concerns of customers that APS' bill is confusing, we find that the issue of what information should be included on an electric bill is industry-wide and should be examined in a proceeding where evidence could be presented by all interested parties. We note that Staff will be providing a recommendation concerning electric competition in Arizona by the end of the year, and agree that any decision to modify the bill format should be made after such consideration.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells, and delivers electricity to wholesale customers in the western United States.

2. On March 24, 2008, APS filed with the Commission an application for a rate increase. The application sought a $371.7 million permanent base rate increase which included $252.6 million in non-fuel base rates and $119.1 million in fuel-related increases. The $252.6 million requested increase included an $86 million attrition allowance, $53 million of which APS proposed to collect through new "hook-up" or "impact" fee.

3. On June 2, 2008, APS filed an amended application, seeking a $448.2 million permanent base rate increase consisting of a $264.3 million increase in non-fuel base rates and $183.9 million in fuel-related increases. The amended application included a $79.3 million attrition adjustment and APS proposed to collect up to $53 million of that through it proposed impact fee.

4. On June 6, 2008, APS filed a Motion for Approval of Interim Rate and Preliminary Order.

5. On July 2, 2008, Staff filed its Sufficiency Letter, indicating that APS' amended application had met the sufficiency requirements of A.A.C. R14-2-103.

6. By Procedural Order issued on July 16, 2008, the hearing on the Motion for Interim Rates was scheduled to commence on September 15, 2008.

7. By Procedural Order issued July 29, 2008, the hearing on the permanent rate application was scheduled to commence on April 2, 2009.

8. The hearing on the Motion for Interim Rates commenced as scheduled on September 15 and concluded on September 19, 2008.

9. On December 24, 2008, the Commission issued Decision No. 70667 which granted APS an emergency interim base rate surcharge of $0.00226 per kwh. The emergency interim surcharge was subject to refund with interest at 10 percent per annum pending the decision on its permanent rate request. Pursuant to Decision No. 70667, on December 30, 2008, APS posted the required $10 million bond.

10. Intervention in this matter has been granted to Kroger; AECC; Mesquite Group; the Town of Wickenburg; WRA; SWEEP; RUCO; AIC; the Hopi Tribe; Cynthia Zwick; IBEW; FEA; ASBA; AASBO; the Az-Ag Group; Interwest Energy Alliance; Ms. Pecora; Catalyst Paper (Snowflake) Inc.; and SCA Tissue North America.

11. On January 23, 2009, APS filed a Notice of Settlement Discussions.

12. On January 27, 2009, Chairman Mayes filed a letter requesting certain issues be addressed during potential settlement negotiations.

13. On January 30, 2009, Commissioner Pierce filed a letter requesting information concerning APS' time-of-use plans.

14. On January 30, 2009, APS filed a Motion to Suspend Procedural Schedule.

15. On February 4, 2009, a Procedural Order was issued which granted a 30 day extension and ordered that the parties make a filing prior to the end of the 30 day suspension period.

16. On February 9, 2009, Commissioner Pierce filed a letter requesting information about APS' low-income customers' electric consumption patterns.

17. On February 23, 2009, APS filed its response to Commissioners Pierce's February 9, 2009 letter.

18. On March 4, 2009, APS filed its response to Commissioners Pierce's January 30, 2009 letter.

19. On March 5, 2009, APS filed a Motion to Further Suspend the Procedural Schedule and by Procedural Order dated March 9, 2009, the procedural schedule was suspended.

20. On March 18, 2009, APS filed a letter from Donald Robinson in compliance with Decision No. 70667 (Interim Rates) regarding cost management efforts undertaken by APS.

21. By Procedural Order issued March 19, 2009, the March 25, 2009 procedural conference and the April 2, 2009 hearing date were vacated, and a procedural conference was scheduled for April 7, 2009 to discuss the status of the settlement discussions and the procedural schedule in this matter.

22. On April 1, 2009, Commissioner Kennedy filed a letter dated March 30, 2009 requesting that the parties discuss APS' DSMAC and time-of-use rates and the effect both may have on APS' low-income customers and houses of worship.

23. On April 2, 2009, Staff docketed its Staff Report on Benchmarked Historical Results and Expenses for APS.

24. On April 6, 2009, Commissioner Pierce filed a letter dated April 2, 2009, concerning APS' bill format for low-income customers.

25. The April 7, 2009 procedural conference was held as scheduled and the parties reported that discussions were continuing and requested another procedural conference in two weeks.

26. On April 17, 2009, APS filed a letter in response to Commissioner Kennedy's March 30, 2009 letter.

27. On April 21, 2009, a procedural conference was held to update the Commission as to

the status of settlement discussions in this matter. During the procedural conference, the Settling Parties indicated that there was an agreement in principle on revenue requirement issues and that substantial agreement had been reached on other issues. The Settling Parties agreed to file a Term Sheet containing the major provisions of the Settlement Agreement on May 4, 2009.

28. On April 23, 2009, Commissioner Stump filed a letter requesting information about re-instating APS' 1,000 foot free-line extension.

29. On April 24, 2009, Commissioner Newman filed a letter requesting information about APS' line extensions.

30. On April 29, 2009, Commission Kennedy filed a letter dated April 28, 2009, requesting information on APS' line extension policies.

31. On May 1, 2009, Staff filed a response to Commissioner Kennedy's March 30, 2009 letter.

32. On May 4, 2009, the Term Sheet containing the major provisions of the Settlement Agreement was filed along with a Request for Procedural Order which proposed a procedural schedule for filing testimony and a hearing date on the contemplated Settlement Agreement.

33. On May 4, 2009, RUCO filed a response to Commissioner Kennedy's March 30, 2009 letter.

34. On May 11, 2009, a Procedural Order was issued establishing procedural dates and setting the matter for hearing to commence on August 19, 2009. The Procedural Order also directed the settling parties to file a joint proposed form of notice.

35. On May 15, 2009, Staff filed a Customer Bill Impact Statement.

36. On May 15, 2009, RUCO filed its response to Commissioners Kennedy, Newman, and Stump's requests for information on APS' line extensions.

37. On May 15, 2009, APS filed a response to a response to Commissioner Stump's April 23, 2009 letter, a response to Commissioner Newman's April 24, 2009 letter, and a response to Commissioner Kennedy's April 28, 2009 letter.

38. On May 19, 2009, Staff filed a response to Commissioner Stump's April 23, 2009 letter, a response to Commissioner Newman's April 24, 2009 letter, and a response to Commissioner

Kennedy's April 28, 2009 letter.

39. On June 9, 2009, Chairman Mayes docketed a letter with questions related to the Term Sheet and requested the parties address those issues in any proposed settlement agreement.

40. On June 12, 2009, the Settlement Agreement and the Joint Form of Proposed Notice were docketed.

41. On June 25, 2009, APS filed a letter in response to Chairman Mayes' June 9, 2009 letter.

42. On June 29, 2009, APS filed its proposed Plan of Administration (Power Supply Adjustor and Demand Side Management Adjustment Charge), Rate Schedules, and Service Schedules that implement the changes contained in the Settlement Agreement.

43. On June 30, 2009, APS filed a Notice of Errata with corrected copies of its E-34 and E-56 Schedules.

44. On July 1, 2009, the Town of Wickenburg filed its Notice of Support of Settlement.

45. On July 15, 2009, APS filed its Request for Approval of 2010 Energy Efficiency Implementation Plan, as required by the Settlement Agreement.

46. On August 5, 2009, Chairman Mayes filed a letter requesting the parties to address additional questions during the hearing on the Settlement Agreement.

47. On August 7, 2009, Chairman Mayes filed a letter concerning the proposed treatment of the line extension policy discussion.

48. On August 13 and 18, 2009, APS filed responses to Chairman Mayes' August 5, 2009 letter.

49. On August 28, 2009, Ms. Pecora filed her response to Chairman Mayes' August 5, 2009 letter.

50. On August 31, 2009, Commissioner Pierce filed a letter requesting information about declining natural gas prices.

51. On September 1, 2009, Chairman Mayes filed a letter requesting information about declining natural gas prices and possible acceleration of refund of PSA over-collection.

52. On September 4, 2009, Staff filed its Notice of Filing Memorandum Regarding APS

Lineman Fatality.

53. On September 9, 2009, APS filed a response to Chairman Mayes' September 1, 2009 letter and Commissioner Pierce's August 31, 2009, letters.

54. On September 17, 2009, Commissioner Newman filed a letter requesting APS to provide responses to questions concerning fuel costs and the PSA and APS' growth, and requested information concerning APS' natural gas, coal, coal transportation under contract, and APS' coal ash ponds.

55. On September 17, 2009, APS filed a response to questions raised by Chairman Mayes during the evidentiary hearing.

56. On October 2, 2009, APS filed its Late-Filed Exhibit 39, which addressed questions pending from the evidentiary hearing and also responded to Commissioner Newman's September 17, 2009 letter.

57. On October 6, 2009, APS filed a letter to Chairman Mayes from APS witness Daniel Froetscher responding to questions regarding load pockets and customer line extension issues raised during the evidentiary hearing.

58. On October 13, 2009, Chairman Mayes docketed a letter in the docket concerning proposed Commission workshops to address the implementation of a statewide feed-in tariff and adoption of a potential Commission Policy Statement calling on Arizona utilities to reach 25 percent renewable energy by 2025.

59. On October 16, 2009, Staff filed its Late-Filed Exhibit 19 and on November 3, 2009, Staff filed its non-redlined version of Exhibit S-19 (Revised Schedule 3), attached hereto as Exhibit B.

60. On November 5, 2009, APS filed a response to an article in the October 29, 2009 edition of the *Arizona Republic*.

61. On November 9, 2009, APS filed its Supplement to Late-Filed Exhibit 39 (Final Report of the Independent Auditor in APS' Request for Proposal for Renewable Energy Small Generation Resources).

62. Public notice of the hearing on the Settlement Agreement was published in the *Arizona Republic* on July 18 and 25, 2009, and was included as a bill insert in customers' monthly bills during

July, 2009.

63. Public comments sessions were held in Phoenix on March 30 and August 12, 2009; in Flagstaff on August 3, 2009; in Prescott on August 6, 2009; and in Yuma on September 29, 2009. Numerous written public comments were received by the Commission and Consumer Services and were filed in the docket.

64. Hearing on the Settlement Agreement began on August 19, 2009 and continued to August 20, 21, 24, 27, 28, 2009, and September 10, 11, 14, 16, 17, and 18, 2009. Testimony was taken from numerous witnesses, including Jeffrey Guldner, David Rumolo, Daniel Froetscher, Peter Ewen, Barbara Lockwood, James Wontor, and James Hatfield for APS; Dr. Ben Johnson and Jodi Jerich for RUCO; Kevin Higgins for AECC; Cynthia Zwick; Dr. David Berry for WRA; Jeff Schlegel for SWEEP; Robert Rice for ASBA; Chuck Essigs for AASBO; Amanda Ormond for Interwest Energy Alliance; Sam Elliott Hoover II for IBEW Locals; Gary Yaquinto for AIC; Ms. Pecora and Joel Lawson, Carl Faulkner, Gary Nelson, Ian Campbell, Bobby Miller, and Rick Merritt; and Elijah Abinah, Ralph Smith, Frank Radigan, Barbara Keene, and William Michael Lewis (for Kenneth Strobl) for Staff. Written pre-filed testimony from Kroger's witness, Stephen Baron; from the FEA's witness, Dr. Larry Blank; and from the Mesquite Group's witness, Leesa Nayudu, were admitted without cross-examination or objection.

65. Initial Closing Briefs were filed on October 9, 2009, by APS, AIC, AECC, Mesquite Group, IBEW, Ms. Zwick, WRA/SWEEP/ASBA/AASBO, FEA, and RUCO; and by Staff and Ms. Pecora on October 16, 2009.

66. Reply Briefs were filed by APS, AIC, AECC, IBEW, RUCO, and Staff on October 23, 2009.

67. The settlement discussions were open, transparent, and inclusive of all parties who desired to participate. All parties were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided an equal opportunity to participate.

68. Ms. Pecora was the only party who objected to the Settlement Agreement.

69. Ms. Pecora requested that the Commission revert back to the previous version of the Schedule 3 that contained a 1,000 free footage allowance for residential applicants.

70. Ms. Pecora's expert witness testified as to the economic effects of no growth in the real estate market, but did not conduct an analysis of the cause of no growth. Witnesses in the real estate and construction business provided anecdotal testimony that the revision to Schedule 3 had affected their property values, but agreed that the current economic conditions were causing problems in Arizona and nationwide.

71. Ms. Pecora's argument that APS' current line extension tariff is responsible for the lack of Arizona's economic growth and that reinstating the previous policy is necessary to address the economic downturn is not supported by the record.

72. We find no reason from the evidence presented in this case to modify our policy that current customers should not be subsidizing new growth, and therefore decline to modify Schedule 3 as requested by Intervenor Ms. Pecora.

73. We find that the Settlement Agreement reasonably resolves the rate application and sets out a plan that includes the requirements, responsibilities, and opportunity for APS to achieve a financial condition that will bring long-term benefits to its customers while comprehensively addressing issues of energy policy affecting APS customers and the State of Arizona.

74. We find that the Settlement Agreement's terms and conditions are just and reasonable.

75. Accordingly, we find that adoption of the Settlement Agreement is in the public interest.

76. APS should be ordered to implement and abide by all the terms and conditions of the Settlement Agreement.

77. We expect APS to use this unique opportunity to finally address and resolve the concerns related to its financial metrics and condition, and will closely scrutinize the Company's compliance with the terms of the Settlement Agreement

78. APS' original cost rate base is $5,582,135,000 and the fair value of APS' jurisdictional rate base for the test year ending December 31, 2007, is $7,665,727,000.

79. A capital structure comprised of 46.21 percent debt and 53.79 percent common equity is appropriate for establishing rates in this matter.

80. A return on common equity of 11.00 percent and an embedded cost of debt of 5.77

percent are appropriate estimates of cost of capital for purposes of this Settlement Agreement.

81. A fair value rate of return of 6.65 percent is appropriate under the terms of the Settlement Agreement.

82. APS should be authorized to increase its base rates by $344,738,000.

83. A Base Cost of Fuel and Power of $0.037571 per kWh is appropriate under the terms of the Settlement Agreement.

84. Staff should open or use an existing generic docket and conduct one or more workshops to evaluate, with input from stakeholders across the state, whether to modify our policy on line extensions, and if so, how, with the goal of incorporating that outcome into APS' next general rate case.

85. Staff should open or use an existing generic docket and conduct one or more workshops to study and discuss the parameters and conditions related to allowing third-party construction of electric facilities related to line extensions.

86. APS' PSA and DSM Revised Plans of Administration and other schedules should be approved and APS should file them in accordance with the Settlement Agreement and this Decision.

87. APS is authorized to cancel the $10 million bond required pursuant to Decision No. 70667.

CONCLUSIONS OF LAW

1. APS is a public service corporation within the meaning of Article XV of the Arizona Constitution, A.R.S. §§ 40-203, -204, -221, -250, -251, and -361, and A.A.C. R14-2-801 et. seq.

2. The Commission has jurisdiction over APS and the subject matter of the application.

3. Notice of the application and hearing was provided in accordance with the law.

4. Adoption of the Settlement Agreement is in the public interest.

5. The rates and charges produced by the Settlement Agreement are just and reasonable.

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement dated June 12, 2009 and attached to this Decision as Exhibit A, is hereby approved.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before December 31, 2009, revised schedules of rates and charges consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after January 1, 2010.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form acceptable to the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement, including filing all reports, studies, and plans as set forth in the Settlement Agreement and herein.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file with the Commission on or before December 31, 2009, the Revised Schedule 3 consistent with Exhibit B attached hereto and with the findings herein.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file with the Commission on or before December 31, 2009, the revised PSA Plan of Administration consistent with the findings herein.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file with the Commission on or before December 31, 2009, the revised DSM Plan of Administration consistent with the findings herein.

IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to complete equity infusions of $700 million through December 31, 2014.

IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to cancel the $10 million bond required pursuant to Decision No. 70667.

IT IS FURTHER ORDERED that Staff shall open or use an existing generic docket and conduct one or more workshops to study and discuss the parameters and conditions related to allowing third-party construction of electric facilities related to line extensions.

. . .

IT IS FURTHER ORDERED that Staff shall open or use an existing generic docket and conduct one or more workshops to study and discuss whether to modify our policy on line extensions, and if so, how, with the goal of incorporating that outcome into APS' next general rate case.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this _______ day of ____________, 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT ____________________________

DISSENT ____________________________

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-08-0172

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EXHIBIT A

ARIZONA PUBLIC SERVICE COMPANY

PROPOSED SETTLEMENT AGREEMENT

DOCKET NO. E-01345A-08-0172

JUNE 12, 2009

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PROPOSED SETTLEMENT OF DOCKET NO. E-01345-A-08-0172 ARIZONA PUBLIC SERVICE COMPANY REQUEST FOR RATE ADJUSTMENT

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Docket No. E-01345A-08-0172, Arizona Public Service Company's ("APS" or "Company") application to increase rates. This Agreement is entered into by the following entities:

AzAg Group
Arizona Association of School Business Officials ("AASBO")
Arizona Corporation Commission Utilities Division ("Staff")
Arizona Investment Council ("AIC")
Arizona Public Service Company ("APS")
Arizona School Boards Association ("ASBA")
Arizonans for Electric Choice and Competition ("AECC")
Bowie Power Station, LLC ("Bowie")
Cynthia Zwick
Federal Executive Agencies ("FEA")
Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan")
IBEW Locals 387, 640, 769
Interwest Energy Alliance ("Interwest")
Kroger Co. ("Kroger")
Mesquite Power, LLC ("Mesquite")
Residential Utility Consumer Office ("RUCO")
Southwest Energy Efficiency Project ("SWEEP")
Southwestern Power Group II, LLC ("SWPG")
Town of Wickenburg
Western Resource Advocates ("WRA")

These entities shall be referred to collectively as "Signatories;" a single entity shall be referred to individually as a "Signatory."

The following numbered paragraphs comprise the Signatories' Agreement.

I. RECITALS.

1.1. The purpose of this Agreement is to settle all issues presented by Docket No. E-01345A-08-0172 in a manner that will promote the public interest.

1.2 Docket No. E-01345A-08-0172 was commenced by the filing of a rate application by APS on March 24, 2008. The Company filed an amended application on June 2, 2008. On June 6, 2008, the Company filed a Motion for Approval of Interim Rates and Preliminary Order. The Company requested an Interim Base Rate Surcharge of $.003987 per kWh (or interim rates in an amount of $115 million), which would offset the fall off of the 2007 Power Supply Adjustor ("PSA") surcharge.

1.3 The Commission approved the applications to intervene filed by Kroger, Freeport-McMoRan and AECC (collectively "AECC"), Mesquite, SWPG, Bowie, the Town of Wickenburg, WRA, SWEEP, RUCO, AIC, AZ-Ag Group, FEA, AASBO, ASBA, IBEW Locals 387, 640 and 769, Interwest, Cynthia Zwick, Catalyst Paper, the Hopi Tribe, SCA Tissue North America, and Barbara Wyllie-Pecora.

1.4 In its Motion, APS asserted that its earnings and cash flow are inadequate to finance its capital needs and so it "must borrow huge sums to keep up with the needs of APS customers." APS asserted that its distribution, transmission, generation plant improvements, and new environmental control systems infrastructure investment requirements have increased and that the underlying cost of material, commodities and land for construction of this infrastructure has also increased. APS testified that its net cash flow for the past five years shows that APS' financial health has weakened considerably. APS also testified that its credit ratings on its outstanding debt are currently among the lowest that they can possibly be without being regarded as "junk." APS also testified that a downgrade to "junk" status was imminent without interim relief and that the effects of a downgrade might cause APS to lose all access to the credit markets, and jeopardize its ability to obtain credit on reasonable terms. APS also testified that the consequences of a downgrade would be dramatic and enduring and would likely cause APS to incur higher interest rates resulting in increased costs to the Company of $1 billion over the next 10 years.

1.5 Staff and Intervenors filed testimony on APS' request for interim rates on August 29, 2008, and APS filed rebuttal on September 8, 2008. An evidentiary hearing was held on the Company's request for interim rates on September 15 through September 20, 2008.

1.6 Staff and RUCO opposed the Company's request for interim rates on different grounds. Staff believed that the Company's filings did not provide a basis under Arizona law in which to grant the Company interim relief. Nonetheless, Staff recognized that given the extraordinary financial market crisis occurring at the time, the Commission may desire to award some interim relief to the Company, and as an alternative Staff proposed an amount of approximately $65 million, based upon increased investment in net plant using the most recently approved cost of capital.

1.7 In the fall of 2008, pre-existing difficulties in the subprime mortgage market escalated, resulting in one of the most severe financial crises in the debt and equity markets this country has seen. That crisis underscored the importance for companies like APS to maintain a financial condition that (i) allows access to the volatile and uncertain financial markets in order to secure necessary financing at reasonable rates, and (ii) allows APS to obtain credit from vendors and lenders on reasonable terms. That financial crisis continues today. In part as a result of that crisis, Arizona and the rest of the nation have also entered into a severe recession which is negatively impacting APS, its customers, and other interested parties.

1.8 On December 24, 2008, the Commission granted APS interim rates in the amount of $65.2 million in Decision No. 70667. The increase was implemented through an interim base rate surcharge of $0.00226 per kWh effective with bills issued after December 31, 2008. The interim rates remain in effect until a final order is issued by the Commission in APS' pending permanent case.

1.9 The procedural schedule on the Company's permanent case set the deadline for Staff and Intervenor non-rate design direct testimony on December 19, 2008. On that date, testimony was filed by Staff, RUCO, AECC, IBEW 387, 640 and 769, Cynthia Zwick, SWEEP, WRA, AASBO and ASBA. Staff and Intervenor direct testimony on rate design issues was filed on January 9, 2009.

1.10 APS proposed, and IBEW Locals 387, 640 and 769 supported, a total rate increase of approximately $448 million. Staff proposed a total rate increase of approximately $307 million. RUCO proposed a total rate increase of approximately $157 million. AECC's testimony would have resulted in a total rate increase of approximately $347 million.

1.11 APS filed a notice of settlement discussions on January 23, 2009. The parties to the proceeding subsequently held settlement discussions. On January 30, 2009, APS filed a Motion to Suspend Procedural Schedule. The Hearing Division granted a similar request made by the Company on March 5, 2009. A procedural conference was held on April 7, 2009 and again on April 21, 2009.

1.12 At a procedural conference held on April 21, 2009, APS, Staff and the other participating Intervenors indicated that they had reached an agreement in principle on revenue requirement issues and that substantial agreement had been reached on other issues. The Settling Parties agreed to file a Term Sheet containing the major provisions of the Agreement on May 4, 2009. On May 4, 2009, the Settling Parties filed a Term Sheet outlining the agreement in principle reached with APS. A bill impact analysis statement was filed by the Settling Parties on May 15, 2009.

1.13 A procedural order was issued on May 11, 2009 establishing deadlines for the filing of testimony on the Settlement Agreement and an evidentiary hearing commencing on August 19, 2009.

1.14 The settlement discussions were open, transparent, and inclusive of all parties to this Docket who desired to participate. All parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate.

1.15 The purpose of this Agreement is to settle all issues presented by Docket No. E-01345-08-0172 in a manner that will promote the public interest. The Signatories believe that this Agreement creates a rate and financial stability program for APS that appropriately balances the risks of

APS, its employees, its customers, and other interested parties. In addition, this Agreement creates a framework that the Signatories agree could ultimately improve APS' financial metrics and bond ratings, which over the long term would benefit customers by allowing APS to borrow at more attractive rates, and also improve its vendor and lender creditworthiness, thereby increasing operational flexibility. Additionally, the terms of this Agreement are just, reasonable, fair and in the public interest in that they, among other things, (i) establish just and reasonable rates for APS' customers; (ii) promote the convenience, comfort and safety, and the preservation of the health, of the employees and patrons of APS; (iii) resolve the issues arising from this Docket; and (iv) avoid unnecessary litigation expense and delay.

1.16 The Signatories believe that they have developed a settlement package that balances APS' rate increase with benefits for customers. These benefits include:

a) Investments in Arizona's Energy Future.

- establishment of energy efficiency goals and the creation of tiered performance incentives to encourage meeting those goals;
- at least 100 schools served by DSM programs and at least 1,000 customers in existing homes served by the Home Performance enhanced program element by December 31, 2010;
- placement of renewable energy projects at Arizona schools and government institutions;
- a plan for utility scale photovoltaic generation and an RFP for in-state wind generation;
- additional renewable energy projects to be in place by 2015 which, in combination with existing renewable commitments, will result in approximately 10% of APS' retail sales coming from renewable resources; and,
- construction of one or more renewable energy transmission facilities.

b) Commitments Benefiting Low-Income Customers.

- continued rate discounts for low income ratepayers, holding these ratepayers harmless from the rate increase;
- creation of a new bill assistance program to benefit customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines, funded by APS; and,
- waiving additional security deposits for low income ratepayers.

c) Rate Stability Plan.

- an increase in rate stability, including an extended period without base rate increases and a scheduled plan for future rate cases, resulting in greater administrative efficiency and reduced uncertainty for both APS and ratepayers.

d) Rate Related Benefits.

- an improvement in APS' ability to attract capital, maintain reliability and sustain growth;
- a limit on recovery through rates of executive incentive compensation based upon performance;
- a sustained reduction of expenses of at least $30 million per year, which will reduce the need for future rate increases;
- an infusion of at least $700 million of additional equity and an improvement in APS' financial metrics, strengthening its bond rating and reducing future debt costs;
- a plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics;
- an acceleration of the refund of any over-collected amounts in the PSA account, resulting in a lower adjustor rate that will partially offset the base rate increase;
- a reduced Systems Benefits Charge in 2012 if a Palo Verde license extension is approved before the conclusion of the next rate case; and,
- continued 90/10 sharing of the PSA.

e) Creation of Performance Measures for APS.

f) New Rate Design Options.

- creation of an optional super-peak tariff for residential customers and other critical peak pricing rates;
- twelve month reopening of the E-20 House of Worship tariff;
- development of Interruptible Rate Schedules and other Demand Response Programs for large customers; and,
- a new optional time of use rate for schools.

1.17 The Signatories desire that the Commission issue an order (i) finding that the terms and conditions of this Agreement are just and reasonable, together with any and all other necessary findings; (ii) concluding that the Agreement is in the public interest; (iii) granting approval of the Agreement; and (iv) ordering that the Agreement and its terms be effective upon Commission approval.

TERMS AND CONDITIONS.

II. RATE CASE STABILITY PROVISIONS.

A. <u>General Rate Case Filing Plan.</u>

2.1 The Signatories agree to two scheduled general base rate cases for APS to address plant additions and other rate matters which schedule shall cover the period of January 1, 2010 through December 31, 2014 ("Plan Term"). APS is prohibited from filing its next two general rate cases until on or after June 1, 2011 and June 1, 2013 respectively. No new base rates resulting from APS' next general rate case will be effective before July 1, 2012.

2.2 The test year end (TYE) date for each of the base rate increase filings contemplated herein shall be:

6/1/2011 filing: TYE no earlier than 12-31-2010

6/1/2013 filing: TYE no earlier than 12-31-2012

2.3 The Signatories agree to use good faith efforts to process APS' case(s) within 12 months of a sufficiency finding. The Company shall provide a one hundred twenty (120) day notice to the Commission and the Signatories of its intent prior to filing a new rate case. The notice shall at a minimum specify the following:

- That an application for a general rate change is planned;
- The anticipated date of the filing;
- The proposed effective date of the general rate change;
- Any major issues which the utility, at the time of filing the notice of intent, expects to raise in conjunction with the application.

2.4 In recognition of resource constraints and to assist the Commission in processing the case(s), within 60 days after the notification filing, APS, Staff and the other Signatories will meet and confer prior to the filing of such case(s) in an effort to narrow issues, to streamline the processing of the case and to identify an initial set of standard data requests to which APS will respond as part of its rate application.

2.5 The Signatories recognize the desirability of maintaining an appropriate interval between the filing of rate applications. If the Commission has not issued a final order in APS' first rate case (the "on or after June 1, 2011" filing) by July 1, 2012, the parties will meet and confer in order to determine an appropriate date for filing APS' next rate case and an appropriate test year ending date. If the parties are unable to agree to such dates, the matter shall be referred to the Commission for determination.

B. <u>Accelerated PSA Reset.</u>

2.6 If, at the time new rates are implemented, the PSA account has an over-collected balance, the PSA reset would be accelerated from February 1, 2010, so that the reduction in the PSA level would partially offset the increase to higher base rates.

III. RATE INCREASE.

3.1 The Commission granted APS an interim increase of $65.2 million in 2008. The Signatories agree that the interim surcharge shall be confirmed without any refund obligation.

3.2 The Signatories agree that APS will receive an additional non-fuel Base Rate Increase as a result of this Agreement of approximately $131.1 million over the interim increase ("revenue deficiency").

3.3 The total non-fuel Base Rate Increase granted in this case (interim plus settlement) will be $196.3 million. When adjusted for both the interim increase and an additional $11.2 million of revenue associated with establishing new base fuel levels, this settlement represents an approximate 7.9% increase in base rate revenue.

3.4 The rationale for the $196.3 million Base Rate Increase includes, in addition to other items contained in Staff's direct case, providing for a return on and of post-test year plant through June 30, 2009, eighteen (18) months beyond the test year ending December 31, 2007, as well as the Signatories' desire to enhance APS' ability to retain and improve its current investment-grade credit rating, thereby enabling APS to attract capital at reasonable cost, and to also optimize its operational flexibility, in order to be better positioned to meet its customers' future energy service needs.

3.5 For ratemaking purposes and for the purposes of this Agreement, the Signatories agree that the fair value of APS' jurisdictional rate base for the test year ending December 31, 2007 (the "test year") is $7,665,727,000.

3.6 In addition, under this Agreement, APS is allowed to recover an increase in base fuel costs of $137.2 million, for a total rate increase of $344.7 million.

3.7 The Signatories agree that the opportunity to recover the revenue deficiency results in just and reasonable rates for APS' customers. The agreements set forth herein regarding the quantification of fair value rate base, fair value rate of return, and the revenue deficiency are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other cases.

3.8 A comparison of various of the Signatories' initial proposed increases compared to that resulting from the Agreement is contained in the following table:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers					
2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers					
2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

3.9 In addition to the base rate increase provided herein, various of the Agreement's provisions relating to fuel and purchased power costs, renewable energy, and energy efficiency may have the impact of increasing or decreasing the amounts collected from customers under the Company's already established adjustment mechanisms (specifically, the Demand Side Management Adjustor Clause ("DSMAC"), the Renewable Energy Surcharge ("RES"), and Power Supply Adjustor ("PSA"). The presently estimated impact of this Agreement on the amount to be collected from the DSMAC and RES in 2010 is approximately an additional $15 million and $2 million respectively. Although the Signatories agree that the amounts collected under the DSMAC and RES will likely increase after 2010, there is not consensus as to the level of such increase.

3.10 In addition, the Signatories acknowledge that certain provisions of the Agreement do not have a rate impact in the present case, but they will have an impact in future APS rate cases. Specifically, the rate impacts shown above do not include the increased cost to customers in a future APS rate case resulting from the treatments specified in this Agreement for recording Schedule 3 receipts as revenue (as opposed to Contributions-in-Aid-of Construction ("CIAC")), for limited pension and other post-retirement benefits ("OPEB") deferrals, and for an anticipated Palo Verde depreciation rate change. Nor do the rate impacts shown above reflect the Agreement's requirement that APS reduce future costs by $30 million annually (or $150 million over the next five years), which will reduce future revenue requirements.

3.11 The Term Sheet, filed with the Commission on May 4, 2009, noted that the Signatories were looking at transitioning the $10 million of DSM costs currently recovered in base rates into the DSMAC so that all DSM costs would be recovered through a single source. In this Settlement, the Signatories agree that it is appropriate to retain the $10 million in base rates and address this issue in APS' next general rate case. At that time, parties and the Commission can analyze whether it is appropriate to move all DSM costs to the DSMAC, whether to retain some or all DSM costs in base rates, and if so what portion of DSM costs should be in base rates, or whether other treatment would be appropriate.

IV. COST OF CAPITAL.

4.1 The Signatories agree that a capital structure comprised of 46.21% debt and 53.79% common equity shall be adopted for ratemaking purposes for this case.

4.2 The Signatories agree that a return on common equity of 11.0%, which is less than the return on common equity requested by APS, and an embedded cost of debt of 5.77% are appropriate and shall be adopted for ratemaking purposes for this Docket.

4.3 The Signatories agree to a fair value rate of return of 6.65% as shown on Attachment A, which includes a fair value increment.

V. DEPRECIATION.

5.1 For ratemaking purposes, upon the effective date of a Commission order approving this Agreement, APS' proposed depreciation and amortization rates are appropriate in this case and should be adopted with the exception of the Company's proposed change to Account No. 370.01 (electronic meters), which should be rejected and the current depreciation rate of 3.68% for such Account retained. The depreciation rates adopted herein (with the exception of Account No. 370.01 (electronic meters)) are contained in the filed direct testimony of Dr. Ronald E. White, submitted on June 2, 2008 in this Docket as Attachment REW-1 and incorporated herein.

5.2 Special provision is made herein for depreciation rates associated with a Palo Verde License Extension in Section XI of this Agreement.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS.

6.1 The Signatories agree that the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

6.2 The Signatories agree that the Base Cost of Fuel and Purchased Power is $0.037571 per kWh. This base fuel amount shall be reflected in APS' base rates.

6.3 Gains on SO2 Allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered and/or refunded through the PSA mechanism.

6.4 The PSA Plan of Administration shall be amended as necessary to reflect the terms of this Agreement and shall be approved concurrent with the approval of this Agreement.

VII. APS EXPENSE REDUCTION COMMITMENT.

7.1 Decision No. 70667 required APS to reduce its operational expenses by $20 million for 2009. This Agreement renews APS' commitment to reduce its expenses on an annual basis and increases the amount of the annual reduction to an average of $30 million per year beginning in 2010. The $30 million average annual expense reduction by APS will continue through the Plan Term. The total expense reduction by APS for the Plan Term shall be at least $150 million.

7.2 The $30 million annual expense reduction by APS represents an average annual reduction over the five year period. In some years, it may exceed $30 million. However, in no year will the expense reduction be less than $25 million.

7.3 APS shall report annually on its expense reductions in similar detail and format to APS' March 18, 2009 filing Re: *Compliance Filing of Arizona Public Service Company Regarding Cost Management Efforts, Docket No. E-01345A-08-0172* (Interim Rate Proceeding).

7.4 As in Decision No. 70667, the Company is not required to make the expense reductions required in this Agreement from any specific area, but shall consider making them in the areas identified by the Commission in that Decision. See Decision No. 70667 at 42, 44. APS shall not make any expense reductions in costs necessary to preserve safe and reliable electric service.

VIII. EQUITY INFUSIONS TO BE MADE BY APS.

8.1 APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. The Opinion and Order approving the Agreement shall constitute authorization to infuse $700 million into APS through December 31, 2014. This amount includes the "up to $400 million" which was previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

8.2 In accordance with its management responsibilities, the Company agrees to use its best efforts to maintain investment grade financial ratios and a balanced capital structure that optimizes benefits to ratepayers, and to work to improve its existing ratings with the financial rating agency community.

8.3 APS will use its best efforts to improve its financial metrics and bond ratings, by completing timely equity infusions and taking other measures to strive to achieve a capital structure with no more than 52% debt/total capital, as calculated by the credit rating agencies, by December 31, 2012.

8.4 APS shall prepare and submit to the Commission and Signatories within 120 days of approval of the Agreement, a plan detailing steps it intends to take to maintain and improve its financial ratings with the credit rating agencies.

IX. PENSION AND OPEB DEFERRALS.

9.1 APS shall be allowed to defer for future recovery, in accordance with the provisions of SFAS No. 71, a portion of its annual Pension and OPEB costs above or below the test year level in years 2011 and 2012, subject to the following maximum amounts for such deferrals in each year:

a. 2011: deferral cannot exceed the lower of $13.5 million or 50% of the cost above the test year level;

b. 2012: deferral cannot exceed $29 million of the cost above the test year level.

9.2 If APS' annual Pension and OPEB costs are below the test year level in either 2011 or 2012, the full amount of such annual savings will be credited to the Pension/OPEB deferral account.

9.3 For purposes of this Agreement, the test year level of Pension and OPEB expense is $23.949 million on a total Company basis.

9.4 APS' ability to record Pension and OPEB deferrals shall expire at the earlier of December 31, 2012 or the conclusion of its next general rate case.

9.5 The Signatories reserve the right to review APS' Pension/OPEB deferrals in APS' next rate case for reasonableness, prudence and the appropriate amortization period, such that the deferrals can be recognized in accordance with the provisions of SFAS No. 71.

X. TREATMENT OF SCHEDULE 3.

10.1 Following approval of this Agreement, APS shall be authorized to record proceeds from its line extension policy ("Schedule 3") as revenue during the period from January 1, 2010 through either the earlier of December 31, 2012 or the conclusion of the Company's next general rate case. Thereafter, Schedule 3 receipts will be recorded as CIAC, unless otherwise ordered by the Commission.

10.2 The income resulting from the revenue treatment to Schedule 3 proceeds provided in Section 10.1 above is material to this Agreement. APS estimates that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

10.3 The Agreement proposes to maintain the Commission's current policy regarding customer payments for line extensions, subject to the modifications described in this Section X. The Signatories acknowledge the letters filed in this Docket from several Commissioners regarding Schedule 3, and agree that, should the Commission decide in this proceeding to modify Schedule 3, offsetting revenue changes should also be ordered that would make any such modification(s) revenue neutral to the provisions of this Agreement.

10.4 Nothing in this Section or the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case.

10.5 APS' Impact Fee proposal in this case shall be withdrawn. However, this shall not act to limit APS' ability to discuss impact or hook-up fees in the context of the generic docket on hook-up fees for future consideration by the Commission.

10.6 The System Facilities Charge proposed by APS shall be withdrawn.

10.7 APS shall submit a revised Schedule 3 to reflect the following modifications before the hearing in this case:

- A clarified definition of Local Facilities;
- A Schedule of Charges;
- A statement that quotes provided to customers will be itemized; and,
- Procedures for refunding amounts to customers when additional customers connect to the line extension.

Such Schedule 3 shall expressly permit customers to hire contractors for trenching, conduit, and backfill necessary for the extension, as is currently permitted.

XI. ADJUSTMENT OF DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION.

11.1 Upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension or (2) 1/1/2012, APS is authorized to adjust depreciation rates used for recording depreciation expense on the Palo Verde generating unit to reflect such license extension, in accordance with the 2008 Depreciation Study results attached hereto as Attachment B. In addition, APS shall file a request that the Commission adjust the Company's System Benefit Charge ("SBC") and reduce such charge to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC and related to the Palo Verde license extension. Such request shall be filed in sufficient time to allow the Commission to make the reduction to the SBC simultaneous with the implementation of the depreciation rate change. APS shall also reduce the PSA amount to reflect a reduction in the independent spent fuel storage installation costs.

11.2 APS estimates that the change in depreciation rates due to the approved license extension will result in a reduction to APS' depreciation expense in the approximate amount of $34 million annually on an ACC jurisdictional basis. Once the reduced depreciation expense is recognized as an expense reduction in the context of the reestablishment of new base rates in APS' next base rate case, it would begin to provide a benefit to customers.

11.3 The changes in the recorded depreciation expense resulting from the Palo Verde depreciation rate change that would occur before the Company's base rates are reestablished in the Company's next rate case are intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS rate base would be higher. The benefit to the Company associated with recording the new depreciation rates prior to their recognition in rates will be offset (in part) by the SBC and PSA reductions discussed in 11.1 above and 11.4 following.

11.4 APS' approved annual level of nuclear decommissioning funding, on a jurisdictional basis, and as reflected in the Agreement's proposed revenue requirement is as set forth in Attachment A to Decision No. 69663. Pursuant to the terms of this Settlement, if and when license extension is granted, APS shall file with the Commission a revised nuclear decommissioning funding requirement and a commensurate downward adjustment to the decommissioning component of the Company's SBC and a reduction to the PSA as discussed above to be effective upon the later of the grant of license extension or January 1, 2012. The revenue requirement, income, expenses, fair value rate base and fair value rate of return utilized by the Signatories fully took into consideration the provisions of this Section 11.

11.5 APS will provide a depreciation rate study in its next rate case that includes a review of all of APS' depreciation rates, including but not limited to the impact of the Palo Verde license extension.

XII. LIMIT ON RECOVERY OF ANNUAL CASH INCENTIVE COMPENSATION FOR APS EXECUTIVES.

12.1 The Signatories contemplate that the Commission will continue to review and evaluate costs associated with Executive compensation as it has in the past. The Signatories, including APS, recognize that the Commission will continue to review such costs to determine to what extent such costs should be borne by the Company's customers. The Signatories also recognize the need for the Company to attract qualified persons and to reward exemplary work performance.

12.2 The Signatories agree that Annual Cash Incentive Compensation for APS Executives paid for 2010, 2011 and 2012 shall not exceed the test year level unless the Company:

a. has met all the components of the Performance Measurements described in Section 13(a) below for that particular year, to the extent such Performance Measurements apply to the year in question;

b. receives a Hardship Waiver from the Commission for failure to meet one or more of the Performance Measures; or

c. issues Annual Cash Incentive Compensation in excess of the test year levels that are absorbed by the shareholders and not recovered from ratepayers.

12.3 For the purposes of this Settlement, "Executive" is defined as any APS employee with a job title of Vice President, its equivalent or higher, or a Pinnacle West employee with a job title of Vice President, its equivalent or higher, that devotes a substantial portion of his or her time to APS matters. For purposes of this Agreement, "substantial portion" shall mean an executive who devotes 25% or more of his or her time to APS matters.

XIII. PERIODIC EVALUATION.

A. Performance Measurements.

13.1 The Signatories agree that the Company should exert its best efforts on an ongoing basis to maximize opportunities for financial soundness provided by virtue of this Agreement and that such efforts by the Company should be subject to periodic evaluation through the use of Performance Measurements and Reporting Requirements.

13.2 APS will be subject to periodic evaluation based upon the following measures, which include both Performance Measurements and Reporting Requirements. The Commission shall decide the appropriateness of any waivers of limits on Annual Cash Incentive Compensation recoverability for APS Executives based upon failure to meet these Performance Measurements and Reporting Requirements. APS shall meet the following Performance Measurements:

a. APS shall initiate and implement the schools renewable program in accordance with the terms set forth in Section XV. For purposes of specific performance goals, the program shall result in 50,000 MWhs of annual energy generation or savings at Arizona schools within 36 months of program approval;

b. The Company shall comply with the terms of its Commission – approved Implementation Plan designed to meet the energy efficiency goals set forth in Section XIV;

c. APS shall comply with the terms of its Commission-approved Implementation Plan designed to meet the goals set forth in the

Renewable Energy Standard and Tariff ("REST") Rules by deriving a portion of the energy it sells from renewable technologies;

d. APS shall comply with the renewable energy goals in accordance with the terms set forth in Section XV of this Agreement;

e. APS shall reduce its expenses by at least $30 million per year, on average, in accordance with the terms set forth in Section VII of this Agreement;

f. The Company will strive to achieve a Capital Structure with no more than 52% total debt, as calculated by the credit rating agencies, by December 31, 2012;

g. APS shall submit a plan to the Commission to maintain investment grade financial ratios and to improve its financial metrics;

h. APS shall complete equity infusions of $700 million in accordance with the terms set forth in Section VIII;

i. The Company shall comply with the Annual Reporting of Financial and Customer Service Criteria as set forth in XIII.B, following; and,

j. APS shall cooperate with the Commission Staff in its conduct of the Benchmarking Study comparing APS with other similarly situated utilities.

13.3 If APS believes that its failure to comply with any measure listed in the Performance Measures set forth in Section XIII.A above is due to factors it believes are beyond its control or would result in an inequitable hardship, the Company may request from the Commission a waiver of such specific measure(s) for that particular year. APS' ability to request a waiver does not guarantee that such a request will be granted by the Commission, or that the Signatories to this Agreement will not oppose such a waiver.

B. Reporting Requirements.

13.4. The Signatories agree that APS shall file a report with the Commission that contains the information set forth in this Section, and will provide such report to the other Signatories to this Agreement. Except where otherwise provided herein, the Company shall provide such report annually each April 30th during the Plan Term, with information relevant to the preceding year, and to include changes from a 2007 base year. Reported information shall include a detailed list of customer service, reliability, safety and financial items including but not limited to:

a. Customer Service, Reliability and Safety Reporting.

i. The frequency and duration of unplanned outages (generation, transmission and distribution) as measured by the industry-used System Average Interruption Duration Index, System Average Interruption Frequency Index, and Customer Average Interruption Duration Index;

ii. Information regarding major unplanned equipment outages or downtime for maintenance, repair and/or replacement, and distribution system outages consistent with the 1000 Hour Report currently filed with the Commission;

iii. Number of calls from customers and level of customer satisfaction (based upon feedback surveys) regarding the way calls were handled;

iv. Information regarding the levels of enrollment in DSM, Demand Response, Low-Income and RES programs;

v. Information regarding the frequency and severity of employee injuries using All Incident Injury Rate ("AIIR"); and,

vi. Information addressing changes to APS' employee counts, including changes to the counts of the employees represented by the two labor unions with whom APS has entered into collective bargaining agreements.

b. Financial Reporting.

i. Information regarding the Company's earned return on equity ("ROE") for the preceding 12 months, including supporting calculation detail and identification of the major factors impacting that ROE. Such reports shall be filed within 60 days following the end of each quarter throughout the Plan Term;

ii. Information regarding the Company's Funds from Operations ("FFO") to Debt ratio, FFO/Interest ratio, and Total Debt/Capital ratio for the preceding 12 months, including supporting calculation detail and identification of the major factors impacting those metrics. Such reports shall be filed within 60 days following the end of each quarter throughout the Plan Term;

iii. Information regarding Pinnacle West Capital Corporation's ("PNW') stock price, net book value and the relationship of PNW's stock price to net book value. Such reports shall be filed within 60 days following the end of each quarter throughout the Plan Term;

iv. Information regarding the status of all shelf registrations for debt and equity issuance(s) of APS and PNW;

v. Information regarding any long-term debt issuances and their impact on APS' capital structure and FFO/Debt ratio within 60 days of such issuance;

vi. Information regarding any equity infusions made in accordance with the terms set forth in Section VIII herein, their impact upon APS' capital structure, the price per share at the time of issuance, any dilution to existing share, and the estimated impact upon APS' FFO/Debt ratio. Such reports shall be filed within 60 days of such infusion;

vii. Information regarding the criteria used to measure achieved performance under its Annual Cash Incentive Compensation Plan. The reporting of this information to the Commission will coincide with when it has been made publicly available and reviewed and approved by the Board of Directors for the purpose of approving Annual Cash Incentive Compensation awards;

viii. Information pertaining to Management Expenses;

ix. Information pertaining to the Company's Dividend Payout Ratio and changes from earlier years;

x. Information pertaining to Operation and Maintenance Expense and any significant changes from year to year;

xi. Information pertaining to Customer and Sales Expense per Customer and any significant changes from year to year; and,

xii. Information regarding the Company's level of major capital expenditures, and its consideration of available alternatives in connection with such capital expenditures for generation facilities.

13.5 APS shall annually file a report with the Commission documenting its performance for the preceding year in relation to the Performance Measures set forth in the "Performance Measures" and "Reporting Requirements" Sections set forth above. Such annual report shall be filed no later than April 30th in the years 2011, 2012, 2013 and 2014, and shall be used for determining whether the Company has met the Performance Measures for the preceding year.

C. Benchmarking Study of APS Operations and Cost Performance.

13.6 The Signatories agree that by March 31, 2010, Staff shall select a benchmarking firm to conduct a benchmarking analysis of APS' operational and cost performance relative to a peer group of at least 30 other investor-owned electric-only utility operating companies, to the extent available and practicable. To the extent practicable, the peer group shall reflect business characteristics comparable to that of APS, including, but not limited to, total revenue, number of customers, nuclear generation, ownership of generation, customer density, customer growth and fuel and resource mix.

13.7 Such analysis shall focus on the following areas at a minimum:

a) Operational Performance

- Safety
  - All Safety Incident Injury Rate (AIIR)
- Customer Satisfaction
- Delivery Reliability
  - System Average Interruption Frequency Index (SAIFI)
  - Momentary Average Interruption Frequency Index (MAIFI)
  - System Average Interruption Duration Index (SAIDI)
  - Customer Average Interruption Duration Index (CAIDI)
- Base Load Power Plant Performance
- Sustainability Performance

b) Cost Performance

- Non-Fuel Operating Expense per Customer
- Distribution Additions to Plant per New Customer
- Capital Expenditures
- Hedging
- Management Expense

c) Financial Health of Company

- Debt/Equity Ratio
- Dividend Payout Ratio
- Return on Average Assets (ROAA)
- Return on Average Equity (ROAE)
- FFO/Debt
- Debt Ratings
- Earnings per Share (Pinnacle West)

- Stock Performance (Pinnacle West)

13.8 The Company shall incur all costs paid to the benchmarking firm related to the study, which costs will be capped at $500,000. No such costs associated with the study shall be recoverable in rates.

13.9 The Benchmark Study Report shall be filed with the Commission no later than December 31, 2010. Such benchmark report shall include the benchmarking firm's conclusions regarding the Company's performance and any significant differences in performance on the benchmarks selected between APS and other utilities analyzed and the likely reasons for those differences. The report shall also identify areas where performance appears to be significantly above or below the norm.

XIV. DEMAND SIDE MANAGEMENT.

14.1 Energy Efficiency goals shall be established, defined as annual energy savings of 1.0% in 2010, 1.25% in 2011, and 1.5% in 2012, expressed as a percent of total energy resources needed to meet retail load. Cumulative annualized energy savings from the programs in 2010-2012 would be approximately 3.75% (1.00% + 1.25% + 1.50%) of total energy resources needed to meet retail load in 2012. If higher goals are adopted by the Commission for 2010, 2011 or 2012 in another docket, then those higher goals will supersede the goals listed above, as will any higher performance incentives.

14.2 The existing performance incentive for energy efficiency programs shall be modified to be a tiered performance incentive as a % of net benefits, capped at a tiered % of program costs.

Achievement Relative to the Energy Efficiency Goals	**Performance Incentive as % of Net Benefits**	**Performance Incentive Capped at % of Program Costs**
Less than 85%	0%	0%
85% to 95%	6%	12%
96% to 105%	7%	14%
106% to 115%	8%	16%
116% to 125%	9%	18%
Above 125%	10%	20%

14.3 Self Direction" of DSM charges will be allowed for large commercial or large industrial customers who use more than 40 million kWh per calendar year, based on an aggregation of all of the customer's accounts. After a customer notifies APS of its intent to Self-Direct, 85% of the customer's DSM contribution will be reserved for tracking purposes for the customer's future energy efficiency project(s). The remaining 15% will be retained to cover the self direction program administration, management and verification, measurement and evaluation, and low-income program costs.

14.4 Self Direction funds will be paid once a year in December beginning in the year that the DSM project is completed and verified by the APS Solutions for Business team. If project costs exceed the credited amount in one year, then funding will continue to be paid in December of each year until the project is 100% funded or on the tenth year of funding, which ever comes sooner. If the energy efficiency project is not completed within two years of the Self Direction election date, then the Self Direction funds from the first calendar year from the Self Direction election will not be available to the Customer and will revert to the program account.

14.5 Self Direction provisions defining the specific parameters for Self Direction are summarized in Attachment C.

14.6 The Signatories agree that it is reasonable for APS' DSMAC to be modified to achieve more current recovery of program costs, similar to the DSMAC approved for Tucson Electric Power Company ("TEP") in Decision No. 70628. New DSMAC rates for the upcoming year will be set by the Commission as part of its consideration of the Implementation Plan. The Implementation Plan shall also include a bill impact analysis. If approved, such rates would become effective with the first billing cycle in March. This will supersede existing DSMAC reset filing dates. The total amount to be recovered by the DSMAC shall be calculated by projecting DSM costs for the next year, adjusted by the previous year's over- or under-collection, and adding revenue to be recovered from the DSMAC performance incentive. The DSM Plan of Administration shall be amended as necessary to reflect the terms of this Agreement and shall be approved concurrent with this Agreement.

14.7 APS shall apply interest whenever an over-collected balance results in a refund to customers. The interest rate shall be based on the one-year Nominal Treasury Constant maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication. The interest rate should be adjusted annually on the first business day of the calendar year. There will be no interest applied to an under-recovered balance.

14.8 APS shall not request recovery of unrecovered fixed costs ("UFC") as a component of DSM program costs until its next general rate case. APS agrees to an explicit exclusion of UFC from the definition of program costs. This provision will not preclude APS from seeking such recovery in other proceedings.

14.9 APS shall file for the Commission's approval an annual Energy Efficiency Implementation Plan for 2010, 2011, and 2012, with new and/or expanded programs or program elements necessary to achieve the energy efficiency goals. Each Implementation Plan shall include estimated energy savings by program and a range of estimated program costs by program necessary to meet the goal. Staff will review each Plan and provide its recommendations to the Commission. For any new programs, the Company and Staff will perform the cost effectiveness tests considering criteria and parameters reviewed by the DSM Collaborative. However, modifications to program elements of existing Commission-approved programs or adjustments to spending levels by program from year to year may not require an updated cost effectiveness test. The Company will file implementation plans on June 1, 2010 and June 1, 2011 for the 2011 and 2012 goals respectively.

14.10 By July 15, 2009, APS shall file for the Commission's approval in this Docket the 2010 Energy Efficiency Implementation Plan with new and/or expanded programs or program elements necessary to achieve the 2010 energy efficiency goal, including the enhancements and program elements set forth below. Staff shall review the Plan and provide its recommendations to the Commission in sufficient time so that the Commission may consider the matter at its regular November Open Meeting. In an effort to achieve timely approval of the Plan, the Signatories urge the Commission to take action on the Implementation Plan on or before the date it takes action on the Agreement. Such Implementation Plan will make clear that its obligations therein are contingent upon Commission approval of the Agreement.

14.11 The Signatories agree that the 2010 Implementation Plan shall include at a minimum:

a. A customer repayment/financing program element for schools, municipalities and small businesses fully integrated in the non-residential programs. This customer repayment element must be fully integrated from the perspective of the customer and not a separate offering. APS may use an actual on-the-bill or a parallel bill approach to implement this provision. Financing costs (including any default or guarantee cost) will be fully recoverable as a program cost. Any financing provided directly by APS will be at its weighted average cost of capital (if APS buys down the financing rate for the end-using customer, the differential between APS' cost of capital and such reduced rate will also be recovered as a program cost);

b. A goal for APS to serve, meaning the installation of measures, through its existing DSM programs or enhanced program elements, at least 100 schools by December 31, 2010;

c. A review of the APS low income weatherization program for possible enhancement;

d. APS will have a Residential Existing Homes Program, which will include both a new Home Performance element and the existing HVAC element. The goal of the Home Performance element will be to serve at least 1,000 existing homes by December 31, 2010. These customers will be served by conducting an on-site energy assessment, direct installation of some energy saving measures (e.g. lighting, air sealing), and delivering information and incentive offers on a comprehensive set of recommended measures for consideration by the customer. The customized list of recommended measures shall include items such as insulation, duct repair and HVAC improvements to save energy, consistent with the national EPA/DOE Home Performance with ENERGY STAR program;

e. A non-residential high performance new construction program element with a second tier of performance and a higher financial incentive; and

f. A residential high performance new home program element with a second tier of performance and a higher financial incentive, which APS will file with the Commission on or before June 30, 2009 as part of its zero-net energy home filing. In an effort to achieve timely approval of the program element, the Signatories urge the Commission to take action on the program element on or before the date it takes action on the Agreement.

XV. RENEWABLE ENERGY.

15.1 APS shall make its best efforts to acquire new renewable energy resources with annual generation or savings of 1,700,000 MWh to be in-service by December 31, 2015, consistent with APS' Resource Plan report, dated January 29, 2009, Appendix 1, Table 1 (Selected Resource Plan: Loads and Resources Table), Docket No. E-01345A-09-0037. These new resources shall be in addition to existing resources or commitments as of the end of 2008, as identified in APS' 2008 RES Compliance Report dated April 1, 2009, Docket No. E-01345A-07-0468. These new renewable acquisitions, in combination with existing renewable commitments, are currently estimated to be approximately 10% of retail sales by the end of 2015. Renewable resources are those defined in A.A.C. R14-2-1802. APS shall obtain a mix of new distributed and non-distributed renewable energy resources. APS shall report to the Commission on its plans for and progress towards acquiring the new resources, including any delays or shortfalls, in its Renewable Energy Standard Implementation Plans and RES Compliance Reports, and in future resource planning filings.

15.2 APS shall issue a new request for proposals for in-state wind generation within 90 days of Commission approval of the Agreement. After evaluating potential projects, APS will file a request for Commission approval of one or more such projects, within 180 days of issuance of the RFP.

15.3 APS shall, within 120 days of the Commission's Order approving the Agreement, file in this Docket for Commission consideration a plan for implementing a utility scale photovoltaic generation project, which shall have a construction initiation date not later than 18 months from the date of filing. This requirement is in addition to the Concentrated Solar Power ("CSP") projects already under consideration or previously approved by the Commission. In selecting a project for this filing, APS shall initiate a competitive procurement that complies with its certified Renewable Energy Competitive Procurement Procedure dated April 10, 2007. Any Signatory may file comments in response to APS' filing with the Commission. The Commission shall not be obligated to act on APS' filing. Any Commission inaction shall not indicate Commission approval of APS' proposal.

15.4 Following the Biennial Transmission Assessment report (as required by Decision No. 70635) prioritizing transmission projects that will facilitate interconnection of renewable resources to Arizona's transmission system, APS shall commence permitting, design, engineering, right of way acquisition, regulatory authorization (which may include a request to FERC for applicable transmission incentives and other cost recovery provisions), and line siting for one or more new transmission lines or upgrades designed to facilitate delivery of solar and other renewable resources to the APS system. APS shall expeditiously pursue permitting and authorizations and shall construct such transmission line(s) or upgrade(s) after satisfactory permitting and authorizations are obtained.

15.5 APS shall file within 120 days of the Commission's Order approving the Settlement Agreement a new program for on-site solar energy including photovoltaics, solar water heating and daylighting, at grades K through 12 public (including charter) schools in its service territory that eliminates up-front customer costs. The program goal shall be installation of projects resulting in 50,000 MWh of annual energy generation or savings within 36 months of program approval by the Commission. APS shall collaborate with the School Facilities Board in determining the priority of projects giving consideration to the assessed valuation of the school district, participation in the National School Lunch Program, geographic diversity and need for the project. The program proposal shall describe options considered by APS for acquiring the necessary energy. In designing its program, APS shall consider among its options, a request for proposals by developers to implement and install solar energy systems on multiple schools such that the schools pay no up-front costs. APS' proposal shall include its estimate of APS' costs associated with the program, APS' proposed method for cost recovery, and APS' proposal for counting the energy produced or saved by the school solar energy systems toward APS' REST requirements. APS shall file its program proposal under a new docket number and shall provide an opportunity for interested stakeholders, including school representatives and solar industry representatives, to provide input prior to preparing its proposal. School programs executed with stimulus funding leveraging REST funds would qualify toward the program goal.

15.6 APS shall file within 120 days of the Commission's Order approving the Settlement Agreement a new program for governmental institutions for distributed solar energy, including photovoltaics, solar water heating and daylighting, to substantially reduce or eliminate up-front customer cost. APS shall file its program proposal under a new docket number and shall provide an opportunity for interested stakeholders to provide input on its proposal. This program may be proposed concurrently with the schools program described in Paragraph 15.6

15.7 All reasonable and prudent expenses incurred by APS pursuant to this Section of the Agreement shall be recoverable through the Power Supply Adjustor, a renewable energy adjustment mechanism, or the Transmission Cost Adjustor, as appropriate. To encourage least cost renewable resources to benefit customers, these expenses would also include the capital carrying costs of any capital investments by APS in renewable energy projects (depreciation expenses at rates established by the Commission, property taxes, and return on both debt and equity at the pre-tax weighted average cost of capital). In consideration of this Paragraph 15.7, APS shall not seek to recover Construction-Work-In-Progress ("CWIP") related to any of the renewable projects required by this Section 15.

15.8 APS agrees to abide by the commitments set forth in paragraphs 15.1 through 15.7 of this Section regardless of the outcome of any judicial challenge to the current REST rules. Through this Agreement, APS reiterates and renews its support of the current REST rules.

XVI. LOW INCOME PROGRAMS.

16.1 The increase in base rate revenue will not apply to the existing low income schedules (E-3 and E-4). As a result, all rate schedules except for the low income schedules will receive an equal percentage of base rate increase. This holds low income customers harmless from the rate increase and applies to both existing customers and those to be enrolled in the low income rate.

16.2 Eligibility for low-income schedule shall be set at 150% of the Federal Poverty Income Guidelines.

16.3 APS shall augment its current bill assistance program, which was approved in Decision No. 69663, to offer identical assistance to customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines. This additional program is to be funded by APS to be used by qualifying customers to assist them in their payment of customer electric bills. The level of the funding requirement during the Plan Term shall be established at $5 million. If any funding remains at the end of the Plan Term, such funds shall be carried forward until expended.

16.4 APS will waive the collection of an additional security deposit from customers on low-income rate schedules (E-3 and E-4) under the following circumstances: (1) the customer has had more than two late payments in the previous 12 months, or (2) the customer has been disconnected for non-payment.

16.5 Treatment of qualifying low-income customers by exempting them from the DSMAC is consistent with Decision No. 70961. The under-recovery of DSM costs attributable to the Commission's exemption of low-income E-3 and E-4 customers from the DSMAC increase is addressed through the regular balancing account provisions of the DSMAC and thus will be collected from all other APS customers.

XVII. REVENUE SPREAD.

17.1 Each retail rate schedule will receive an equal percentage total base rate increase, inclusive of the interim rate increase, and inclusive of fuel and purchased power costs that are incorporated into base rates.

17.2 Within E-32, the percentage increase will be differentiated such that:

a. E-32 (401 + kW) receives an increase that is 2.5% below average for the group;

b. E-32 (101-400 kW) receives the group average increase;

c. E-32 (21-100 kW) receives an increase that is 1% above the average for the group; and

d. E-32 (0-20 kW) receives an increase that is above the average for the group by the necessary residual amount (approximately 2.8%).

XVIII. RATE DESIGN.

18.1 The voltage discount for E-35 customers taking service at transmission voltage will be equal to the current discount adjusted by the overall E-35 percentage increase.

18.2 The third-party transmission charge for Rates E-34 and E-35 proposed by APS is not adopted.

18.3 The rate increase for Rates E-34, E-35 and E-32 (401+ kW) will be implemented by adopting APS' proposed changes in the customer charge with an equal percentage increase in the demand and energy charges.

XIX. INTERRUPTIBLE RATE SCHEDULES AND OTHER DEMAND REDUCTION PROGRAMS.

19.1 Within 180 days of Commission approval of the Settlement Agreement, APS, in consultation with Staff and interested stakeholders, will file an Interruptible Rate Rider ("IRR") for customers with loads over three megawatts (Rate Schedules E-34 and E-35). The IRR will provide a range of options with respect to notice requirements, duration, and frequency, and will provide credits to participating customers based on avoided capacity costs. The IRR may consist of two rate elements: a short term customer commitment, (e.g. one year for customers who are willing to commit to the interruption option for a short term), and a long term customer commitment, (e.g. for customers willing to commit for a five year period). In addition to the IRR, APS may offer Demand Response Programs applicable to these customers.

XX. DEMAND RESPONSE.

20.1 Broadly defined, APS' demand response programs include time-of-use rates, super peak and critical peak pricing rates, and other programs which influence the timing of a customer's energy usage.

20.2 To provide prospective customers that may participate in any demand response program with clear and complete information about all of their demand side management options and to improve the efficiency with which energy is used, APS shall offer and market its demand response programs jointly with its energy efficiency programs. These marketing materials shall be submitted to Staff for its review.

20.3 A new demand response super peak time-of-use rate for residential customers, as proposed by APS in the direct testimony of Charles Miessner, should be approved.

20.4 The proposed critical peak pricing rate CPP-GS will be implemented on a pilot basis, specifying a minimum number of called critical days during the program. The Company will make a good faith effort to attain participation levels of at least 200 customers in this pilot.

20.5 A residential critical peak pricing rate pilot program will be implemented on a pilot basis, and APS shall make good faith efforts to attain participation levels of at least 300 residential customers in such pilot. This program will be designed to provide participating customers with strong, clear price signals that are narrowly focused on a limited number of specific hours of each year. APS will provide participating customers with notice of each critical peak period, via email, text message or telephone message, at least 6 hours in advance of the commencement of each critical peak period.

20.6 APS shall prepare a study on the impact of its super peak and critical peak pricing programs on:

a. The mix of power generation resources, including the use of coal-fired power resources;

b. Air emissions including carbon dioxide, sulfur dioxide, nitrogen oxides, particulate matter, and mercury; and

c. Energy use by program participants.

The study shall also identify methods to better integrate demand response programs and energy efficiency programs and shall analyze the benefits of demand response programs. Benefits of the demand response program include avoided or deferred generating capacity costs and fuel and other variable cost savings. The study shall examine actual experience with APS' demand response programs and shall be filed in Docket Control within two years of the Commission's decision in this Docket.

XXI. OTHER RATE SCHEDULE MATTERS.

21.1 The Signatories agree that APS shall unfreeze the existing Rate Schedule E-20 (House of Worship) tariff for a period of 12 months to allow for additional customer participation.

21.2 Within 90 days of approval of the Settlement Agreement, APS will file a new optional TOU rate applicable to K-12 schools designed to provide daily and seasonal price signals to encourage load reductions during peak periods.

XXII. FORCE MAJEURE PROVISION.

22.1 Notwithstanding anything contained herein to the contrary, APS shall not be prevented from requesting a change to its base rates in the event of conditions or circumstances that constitute an emergency. For the purposes of this Agreement, the term "emergency" is limited to an extraordinary event that is beyond APS' control and that, in the Commission's judgment, requires base rate relief in order to protect the public interest. This provision is not intended to preclude APS from seeking rate relief pursuant to this Section in the event of the imposition of a federal carbon tax or related federal "cap and trade" system. This provision is not intended to preclude any party including any Signatory to this Agreement from opposing an application for rate relief filed by APS pursuant to this paragraph.

XXIII. COMMISSION EVALUATION OF PROPOSED SETTLEMENT.

23.1 The Signatories agree that all currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

23.2 The Signatories recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

23.3 This Agreement shall serve as a procedural device by which the Signatories will submit their proposed settlement of APS' pending rate case, Docket No. E-01345A-08-0172, to the Commission.

23.4 The Signatories recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signatories shall abide by the terms as approved by the Commission.

23.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement. If a Signatory withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signatories, except for Staff, shall support the application for rehearing by filing a document to that effect with the Commission that supports approval of the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signatory's application for rehearing.

23.6 Within ten days after the Commission issues an order in this matter, if not sooner, APS shall file compliance schedules for Staff review. Subject to Staff review, such compliance schedules will become effective January 1, 2010.

XXIV. MISCELLANEOUS PROVISIONS.

24.1 This Agreement represents the Signatories' mutual desire to compromise and settle disputed issues in a manner consistent with the public interest. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement.

24.2 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, with its various provisions for settling the issues presented by this case, is consistent with their long-term interests and with the broad public interest. The acceptance by any Signatory of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

24.3 Nothing in this Agreement shall be construed as an admission by any Signatory as to the reasonableness or unreasonableness or lawfulness or unlawfulness of any position previously taken by any other Signatory in this proceeding.

24.4 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signatory shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court.

24.5 Neither this Agreement or any of the positions taken in this Agreement by any of the Signatories may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except in furtherance of securing the approval and enforcement of this Agreement.

24.6 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control. Nothing contained in this Agreement is intended to interfere with the Commission's authority to exercise any regulatory authority by the issuance of orders, rules or regulations.

24.7 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

24.8 The Signatories shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signatories shall support and defend this Agreement before the Commission. Subject to paragraph 23.5, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

24.9 This Agreement may be executed in any number of counterparts and by each Signatory on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

Attachment A

Settlement Fair Value Rate of Return
12/31/07 Test Year
($ in Thousands)

Line	Capital Structure	Amount	%	Cost Rate	Weighted Avg	Line
	Weighted Average Cost of Capital					
1.	Short-Term Debt	$ -	0.00%	0.00%	0.00%	1.
2.	Long-Term Debt	2,886,741	46.21%	5.77%	2.67%	2.
3.	Common Stock Equity	3,360,185	53.79%	11.00%	5.92%	3.
4.	Total	$ 6,246,926	100.00%		8.58%	4.
	Fair Value Rate of Return					
5.	Short-Term Debt	$ -	0.00%	0.00%	0.00%	5.
6.	Long-Term Debt	2,579,505	33.65%	5.77%	1.94%	6.
7.	Common Stock Equity	3,002,630	39.17%	11.00%	4.30%	7.
8.	Capital Financing from OCRB	5,582,135				8.
9.	Appreciation above OCRB not recognized on utility's books	2,083,592	27.18%	1.50%	0.41%	9.
10.	Total Capital supporting FVRB	$ 7,665,727	100.00%		6.65%	10.
	Fair Value Rate Base vs. Original Cost Rate Base					
11.	Fair Value Rate Base	$ 7,665,727				11.
12.	Original Cost Rate Base	5,582,135				12.
13.	Difference	$ 2,083,592				13.

DECISION NO. ____________

ATTACHMENT B

2008 Depreciation Rate Study

Arizona Public Service Company

Palo Verde License Extended

Prepared by
Foster Associates, Inc.

DECISION NO. ____

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended) — Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	3.22%	0.57%	3.79%	3.14%	0.38%	3.52%
312.00 Boiler Plant Equipment	3.39%	0.61%	4.00%	3.17%	0.41%	3.58%
314.00 Turbogenerator Units	3.03%	0.60%	3.63%	3.07%	0.39%	3.46%
315.00 Accessory Electric Equipment	2.51%	0.47%	2.98%	2.37%	0.31%	2.68%
316.00 Miscellaneous Power Plant Equipment	3.95%	0.81%	4.76%	3.90%	0.59%	4.49%
Total Steam Production Plant	3.26%	0.60%	3.86%	3.10%	0.41%	3.51%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	2.62%		2.62%	1.28%	0.01%	1.29%
322.00 Reactor Plant Equipment	2.83%	0.01%	2.84%	1.38%	0.06%	1.44%
322.10 Steam Generators	2.92%		2.92%	1.16%	0.02%	1.18%
323.00 Turbogenerator Units	2.85%	0.01%	2.86%	1.34%	0.01%	1.35%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	1.22%	0.01%	1.23%
325.00 Miscellaneous Power Plant Equipment	3.32%	0.03%	3.35%	1.45%	0.04%	1.49%
Total Nuclear Production Plant	2.79%	0.01%	2.80%	1.33%	0.03%	1.36%
OTHER PRODUCTION						
341.00 Structures and Improvements	2.39%	0.08%	2.47%	2.79%	0.24%	3.03%
342.00 Fuel Holders, Products and Accessories	2.51%	0.12%	2.63%	3.03%	0.15%	3.18%
343.00 Prime Movers	2.27%	0.04%	2.31%	2.60%	0.10%	2.70%
344.00 Generators and Devices	2.88%	0.06%	2.94%	3.23%	0.14%	3.37%
345.00 Accessory Electric Equipment	2.39%	0.04%	2.43%	2.80%	0.13%	2.93%
346.00 Miscellaneous Power Plant Equipment	2.59%	0.01%	2.60%	2.83%	0.15%	2.98%
Total Other Production Plant	2.54%	0.05%	2.59%	2.89%	0.13%	3.02%
TRANSMISSION PLANT						
352.02 Structures and Improvements	-0.25%	-0.01%	-0.26%	2.45%		2.45%
353.00 Station Equipment	1.35%		1.35%	2.29%		2.29%
354.00 Towers and Fixtures	1.08%	0.37%	1.45%	1.78%		1.78%
355.00 Poles and Fixtures	1.97%	0.30%	2.27%	2.03%	0.40%	2.43%
356.00 Overhead Conductors and Devices	1.54%	0.53%	2.07%	1.72%	-0.33%	1.39%
Total Transmission Plant	1.36%	0.02%	1.38%	2.26%		2.26%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.95%	0.20%	2.15%	1.51%	0.06%	1.57%
362.00 Station Equipment	2.12%		2.12%	2.16%	-0.21%	1.95%
364.01 Poles, Towers and Fixtures - Wood	2.37%	0.24%	2.61%	2.26%	-0.04%	2.22%
364.02 Poles, Towers and Fixtures - Steel	1.95%	0.10%	2.05%	2.75%	0.16%	2.91%
365.00 Overhead Conductors and Devices	1.80%	0.18%	1.98%	1.89%	-0.19%	1.70%
366.00 Underground Conduit	1.14%	0.06%	1.20%	1.46%	0.07%	1.53%
367.00 Underground Conductors and Devices	3.09%	0.16%	3.25%	2.76%	0.10%	2.86%
368.00 Line Transformers	2.28%	0.11%	2.39%	1.66%	0.07%	1.73%
369.00 Services	2.35%	0.23%	2.58%	2.20%		2.20%
370.01 Meters - Electronic	3.68%		3.68%	← 5 Year Amortization →		
370.02 Meters - Electromechanical	3.02%		3.02%	← 5 Year Amortization →		
370.03 Meters - AMI	3.61%		3.61%	3.82%		3.82%
371.00 Installations on Customers' Premises	1.93%	0.39%	2.32%	1.75%	0.19%	1.94%
373.00 Street Lighting and Signal Systems	2.43%	0.48%	2.91%	1.47%	0.13%	1.60%
Total Distribution Plant	2.37%	0.14%	2.51%	2.34%	0.03%	2.37%

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended)

Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.56%	0.38%	2.94%	2.05%	0.11%	2.16%
391.CM Office Furn. and Equip. - Computer	12.46%		12.46%	10.19%	0.01%	10.20%
392.EL Transportation Equipment - Electric Vehic	3.67%		3.67%	5.83%	0.01%	5.84%
392.HD Transportation Equipment - Heavy Duty	2.04%		2.04%	2.41%	0.17%	2.58%
392.LD Transportation Equipment - Light Duty	10.50%		10.50%	10.14%	-1.73%	8.41%
392.MD Transportation Equipment - Medium Duty	3.25%		3.25%	3.55%		3.55%
392.TR Transportation Equipment - Trailers	1.17%		1.17%	2.54%		2.54%
396.00 Power Operated Equipment	3.32%		3.32%	3.81%	-0.11%	3.70%
397.00 Communication Equipment	5.25%		5.25%	4.72%		4.72%
Total Depreciable	5.89%	0.13%	6.02%	5.10%	-0.03%	5.07%
Amortizable						
391.FE Office Furn. and Equip. - Furniture	4.84%		4.84%	← 20 Year Amortization →		
393.00 Stores Equipment	4.83%		4.83%	← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	4.99%		4.99%	← 20 Year Amortization →		
395.00 Laboratory Equipment	4.99%		4.99%	← 20 Year Amortization →		
398.00 Miscellaneous Equipment	12.94%		12.94%	← 24 Year Amortization →		
Total Amortizable	5.88%		5.88%	4.67%		4.67%
Total General Plant	5.89%	0.10%	5.99%	5.02%	-0.03%	4.99%
TOTAL UTILITY	2.77%	0.16%	2.93%	2.39%	0.10%	2.49%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	1.93%	0.36%	2.29%	1.64%	0.18%	1.82%
312.00 Boiler Plant Equipment	2.52%	0.47%	2.99%	2.06%	0.23%	2.29%
314.00 Turbogenerator Units	2.32%	0.46%	2.78%	2.31%	0.22%	2.53%
315.00 Accessory Electric Equipment	1.99%	0.39%	2.38%	1.65%	0.18%	1.83%
316.00 Miscellaneous Power Plant Equipment	2.86%	0.54%	3.40%	2.29%	0.28%	2.57%
Total Cholla	2.37%	0.45%	2.82%	2.01%	0.22%	2.23%
Cholla Unit 1						
311.00 Structures and Improvements	2.25%	0.35%	2.60%	2.29%	0.20%	2.49%
312.00 Boiler Plant Equipment	3.67%	0.60%	4.27%	3.61%	0.37%	3.98%
314.00 Turbogenerator Units	2.97%	0.47%	3.44%	1.44%	0.13%	1.57%
315.00 Accessory Electric Equipment	2.91%	0.47%	3.38%	2.50%	0.24%	2.74%
316.00 Miscellaneous Power Plant Equipment	4.39%	0.71%	5.10%	2.15%	0.21%	2.36%
Total Cholla Unit 1	3.49%	0.57%	4.06%	3.17%	0.32%	3.49%
Cholla Unit 2						
311.00 Structures and Improvements	2.17%	0.39%	2.56%	2.02%	0.19%	2.21%
312.00 Boiler Plant Equipment	2.20%	0.42%	2.62%	1.62%	0.17%	1.79%
314.00 Turbogenerator Units	1.94%	0.35%	2.29%	2.21%	0.19%	2.40%
315.00 Accessory Electric Equipment	1.87%	0.35%	2.22%	1.50%	0.14%	1.64%
316.00 Miscellaneous Power Plant Equipment	2.54%	0.48%	3.02%	2.06%	0.21%	2.27%
Total Cholla Unit 2	2.11%	0.40%	2.51%	1.71%	0.17%	1.88%
Cholla Unit 3						
311.00 Structures and Improvements	1.87%	0.40%	2.27%	1.54%	0.19%	1.73%
312.00 Boiler Plant Equipment	2.25%	0.47%	2.72%	1.67%	0.22%	1.89%
314.00 Turbogenerator Units	2.47%	0.54%	3.01%	2.57%	0.27%	2.84%
315.00 Accessory Electric Equipment	1.93%	0.42%	2.35%	1.55%	0.20%	1.75%
316.00 Miscellaneous Power Plant Equipment	2.54%	0.53%	3.07%	2.00%	0.27%	2.27%
Total Cholla Unit 3	2.25%	0.48%	2.73%	1.88%	0.23%	2.11%

DECISION NO. ____________

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended) Statement A

Component Accrual Rates

Present: BG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007)			Proposed (at 12/31/2007)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Cholla Common						
311.00 Structures and Improvements	1.88%	0.35%	2.23%	1.55%	0.17%	1.72%
312.00 Boiler Plant Equipment	2.45%	0.48%	2.93%	2.07%	0.29%	2.36%
314.00 Turbogenerator Units	1.88%	0.36%	2.24%	2.20%	0.13%	2.33%
315.00 Accessory Electric Equipment	2.10%	0.40%	2.50%	2.22%	0.26%	2.48%
316.00 Miscellaneous Power Plant Equipment	2.81%	0.54%	3.35%	2.60%	0.33%	2.93%
Total Cholla Common	2.20%	0.42%	2.62%	1.91%	0.23%	2.14%
Four Corners						
311.00 Structures and Improvements	4.76%	0.77%	5.53%	5.18%	0.62%	5.80%
312.00 Boiler Plant Equipment	4.32%	0.72%	5.04%	4.50%	0.59%	5.09%
314.00 Turbogenerator Units	4.13%	0.67%	4.80%	4.91%	0.56%	5.47%
315.00 Accessory Electric Equipment	3.68%	0.64%	4.32%	4.07%	0.51%	4.58%
316.00 Miscellaneous Power Plant Equipment	4.66%	0.85%	5.51%	5.58%	0.74%	6.32%
Total Four Corners	4.31%	0.72%	5.03%	4.64%	0.59%	5.23%
Four Corners Units 1-3						
311.00 Structures and Improvements	5.96%	0.84%	6.80%	6.56%	0.73%	7.29%
312.00 Boiler Plant Equipment	5.18%	0.76%	5.94%	5.81%	0.71%	6.52%
314.00 Turbogenerator Units	4.77%	0.69%	5.46%	5.90%	0.64%	6.54%
315.00 Accessory Electric Equipment	4.73%	0.68%	5.41%	5.43%	0.61%	6.04%
316.00 Miscellaneous Power Plant Equipment	6.65%	0.96%	7.61%	8.65%	1.02%	9.67%
Total Four Corners Units 1-3	5.22%	0.76%	5.98%	5.96%	0.71%	6.67%
Four Corners Units 4-5						
311.00 Structures and Improvements	2.22%	0.59%	2.81%	2.12%	0.35%	2.47%
312.00 Boiler Plant Equipment	2.63%	0.63%	3.26%	1.80%	0.32%	2.12%
314.00 Turbogenerator Units	2.49%	0.65%	3.14%	2.21%	0.36%	2.57%
315.00 Accessory Electric Equipment	2.47%	0.65%	3.12%	1.96%	0.33%	2.29%
316.00 Miscellaneous Power Plant Equipment	2.95%	0.70%	3.65%	2.21%	0.38%	2.59%
Total Four Corners Units 4-5	2.58%	0.63%	3.21%	1.89%	0.33%	2.22%
Four Corners Common						
311.00 Structures and Improvements	2.42%	0.70%	3.12%	2.79%	0.46%	3.25%
312.00 Boiler Plant Equipment	2.52%	0.63%	3.15%	2.71%	0.48%	3.19%
314.00 Turbogenerator Units	1.65%	0.44%	2.09%	2.20%	0.32%	2.52%
315.00 Accessory Electric Equipment	1.80%	0.45%	2.25%	2.95%	0.49%	3.44%
316.00 Miscellaneous Power Plant Equipment	2.91%	0.76%	3.67%	3.09%	0.54%	3.63%
Total Four Corners Common	2.48%	0.64%	3.12%	2.82%	0.49%	3.31%
Navajo Units 1-3						
311.00 Structures and Improvements	2.95%	0.43%	3.38%	2.63%	0.27%	2.90%
312.00 Boiler Plant Equipment	3.15%	0.50%	3.65%	2.80%	0.32%	3.12%
314.00 Turbogenerator Units	2.49%	0.37%	2.86%	2.06%	0.22%	2.28%
315.00 Accessory Electric Equipment	2.55%	0.38%	2.93%	2.19%	0.24%	2.43%
316.00 Miscellaneous Power Plant Equipment	3.49%	0.55%	4.04%	3.22%	0.36%	3.58%
Total Navajo Units 1-3	3.04%	0.47%	3.51%	2.69%	0.30%	2.99%
Ocotillo Units 1-2						
311.00 Structures and Improvements	3.70%	1.41%	5.11%	3.59%	1.02%	4.61%
312.00 Boiler Plant Equipment	3.23%	1.06%	4.29%	2.83%	0.85%	3.68%
314.00 Turbogenerator Units	2.94%	1.07%	4.01%	2.64%	0.79%	3.43%
315.00 Accessory Electric Equipment	3.09%	1.08%	4.17%	3.12%	0.91%	4.03%
316.00 Miscellaneous Power Plant Equipment	5.35%	1.97%	7.32%	5.26%	1.52%	6.78%
Total Ocotillo Units 1-2	3.40%	1.19%	4.59%	3.10%	0.92%	4.02%

DECISION NO. ____________

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended)

Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro Units 1-2						
311.00 Structures and Improvements	4.68%	1.36%	6.04%	2.81%	0.80%	3.61%
312.00 Boiler Plant Equipment	4.39%	1.22%	5.61%	2.47%	0.71%	3.18%
314.00 Turbogenerator Units	3.66%	1.06%	4.72%	2.04%	0.59%	2.63%
315.00 Accessory Electric Equipment	3.40%	0.97%	4.37%	4.27%	1.23%	5.50%
316.00 Miscellaneous Power Plant Equipment	6.37%	1.81%	8.18%	3.95%	1.16%	5.11%
Total Saguaro Units 1-2	4.20%	1.19%	5.39%	2.62%	0.76%	3.38%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	2.62%		2.62%	1.28%	0.01%	1.29%
322.00 Reactor Plant Equipment	2.83%	0.01%	2.84%	1.38%	0.06%	1.44%
322.10 Steam Generators	2.92%		2.92%	1.16%	0.02%	1.18%
323.00 Turbogenerator Units	2.85%	0.01%	2.86%	1.34%	0.01%	1.35%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	1.22%	0.01%	1.23%
325.00 Miscellaneous Power Plant Equipment	3.32%	0.03%	3.35%	1.45%	0.04%	1.49%
Total Palo Verde	2.79%	0.01%	2.80%	1.33%	0.03%	1.36%
Palo Verde Unit 1						
321.00 Structures and improvements	2.63%		2.63%	1.22%	0.01%	1.23%
322.00 Reactor Plant Equipment	2.76%		2.76%	1.47%	0.05%	1.52%
322.10 Steam Generators	1.47%		1.47%			
323.00 Turbogenerator Units	2.83%	0.01%	2.84%	1.41%	0.01%	1.42%
324.00 Accessory Electric Equipment	2.69%	0.01%	2.70%	1.21%	0.01%	1.22%
325.00 Miscellaneous Power Plant Equipment	3.25%	0.03%	3.28%	1.35%	0.03%	1.38%
Total Palo Verde Unit 1	2.75%		2.75%	1.38%	0.03%	1.41%
Palo Verde Unit 2						
321.00 Structures and Improvements	2.73%		2.73%	1.24%	0.01%	1.25%
322.00 Reactor Plant Equipment	3.21%	0.01%	3.22%	1.48%	0.08%	1.56%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.12%	0.01%	3.13%	1.40%	0.02%	1.42%
324.00 Accessory Electric Equipment	2.85%	0.01%	2.86%	1.27%	0.01%	1.28%
325.00 Miscellaneous Power Plant Equipment	3.61%	0.02%	3.63%	1.49%	0.02%	1.51%
Total Palo Verde Unit 2	3.09%	0.01%	3.10%	1.40%	0.04%	1.44%
Palo Verde Unit 3						
321.00 Structures and Improvements	2.52%		2.52%	1.18%	0.01%	1.19%
322.00 Reactor Plant Equipment	2.66%	0.01%	2.67%	1.21%	0.05%	1.26%
322.10 Steam Generators	2.92%		2.92%	1.16%	0.02%	1.18%
323.00 Turbogenerator Units	2.72%	0.01%	2.73%	1.23%	0.01%	1.24%
324.00 Accessory Electric Equipment	2.61%	0.01%	2.62%	1.19%	0.01%	1.20%
325.00 Miscellaneous Power Plant Equipment	3.17%	0.03%	3.20%	1.30%	0.02%	1.32%
Total Palo Verde Unit 3	2.66%	0.01%	2.67%	1.21%	0.02%	1.23%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	2.66%		2.66%	1.44%	0.02%	1.46%
322.00 Reactor Plant Equipment	4.06%	0.01%	4.07%	2.09%	0.03%	2.12%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.06%	0.01%	3.07%	1.48%	0.02%	1.50%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	3.42%	0.03%	3.45%	1.47%	0.05%	1.52%
Total Palo Verde Water Reclamation	2.66%		2.66%	1.44%	0.02%	1.46%

DECISION NO. ________

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended)

Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Common						
321.00 Structures and Improvements	2.61%		2.61%	1.32%	0.01%	1.33%
322.00 Reactor Plant Equipment	2.73%	0.01%	2.74%	1.24%	0.08%	1.32%
322.10 Steam Generators						
323.00 Turbogenerator Units	3.12%	0.01%	3.13%	2.28%	0.05%	2.33%
324.00 Accessory Electric Equipment	2.67%	0.01%	2.68%	1.24%	0.02%	1.26%
325.00 Miscellaneous Power Plant Equipment	3.29%	0.03%	3.32%	1.56%	0.06%	1.62%
Total Palo Verde Common	2.81%	0.01%	2.82%	1.37%	0.04%	1.41%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	0.71%	0.03%	0.74%	5.94%	0.29%	6.23%
342.00 Fuel Holders, Products and Accessories	1.92%	0.09%	2.01%	1.82%	0.06%	1.88%
343.00 Prime Movers	0.71%		0.71%	0.73%	0.04%	0.77%
344.00 Generators and Devices	0.12%		0.12%	0.70%	0.03%	0.73%
345.00 Accessory Electric Equipment	0.89%		0.89%	0.98%	0.07%	1.05%
346.00 Miscellaneous Power Plant Equipment	1.85%		1.85%	1.65%	0.08%	1.73%
Total Douglas CT	0.69%	0.01%	0.70%	0.96%	0.05%	1.01%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	2.34%	0.12%	2.46%	2.02%	0.10%	2.12%
342.00 Fuel Holders, Products and Accessories	2.16%	0.11%	2.27%	1.93%	0.09%	2.02%
343.00 Prime Movers	1.38%		1.38%	1.26%	0.06%	1.32%
344.00 Generators and Devices	3.34%		3.34%	3.26%	0.13%	3.39%
345.00 Accessory Electric Equipment	1.69%		1.69%	1.68%	0.10%	1.78%
346.00 Miscellaneous Power Plant Equipment	1.97%		1.97%	1.77%	0.08%	1.85%
Total Ocotillo CT Units 1-2	2.29%	0.01%	2.30%	2.18%	0.10%	2.28%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	2.67%	0.08%	2.75%	3.01%	0.42%	3.43%
342.00 Fuel Holders, Products and Accessories	2.67%	0.08%	2.75%	3.46%	0.17%	3.63%
343.00 Prime Movers	2.67%	0.08%	2.75%	2.98%	0.07%	3.05%
344.00 Generators and Devices	2.67%	0.08%	2.75%	3.02%	0.12%	3.14%
345.00 Accessory Electric Equipment	2.67%	0.08%	2.75%	2.99%	0.12%	3.11%
346.00 Miscellaneous Power Plant Equipment	2.67%	0.08%	2.75%	3.27%	0.17%	3.44%
Total Redhawk CC Units 1-2	2.67%	0.08%	2.75%	3.00%	0.12%	3.12%
Saguaro						
341.00 Structures and Improvements	4.65%	0.23%	4.88%	3.82%	0.19%	4.01%
342.00 Fuel Holders, Products and Accessories	1.74%	0.09%	1.83%	1.62%	0.07%	1.69%
343.00 Prime Movers	1.54%		1.54%	1.38%	0.06%	1.44%
344.00 Generators and Devices	2.85%		2.85%	3.10%	0.15%	3.25%
345.00 Accessory Electric Equipment	1.44%		1.44%	1.35%	0.08%	1.43%
346.00 Miscellaneous Power Plant Equipment	3.42%		3.42%	3.20%	0.16%	3.36%
Total Saguaro	2.59%	0.01%	2.60%	2.70%	0.13%	2.83%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.65%	0.23%	4.88%	3.82%	0.19%	4.01%
342.00 Fuel Holders, Products and Accessories	1.74%	0.09%	1.83%	1.62%	0.07%	1.69%
343.00 Prime Movers	1.44%		1.44%	1.25%	0.06%	1.31%
344.00 Generators and Devices	3.67%		3.67%	4.08%	0.18%	4.26%
345.00 Accessory Electric Equipment	1.34%		1.34%	1.23%	0.07%	1.30%
346.00 Miscellaneous Power Plant Equipment	3.42%		3.42%	3.20%	0.16%	3.36%
Total Saguaro CT Units 1-2	2.37%	0.03%	2.40%	2.30%	0.10%	2.40%

DECISION NO. ________

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended)

Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.72%		2.72%	2.94%	0.15%	3.09%
344.00 Generators and Devices	2.72%		2.72%	2.94%	0.15%	3.09%
345.00 Accessory Electric Equipment	2.72%		2.72%	2.94%	0.15%	3.09%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.72%		2.72%	2.94%	0.15%	3.09%
Solar Units						
341.00 Structures and Improvements	-10.58%	-0.01%	-10.59%	0.52%	0.02%	0.54%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	6.04%		6.04%	5.59%	0.31%	5.90%
345.00 Accessory Electric Equipment	6.30%		6.30%	5.36%	0.27%	5.63%
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	5.61%		5.61%	5.45%	0.31%	5.76%
Sundance						
341.00 Structures and Improvements	1.94%		1.94%	2.21%	0.11%	2.32%
342.00 Fuel Holders, Products and Accessories	1.93%		1.93%	2.19%	0.11%	2.30%
343.00 Prime Movers	1.94%		1.94%	2.20%	0.11%	2.31%
344.00 Generators and Devices	2.14%		2.14%	3.02%	0.15%	3.17%
345.00 Accessory Electric Equipment	1.92%		1.92%	2.19%	0.11%	2.30%
346.00 Miscellaneous Power Plant Equipment	1.92%		1.92%	2.19%	0.11%	2.30%
Total Sun Dance	1.94%		1.94%	2.20%	0.11%	2.31%
West Phoenix						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	2.86%	0.16%	3.02%
342.00 Fuel Holders, Products and Accessories	2.83%	0.15%	2.98%	3.51%	0.18%	3.69%
343.00 Prime Movers	2.46%	0.05%	2.51%	2.97%	0.12%	3.09%
344.00 Generators and Devices	2.92%	0.06%	2.98%	3.33%	0.16%	3.49%
345.00 Accessory Electric Equipment	2.78%	0.05%	2.83%	3.37%	0.16%	3.53%
346.00 Miscellaneous Power Plant Equipment	2.81%		2.81%	3.11%	0.17%	3.28%
Total West Phoenix	2.72%	0.06%	2.78%	3.20%	0.14%	3.34%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	4.01%	0.19%	4.20%
342.00 Fuel Holders, Products and Accessories	3.08%	0.16%	3.24%	3.75%	0.19%	3.94%
343.00 Prime Movers						
344.00 Generators and Devices	3.23%	0.07%	3.30%	3.83%	0.16%	3.99%
345.00 Accessory Electric Equipment	2.94%		2.94%	3.77%	0.18%	3.95%
346.00 Miscellaneous Power Plant Equipment	2.56%		2.56%	2.98%	0.16%	3.14%
Total West Phoenix CC Units 1-3	3.14%	0.08%	3.22%	3.80%	0.17%	3.97%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	1.85%	0.09%	1.94%	3.04%	0.15%	3.19%
342.00 Fuel Holders, Products and Accessories	1.90%	0.09%	1.99%	2.98%	0.15%	3.13%
343.00 Prime Movers	1.95%	0.04%	1.99%	2.98%	0.15%	3.13%
344.00 Generators and Devices	2.51%	0.05%	2.56%	3.02%	0.16%	3.18%
345.00 Accessory Electric Equipment	2.08%	0.10%	2.18%	3.25%	0.16%	3.41%
346.00 Miscellaneous Power Plant Equipment	1.96%	0.09%	2.05%	3.19%	0.16%	3.35%
Total West Phoenix CC Unit 4	2.05%	0.05%	2.10%	2.99%	0.15%	3.14%

DECISION NO. ____________

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY (Palo Verde License Extended)

Statement A

Component Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present (at 12/31/2007) Investment	Present Net Salvage	Present Total	Proposed (at 12/31/2007) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	2.74%	0.14%	2.88%	3.02%	0.16%	3.18%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.74%	0.06%	2.80%	3.06%	0.10%	3.16%
344.00 Generators and Devices	2.74%	0.06%	2.80%	3.03%	0.15%	3.18%
345.00 Accessory Electric Equipment	2.74%	0.14%	2.88%	3.02%	0.15%	3.17%
346.00 Miscellaneous Power Plant Equipment	2.74%	0.14%	2.88%	3.18%	0.16%	3.34%
Total West Phoenix CC Unit 5	2.74%	0.07%	2.81%	3.04%	0.13%	3.17%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	1.55%	0.08%	1.63%	1.36%	0.07%	1.43%
342.00 Fuel Holders, Products and Accessories	1.81%	0.10%	1.91%	1.57%	0.08%	1.65%
343.00 Prime Movers	2.33%		2.33%	1.95%	0.08%	2.03%
344.00 Generators and Devices	2.91%		2.91%	2.48%	0.13%	2.61%
345.00 Accessory Electric Equipment	1.47%	-0.01%	1.46%	1.83%	0.10%	1.93%
346.00 Miscellaneous Power Plant Equipment	3.50%		3.50%	3.46%	0.17%	3.63%
Total West Phoenix CT Units 1-2	2.41%	0.01%	2.42%	2.12%	0.10%	2.22%
West Phoenix Common						
341.00 Structures and Improvements	2.45%	0.12%	2.57%	1.59%	0.13%	1.72%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.45%	0.12%	2.57%	1.59%	0.13%	1.72%
Yucca CT Units 1-4						
341.00 Structures and Improvements	3.68%	0.19%	3.87%	3.58%	0.17%	3.75%
342.00 Fuel Holders, Products and Accessories	0.91%	0.04%	0.95%	0.81%	0.04%	0.85%
343.00 Prime Movers	0.62%		0.62%	0.58%	0.03%	0.61%
344.00 Generators and Devices	1.39%		1.39%	2.61%	0.12%	2.73%
345.00 Accessory Electric Equipment	1.25%	-0.01%	1.24%	2.36%	0.13%	2.49%
346.00 Miscellaneous Power Plant Equipment	1.81%		1.81%	2.37%	0.11%	2.48%
Total Yucca CT Units 1-4	1.08%	0.01%	1.09%	1.58%	0.07%	1.65%

DECISION NO. ____________

Attachment C
Self Direction Provisions

DSM Self-Direction is an option that will be made available to qualifying customers of sufficient size by which these customers may reserve their DSM contributions, less administrative and other program costs, for their exclusive use to help fund qualifying DSM projects at their facilities. Self direction will be offered to the largest customers since they have the ability and resources (technical knowledge, expertise, and funding) to implement effective DSM and they may desire to have the flexibility to use their DSM contributions to fund their energy efficiency projects. The following parameters define the specifics for Self Direction:

1. To be eligible for Self Direction, a customer must use a minimum of 40 million kWh per calendar year, based on an aggregation of all of the customer's accounts.

2. Qualifying Self Direction customers who choose to Self Direct their DSM funds must elect self direction by notifying APS in each year that they wish to self direct. Customers who elect to self direct must continue to contribute their share of DSM funds through base rates and the DSM Adjustor Charge (DSMAC).

3. After a customer notifies APS of their intent to Self-Direct, 85% of the customer's DSM contribution will be reserved for tracking purposes for the customer's future energy efficiency project. The remaining 15% will be retained to cover the self direction program administration, management and verification, measurement and evaluation and low-income program costs.

4. Self Direction funds will be reserved for tracking purposes for the calendar year the Self Direction election is received by APS, such election must be received on or before December 1st. There will be no retroactive Self Direction funds set aside from prior budget years since the books were closed prior to the Customer's election.

5. Self Direction funds will be paid once a year in December beginning in the year that the DSM project is completed and verified by the APS Solutions for Business team. If project costs exceed the credited amount in one year, then funding will continue to be paid in December of each year until the project is 100% funded or on the tenth year of funding, which ever comes sooner.

6. If the energy efficiency project is not completed within two years of the Self Direction election date, then the Self Direction funds from the first calendar year from the Self Direction election will not be available to the Customer and will revert to the program account.

7. Qualifying customers will be required to commit all of their facilities to the Self Direction option for the duration of the specific Self Direction project's funding period. Customers would not be able designate some of their accounts for Self

Direction while designating some of their other accounts for the standard APS Solutions for Business program offerings. Customers choosing to Self Direct will not be permitted to participate in any of the APS Solutions for Business[1] program offerings for any of their accounts.

8. Aggregation would be allowed only within a given customer set of accounts, not across groups of customers. This means that groups of customers would not be able to form buying associations for the purpose of meeting the Self Direction size criteria.

9. All Self Direction projects must be considered to be a subset of either the Company's Non-Residential Large Existing Facilities DSM Program or New Construction DSM Program, for budgeting and energy savings purposes. The qualifying projects must be cost effective and meet the same requirements as these Non-Residential DSM Programs. Self Direction customers would apply for the same prescriptive and custom incentive measures as defined in APS' existing DSM program. However, annual customer incentive caps do not apply to Self Direction funds.

10. Within two years of the Self Direction election, an energy efficiency project application must be filed. This project application will include:
    a. Name of the retail electricity customer
    b. Description of the electricity conservation project(s)
    c. Project scope of work
    d. Annual energy (kWh) and peak demand (kW) savings estimate
    e. First cost estimate
    f. Project schedule
    g. Calculations that support or demonstrate the electricity savings and simple payback of the project

11. APS Solutions for Business program will review the Self Direction energy efficiency project and administer the Self Direction funding and accounting. This work will include: verifying that the technologies meet the program specifications; reviewing backup documentation that supports the savings claims; and providing measurement and evaluation after the Self Direction project is in operation. All specification documentation requirements will be identical to existing program requirements.

12. Upon completion of the final Self Direction payment, the customer may elect to continue to Self Direct by submitting a Self Direction application before December 1st. If the customer does not apply for Self Direction, then they will be treated like all other Non-Residential customers and will be eligible to participate in the

[1] The APS Solutions for Business Program is the name of the energy efficiency program that is offered to APS non-residential customers.

Solutions for Business program beginning January 1st following their final Self Direction payment.

13. All kWh energy, kW demand, and environmental savings will be reported as part of the APS Solutions for Business DSM savings and will be claimed as part of meeting the energy efficiency portfolio targets.

ARIZONA CORPORATION COMMISSION

By ______________________

Ernest G. Johnson
Director, Utilities Division

ARIZONA PUBLIC SERVICE COMPANY

By ______________________
Jeffrey B. Guldner

RESIDENTIAL UTILITY CONSUMER OFFICE

By ______________________________

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ARIZONA ASSOCIATION OF SCHOOL
BUSINESS OFFICIALS

By ______________________
Timothy M. Hogan

ARIZONA SCHOOL BOARDS ASSOCIATION

By ______________________
Timothy M. Hogan

SOUTHWEST ENERGY EFFICIENCY PROJECT

By ______________________
Timothy M. Hogan

WESTERN RESOURCE ADVOCATES

By ______________________
Timothy M. Hogan

DECISION NO. ___________

FREEPORT-MCMORAN COPPER & GOLD INC.

By ______________________________

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ARIZONANS FOR ELECTRIC CHOICE AND
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CYNTHIA ZWICK

By ______________________________
Cynthia Zwick

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By ______________________
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EXHIBIT B

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation and upgrade to existing facilities. Costs for construction depend on the customer's location, scope of project, load size, and load characteristics and include but not limited to project management, coordination, engineering, design, surveys, permits, construction inspection, and support services. This schedule establishes the terms and conditions under which Company will extend, relocate, or upgrade its facilities in order to provide service.

All facility installations shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric facilities to customers or developers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Conduit Only Design means the conduit layout design for the installation of underground Extension Facilities that will be required to serve a project. Extension Facilities are to be installed at a later date when service is requested.

b. Corporate Business & Industrial Development means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use.

c. Extension Facilities means the electrical facilities, inclusive of conductors, cables, transformers and meters, installed solely to serve an individual customer, developer, or groups of customers. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to tie the subdivision to APS existing system as well as the Electrical Facilities constructed within the subdivision which would include primary and service lines, transformers, and meters.

d High Rise Development means buildings built with four or more floors, usually using elevators for accessing floors that may consist of either residential or non-residential use or both, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Development means a development that consists of a number of separately subdivided parcels for different "Residential Subdivisions". Developments may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

g. Residential Custom Home "Lot Sale" Development means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home.

h. Residential Subdivision means a tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

i. Residential Multi-family Development means a development consisting of apartments, condominiums, or townhouses.

j. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

k. Statement of Charges means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities. The Statement of Charges is attached to this Service Schedule as Attachment 1. An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Statement of Charges or other applicable details. The Statement of Charges is not applicable to Extension Facilities requiring the relocation, modification, or upgrade of existing facilities or for non-residential customers with estimated loads over 3 megawatts, or that require 3,000 kVA of transformer capacity or greater, or special requests involving primary metering or specialized or additional equipment for enhanced reliability. When the Statement of Charges is not applicable, charges for Extension Facilities shall be determined by the Company based on project-specific cost estimates.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Extension Facilities will be installed to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.1.2 In instances where an applicant requests service directly from a customer-funded extension constructed in accordance with Section 1.1.1 hereof, the initial applicant may be eligible for refund on a pro-rata basis for a portion of the initial extension cost related to the shared Extension Facilities. If the initial applicant no longer owns the property, the refund will be provided to the current property owner.

1.1.3 The first and second applicants connecting to an extension completed under the provisions of this Section will be required to pay a pro-rata share of the cost of the initial extension plus the costs attributable to the applicant's own extension.

1.1.4 In no event shall the total of refund payments made to the initial customer be in excess of the total amount originally paid by the initial customer.

1.1.5 The refund eligibility period shall be five years from the execution date of APS' line extension agreement to the initial applicant.

1.2 RESIDENTIAL SUBDIVISION DEVELOPMENTS

Extension Facilities will be installed to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant signs an extension agreement. The subdivision development plat shall be approved and recorded in the county having jurisdiction. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

1.3.1 Extension Facilities will be installed for residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant sign an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3.2 Extension Facilities will be installed for each permanent customer upon request for service in accordance with Section 1.1 of this service schedule.

1.3.3 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

1.4.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by permanent customers, provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.4.2 Extension Facilities will be installed to each subdivided tract within the planned development in advance of application for service by permanent customers in accordance with the applicable sections of this Service Schedule.

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

Extension Facilities will be installed to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.6 HIGH RISE DEVELOPMENTS

1.6.1 APS will provide service to this type of development at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical facilities within the building.

1.6.2 Extensions will be made to High Rise Developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 5.11.

1.6.3 Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

1.6.4 Extension Facilities will be installed to High Rise Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined based on project-specific requirements and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

2.0 NON-RESIDENTIAL

2.0.1 Extension Facilities will be installed for applicants not meeting the definition of Residential or as provided for in Section 2.1, or Section 3.0 of this Schedule. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

2.0.2 The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

2.0.3 Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.0.4 In instances where an applicant requests service directly from a customer-funded extension constructed in accordance with this Section 2.0, the initial applicant may be eligible for refund on a pro-rata basis for a portion of the initial extension cost related to the shared Extension Facilities. If the initial applicant no longer owns the property, the refund will be provided to the current property owner.

2.0.5 The first and second applicants connecting to an extension completed under the provisions of this Section will be required to pay a pro-rata share of the cost of the initial extension plus the costs attributable to the applicant's own extension.

2.0.6 In no event shall the total of refund payments made to the initial customer be in excess of the total amount originally paid by the initial customer.

2.0.7 The refund eligibility period shall be five years from the execution date of APS' line extension agreement to the initial applicant.

2.1 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.1.1 Extension Facilities will be installed for Corporate Business & Industrial Park Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.1.2 Extension Facilities will be installed to individual lots (applicants/customers) within the Corporate and Business Park Development in accordance with the applicable sections of this Service Schedule.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Extension Facilities will be installed for Irrigation Customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the applicant, the applicant shall make a payment in advance of installation or construction equal to the cost of installing and removing the facilities required to provide service, less the salvage value of such facilities. Charges will be in accordance with a cost estimate determined by the Companybased on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 MUNICIPALITIES AND OTHER GOVERNMENTAL AGENCIES

Relocation of existing facilities and/or Extension Facility installations required to serve the loads of municipalities or other governmental agencies may be constructed prior to the receipt of an executed extension agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the extension costs in accordance with the applicable sections of this

Service Schedule.

4.0 UNDERGROUND CONSTRUCTION

4.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

4.1.1 The extension meets all requirements as specified in Sections 1.0, 2.0, or 3.0.

4.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications. Customer or applicant(s) may hire contractors to perform this work.

4.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

4.1.4 In lieu of customer or applicant(s) providing these services and equipment, the Company may provide and the customer or applicant(s) will make a payment equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.0 GENERAL CONDITIONS

5.1 VOLTAGE

All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department, applicant will be required to pay the costs of any required studies.

Extension Facilities installed at higher voltages are limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or public property or right of way.

5.2 POINT OF DELIVERY

5.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

5.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

5.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

5.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be conveyed to the Company in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.4 GRADE MODIFICATIONS

If subsequent to construction of electric facilities the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

5.5 OWNERSHIP

Except for customer-owned facilities, all electric facilities installed in accordance with this Service Schedule will be owned, operated, and maintained by Company.

5.6 MEASUREMENT AND LOCATION

5.6.1 Measurement must be along the proposed route of construction.

5.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

5.6.3 The extension must be a branch from, the continuation of, or an addition to, the Company's existing distribution facilities.

5.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

5.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the customer will be included in the payment described in previous sections of this Service Schedule.

5.10 UPGRADES, RELOCATIONS AND/OR CONVERSIONS

5.10.1 Company will upgrade, relocate or convert its facilities for the customer's convenience or aesthetics. The cost of upgrades, relocation or conversion will be as determined by the Company by a detailed estimate will be included in the payment described in previous sections of this Service Schedule.

5.10.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make payment equal to the estimated cost of relocation as determined by the Company by a cost estimate.

5.11 MASTER METERING

5.11.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

5.11.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 5.11.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

5.11.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

5.11.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

5.11.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

5.11.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a payment equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

5.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild, modify, or upgrade existing facilities to meet the customer's added load or change in service requirements. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension otherwise the payment shall be non-refundable. Charges for such changes will be in accordance with a cost estimate determined by the Company based on project-specific requirements.

5.13 STUDY AND DESIGN PAYMENT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension otherwise the payment shall be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

5.14 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

5.15 EXTENSION AGREEMENTS

All facility installations or equipment upgrades requiring payment by an applicant or customer shall be in writing and signed by both the applicant or customer and Company.

5.16 ADDITIONAL PRIMARY FEED

When specifically requested by an applicant or customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the feasibility of the request The applicant or customer will be required to pay for the added cost as well as the applicable rate for the additional feed requested. Installation cost will be based on a cost estimate based on project-specific requirements. Payment for the installation of facilities is due at the time the facilities agreement is executed by the applicant.

5.17 POLICY EXCEPTION

The Schedule 3 as stated herein is applicable to all applicants and customers unless specific exemptions are approved by the Arizona Corporation Commission. The following exemptions have been approved:

5.17.1 Residential Homes on Native American Land

Extensions for residential homes on Native American Reservations will be made in accordance with the provisions of Service Schedule 3 that was in effect April 1, 2005 through June 30, 2007. Application of this Section 5.17.1 is limited to Native American Reservations as defined by applicable Federal law.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

ATTACHMENT 1
SCHEDULE OF CHARGES – SINGLE PHASE

APS Schedule #3, Line Extension Statement of Charges
Single Phase Extension Costs, Year 2010

Primary Single Phase	Overhead	Underground		
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Switch Gear
	$15.32	$5.75	$719	$3,770

Transformer Single Phase	SES Size	Transformer Size	Overhead	Underground Padmount
	200 Amp	25kVA	$3,324	$3,393
	200 Amp	50kVA	$4,160	$4,740
	400 Amp	50kVA	$4,160	$4,740
	600 Amp	75kVA	$5,633	$5,649
	800 Amp	100kVA	$7,152	$6,754

Services Single Phase	Service	Service Line per Circuit Foot	
	Size	Overhead	Underground
Res & Non-Res	200 Amp	$4.57	$2.79
Residential	400 Amp	$8.58	$3.27
Non-Residential	400 Amp	$8.58	$3.27
Res & Non-Res	600 Amp	$17.16	$6.54
Res & Non-Res	800 Amp	$25.74	$9.87

Notes:
1) Extension Facilities that do not qualify for the Statement of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Footage for each circuit will be summed to determine charges.

ATTACHMENT 1
SCHEDULE OF CHARGES – THREE PHASE

APS Schedule #3 Line Extension Statement of Charges
Three Phase Extension Costs, Year 2010

	Overhead	Underground						
Feeder Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (1 Circuit)	Pull Box (1 Circuit)	Manhole (1 Circuit)	Cost per Circuit Foot (2 Circuits)	Pull Box (2 Circuits)	Manhole (2 Circuits)	Pad Mount Switch Gear
	$34.33	$24.73	$3,637	$8,447	$47.06	$6,284	$12,036	$15,519

	Overhead	Underground		
Primary Three Phase	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Switch Gear
	$21.98	$16.66	$1,284	$15,519

	SES Size	Overhead				Underground Padmount			
		120/208 Volts		277/480 Volts		120/208 Volts		277/480 Volts	
Transformer Three Phase	200 Amp	3-25kVA	$8,839	3-50kVA	$9,063	112.5kVA	$12,472	112.5kVA	$13,277
	400 Amp	3-50kVA	$11,349	3-75kVA	$11,033	112.5kVA	$12,472	225kVA	$15,841
	600 Amp	3-50kVA	$11,349	3-100kVA	$11,545	150kVA	$14,682	300kVA	$17,823
	800 Amp	3-75kVA	$15,753			225kVA	$15,692	500kVA	$19,870
	1000 Amp	3-75kVA	$15,753			225kVA	$15,692	500kVA	$19,870
	1200 Amp	3-100kVA	$20,112			300kVA	$18,413	750kVA	$25,391
	1600 Amp	3-167kVA	$23,638			500kVA	$21,843	1000kVA	$25,642
	2000 Amp					500kVA	$21,843	1000kVA	$25,642
	2500 Amp					750kVA	$23,415	1500kVA	$39,086
	3000 Amp					750kVA	$23,415	1500kVA	$39,086

	Service	Service Line per Circuit Foot			Service	Service Line per Circuit Foot	
	Size	Overhead	Underground		Size	Overhead	Underground
Services Three Phase	200 Amp	$3.43	$5.10		1200 Amp	$29.76	$31.65
	400 Amp	$9.40	$10.18		1600 Amp	$29.76	$50.64
	600 Amp	$14.88	$11.42		2000 Amp		$50.64
	800 Amp	$14.88	$25.32		2500 Amp		$82.31
	1000 Amp	$29.76	$25.32		3000 Amp		$88.62

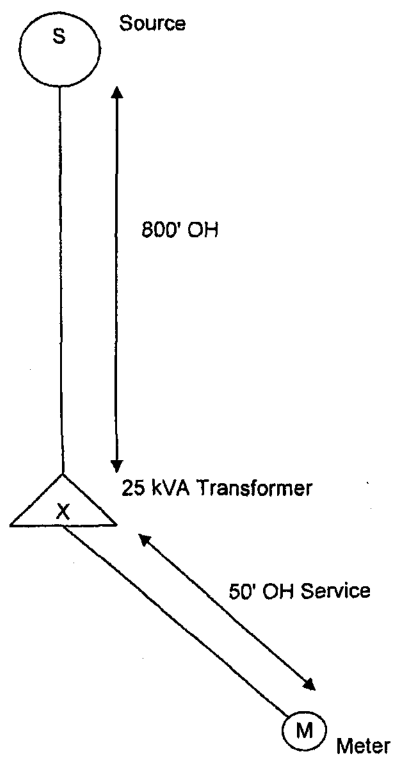
Notes:

1) Extension Facilities that do not qualify for the Statement of Charges will be determined by a project specific cost estimate.

2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Footage for each circuit will be summed to determine charges.

3) For Multiple services out of one three phase transformer, the service cost will be determined by each SES and the transformer cost will be determined from the combined of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000. amps.

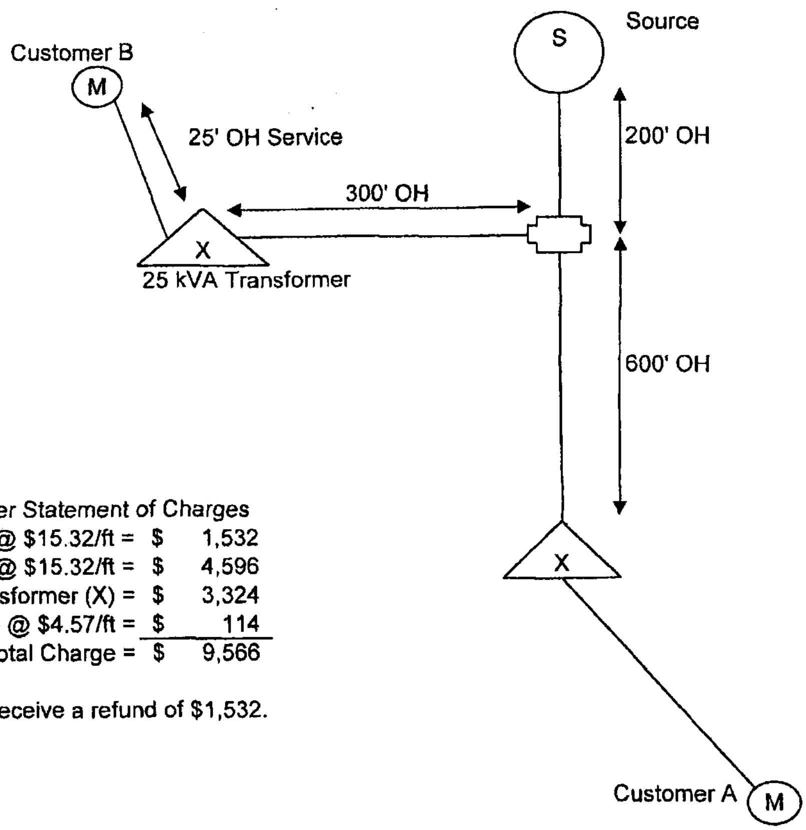
Customer A



Cost per Statement of Charges

800' OH @ $15.32/ft =	$	12,256
25 kVA OH Transformer (X) =	$	3,324
50' OH Service @ $4.57/ft =	$	229
Total Charge =	$	15,809

Customer B
Added to Extension Funded by Customer A



Cost per Statement of Charges

1/2 of 200' OH @ $15.32/ft =	$	1,532
300' OH @ $15.32/ft =	$	4,596
25 kVA OH Transformer (X) =	$	3,324
25' OH Service @ $4.57/ft =	$	114
Total Charge =	$	9,566

Customer A will receive a refund of $1,532.