NEW APPLICATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

E-01345A-11-0224

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-11- APPLICATION

I. INTRODUCTION.

In this Application, Arizona Public Service Company ("APS") seeks a net increase in base rates of $95.5 million, or 3.3%, to become effective on July 1, 2012.[1] The requested increase is required for the Company to continue to meet Arizona's

[1] This Application is filed pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-102 to R14-2-103.

Application
E-01345A-11-0224

PART 1 OF 3
BAR CODE # 0000126066

To review remaining parts please see the following:

PART 2 OF 3 BAR CODED #0000126067

PART 3 OF 3 BAR CODED #0000126068

energy goals for the second phase of the Rate Case Filing Plan established for APS in the 2009 Settlement Agreement ("Settlement").[2]

Specifically, this increase will recover $1.5 billion worth of infrastructure investments that are now or will be in service for customers by the proposed effective date of new rates. These investments, among other things, bring renewable energy to Arizona – particularly solar. They also reflect environmental and other upgrades at the Company's power plants and to its electric delivery system, allowing them to operate safely and reliably for the benefit of APS customers. And they give customers the tools they seek to better manage and control their energy use. The requests made in this Application will also allow APS, among other things, to keep pace with costs required by environmental regulation and generation additions and incurred in pursuit of the Commission's ambitious energy efficiency standard. As proposed, these benefits would be funded through progressive, cost of service based rate mechanisms that will align the utility business model with the public interest and smooth the resulting rate impact on customer bills, bringing more rate stability and predictability in the long run.

In many ways, the Company's requests build on the regulatory framework established in the Settlement. The Settlement set clear renewable energy and energy efficiency goals for APS, which APS is meeting. The Settlement also recognized that the cost required to achieve these goals and provide reliable electric service must be timely reflected in our rates. It thus took steps to make rate changes more gradual and predictable for customers and rate case stakeholders, rather than requiring APS to seek more sporadic and dramatic rate hikes. The Settlement put APS on a two-phase rate case filing plan that lasts through December 31, 2014, and funded the energy policy goals set in the Settlement through 2012. Recognizing that the Company would need additional funding thereafter to sustain its energy goals, the Settlement established a

[2] Approved in Decision No. 71448 (December 30, 2009).

June 1, 2011 filing date for this rate case and provided that the parties should work to resolve it by July 2012.

Working from that framework, this Application proposes new tools that further adapt the Company's rate structures to meet today's needs and continue the work that started with the Commission and 22 Settlement signatories in 2009. The rates set for the first phase of the Rate Case Filing Plan do not recover the legitimate cost of providing electric service to customers today (let alone for the rest of the Filing Plan term). As a result, the Company's current rates do not produce a reasonable return on the fair value of the property that APS devotes to public service, and are therefore unjust and unreasonable. This Application, which the Settlement expressly anticipated, proposes to raise base rates to adequate levels. It also sets forth the next step in a long-term strategy to bring APS customers the levels of reliability they expect, outstanding customer service, comprehensive energy efficiency and renewable energy programs, and needed upgrades to our electric system – using rate mechanisms that will smooth bill impacts to customers over a longer time period.

The Settlement is universally recognized as a critical turning point in Arizona regulation. To continue that momentum, APS asks the Commission to approve the Company's requests and render an order within 13 months -- by July 1, 2012 -- as the Settlement contemplated.

II. COMPONENTS OF THE RATE REQUEST.

As required by Section 2.2 of the Settlement, the requested rate increase is based on adjusted test year sales and expenses for the Company's ACC-jurisdictional electric operations during the twelve months ending December 31, 2010 ("Test Year"). As also contemplated by the Settlement (Section 2.3), APS asks that the increase become effective on July 1, 2012.

A. Base Rate Request

The net base rate increase proposed by APS is $95.5 million, which sum is made up of three parts: (1) a non-fuel increase of $194.1 million; (2) the transfer into base rates of $44.9 million in revenue requirement related to certain assets now being recovered or which we expect to recover through the Renewable Energy Surcharge (the "RES"); and (3) the transfer of a negative balance of the PSA adjustor into base rates, in the amount of (-)$143.5 million. As proposed, APS's base rates will increase by 3.3%. However, the percentage impact of the Company's requests on customer bills will be higher, approximately 6.6% on average, primarily because the present negative Power Supply Adjustor ("PSA") charge will simultaneously be reset to zero, thereby removing a PSA credit that currently reduces customer bills. Shown mathematically, the components of the net base rate increase are:

Non-fuel increase (ex. RES transfer to base rates)	$ 194.1
PLUS: RES recovery transferred to base rates	44.9
LESS: Decrease in base fuel rate	(143.5)
Net base rate increase proposed by APS	$ 95.5

Key non-fuel components of the base rate increase, other than the transfer of RES projects into base rates, include the following. First, $48.9 million of the total non-fuel increase relates to a pro forma adjustment that adds 18 months of post-Test Year plant to APS's authorized revenue requirement. This adjustment, which is consistent with that authorized for the first phase of the Settlement, is a valuable tool that allows APS's rates to reflect the plant that is already serving customers as of the rate effective date within Arizona's traditional historical test year ratemaking model. These are "known and measurable changes" from Test Year expenses – no dollars will be included as part of this adjustment unless they represent plant that is already in service for customers as of the July 1, 2012 effective date of new rates and its actual revenue requirement is

calculable. A detailed breakdown of each of these expenses is contained in the testimonies of APS business witnesses Mark Schiavoni, Randy Edington, and Daniel Froetscher.

Approximately $44.9 million of the net base rate increase relates to revenue requirements on Commission-approved APS-owned renewable generation that will close prior to June 30, 2012 (most of which was authorized as part of the Company's AZ Sun program). These generation facilities are also post-Test Year plant additions. As APS Witness Jeff Guldner describes, APS proposes to recover these costs through the RES in 2012 until the recovery is authorized in base rates. Future phases of AZ Sun would be recovered through the RES mechanism and then incorporated into base rates in a subsequent general rate case.

With respect to APS's line extension policy ("Schedule 3"), the Settlement required that customer proceeds received under Schedule 3 be treated as revenue through the earlier of December 31, 2012 or the conclusion of the first rate case filed pursuant to the Settlement's rate case filing plan. In this case, APS proposes to again treat future line extension proceeds as customer advances and contributions in aid of construction. A corresponding pro forma adjustment to the Test Year removes the revenue credit for the proceeds from line extensions as a known and measureable change from the Test Year.

Another pro forma adjustment begins to collect the deferred expenses related to APS's historical pension and other post-retirement benefits ("OPEB") costs, as authorized by the Settlement. APS proposed to recover this deferral over a three year period.

This Application also presents an updated Depreciation Study that reflects the Company's depreciation expense using 2010 data. This update results in a $32.4 million decrease to APS's revenue requirements, primarily related to the license extension

recently authorized for APS's Palo Verde Nuclear Generating Station. APS Witness Ron White presents the 2010 Depreciation Study and discusses it in detail.

APS firmly believes that stock compensation and the Supplemental Executive Retirement Benefits Plan are standard components of compensation for electric utilities throughout the United States, and that the related costs should therefore be included in the Company's cost of service. However, given the current economic climate, APS chose not to seek recovery of those costs in this rate request.

For the same reason, APS chose to reduce the Fair Value increment that it would request in this rate case below that supported by its expert, APS witness Dr. William Avera, and below the level recommended by Staff and ultimately granted for APS in the Settlement. Dr. Avera explains in his testimony why a higher Fair Value increment would be the most appropriate measure of Fair Value rate of return for APS.

B. Other Requests

As noted above, this Application proposes additional rate mechanisms that align the Company's and customers' economic interests as well as smooth the rate impact on customer bills, bringing customers more rate stability and predictability in the long run. Specifically, this Application requests:

- Establishment of an "Efficiency and Infrastructure Account" ("EIA") – Consistent with the Commission's recently approved decoupling policy statement,[3] the Company proposes an annually adjusted mechanism based on a revenue per customer calculation. The EIA attempts to address the loss in fixed cost recovery that occurs when the historical volumetric pricing structure is used in combination with increasing energy efficiency and distributed generation requirements.

[3] Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-000005-08-0314 and G-00000C-08-0314, Dec. 29, 2010.

- Establishment of an "Environmental and Reliability Account" ("ERA") – This mechanism proposes to recover new or acquired generation plant capacity additions and plant investment required to meet environmental compliance standards. It would include investments in pollution control equipment and efficiency projects at the Company's power plants as well as investments in new non-renewable generation. The ERA is intended to replace APS's existing Environmental Improvement Surcharge, which APS requests that the Commission cancel if the ERA is approved.
- Amendments to the Power Supply Adjustor ("PSA") – APS requests two changes relating to the PSA:
  - First, APS seeks to eliminate the current 90/10 sharing provision now required by the PSA Plan of Administration. APS is the only Arizona utility to have a 90/10 sharing provision, pursuant to which APS can only recover from customers 90% of its banked fuel and purchased power expense above what the Company recovers as base fuel. This mechanism also allows APS to keep 10% of banked fuel credits, which has worked to APS's benefit with the lower than usual price of natural gas over the recent past.
  - Second, APS seeks to capture the cost of chemicals (such as lime) that are needed to operate environmental equipment at our power plants. These costs directly correlate to the use of fuel, and annual changes in these costs are appropriate to include in the PSA calculation.

- Amendment to the Transmission Cost Adjustor ("TCA") – APS requests two changes related to the TCA.
  - First, a portion of APS's transmission costs currently are collected in base rates. Any excess amount is collected through the TCA. In this case, for simplicity and to better harmonize the Company's Commission rate filings with its Federal Energy Regulatory Commission ("FERC") filings, APS requests authorization to transfer the transmission costs now in base rates for collection, with all other transmission costs, through the TCA.
  - Second, this Application requests a process change that allows for APS to charge the FERC-approved transmission rate to retail customers on the date that it becomes effective for wholesale customers. By federal law, FERC has jurisdiction over APS's transmission rates to both retail and wholesale customers, and this request would allow the FERC rate update to occur without requiring a separate proceeding before the Commission. Commission Staff regularly and thoroughly reviews APS's FERC formula rate filings and its rights to do so would continue notwithstanding the Company's proposed changes to the TCA.

In addition to these and the other requests discussed above, APS is proposing several new rate programs or modifications to existing rates and schedules. For example, APS seeks to adjust the relative on-peak and off-peak prices for its time-of-use rate schedules, based on the most recent information for wholesale market prices to reflect more accurate price signals to customers. Further, APS proposes to implement an experimental Peak Time Rebate program, which is an additional option for demand response pricing. This rate option will provide a rebate to customers who reduce usage

during critical peak hours. APS also seeks to implement a new optional rate for APS's largest commercial and industrial customers, pursuant to which APS would, for a specified period of time, procure or provide generation resources from the market tailored to the specific needs of the customer. Finally, APS requests authorization to implement an economic development service schedule that, if approved, could promote new jobs and cost effective business expansion in Arizona.

Although no other significant rate design changes are requested, APS seeks to make minor adjustments to rates so as to better track costs of service, to improve ease of rate administration, and to improve rate clarity for customers. APS will also propose minor modifications to service schedules to improve clarity and ease of administration.

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In support of this Application, the Company respectfully states as follows:

1. The Company is a corporation duly organized, existing, and in good standing under the laws of the State of Arizona. Its principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004.

2. The Company is a public service corporation, engaged in the generation, transmission, and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric system.

3. All communications and correspondence concerning this Application, as well as discovery and pleadings with respect thereto, should be served upon:

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4. This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of the public service corporation, to fix a just and reasonable rate of return thereon, and, thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearings, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and post-hearing matters.

5. Accompanying this Application are all the relevant Standard Filing Requirements ("SFRs") and rate design schedules described in A.A.C. R14-2-103[4] and the direct testimony and attachments of the following witnesses:

Mr. Donald G. Robinson	State of the Company and general content of rate case
Mr. Jeffrey B. Guldner	Overview of the rate case and central issues
Mr. James R. Hatfield	Financial projections, bond rating information
Mr. Mark A. Schiavoni	Fossil generation operations and capital expenditures
Mr. Randy Edington	Nuclear generation operations and capital expenditures

[4] This Application does not include SFR Schedule E-6 because that schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q), and APS is not a "combination utility."

Mr. Daniel T. Froetscher	Distribution operations and capital expenditures
Dr. William E. Avera	Cost of equity and fair value rate of return
Mr. Leland R. Snook	Efficiency and Infrastructure Account and the Environmental and Reliability Account
Mr. Zachary J. Fryer	Cost of service and fair value calculation
Mr. Jason C. La Benz	Historical accounting information and rate base and income statement pro formas
Dr. Ronald E. White	Depreciation study and cost expense
Mr. Peter Ewen	Base fuel cost and the Power Supply Adjustor
Mr. Charles A. Miessner	Rate design and programs

6. The Company respectfully requests that this Commission set a date for the hearing on this Application such that new rates for the Company will become effective by July 1, 2012. At the hearing conducted pursuant to this rate request, APS will establish and hereby alleges that:

(a) APS's current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable.

(b) The requested increase produces the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity, and for the attraction of new capital investment on reasonable terms.

(c) The Company requires additional permanent base revenue of at least a net $95.5 million based on annualized test period sales,

calculated as described in this Application, in order to continue to provide, both now and in the future, adequate and reliable electric service to its customers as required by law.

(d) The EIA should be established, as described above.

(e) The EIS approved by Decision No. 69663 should be cancelled and replaced with the ERA, as described above.

(f) The PSA should be modified to remove the 90/10 sharing mechanism and allow for the recovery of chemical costs, as described above.

(g) The Company's FERC-approved transmission rates should be directly reflected in rates to retail customers through the TCA, without specific Commission action.

(h) The portion of transmission costs now recovered through base rates should be transferred for recovery through the TCA.

(i) The portion of renewable-generation related capital investment now being recovered through the RES should be transferred for recovery through base rates.

(j) APS's new rate and service offerings (Peak Time Rebate, optional generation service for large customers and economic development service schedule) are in the public interest and should be approved.

(k) Modifications to existing rate and service schedules as proposed by the Company are in the public interest and should be approved.

(l) All other initiatives supported by the testimony and exhibits attached thereto are in the public interest and should be approved.

7. In addition to setting a hearing date, APS asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate

discovery. To facilitate the intent of Section 2.2 of the Settlement, APS requests that the procedural order set dates such that a final order will be rendered in this case within twelve months of a sufficiency finding. With respect to discovery, APS requests that the Company should be authorized to serve all pleadings, testimony, discovery requests, answers, and objections electronically. Hard copy service would remain available to all parties upon request or if the confidential nature of the information makes the use of electronic service impractical.

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WHEREFORE, THE COMPANY RESPECTFULLY REQUESTS that the Commission:

A. Issue a procedural order establishing a date or dates for the filing of testimony and the hearing of evidence concerning the Application that meets the intent of Section 2.2 of the Settlement Agreement, and also prescribing the time and form of notice to APS customers;

B. Issue a final order granting the Company the permanent base rate increase sought herein;

C. Modify the PSA and TCA as requested herein;

D. Establish the EIA and the ERA, as requested herein;

E. Authorize the transfer of recovery of certain assets now recovered through the RES into base rates, as requested herein;

F. Issue a final order approving the new or modified rate and service schedules included with the Company's Application, as well as the cancellation of certain schedules, all with an effective date of July 1, 2012;

G. Issue a final order authorizing APS's proposed depreciation and present amortization rates and classifications;

H. Grant the Company such other relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 1st day of June, 2011.

By: Meghan H. Grabel
Meghan H. Grabel
Thomas L. Mumaw
Attorneys for Arizona Public Service Company

ORIGINAL and thirteen (13) copies of the foregoing filed this 1st day of June, 2011, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

A-1

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Adjusted Rate Base	$ 5,720,277 (a)	$ 10,728,532 (a)	$ 8,224,405	1.
2.	Adjusted Operating Income	474,356 (b)	474,356 (b)	474,356 (b)	2.
3.	Current Rate of Return	8.29%	4.42%	5.77%	3.
4.	Required Operating Income	507,389	507,389	507,389	4.
5.	Required Rate of Return	8.87% *	4.73% *	6.17% *	5.
6.	Adjusted Operating Income Deficiency	33,033	33,033	33,033	6.
7.	Gross Revenue Conversion Factor	1.6532 (c)	1.6532 (c)	1.6532 (c)	7.
8.	Requested Increase in Base Revenue Requirements	$ 54,610 **	$ 54,610 **	$ 54,610 **	8.
9.	Fair Value Increment			40,883	9.
10.	Requested Increase in Base Revenue Requirements			$ 95,493	10.
11.	Required Rate of Return with Fair Value Increment			6.47%	11.

	Customer Classification	Projected Revenue Increase Due to Rates	% Increase	
12.	Residential	$ 58,104	3.95%	12.
13.	General Service	35,413	2.64%	13.
14.	Irrigation and Water Pumping	966	3.62%	14.
15.	Outdoor Lighting	761	3.62%	15.
16.	Dusk-to-Dawn	249	2.94%	16.
17.	Total	$ 95,493	3.33%	17.
18.	Total Sales to Ultimate Retail Customers	$ 2,868,858 (d)		18.

Notes:

* The Required Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) H-1

Recap Schedules:
N/A

A-2

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY RESULTS OF OPERATIONS
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Prior Years		Test Year		Projected Years					Line No.
		Year Ended 12/31/2008 (a)	Year Ended 12/31/2009 (a)	Actual 12/31/2010 (a)	Adjusted 12/31/2010 (b)	Present Rates 12/31/2011 (c)	Present Rates 12/31/2012 (c)	Present Rates 12/31/2013 (c)	Proposed Rates 12/31/2012 (c)	Proposed Rates 12/31/2013 (c)	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1.	Gross Revenues	$ 3,133,496	$ 3,149,500	$ 3,180,807	$ 3,089,173	$ 3,242,469	$ 3,393,545	$ 3,447,159	$ 3,478,076	$ 3,693,927	1.
2.	Revenue Deductions & Operating Expenses	2,698,096	2,711,657	2,663,726	2,542,246	2,716,785	2,837,977	2,924,410	2,892,322	3,063,136	2.
3.	Operating Income	435,400	437,843	517,081	546,927	525,684	555,568	522,749	585,754	630,791	3.
4.	Other Income and (Deductions)	836	13,893	20,138	20,138	20,473	17,940	16,562	17,883	16,335	4.
5.	Interest Expense	173,892	200,511	201,556	201,556	207,491	204,400	229,824	199,234	215,151	5.
6.	Net Income	$ 262,344	$ 251,225	$ 335,663	$ 365,509	$ 338,666	$ 369,108	$ 309,487	$ 404,403	$ 431,975	6.
7.	Earned Per Average Common Share *	$ 3.68	$ 3.53	$ 4.71	$ 5.13	N/A	N/A	N/A	N/A	N/A	7.
8.	Dividends Per Common Share *	$ 2.39	$ 2.39	$ 2.56	$ 2.56	N/A	N/A	N/A	N/A	N/A	8.
9.	Payout Ratio *	64.8%	67.7%	54.3%	49.9%	N/A	N/A	N/A	N/A	N/A	9.
10.	Return on Average Invested Capital	6.9%	6.8%	7.7%	8.1%	7.9%	7.9%	6.9%	8.4%	8.3%	10.
11.	Return on Year End Capital	6.7%	6.8%	7.6%	8.0%	7.8%	7.6%	6.7%	8.0%	8.2%	11.
12.	Return on Average Common Equity	7.7%	7.5%	9.3%	10.1%	8.8%	9.1%	7.1%	10.0%	9.7%	12.
13.	Return on Year End Common Equity	7.9%	7.3%	8.8%	9.6%	8.6%	8.6%	7.1%	9.3%	9.5%	13.
14.	Times Bond Interest Earned-Before Income Taxes	2.7	2.7	3.3	3.6	3.1	3.3	2.8	3.6	3.7	14.
15.	Times Total Interest & Preferred Dividends Earned-After Income Taxes	2.2	2.1	2.5	2.6	2.3	2.5	2.1	2.6	2.7	15.

Notes:

* Optional for projected years. Lines 7 and 8 are calculated using the common stock shares of Arizona Public Service Company, as indicated by the SFRs. APS's common stock shares have remained constant at 71.3 million, even though Pinnacle West has increased its equity investment in APS, and all APS shares are wholly owned by Pinnacle West Capital Corp. Pinnacle West's common stock is publicly held and the PNW share count is more indicative of the increasing equity investment needed to support APS's investment to serve its customers. APS's earnings per share of Pinnacle West diluted common stock outstanding was $2.60, $2.48, $3.13, $3.41for 2008, 2009, Test Year ended 12/31/2010, and adjusted Test Year ended 12/31/2010, respectively. APS's dividends per share of Pinnacle West diluted common stock outstanding was $1.68, $1.68, $1.70, $1.70 for 2008, 2009, Test Year ended 12/31/2010, and adjusted Test Year ended 12/31/2010, respectively.

Supporting Schedules:
(a) E-2
(b) C-1
(c) F-1

Recap Schedules:
N/A

A-3

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF CAPITAL STRUCTURE
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Prior Years (a) Year Ended 12/31/2008 (A)	Prior Years (a) Year Ended 12/31/2009 (B)	Actual Test Year (a) Ended 12/31/2010 (C)	Projected Years (b) Present Rates Year Ended 12/31/2011 (D)	Projected Years (b) Present Rates Year Ended 12/31/2012 (E)	Projected Years (b) Present Rates Year Ended 12/31/2013 (F)	Projected Years (b) Proposed Rates Year Ended 12/31/2012 (G)	Projected Years (b) Proposed Rates Year Ended 12/31/2013 (H)	Line No.
1.	Short-Term Debt *	$ 521,684	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1.
2.	Long-Term Debt (with Cur Maturities) **	2,859,024	3,384,767	3,382,856	3,381,390	3,605,855	3,980,855	3,555,855	3,680,855	2.
3.	TOTAL DEBT	3,380,708	3,384,767	3,382,856	3,381,390	3,605,855	3,980,855	3,555,855	3,680,855	3.
4.	Preferred Stock	-	-	-	-	-	-	-	-	4.
5.	Common Equity	3,339,150	3,445,355	3,824,953	3,933,021	4,315,940	4,378,141	4,351,452	4,537,066	5.
6.	Total Capital	$ 6,719,858	$ 6,830,122	$ 7,207,809	$ 7,314,411	$ 7,921,795	$ 8,358,996	$ 7,907,307	$ 8,217,921	6.
	Capitalization Ratios:									
7.	Short-Term Debt	7.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.
8.	Long-Term Debt	42.55%	49.56%	46.93%	46.23%	45.52%	47.62%	44.97%	44.79%	8.
9.	TOTAL DEBT	50.31%	49.56%	46.93%	46.23%	45.52%	47.62%	44.97%	44.79%	9.
10.	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.
11.	Common Equity	49.69%	50.44%	53.07%	53.77%	54.48%	52.38%	55.03%	55.21%	11.
		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
12.	Weighted Cost of Short-Term Debt	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.
13.	Weighted Cost of Long-Term Debt	2.83%	3.04%	2.99%	2.96%	2.75%	2.91%	2.69%	2.79%	13.
14.	Weighted Cost of Senior Capital	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	14.

Notes:
* Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2010 there was no short-term debt.

** Debt balances exclude unamortized discounts/premiums.

Supporting Schedules:
(a) E-1
(b) D-1

Recap Schedules:
N/A

A-4

ARIZONA PUBLIC SERVICE COMPANY
CONSTRUCTION EXPENDITURES, NET PLANT PLACED IN SERVICE AND GROSS UTILITY PLANT IN SERVICE
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Year	Construction Expenditures (a)* (A)	Net Plant Placed In Service (B)	Gross Utility Plant in Service (b) (C)	*Line No.*
1.	Year Ended 2008	$ 853,759	$ 627,603	$ 12,553,328	*1.*
2.	Year Ended 2009	730,301	614,670	13,167,998	*2.*
3.	Year Ended 2010	664,258	488,107	13,656,105	*3.*
4.	Projected Year - Year Ended 12/31/2011	949,567	759,696	14,415,801	*4.*
5.	Projected Year - Year Ended 12/31/2012 **	1,336,666 ***	1,120,249	15,536,049	*5.*
6.	Projected Year - Year Ended 12/31/2013	958,515	625,880	16,161,929	*6.*

Notes:
* Includes nuclear fuel.
** Includes $294M purchase of SCE share of Four Corners Units 4 and 5
*** 2012 construction expenditures are higher for present rates due to the current treatment of Schedule 3 proceeds through 12/31/12.

Supporting Schedules:
(a) F-3
(b) E-5

Recap Schedules:
N/A

A-5

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY CHANGES IN FINANCIAL POSITION
PRIOR YEARS, TEST YEAR AND PROJECTED YEARS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Prior Years (a) Year Ended 12/31/2008 (A)	Prior Years (a) Year Ended 12/31/2009 (B)	Actual Test Year (a) Ended 12/31/2010 (C)	Projected Years (b) Present Rates Year Ended 12/31/2011 (D)	Present Rates Year Ended 12/31/2012 (E)	Present Rates Year Ended 12/31/2013 (F)	Proposed Rates Year Ended 12/31/2012 (G)	Proposed Rates Year Ended 12/31/2013 (H)	Line No.
	Sources of Funds:									
1.	Operations	$ 785,260	$ 958,719	$ 658,149	$ 1,185,600	$ 1,117,745	$ 864,531	$ 1,205,538	$ 1,126,856	1.
2.	Outside Financing	113,568	(171,845)	68,522	(230,598)	270,645	141,590	189,028	(119,440)	2.
3.	Total Funds Provided	$ 898,828	$ 786,874	$ 726,671	$ 955,002	$ 1,388,389	$ 1,006,121	$ 1,394,566	$ 1,007,416	3.
	Application of Funds:									
4.	Capital Expenditures *	$ 849,897	$ 700,776	$ 715,213	$ 952,102	$ 1,348,730	$ 961,416	$ 1,339,430	$ 961,416	4.
5.	Other	29,538	36,844	32,319	(11,658)	154,132	44,695	154,203	44,779	5.
6.	Total Funds Applied	$ 879,435	$ 737,620	$ 747,532	$ 940,444	$ 1,502,862	$ 1,006,111	$ 1,493,633	$ 1,006,194	6.

Notes:
* Net of contributions in aid of construction.

Supporting Schedules:
(a) E-3
(b) F-2

Recap Schedules:
N/A

B-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Original Cost						Line No.
		Total Company			ACC			
		Unadjusted Test Year (a)	Pro Forma (a)	Adjusted Test Year (a)	Unadjusted Test Year (a)	Pro Forma (a)	Adjusted Test Year (a)	
		(A)	(B)	(C)	(D)	(E)	(F)	
1.	Gross utility plant in service	$ 13,656,105	$ 972,934	$ 14,629,039	$ 11,522,113	$ 945,501	$ 12,467,614	1.
2.	Less: Accumulated depreciation & amortization	5,219,000	500,580	5,719,580	4,528,867	487,072	5,015,939	2.
3.	Net utility plant in service	8,437,105	472,354	8,909,459	6,993,246	458,429	7,451,675	3.
	Deductions:							
4.	Deferred income taxes	1,931,063	48,834	1,979,897	1,567,902	47,231	1,615,133	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction (c)	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements (c)	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	-	66,842	64,107	-	64,107	10.
11.	Coal mine reclamation (c)	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits (c)	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	3,671,569	48,834	3,720,403	3,226,831	47,231	3,274,062	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable (c)	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	-	77,674	72,203	-	72,203	17.
18.	Decommissioning trust accounts (c)	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital (d)	233,778	(14,220)	219,558	212,065	(9,859)	202,206	19.
20.	Total additions	1,669,013	(14,220)	1,654,793	1,552,523	(9,859)	1,542,664	20.
21.	Total rate base	$ 6,434,549	$ 409,300	$ 6,843,849	$ 5,318,938	$ 401,339	$ 5,720,277 (e)	21.

Supporting Schedules:
(a) B-2
(b) B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) A-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	RCND Total Company Unadjusted Test Year (b) (A)	Total Company Pro Forma (b) (B)	Total Company Adjusted Test Year (b) (C)	ACC Unadjusted Test Year (b) (D)	ACC Pro Forma (b) (E)	ACC Adjusted Test Year (b) (F)	Line No.
1.	Gross utility plant in service	$ 26,378,778	$ 972,934	$ 27,351,712	$ 22,255,775	$ 945,501	$ 23,201,276	1.
2.	Less: Accumulated depreciation & amortization	9,826,977	500,580	10,327,557	8,527,851	487,072	9,014,923	2.
3.	Net utility plant in service	16,551,801	472,354	17,024,155	13,727,924	458,429	14,186,353	3.
	Deductions:							
4.	Deferred income taxes	4,057,550	48,834	4,106,384	3,294,325	47,231	3,341,556	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction (c)	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements (c)	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	-	66,842	64,107	-	64,107	10.
11.	Coal mine reclamation (c)	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits (c)	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	5,798,056	48,834	5,846,890	4,953,254	47,231	5,000,485	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable (c)	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	-	77,674	72,203	-	72,203	17.
18.	Decommissioning trust accounts (c)	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital (d)	233,778	(14,220)	219,558	212,065	(9,859)	202,206	19.
20.	Total additions	1,669,013	(14,220)	1,654,793	1,552,523	(9,859)	1,542,664	20.
21.	Total rate base	$ 12,422,758	$ 409,300	$ 12,832,058	$ 10,327,193	$ 401,339	$ 10,728,532 (e)	21.

Supporting Schedules:
(a) B-2
(b) B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) A-1

B-2

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 12/31/2010 (a) Total Co. (A)	(1) Actual at End of Test Year 12/31/2010 (a) ACC (B)	(2) West Phoenix Unit 4 Regulatory Disallowance Total Co. (C)	(2) West Phoenix Unit 4 Regulatory Disallowance ACC (D)	(3) Solar Generation Post-Test Year Plant Additions Total Co. (E)	(3) Solar Generation Post-Test Year Plant Additions ACC (F)
1.	Gross Utility Plant in Service	$ 13,656,105	$ 11,522,113	$ (13,833)	$ (13,363)	$ 277,411	$ 267,979
2.	Less: Accumulated Depreciation & Amort.	5,219,000	4,528,867	(3,635)	(3,511)	5,799	5,602
3	Net Utility Plant in Service	8,437,105	6,993,246	(10,198)	(9,852)	271,612	262,377
4.	Less: Total Deductions	3,671,569	3,226,831	(1,469)	(1,419)	3,979	3,844
5.	Total Additions	1,669,013	1,552,523	-	-	-	-
6.	Total Rate Base	$ 6,434,549	$ 5,318,938	$ (8,729)	$ (8,433)	$ 267,633	$ 258,533

WITNESS: LA BENZ GULDNER / LA BENZ

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Fossil Generation Post-Test Year Plant Additions		(5) Nuclear Generation Post-Test Year Plant Additions		(6) Distribution and General and Intangibles Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 156,269	$ 150,956	$ 120,103	$ 116,019	$ 432,984	$ 423,910
2.	Less: Accumulated Depreciation & Amort.	133,240	128,710	95,937	92,675	269,239	263,596
3	Net Utility Plant in Service	23,029	22,246	24,166	23,344	163,745	160,314
4.	Less: Total Deductions	12,583	12,155	29,329	28,331	4,412	4,320
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ 10,446	$ 10,091	$ (5,163)	$ (4,987)	$ 159,333	$ 155,994

WITNESS: SCHIAVONI / LA BENZ | EDINGTON / LA BENZ | FROETSCHER / LA BENZ

(4) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for fossil generation with an estimated in service date prior to 6/30/2012.

(5) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for nuclear generation with an estimated in service date prior to 6/30/2012.

(6) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for distribution and general and intangibles with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Adjust Cash Working Capital for Cost of Service Pro Formas		(8) Total Original Cost Rate Base Pro Forma Adjustments		(9) Adjusted at End of Test Year 12/31/2010	
		Total Co. (M)	ACC (N)	(b) Total Co. (O)	(b) ACC (P)	(b) Total Co. (Q)	(b) ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ 972,934	$ 945,501	$ 14,629,039	$ 12,467,614
2.	Less: Accumulated Depreciation & Amort.	-	-	500,580	487,072	5,719,580	5,015,939
3	Net Utility Plant in Service	-	-	472,354	458,429	8,909,459	7,451,675
4.	Less: Total Deductions	-	-	48,834	47,231	3,720,403	3,274,062
5.	Total Additions	(14,220)	(9,859)	(14,220)	(9,859)	1,654,793	1,542,664
6.	Total Rate Base	$ (14,220)	$ (9,859)	$ 409,300	$ 401,339	$ 6,843,849	$ 5,720,277

WITNESS: LA BENZ

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) B-1

B-3

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 12/31/2010 (a) Total Co. (A)	(1) Actual at End of Test Year 12/31/2010 (a) ACC (B)	(2) West Phoenix Unit 4 Regulatory Disallowance Total Co. (C)	(2) West Phoenix Unit 4 Regulatory Disallowance ACC (D)	(3) Solar Generation Post-Test Year Plant Additions Total Co. (E)	(3) Solar Generation Post-Test Year Plant Additions ACC (F)
1.	Gross Utility Plant in Service	$ 26,378,778	$ 22,255,775	$ (13,833)	$ (13,363)	$ 277,411	$ 267,979
2.	Less: Accumulated Depreciation & Amort.	9,826,977	8,527,851	(3,635)	(3,511)	5,799	5,602
3	Net Utility Plant in Service	16,551,801	13,727,924	(10,198)	(9,852)	271,612	262,377
4.	Less: Total Deductions	5,798,056	4,953,254	(1,469)	(1,419)	3,979	3,844
5.	Total Additions	1,669,013	1,552,523	-	-	-	-
6.	Total Rate Base	$ 12,422,758	$ 10,327,193	$ (8,729)	$ (8,433)	$ 267,633	$ 258,533

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Fossil Generation Post-Test Year Plant Additions		(5) Nuclear Generation Post-Test Year Plant Additions		(6) Distribution and General and Intangibles Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 156,269	$ 150,956	$ 120,103	$ 116,019	$ 432,984	$ 423,910
2.	Less: Accumulated Depreciation & Amort.	133,240	128,710	95,937	92,675	269,239	263,596
3	Net Utility Plant in Service	23,029	22,246	24,166	23,344	163,745	160,314
4.	Less: Total Deductions	12,583	12,155	29,329	28,331	4,412	4,320
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ 10,446	$ 10,091	$ (5,163)	$ (4,987)	$ 159,333	$ 155,994

(4) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for fossil generation with an estimated in service date prior to 6/30/2012.

(5) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for nuclear generation with an estimated in service date prior to 6/30/2012.

(6) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for distribution and general and intangibles with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Adjust Cash Working Capital for Cost of Service Pro Formas		(8) Total RCND Cost Rate Base Pro Forma Adjustments		(9) Adjusted at End of Test Year 12/31/2010	
		Total Co. (M)	ACC (N)	(b) Total Co. (O)	(b) ACC (P)	(b) Total Co. (Q)	(b) ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ 972,934	$ 945,501	$ 27,351,712	$ 23,201,276
2.	Less: Accumulated Depreciation & Amort.	-	-	500,580	487,072	10,327,557	9,014,923
3	Net Utility Plant in Service	-	-	472,354	458,429	17,024,155	14,186,353
4.	Less: Total Deductions	-	-	48,834	47,231	5,846,890	5,000,485
5.	Total Additions	(14,220)	(9,859)	(14,220)	(9,859)	1,654,793	1,542,664
6.	Total Rate Base	$ (14,220)	$ (9,859)	$ 409,300	$ 401,339	$ 12,832,058	$ 10,728,532

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) B-1

B-4

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN	Condition Percent	RCND	Line No.
				(A)	(B)	(C)	
1.	INTANGIBLES	301	Organization	$ -	100.00%	$ -	1.
2.		302	Franchises and consents	3,341	69.49%	2,322	2.
3.		303	Miscellaneous intangible plant	522,876	37.20%	194,507	3.
4.			SUBTOTAL	526,217		196,829	4.
5.	PRODUCTION	310	Land and Land Rights	5,181	100.00%	5,181	5.
6.		310	Limit Term Land Rights	64	17.62%	11	6.
7.		311	Structures and improvements	386,293	46.92%	181,249	7.
8.		312	Boiler plant equipment	2,653,469	53.80%	1,427,566	8.
9.		314	Turbogenerator units	713,147	43.19%	308,008	9.
10.		315	Accessory electric equipment	669,854	44.34%	297,013	10.
11.		316	Miscellaneous power plant equip.	78,962	47.97%	37,878	11.
12.		317	ARO for Steam Production	12,976	84.99%	11,028	12.
13.		320	Land and land rights	4,418	100.00%	4,418	13.
14.		321	Structures and improvements	1,214,622	44.19%	536,786	14.
15.		322	Reactor plant equipment	2,068,700	50.95%	1,054,022	15.
16.		323	Turbogenerator units	646,931	51.40%	332,507	16.
17.		324	Accessory electric equipment	856,276	38.78%	332,035	17.
18.		325	Misc power plant equip	271,205	47.78%	129,588	18.
19.		326	ARO for Nuclear Production	23,461	-5.94%	(1,394)	19.
20.		330	Limit Term Land Rights	-	0.00%	-	20.
21.		331	Structures and improvements	-	0.00%	-	21.
22.		332	Reservoirs, dams, and waterways	-	0.00%	-	22.
23.		333	Water wheels, turbines and generators	-	0.00%	-	23.
24.		334	Accessory electric equipment	-	0.00%	-	24.
25.		335	Miscellaneous power plant equip.	-	0.00%	-	25.
26.		336	Roads, railroads and bridges	-	0.00%	-	26.
27.		337	ARO for Hydraulic Production	5,903	0.00%	-	27.
28.		340	Land and land rights	2,946	100.00%	2,946	28.
29.		341	Structures and improvements	107,079	72.27%	77,388	29.
30.		342	Fuel holders, products, and accessories	75,025	60.01%	45,023	30.
31.		343	Prime movers	1,183,270	66.91%	791,785	31.
32.		344	Generators	972,274	71.78%	697,899	32.
33.		345	Accessory electric equipment	185,044	63.67%	117,810	33.
34.		346	Miscellaneous power plant equip.	23,671	68.59%	16,236	34.
35.			SUBTOTAL	12,160,771		6,404,983	35.
36.	TRANSMISSION	350	Land and land rights	86,202	99.98%	86,186	36.
37.		350	Limit Term Land Rights	34,994	58.57%	20,494	37.
38.		352	Structures and improvements	121,457	64.46%	78,291	38.
39.		353	Station equipment	1,731,696	78.50%	1,359,441	39.
40.		354	Towers and fixtures	364,935	56.67%	206,826	40.
41.		355	Poles and fixtures	636,671	85.87%	546,724	41.
42.		356	Overhead conductors and devices	970,469	74.49%	722,902	42.
43.		357	Underground conduit	38,402	65.31%	25,079	43.
44.		358	Underground conductors and devices	80,108	57.38%	45,966	44.
45.			SUBTOTAL	4,064,934		3,091,909	45.

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN (A)	Condition Percent (B)	RCND (C)	Line No.
46.	DISTRIBUTION	360	Land and land rights	38,898	100.00%	38,898	46.
47.		360	Limit Term Land Rights	7,759	76.57%	5,941	47.
48.		361	Structures and improvements	103,298	79.37%	81,990	48.
49.		362	Station equipment	762,393	82.99%	632,692	49.
50.		364	Poles, towers, and fixtures	831,744	77.88%	647,732	50.
51.		365	Overhead conductors and devices	633,859	84.68%	536,752	51.
52.		366	Underground conduit	912,958	81.39%	743,057	52.
53.		367	Underground conductors and devices	2,588,324	68.85%	1,782,061	53.
54.		368	Line transformers	1,815,593	77.23%	1,402,182	54.
55.		369	Services	519,618	66.89%	347,572	55.
56.		370	Meters	276,437	86.04%	237,846	56.
57.		371	Installations on customers' premises	94,973	96.38%	91,535	57.
58.		373	Street lighting and signal systems	168,326	90.36%	152,099	58.
59.			SUBTOTAL	8,754,180		6,700,357	59.
60.	GENERAL	389	Land and land rights	14,512	99.30%	14,410	60.
61.		390	Structures and improvements	296,355	61.00%	180,777	61.
62.		390	Structures and improvements - Lease	-	100.00%	-	62.
63.		391	Office furniture and equipment	196,127	68.96%	135,249	63.
64.		391	Capitalized Lease-Computer Equipment	-	0.00%	-	64.
65.		392	Transportation equipment	41,524	30.67%	12,735	65.
66.		392	Capitalized Lease-Transportation Equip.	6,992	27.62%	1,931	66.
67.		393	Stores equipment	6,129	79.35%	4,863	67.
68.		394	Tools, shop and garage equipment	40,306	46.32%	18,670	68.
69.		395	Laboratory equipment	3,774	39.72%	1,499	69.
70.		396	Power operated equipment	24,150	36.63%	8,846	70.
71.		397	Communication equipment	233,393	65.07%	151,866	71.
72.		398	Miscellaneous equipment	9,413	62.06%	5,842	72.
73.			SUBTOTAL	872,676		536,688	73.
74.		Removal Cost		-		(378,965)	74.
75.		TOTAL PLANT (a)		$ 26,378,778		$ 16,551,801	75.

Supporting Schedules:
RCND Study

Recap Schedules:
(a) B-3

B-4a

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF RCND RATE BASE ELEMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.		Description	Total * Company (B + C) (A)	ACC (B)	All Other (D + E) (C)	SCE 500KV (D)	Other (E)	Line No.
1.	A.	ORIGINAL COST:						1.
2.		Gross Utility Plant in Service	$ 13,656,105	$ 11,522,113	$ 2,133,992	$ 67,640	$ 2,066,352	2.
3.		Accumulated Depreciation & Amortization	5,219,000	4,528,867	690,133	59,041	631,092	3.
4.		Net Utility Plant in Service	8,437,105	6,993,246	1,443,859	8,599	1,435,260	4.
5.	B.	RCND:						5.
6.		Reproduction Cost New	26,378,778	22,255,775	4,123,003	307,973	3,815,030	6.
7.		Accumulated Depreciation	9,826,977	8,527,851	1,299,126	268,822	1,030,304	7.
8.		Total RCND Plant in Service at 12/31/2010 from B-4	16,551,801	13,727,924	2,823,877	39,151	2,784,726	8.
9.		Deductions:						9.
10.		Deferred Taxes	4,057,550	3,294,325	763,225	-	763,225	10.
11.		Investment Tax Credits	907	876	31	-	31	11.
12.		Total Deferred Taxes and ITC	4,058,457	3,295,201	763,256	-	763,256	12.
13.		Customer Advances for Construction	121,645	121,645	-	-	-	13.
14.		Customer Deposits	68,084	68,084	-	-	-	14.
15.		Pension Liability	711,164	661,518	49,646	-	49,646	15.
16.		Liability for Asset Retirement	328,571	320,592	7,979	-	7,979	16.
17.		Other Deferred Credits	66,842	64,107	2,735	-	2,735	17.
18.		Coal Mine Reclamation	117,243	114,396	2,847	-	2,847	18.
19.		Unrecognized Tax Benefits	65,363	53,961	11,402	-	11,402	19.
20.		Regulatory Liabilities	260,687	253,750	6,937	-	6,937	20.
21.		Total Deductions	5,798,056	4,953,254	844,802	-	844,802	21.
22.		Additions:						22.
23.		Regulatory Assets	822,177	746,508	75,669	-	75,669	23.
24.		Deferred Debit Income Tax Receivable	65,498	63,271	2,227	-	2,227	24.
25.		Miscellaneous Deferred Debits	77,674	72,203	5,471	-	5,471	25.
26.		Depreciation Fund - Decommissioning	469,886	458,476	11,410	-	11,410	26.
27.		Allowance for Working Capital	233,778	212,065	21,713	-	21,713	27.
28.		Total Additions	1,669,013	1,552,523	116,490	-	116,490	28.
29.		Total RCND Rate Base Before Proforma Adj.	12,422,758	10,327,193	2,095,565	39,151	2,056,414	29.
30.		Proforma Adjustments	409,300	401,339	7,961		7,961	30.
31.		Total RCND Rate Base	$ 12,832,058	$ 10,728,532	$ 2,103,526	$ 39,151	$ 2,064,375	31.

Notes:

* Includes SCE 500KV

Supporting Schedules:
For Lines 2, 3, 9-28, Col. (A): See Schedule B-1, Column (A).
For Lines 2, 3, 9-28, Col. (B): See Schedule B-1, Column (D).
For Line 6, Col. (A): See Schedule B-4, Column (A) page 2 of 2.
For Line 8, Col. (A): See Schedule B-4, Column (C) page 2 of 2.

Recap Schedules:
N/A

B-5

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF WORKING CAPITAL
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Amount	*Line No.*
1.	Working Capital - Operations (a)	$ (101,570)	*1.*
2.	Materials and Supplies (b)	181,414	*2.*
3.	Fuel - Coal and Oil (b)	21,575	*3.*
4.	Fuel - Nuclear, Net (b)	108,794	*4.*
5.	Prepayments (b)	23,346	*5.*
6.	Special Deposits & Working Funds (b)	219	*6.*
7.	Total Allowance for Working Capital (c)	$ 233,778	*7.*

Supporting Schedules:
(a) Lead-Lag Study
(b) Schedule E-1

Recap Schedule
(c) B-1

C-1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	Total Company Actual For The Test Year Ended 12/31/2010 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,946,463	$ 5,861	$ 2,952,324	1.
2.	Revenues from Surcharges	71,530	(71,530)	-	2.
3.	Other Electric Revenues	162,814	(25,965)	136,849	3.
4.	Total	3,180,807	(91,634)	3,089,173	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,046,815	(5,931)	1,040,884	5.
6.	Operations and maintenance excluding fuel expenses	900,372	(193,288)	707,084	6.
7.	Depreciation and amortization	406,632	(1,482)	405,150	7.
8.	Income taxes	175,440	50,918	226,358	8.
9.	Other taxes	134,467	28,303	162,770	9.
10.	Total	2,663,726	(121,480)	2,542,246	10.
11.	Operating income	517,081	29,846	546,927	11.
	Other income (deductions):				
12.	Income taxes	4,975	-	4,975	12.
13.	Allowance for equity funds used during construction	22,066	-	22,066	13.
14.	Other income	8,956	-	8,956	14.
15.	Other expense	(15,859)	-	(15,859)	15.
16.	Total	20,138	-	20,138	16.
17.	Income before interest deductions	537,219	29,846	567,065	17.
	Interest deductions:				
18.	Interest on long-term debt	205,209	-	205,209	18.
19.	Interest on short-term borrowings	8,267	-	8,267	19.
20.	Debt discount, premium and expense	4,559	-	4,559	20.
21.	Allowance for borrowed funds used during construction	(16,479)	-	(16,479)	21.
22.	Total	201,556	-	201,556	22.
23.	Net income	$ 335,663	$ 29,846	$ 365,509	23.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 12/31/2010 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (b) (C)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ 2,862,997	$ 5,861	$ 2,868,858	1.
2.	Revenues from Surcharges	71,238	(71,238)	-	2.
3.	Other Electric Revenues	146,808	(25,795)	121,013	3.
4.	Total	3,081,043	(91,172)	2,989,871	4.
	Operating expenses:				
5.	Electric fuel and purchased power	1,021,577	(5,979)	1,015,598	5.
6.	Operations and maintenance excluding fuel expenses	1,000,134	(192,116)	808,018	6.
7.	Depreciation and amortization	358,023	(5,997)	352,026	7.
8.	Income taxes	150,805	49,651	200,456	8.
9.	Other taxes	114,221	25,196	139,417	9.
10.	Total	2,644,760	(129,245)	2,515,515	10.
11.	Operating income	436,283	38,073	474,356	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	436,283	38,073	474,356	17.
	Interest deductions:				
18.	Interest on long-term debt	-	-	-	18.
19.	Interest on short-term borrowings	-	-	-	19.
20.	Debt discount, premium and expense	-	-	-	20.
21.	Allowance for borrowed funds used during construction	-	-	-	21.
22.	Total	-	-	-	22.
23.	Net income	$ 436,283	$ 38,073	$ 474,356	23.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

C-2

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(1) Remove Bark Beetle Remediation Amortization		(2) Remove Test Year Surcharges and Adjustors		(3) Include West Phoenix Unit 4 Regulatory Disallowance	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	(192,761)	(192,469)	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	(192,761)	(192,469)	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	(8,201)	(8,201)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(184,560)	(184,268)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(1,918)	(1,918)	(177,253)	(176,961)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(1,918)	(1,918)	(177,253)	(176,961)	-	-
10.	Depreciation and Amortization					(329)	(318)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(1,918)	(1,918)	(177,253)	(176,961)	(329)	(318)
15.	Operating Income Before Income Tax	1,918	1,918	(7,307)	(7,307)	329	318
16.	Interest Expense	-	-	-	-	(257)	(248)
17.	Taxable Income	1,918	1,918	(7,307)	(7,307)	586	566
18.	Current Income Tax Rate - 39.51%	758	758	(2,887)	(2,887)	232	224
19.	Operating Income (line 15 minus line 18)	$ 1,160	$ 1,160	$ (4,420)	$ (4,420)	$ 97	$ 94
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(1) Adjustment to Test Year operations to remove 6-months of deferred bark beetle costs as authorized in Decision No. 69663.

(2) Adjustment to Test Year operations to remove the Renewable Energy Standard, Competition Rules Compliance Charge, Demand Side Management, Transmission Cost Adjustor and Regulatory Assessment surcharges from both operating revenues and expenses.

(3) Adjustment to Test Year operations to reflect depreciation of regulatory disallowance of West Phoenix Unit 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(4) Include Interest Expense on Customer Deposits Total Co. (G)	(4) ACC (H)	(5) Adjust Depreciation Expense - 2010 Study Total Co. (I)	(5) ACC (J)	(6) Solar Generation Post-Test Year Plant Additions Total Co. (K)	(6) ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	197	197	-	-	-	-
8.	Maintenance	-	-	-	-	1,785	1,724
9.	Subtotal	197	197	-	-	1,785	1,724
10.	Depreciation and Amortization			(28,646)	(32,389)	9,405	9,085
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	217	210
13.	Other Taxes	-	-	-	-	978	945
14.	Total	197	197	(28,646)	(32,389)	12,385	11,964
15.	Operating Income Before Income Tax	(197)	(197)	28,646	32,389	(12,385)	(11,964)
16.	Interest Expense			-	-	7,868	7,601
17.	Taxable Income	(197)	(197)	28,646	32,389	(20,253)	(19,565)
18.	Current Income Tax Rate - 39.51%	(78)	(78)	11,318	12,797	(8,002)	(7,730)
19.	Operating Income (line 15 minus line 18)	$ (119)	$ (119)	$ 17,328	$ 19,592	$ (4,383)	$ (4,234)
	WITNESS:	LA BENZ		LA BENZ		GULDNER / LA BENZ	

(4) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2011 interest rates.

(5) Adjustment to Test Year operations to reflect depreciation expense based on the 2010 depreciation study.

(6) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Solar Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(7) Fossil Generation Post-Test Year Plant Additions		(8) Nuclear Generation Post-Test Year Plant Additions		(9) Distribution and General and Intangible Post-Test Year Plant Additions	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -		$ -	$ -
2.	Revenues from Surcharges	-	-	-		-	-
3.	Other Electric Revenues	-	-	-		-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-		-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-		-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	4,245	4,101	1,729	1,670	13,847	13,557
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	950	918	735	710	7,669	7,508
14.	Total	5,195	5,019	2,464	2,380	21,516	21,065
15.	Operating Income Before Income Tax	(5,195)	(5,019)	(2,464)	(2,380)	(21,516)	(21,065)
16.	Interest Expense	307	297	(152)	(147)	4,684	4,586
17.	Taxable Income	(5,502)	(5,316)	(2,312)	(2,233)	(26,200)	(25,651)
18.	Current Income Tax Rate - 39.51%	(2,174)	(2,100)	(913)	(882)	(10,352)	(10,135)
19.	Operating Income (line 15 minus line 18)	$ (3,021)	$ (2,919)	$ (1,551)	$ (1,498)	$ (11,164)	$ (10,930)
	WITNESS:	SCHIAVONI / LA BENZ		EDINGTON / LA BENZ		FROETSCHER / LA BENZ	

(7) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Fossil Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

(8) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Nuclear Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(9) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Distribution Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(10) Decommissioning and Spent Fuel Costs Total Co. (S)	(10) Decommissioning and Spent Fuel Costs ACC (T)	(11) Annualize Payroll Expense Total Co. (U)	(11) Annualize Payroll Expense ACC (V)	(12) Normalize Employee Benefits Total Co. (W)	(12) Normalize Employee Benefits ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(4,236)	(4,133)	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	4,236	4,133	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(406)	(377)	8,148	7,572
8.	Maintenance	-	-	(113)	(105)	-	-
9.	Subtotal	-	-	(519)	(482)	8,148	7,572
10.	Depreciation and Amortization	(2,947)	(2,875)	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(2,947)	(2,875)	(519)	(482)	8,148	7,572
15.	Operating Income Before Income Tax	7,183	7,008	519	482	(8,148)	(7,572)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	7,183	7,008	519	482	(8,148)	(7,572)
18.	Current Income Tax Rate - 39.51%	2,838	2,769	205	190	(3,219)	(2,992)
19.	Operating Income (line 15 minus line 18)	$ 4,345	$ 4,239	$ 314	$ 292	$ (4,929)	$ (4,580)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(10) Adjustment to Test Year operations to reflect updated decommissioning funding levels for Palo Verde due to license extension and updated ISFSI expense.

(11) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2011 employee levels for performance review and Union employees.

(12) Adjustment to Test Year operations to reflect the current December 2010 actuarial valuation of retirement program expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(13) Normalize Income Tax Expense/Interest Synchronization Total Co. (Y)	(13) ACC (Z)	(14) Annualize Property Tax Expense Total Co. (AA)	(14) ACC (BB)	(15) Annualize Severance Costs Total Co. (CC)	(15) ACC (DD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	(6,732)	(6,256)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	(6,732)	(6,256)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	17,971	15,115	-	-
14.	Total	-	-	17,971	15,115	(6,732)	(6,256)
15.	Operating Income Before Income Tax	-	-	(17,971)	(15,115)	6,732	6,256
16.	Interest Expense	(60,142)	(49,742)	-	-	-	-
17.	Taxable Income	60,142	49,742	(17,971)	(15,115)	6,732	6,256
18.	Current Income Tax Rate - 39.51%	23,762	19,653	(7,100)	(5,972)	2,660	2,472
19.	Operating Income (line 15 minus line 18)	$ (23,762)	$ (19,653)	$ (10,871)	$ (9,143)	$ 4,072	$ 3,784

WITNESS: LA BENZ | LA BENZ | LA BENZ

(13) Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663 and 71448 using the 12/31/2010 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

(14) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2011 tax assessment ratio and tax rate.

(15) Adjustment to Test Year operations to amortize the expense associated with employees severed in 2010 over a three year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(16) Amortize Childs-Irving Excess Decommissioning Costs Total Co. (EE)	(16) ACC (FF)	(17) Remove Schedule 3 Revenues Total Co. (GG)	(17) ACC (HH)	(18) Normalize Fossil Maintenance Total Co. (II)	(18) ACC (JJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	(18,660)	(18,660)	-	
4.	Total Electric Operating Revenues	-	-	(18,660)	(18,660)	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(18,660)	(18,660)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	(4,397)	(4,290)
9.	Subtotal	-	-	-	-	(4,397)	(4,290)
10.	Depreciation and Amortization	(893)	(863)	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-		-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(893)	(863)	-	-	(4,397)	(4,290)
15.	Operating Income Before Income Tax	893	863	(18,660)	(18,660)	4,397	4,290
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	893	863	(18,660)	(18,660)	4,397	4,290
18.	Current Income Tax Rate - 39.51%	353	341	(7,373)	(7,373)	1,737	1,695
19.	Operating Income (line 15 minus line 18)	$ 540	$ 522	$ (11,287)	$ (11,287)	$ 2,660	$ 2,595

WITNESS: LA BENZ (16) | LA BENZ (17) | LA BENZ (18)

(16) Adjustment to amortize the excess decommissioning costs for the Childs Irving Power Plant over a three year period.

(17) Adjustment to remove revenues associated with Schedule 3 (line extension policy) in the Test Year.

(18) Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(19) Normalize Nuclear Maintenance Total Co. (KK)	(19) Normalize Nuclear Maintenance ACC (LL)	(20) Annualize Four Corners Coal Reclamation Costs Total Co. (MM)	(20) Annualize Four Corners Coal Reclamation Costs ACC (NN)	(21) Adjust Cash Working Capital for Cost of Service Pro Formas Total Co. (OO)	(21) Adjust Cash Working Capital for Cost of Service Pro Formas ACC (PP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	6,216	6,065	-	
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	(6,216)	(6,065)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	5,383	5,252	-		-	-
9.	Subtotal	5,383	5,252	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	5,383	5,252	-	-	-	-
15.	Operating Income Before Income Tax	(5,383)	(5,252)	(6,216)	(6,065)	-	-
16.	Interest Expense	-	-	-	-	(418)	(290)
17.	Taxable Income	(5,383)	(5,252)	(6,216)	(6,065)	418	290
18.	Current Income Tax Rate - 39.51%	(2,127)	(2,075)	(2,456)	(2,396)	165	115
19.	Operating Income (line 15 minus line 18)	$ (3,256)	$ (3,177)	$ (3,760)	$ (3,669)	$ (165)	$ (115)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(19) Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

(20) Adjustment to Test Year operations to reflect most recent Four Corners coal reclamation study.

(21) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment, as shown on Schedule B-2, page 3, column 7.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(22) Remove PWEC Loan Amortization Total Co. (QQ)	(22) ACC (RR)	(23) Amortize Pension and OPEB Deferral Total Co. (SS)	(23) ACC (TT)	(24) Normalize Pole Attachment Revenues Total Co. (UU)	(24) ACC (VV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(305)	(305)
4.	Total Electric Operating Revenues	-	-	-	-	(305)	(305)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(305)	(305)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	8,740	8,122	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	8,740	8,122	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	2,107	2,035	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	2,107	2,035	8,740	8,122	-	-
15.	Operating Income Before Income Tax	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
18.	Current Income Tax Rate - 39.51%	(832)	(804)	(3,453)	(3,209)	(121)	(121)
19.	Operating Income (line 15 minus line 18)	$ (1,275)	$ (1,231)	$ (5,287)	$ (4,913)	$ (184)	$ (184)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(22) Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision No. 65796 and 67744.

(23) Adjustment to Test Year operations reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.

(24) Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(25) Remove Supplemental Executive Retirement Plan Benefits Total Co. (WW)	(25) ACC (XX)	(26) Remove Stock Compensation Total Co. (YY)	(26) ACC (ZZ)	(27) Remove Out of Period and Miscellaneous Items Total Co. (AAA)	(27) ACC (BBB)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(7,000)	(6,830)
4.	Total Electric Operating Revenues	-	-	-	-	(7,000)	(6,830)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(7,000)	(6,830)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(8,492)	(7,892)	(12,421)	(11,543)	3,000	2,996
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(8,492)	(7,892)	(12,421)	(11,543)	3,000	2,996
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	(2,529)	(2,350)
13.	Other Taxes	-	-	-	-	-	-
14.	Total	(8,492)	(7,892)	(12,421)	(11,543)	471	646
15.	Operating Income Before Income Tax	8,492	7,892	12,421	11,543	(7,471)	(7,476)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	8,492	7,892	12,421	11,543	(7,471)	(7,476)
18.	Current Income Tax Rate - 39.51%	3,355	3,118	4,908	4,561	(2,952)	(2,954)
19.	Operating Income (line 15 minus line 18)	$ 5,137	$ 4,774	$ 7,513	$ 6,982	$ (4,519)	$ (4,522)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(25) Adjustment to Test Year operations to remove supplemental executive retirement benefits ("SERP").

(26) Adjustment to Test Year operations to remove stock compensation.

(27) Adjustment to Test Year operations to remove legal accrual reserve, bad debt reversal accrual, grant reserve, benchmark study costs, branding costs and a non-recurring payroll expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(28) Base Fuel and Purchased Power Total Co. (CCC)	(28) Base Fuel and Purchased Power ACC (DDD)	(29) Test Year PSA Revenue and Deferred Fuel Amortization Total Co. (EEE)	(29) Test Year PSA Revenue and Deferred Fuel Amortization ACC (FFF)	(30) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals Total Co. (GGG)	(30) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals ACC (HHH)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	121,231	121,231	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	121,231	121,231	-	-
5.	Electric Fuel and Purchased Power Costs	(29,810)	(29,810)	127,728	127,728	(101,790)	(101,790)
6.	Oper Rev Less Fuel & Purch Pwr Costs	29,810	29,810	(6,497)	(6,497)	101,790	101,790
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(6,497)	(6,497)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	(6,497)	(6,497)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	(6,497)	(6,497)	-	-
15.	Operating Income Before Income Tax	29,810	29,810	-	-	101,790	101,790
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	29,810	29,810	-	-	101,790	101,790
18.	Current Income Tax Rate - 39.51%	11,778	11,778	-	-	40,217	40,217
19.	Operating Income (line 15 minus line 18)	$ 18,032	$ 18,032	$ -	$ -	$ 61,573	$ 61,573
	WITNESS:	EWEN		EWEN		EWEN	

(28) Adjustment to Test Year Operations to include 2012 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

(29) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(30) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(31) Normalize Weather Conditions Total Co. (III)	(31) Normalize Weather Conditions ACC (JJJ)	(32) Annualize Customer Levels Total Co. (KKK)	(32) Annualize Customer Levels ACC (LLL)	(33) Low Income Customer Discount Total Co. (MMM)	(33) Low Income Customer Discount ACC (NNN)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ 10,330	$ 10,330	$ (290)	$ (290)	$ (4,179)	$ (4,179)
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	10,330	10,330	(290)	(290)	(4,179)	(4,179)
5.	Electric Fuel and Purchased Power Costs	3,909	3,909	253	253	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	6,421	6,421	(543)	(543)	(4,179)	(4,179)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	-	-	-	-
15.	Operating Income Before Income Tax	6,421	6,421	(543)	(543)	(4,179)	(4,179)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	6,421	6,421	(543)	(543)	(4,179)	(4,179)
18.	Current Income Tax Rate - 39.51%	2,537	2,537	(215)	(215)	(1,651)	(1,651)
19.	Operating Income (line 15 minus line 18)	$ 3,884	$ 3,884	$ (328)	$ (328)	$ (2,528)	$ (2,528)

WITNESS: MIESSNER MIESSNER MIESSNER

(31) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2010.

(32) Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2010.

(33) Adjustment to Test Year operations to reflect the increase in low income customer discounts from the Teat Year through July 2012.

Recap Schedules:
(a) C-1

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

(34)

Line No.	Description	Total Income Statement Adjustments (a) Total Co. (OOO)	ACC (PPP)
	Electric Operating Revenues		
1.	Revenues from Base Rates	$ 5,861	$ 5,861
2.	Revenues from Surcharges	(71,530)	(71,238)
3.	Other Electric Revenues	(25,965)	(25,795)
4.	Total Electric Operating Revenues	(91,634)	(91,172)
5.	Electric Fuel and Purchased Power Costs	(5,931)	(5,979)
6.	Oper Rev Less Fuel & Purch Pwr Costs	(85,703)	(85,193)
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense	(193,634)	(192,557)
8.	Maintenance	2,658	2,581
9.	Subtotal	(190,976)	(189,976)
10.	Depreciation and Amortization	(3,589)	(8,032)
11.	Amortization of Gain	2,107	2,035
12.	Administrative and General	(2,312)	(2,140)
13.	Other Taxes	28,303	25,196
14.	Total	(166,467)	(172,917)
15.	Operating Income Before Income Tax	80,764	87,724
16.	Interest Expense	(48,110)	(37,943)
17.	Taxable Income	128,874	125,667
18.	Current Income Tax Rate - 39.51%	50,918	49,651
19.	Operating Income (line 15 minus line 18)	$ 29,846	$ 38,073

WITNESS:

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

C-3

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TEST YEAR ENDED 12/31/2010

Line No.	Description	Percentage of Incremental Gross Revenues	*Line No.*
1.	Federal Income Taxes	32.57%	*1.*
2.	State Income Taxes	6.94%	*2.*
3.	Total Tax Percentage	39.51%	*3.*
4.	Operating Income % = 100% - Tax Percentage	60.49%	*4.*
5.	1/Operating Income % = Gross Revenue Conversion Factor (a)	1.6532	*5.*

Supporting Schedules:
N/A

Recap Schedules:
(a) A-1

D-1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
SUMMARY COST OF CAPITAL
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Invested Capital	Adjusted *** End of Test Year 12/31/2010 Amount	%	Cost Rate	Composite Cost	Projected - Present Rates End Of 12/31/2011 Amount	%	Cost Rate	Composite Cost (d)	Projected - Present Rates End Of 12/31/2012 Amount	%	Cost Rate	Composite Cost (d)	Line No.
1.	Long-Term Debt * (a)	$3,382,856	46.06%	6.38%	2.94%	$3,381,390	46.23%	6.40%	2.96%	$3,605,855	45.52%	6.05%	2.75%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	3,961,248	53.94%	11.00%	5.93%	3,933,021	53.77%	11.00%	5.91%	4,315,940	54.48%	11.00%	5.99%	3.
4.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	4.
5.	Total	$ 7,344,104	100.00%		8.87%	$ 7,314,411	100.00%		8.87%	$ 7,921,795	100.00%		8.74%	5.

		Projected - Present Rates End Of 12/31/2013 Amount	%	Cost Rate	Composite Cost (d)	Projected - Proposed Rates End Of 12/31/2012 Amount	%	Cost Rate	Composite Cost (d)	Projected - Proposed Rates End Of 12/31/2013 Amount	%	Cost Rate	Composite Cost (d)	
6.	Long-Term Debt * (a)	$3,980,855	47.62%	6.11%	2.91%	$3,555,855	44.97%	5.97%	2.69%	$3,680,855	44.79%	6.23%	2.79%	6.
7.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	7.
8.	Common Equity (c)	4,378,141	52.38%	11.00%	5.76%	4,351,452	55.03%	11.00%	6.05%	4,537,066	55.21%	11.00%	6.07%	8.
9.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	9.
10.	Total	$ 8,358,996	100.00%		8.67%	$ 7,907,307	100.00%		8.74%	$ 8,217,921	100.00%		8.86%	10.

Notes:
* Debt balances exclude unamortized discounts/premiums.
** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions.
*** See Schedule D-1, page 2 of 2 for proforma adjustments to Test Year actual period ended 12/31/2010.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4

Recap Schedules:
(d) A-3

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
SUMMARY COST OF CAPITAL
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Invested Capital	End of Test Year 12/31/2010 - Unadjusted Amount	%	Cost Rate	Composite Cost (d)	Proformas to Test Year Ended 12/31/2010 Adjusted Pension OCI to Zero	Adjusted Derivative OCI to Zero	Combined Total Adj. Amount	Cost Rate Adj.	End of Test Year 12/31/2010 - Adjusted Amount	%	Cost Rate	Composite Cost	Line No.
1.	Long-Term Debt * (a)	$3,382,856	46.93%	6.38%	2.99%	-	-	-	-	$3,382,856	46.06%	6.38%	2.94%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	-	-	-	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	3,824,953	53.07%	11.00%	5.84%	35,961	100,334	136,295	0.00%	3,961,248	53.94%	11.00%	5.93%	3.
4.	Short-Term Debt ** (a)	-	0.00%	0.00%	0.00%	-	-	-	-	-	0.00%	0.00%	0.00%	4.
5.	Total	$7,207,809	100.00%		8.83%					$7,344,104	100.00%		8.87%	5.

Notes:
* Debt balances exclude unamortized discounts/premiums.
** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2010 there was no short-term debt.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4

Recap Schedules:
(d) A-3

D-2

ARIZONA PUBLIC SERVICE COMPANY
COST OF LONG-TERM AND SHORT-TERM DEBT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description of Debt	Test Year End of Year 12/31/2010 Outstanding	Test Year End of Year 12/31/2010 Annual Interest *	Projected - Present Rates End of Year 12/31/2011 Outstanding	Projected - Present Rates End of Year 12/31/2011 Annual Interest *	Projected - Present Rates End of Year 12/31/2012 Outstanding	Projected - Present Rates End of Year 12/31/2012 Annual Interest *	Projected - Present Rates End of Year 12/31/2013 Outstanding	Projected - Present Rates End of Year 12/31/2013 Annual Interest *	Projected - Proposed Rates End of Year 12/31/2012 Outstanding	Projected - Proposed Rates End of Year 12/31/2012 Annual Interest *	Projected - Proposed Rates End of Year 12/31/2013 Outstanding	Projected - Proposed Rates End of Year 12/31/2013 Annual Interest *	Line No.
	Long-Term:													
1.	Pollution Control Indebtedness	$ 655,855	$ 34,459	$ 655,855	$ 32,408	$ 655,855	$ 32,563	$ 655,855	$ 32,798	$ 655,855	$ 32,563	$ 655,855	$ 32,798	1.
2.	Capitalized Lease obligation	2,001	106	535	28	-	-	-	-	-	-	-	-	2.
3.	Other Long-Term Debt - Unsecured Notes	2,725,000	180,074	2,725,000	182,590	2,950,000	184,233	3,325,000	209,253	2,900,000	178,553	3,025,000	195,113	3.
4.	Other	-	1,286	-	1,284	-	1,286	-	1,286	-	1,286	-	1,286	4.
5.	Total Long-Term (a) **	$ 3,382,856	(b) $ 215,925	$ 3,381,390	$ 216,310	$3,605,855	$ 218,082	$3,980,855	$ 243,337	$3,555,855	$ 212,402	$3,680,855	$ 229,197	5.
6.	Cost Rate (a)	6.38%		6.40%		6.05%		6.11%		5.97%		6.23%		6.
	Short-term:													
7.	Commercial Paper	-	-	-	-	-	-	-	-	-	-	-	-	7.
8.	Total Short-Term (a) ***	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	8.
9.	Cost Rate (a)	0%		0%		0%		0%		0%		0%		9.

Notes:
* Including amortization of discount, premium and expense.
** Excludes unamortized discount of ($6,183).
*** Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work in Progress, therefore recoverable through AFUDC provisions. For the unadjusted Test Year ending 12/31/2010, actual short-term debt was zero.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D-3

ARIZONA PUBLIC SERVICE COMPANY
COST OF PREFERRED STOCK
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description of Issue	End of Test Year 12/31/2010			Projected - Present Rates End of Year 12/31/2011			Projected - Present Rates End of Year 12/31/2012			Projected - Present Rates End of Year 12/31/2013			Projected - Projected Rates End of Year 12/31/2012			Projected - Projected Rates End of Year 12/31/2013			Line No.
		Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	
1.	No Outstanding Issues	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.
2.	Total (a) (b)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.
3.	Cost Rate (a)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF COMMON EQUITY
TEST YEAR ENDED 12/31/2010

For purposes of this filing, the Company is proposing a return on common equity of 11.00%.

Supporting Schedules
N/A

Recap Schedules
D-1

E-1

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE BALANCE SHEETS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 12/31/2010 (A)	Prior Year Ended 12/31/2009 (B)	Prior Year Ended 12/31/2008 (C)	Line No.
	UTILITY PLANT:				
1.	Electric plant in service and held for future use	$ 13,197,254	$ 12,781,256	$ 12,198,010	1.
2.	Less accumulated depreciation and amortization	4,889,556	4,712,137	4,517,947	2.
3.	Net	8,307,698	8,069,119	7,680,063	3.
4.	Construction work in progress	459,316	460,748	571,977	4.
5.	Intangible assets, net of accumulated amortization	184,768	164,183	131,243	5.
6.	Nuclear fuel, net of amortization	108,794	118,243	89,323	6.
7.	Utility plant - net (a)	9,060,576	8,812,293	8,472,606	7.
	INVESTMENTS AND OTHER ASSETS:				
8.	Nuclear decommissioning trust	469,886	414,576	343,052	8.
9.	Assets from risk management activities	39,032	28,855	33,675	9.
10.	Other assets	71,428	68,839	60,604	10.
11.	Total investments and other assets	580,346	512,270	437,331	11.
	CURRENT ASSETS:				
12.	Cash and cash equivalents	99,937	120,798	71,544	12.
13.	Customer and other receivables	288,323	280,226	262,177	13.
14.	Accrued unbilled revenues	103,292	110,971	100,089	14.
15.	Allowance for doubtful accounts	(7,646)	(6,063)	(3,155)	15.
16.	Materials and supplies, at average cost	181,414	176,020	173,252	16.
17.	Fossil fuel, at average cost	21,575	39,245	29,752	17.
18.	Assets from risk management activities	73,788	50,619	32,181	18.
19.	Deferred income taxes	74,747	53,990	79,694	19.
20.	Other current assets	25,135	25,724	19,866	20.
21.	Total current assets	860,565	851,530	765,400	21.
	DEFERRED DEBITS:				
22.	Deferred fuel and purchased power regulatory asset	-	-	7,984	22.
23.	Other regulatory assets	1,016,147	781,714	787,506	23.
24.	Income tax receivable	65,498	65,498	-	24.
25.	Unamortized debt issue costs	20,530	20,959	22,026	25.
26.	Other	88,490	73,909	82,735	26.
27.	Total deferred debits	1,190,665	942,080	900,251	27.
28.	TOTAL	$ 11,692,152	$ 11,118,173	$ 10,575,588	28.

Supporting Schedules:
(a) E-5

Recap Schedules:
N/A - See Next Page

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE BALANCE SHEETS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 12/31/2010 (A)	Prior Year Ended 12/31/2009 (B)	Prior Year Ended 12/31/2008 (C)	Line No.
	CAPITALIZATION:				
1.	Common stock	$ 178,162	$ 178,162	$ 178,162	1.
2.	Additional paid-in capital	2,379,696	2,126,863	2,117,789	2.
3.	Retained earnings	1,403,390	1,250,126	1,168,901	3.
	Accumulated other comprehensive income (loss):				
4.	Derivative instruments	(100,334)	(80,682)	(98,742)	4.
5.	Pension and other postretirement benefits	(35,961)	(29,114)	(26,960)	5.
6.	Common stock equity (b)	3,824,953	3,445,355	3,339,150	6.
7.	Long-term debt less current maturities	2,948,991	3,180,406	2,850,242	7.
8.	Total capitalization	6,773,944	6,625,761	6,189,392	8.
	CURRENT LIABILITIES:				
9.	Short-term borrowings	-	-	521,684	9.
10.	Current maturities of long-term debt	427,682	197,176	874	10.
11.	Accounts payable	218,491	213,833	233,529	11.
12.	Accrued taxes	106,431	158,051	219,129	12.
13.	Accrued interest	54,638	54,099	39,860	13.
14.	Customer deposits	68,312	70,780	77,452	14.
15.	Liabilities from risk management activities	58,976	55,908	69,585	15.
16.	Other current liabilities	132,170	124,995	105,655	16.
17.	Total current liabilities	1,066,700	874,842	1,267,768	17.
	DEFERRED CREDITS AND OTHER:				
18.	Deferred income taxes	1,865,359	1,582,945	1,401,412	18.
19.	Deferred fuel and purchased power regulatory liability	58,442	87,291	-	19.
20.	Other regulatory liabilities	315,624	293,843	199,597	20.
21.	Liability for asset retirements and removals	328,571	301,783	275,970	21.
22.	Pension and other postretirement benefits	770,611	766,378	635,327	22.
23.	Customer advances for construction	121,645	136,595	132,023	23.
24.	Liabilities from long-term risk management activities	65,390	62,443	126,532	24.
25.	Coal mine reclamation	117,243	92,060	91,201	25.
26.	Unrecognized tax benefits	65,363	140,638	67,846	26.
27.	Other	143,260	153,594	188,520	27.
28.	Total deferred credits and other	3,851,508	3,617,570	3,118,428	28.
29.	TOTAL	$11,692,152	$11,118,173	$10,575,588	29.

Supporting Schedules:
N/A - See previous page

Recap Schedules:
(b) A-3

E-2

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE INCOME STATEMENTS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of dollars, except per share amounts)

Line No.	Description	Test Year Ended 12/31/2010 (A)	Prior Year Ended 12/31/2009 (B)	Prior Year Ended 12/31/2008 (C)	Line No.
1.	Electric Operating Revenues (a)	$ 3,180,807	$ 3,149,500	$ 3,133,496	1.
	Operating Expenses:				
2.	Fuel and purchased power	1,046,815	1,178,620	1,289,883	2.
3.	Operations and maintenance excluding fuel expenses	900,372	852,563	787,270	3.
4.	Depreciation and amortization	406,632	399,455	383,098	4.
5.	Income taxes	175,440	158,661	113,799	5.
6.	Other taxes	134,467	122,358	124,046	6.
7.	Total (a)	2,663,726	2,711,657	2,698,096	7.
8.	Operating Income	517,081	437,843	435,400	8.
	Other Income (Deductions)				
9.	Income taxes	4,975	6,087	6,538	9.
10.	Allowance for equity funds used during construction	22,066	14,999	18,636	10.
11.	Other income	8,956	10,808	6,231	11.
12.	Other expense	(15,859)	(18,001)	(30,569)	12.
13.	Total (a)	20,138	13,893	836	13.
14.	Income Before Interest Deductions	537,219	451,736	436,236	14.
	Interest Deductions				
15.	Interest on long-term debt	205,209	199,907	170,071	15.
16.	Interest on short-term borrowings	8,267	6,315	13,432	16.
17.	Debt discount, premium and expense	4,559	4,675	4,702	17.
18.	Allowance for borrowed funds used during construction	(16,479)	(10,386)	(14,313)	18.
19.	Total (a)	201,556	200,511	173,892	19.
20.	Net Income	$ 335,663	$ 251,225	$ 262,344	20.
21.	Average Common Shares Outstanding	71,264,947	71,264,947	71,264,947	21.
	Earnings Per Share of Average Common (a)				
22.	Stock Outstanding (line 20/line 21)	$ 4.71	$ 3.53	$ 3.68	22.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-2

E-3

ARIZONA PUBLIC SERVICE COMPANY
COMPARATIVE STATEMENTS OF CASH FLOWS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 12/31/2010 (a) (A)	Prior Year Ended 12/31/2009 (a) (B)	Prior Year Ended 12/31/2008 (a) (C)	Line No.
	Cash Flows from Operating Activities:				
1.	Net income	$ 335,663	$ 251,225	$ 262,344	1.
	Items Not Requiring Cash:				
2.	Depreciation and amortization including nuclear fuel	463,522	438,284	416,711	2.
3.	Deferred fuel and purchased power	93,631	(51,742)	(80,183)	3.
4.	Deferred fuel and purchased power amortization	(122,481)	147,018	183,126	4.
5.	Allowance for equity funds used during construction	(22,066)	(14,999)	(18,636)	5.
6.	Deferred income taxes	224,095	192,914	145,157	6.
7.	Changes in mark-to-market valuations	2,688	(6,939)	7,792	7.
	Changes in Current Assets and Liabilities:				
8.	Customer and other receivables	(49,956)	2,603	40,782	8.
9.	Accrued unbilled revenues	7,679	(10,882)	6,784	9.
10.	Materials, supplies and fossil fuel	12,276	(12,261)	(25,453)	10.
11.	Other current assets	597	(9,435)	128	11.
12.	Accounts payable	18,066	(22,129)	(5,915)	12.
13.	Accrued taxes	(51,620)	(61,078)	(12,377)	13.
14.	Other current liabilities	(570)	26,907	20,527	14.
15.	Change in margin and collateral accounts - assets	(9,937)	(13,206)	17,850	15.
16.	Change in margin and collateral accounts - liabilities	(88,315)	35,654	(132,416)	16.
17.	Change in regulatory liabilities	54,518	110,642	(12,129)	17.
18.	Change in long-term income tax receivable	-	(132,379)	-	18.
19.	Change in unrecognized tax benefits	(73,189)	137,478	(92,064)	19.
20.	Change in other long-term assets	(41,989)	(53,734)	14,340	20.
21.	Change in other long-term liabilities	(94,463)	4,778	48,892	21.
22.	Net cash flow provided by operating activities	658,149	958,719	785,260	22.
	Cash Flows from Investing Activities:				
23.	Capital expenditures	(747,967)	(754,301)	(910,189)	23.
24.	Contributions in aid of construction	32,754	53,525	60,292	24.
25.	Allowance for borrowed funds used during construction	(16,479)	(10,386)	(14,313)	25.
26.	Proceeds from nuclear decommissioning trust sales	560,469	441,242	317,619	26.
27.	Investment in nuclear decommissioning trust	(584,885)	(463,033)	(338,361)	27.
28.	Other	8,576	(4,667)	5,517	28.
29.	Net cash flow used for investing activities	(747,532)	(737,620)	(879,435)	29.
	Cash Flows from Financing Activities:				
30.	Issuance of long-term debt	-	863,780	-	30.
31.	Repayment of long-term debt	(1,911)	(343,941)	(27,717)	31.
32.	Short-term borrowings and payments-net	-	(521,684)	303,684	32.
33.	Equity infusion	252,833	-	7,601	33.
34.	Dividends paid on common stock	(182,400)	(170,000)	(170,000)	34.
35.	Net cash flow provided by (used for) financing activities	68,522	(171,845)	113,568	35.
36.	Net increase (decrease) in cash and cash equivalents	(20,861)	49,254	19,393	36.
37.	Cash and cash equivalents at beginning of period	120,798	71,544	52,151	37.
38.	Cash and cash equivalents at end of period	$ 99,937	$ 120,798	$ 71,544	38.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-5

E-4

ARIZONA PUBLIC SERVICE COMPANY
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Common Shares	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total	Line No.
1.	Balance at December 31, 2007	71,264,947	$ 178,162	$ 2,105,466	$ 1,076,557	$ (8,744)	$ 3,351,441	1.
2.	Net income				262,344		262,344	2.
3.	Unrealized actuarial loss, net of tax benefit of ($5,075)					(7,597)	(7,597)	3.
	Amortization to Income:							
4.	Actuarial loss, net of tax benefit of $1,393					2,130	2,130	4.
5.	Prior service cost, net of tax benefit of $189					289	289	5.
6.	Net unrealized loss, net of tax benefit of of ($56,149)					(85,670)	(85,670)	6.
7.	Reclassification of net realized gains to income, net of tax expense of ($16,890)					(26,110)	(26,110)	7.
8.	Comprehensive income				262,344	(116,958)	145,386	8.
9.	Common stock dividends				(170,000)		(170,000)	9.
10.	Equity Infusion			7,601			7,601	10.
11.	Other			4,722			4,722	11.
12.	Balance at December 31, 2008	71,264,947	$ 178,162	$ 2,117,789	$ 1,168,901	$ (125,702)	$ 3,339,150	12.
13.	Net income				251,225		251,225	13.
14.	Unrealized actuarial loss, net of tax benefit of ($2,938)					(4,571)	(4,571)	14.
	Amortization to Income:							
15.	Actuarial loss, net of tax benefit of $1,387					2,126	2,126	15.
16.	Prior service cost, net of tax benefit of $190					291	291	16.
17.	Net unrealized loss, net of tax benefit of of ($61,317)					(94,008)	(94,008)	17.
18.	Reclassification of net realized losses to income, net of tax benefit of $73,261					112,068	112,068	18.
19.	Comprehensive income				251,225	15,906	267,131	19.
20.	Common stock dividends				(170,000)		(170,000)	20.
21.	Equity Infusion			-			-	21.
22.	Other			9,074			9,074	22.
23.	Balance at December 31, 2009	71,264,947	$ 178,162	$ 2,126,863	$ 1,250,126	$ (109,796)	$ 3,445,355	23.
24.	Net income				335,663		335,663	24.
25.	Unrealized actuarial loss, net of tax benefit of $(6,344)					(9,684)	(9,684)	25.
	Amortization to Income:							
26.	Actuarial loss, net of tax benefit of $1,658					2,541	2,541	26.
27.	Prior service cost, net of tax benefit of $193					295	295	27.
28.	Net unrealized loss, net of tax benefit of of ($61,358)					(93,929)	(93,929)	28.
29.	Reclassification of net realized losses to income, net of tax benefit of $48,462					74,278	74,278	29.
30.	Comprehensive income				335,663	(26,499)	309,164	30.
31.	Common stock dividends				(182,400)		(182,400)	31.
32.	Equity Infusion			252,833			252,833	32.
33.	Other				1		1	33.
34.	Balance at December 31, 2010	71,264,947	$ 178,162	$ 2,379,696	$ 1,403,390	$ (136,295)	$ 3,824,953	34.

Supporting Schedules:
N/A

Recap Schedules:
N/A

E-5

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY DETAIL OF UTILITY PLANT
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account Number	Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	Line No.
		Gross Plant Includible in Rate Base: (a)				
1.	101	Plant in Service	$ 13,167,998	$ 488,107	$ 13,656,105	1.
2.	108	Less: Accum. Depreciation-Plant in Service	4,647,183	131,905	4,779,088	2.
3.	111	Accum. Amortization-Plant in Service	358,403	81,509	439,912	3.
4.		Net Plant Includible in Rate Base	8,162,412	274,693	8,437,105	4.
5.	120.2-120.5	Nuclear fuel, net of amortization (b)	118,243	(9,449)	108,794	5.
6.	107	Construction Work in Progress	391,599	(24,167)	367,432	6.
7.	120.1	Nuclear Fuel in Process	69,149	22,735	91,884	7.
8.		Total Construction Work in Progress (b)	460,748	(1,432)	459,316	8.
9.	105	Plant Held for Future Use	70,891	(15,530)	55,361	9.
10.	108	Less: Accum Depreciation Related to Plant Held for Future Use	1	(1)	-	10.
11.		Net Plant held for Future Use	70,890	(15,529)	55,361	11.
12.		Utility Plant - Net (b)	$ 8,812,293	$ 248,283	$ 9,060,576	12.

Supporting Schedules:
N/A

Recap Schedule:
(a) A-4
(b) E-1

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	Line No.
		Intangible Plant:				
1.	301	Organization	$ -	$ -	$ -	1.
2.	302	Franchises and Consents	3,341	0	3,341	2.
3.	303	Miscellaneous Intangible Plant	479,385	43,491	522,876	3.
4.		Total Intangible Plant	$ 482,726	$ 43,491	$ 526,217	4.
		Production Plant:				
		Steam Production Plant:				
5.	310	Land and Land Rights	$ 5,242	$ 3	$ 5,245	5.
6.	311	Structures and Improvements	164,774	3,757	168,531	6.
7.	312	Boiler Plant Equipment	1,103,871	11,063	1,114,934	7.
8.	314	Turbogenerator Units	252,224	8,248	260,472	8.
9.	315	Accessory Electric Equipment	161,052	3,481	164,533	9.
10.	316	Miscellaneous Power Plant Equip	77,257	5,017	82,274	10.
11.	317	Asset Retirement Costs for Steam Production	7,666	5,310	12,976	11.
12.		Total Steam Production Plant	$ 1,772,086	$ 36,879	$ 1,808,965	12.
		Nuclear Production Plant:				
13.	320	Land and Land Rights	$ 4,423	$ (5)	$ 4,418	13.
14.	321	Structures and Improvements	696,871	8,622	705,493	14.
15.	322	Reactor Plant Equipment	1,153,729	30,638	1,184,367	15.
16.	323	Turbogenerator Units	359,747	4,735	364,482	16.
17.	324	Accessory Electric Equipment	277,488	(364)	277,124	17.
18.	325	Miscellaneous Power Plant Equip	142,325	4,424	146,749	18.
19.	326	Asset Retirement Costs for Nuclear Production	23,461	(0)	23,461	19.
20.		Total Nuclear Production Plant	$ 2,658,044	$ 48,050	$ 2,706,094	20.

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	Line No.
		Hydraulic Production Plant:				
1.	330	Land and Land Rights	$ -	$ -	$ -	1.
2.	331	Structures and Improvements	-	-	-	2.
3.	332	Reservoirs, Dams and Waterways	-	-	-	3.
4.	333	Water Wheels, Turbines and Generators	-	-	-	4.
5.	334	Accessory Electric Equipment	-	-	-	5.
6.	335	Miscellaneous Power Plant Equip	-	-	-	6.
7.	336	Roads, Railroads and Bridges	-	-	-	7.
8.	337	Asset Retirement Costs for Hydraulic Production	5,903	0	5,903	8.
9.		Total Hydraulic Production Plant	$ 5,903	$ 0	$ 5,903	9.
		Other Production Plant:				
10.	340	Land and Land Rights	$ 2,946	$ 0	$ 2,946	10.
11.	341	Structures and Improvements	65,765	1,497	67,262	11.
12.	342	Fuel Holders, Producers and Accessories	40,436	1,743	42,179	12.
13.	343	Prime Movers	663,170	1,472	664,642	13.
14.	344	Generators	550,448	37,722	588,170	14.
15.	345	Accessory Electric Equipment	86,542	(268)	86,274	15.
16.	346	Miscellaneous Power Plant Equip	13,559	1,152	14,711	16.
17.		Total Other Production Plant	$ 1,422,866	$ 43,319	$ 1,466,185	17.
18.		Total Production Plant	$ 5,858,899	$ 128,249	$ 5,987,148	18.

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account No.		Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	Line No.
			Transmission Plant				
1.	350	*	Land and Land Rights	$ 91,928	$ 26,947	$ 118,875	1.
2.	352	*	Structures and Improvements	51,725	23,451	75,176	2.
3.	353	*	Station Equipment	777,646	43,289	820,935	3.
4.	354	*	Towers and Fixtures	87,902	791	88,693	4.
5.	355	*	Poles and Fixtures	326,317	60,830	387,147	5.
6.	356	*	Overhead Conductors and Devices	310,653	32,604	343,257	6.
7.	357		Underground Conduit	19,401	535	19,936	7.
8.	358		Underground Conductors and Devices	28,193	(269)	27,924	8.
9.			Total Transmission Plant	$ 1,693,765	$ 188,178	$ 1,881,943	9.
			Distribution Plant:				
10.	360		Land and Land Rights	$ 47,107	$ (450)	$ 46,657	10.
11.	361		Structures and Improvements	49,519	11,565	61,084	11.
12.	362		Station Equipment	393,847	12,953	406,800	12.
13.	364		Poles, Towers, and Fixtures	473,455	4,121	477,576	13.
14.	365		Overhead Conductors and Devices	287,566	5,077	292,643	14.
15.	366		Underground Conduit	611,079	9,409	620,488	15.
16.	367		Underground Conductors and Devices	1,371,420	51,289	1,422,709	16.
17.	368		Line Transformers	705,154	12,445	717,599	17.
18.	369		Services	318,064	5,278	323,342	18.
19.	370		Meters	197,242	(17,319)	179,923	19.
20.	371		Installations on Customers' Premises	41,547	(1,657)	39,890	20.
21.	373		Street Lighting and Signal Systems	73,280	423	73,703	21.
22.			Total Distribution Plant	$ 4,569,280	$ 93,134	$ 4,662,414	22.

Notes:

* Excludes SCE 500kv Transmission Line

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account No.		Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	Line No.
			General Plant				
1.	389		Land and Land Rights	$ 11,538	$ 2,974	$ 14,512	1.
2.	390		Structures and Improvements	141,788	(1,738)	140,050	2.
3.	391		Office Furniture and Equipment	125,778	12,450	138,228	3.
4.	392	**	Transportation Equipment	32,167	4,387	36,554	4.
5.	393		Stores Equipment	1,260	(1,003)	257	5.
6.	394	*	Tools, Shop and Garage Equipment	24,663	3,673	28,336	6.
7.	395		Laboratory Equipment	1,895	(510)	1,385	7.
8.	396		Power Operated Equipment	10,458	1,877	12,335	8.
9.	397	*	Communication Equipment	142,451	10,725	153,176	9.
10.	398		Miscellaneous Equipment	11,578	(5,669)	5,909	10.
11.			Total General Plant	$ 503,576	$ 27,167	$ 530,743	11.
			SCE 500kv Transmission Line				
12.	350		Land and Land Rights	$ 2,321	$ 1	$ 2,322	12.
13.	352		Structures and Improvements	410	(0)	410	13.
14.	353		Station Equipment	18,911	7,889	26,800	14.
15.	354		Towers and Fixtures	13,753	(0)	13,753	15.
16.	355		Poles and Fixtures	930	0	930	16.
17.	356		Overhead Conductors and Devices	22,654	(0)	22,654	17.
18.			Total SCE Transmission Line	$ 58,979	$ 7,888	$ 66,867	18.

Notes:
* Excludes SCE 500kv Transmission Line
** Includes Capitalized Leases

Supporting Schedules:
N/A

Recap Schedule:
N/A

ARIZONA PUBLIC SERVICE COMPANY
DETAIL OF PLANT INCLUDIBLE IN RATE BASE
TEST YEAR ENDED 12/31/2010 & PRIOR YEAR ENDED 12/31/2009
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2009 (A)	Net Additions (12 Months) (B)	Test Year Ended Bal. 12/31/2010 (C)	*Line No.*
		SCE 500kv - General Plant				
1.	394	Tools, Shop and Garage Equipment	$ 88	$ (0)	$ 88	*1.*
2.	397	Communication Equipment	685	(0)	685	*2.*
3.		Total SCE 500kv Line	$ 59,752	$ 7,888	$ 67,640	*3.*
4.		Total Net Plant Includible in Rate Base (a)	$ 13,167,998	$ 488,107	$ 13,656,105	*4.*

Supporting Schedules:
N/A

Recap Schedule:
(a) E-5, page 1 of 6

E-6

SCHEDULE E-6 DOES NOT APPLY

E-7

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC OPERATING STATISTICS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS

Line No.	Description	Test Year Ended 12/31/2010 (A)	Prior Year Ended 12/31/2009 (B)	Prior Year Ended 12/31/2008 (C)	Line No.
1.	**kWh Sales (thousands)**				1.
2.	Residential	13,058,573	13,196,069	13,416,194	2.
3.	Commercial	12,399,046	12,583,203	12,920,921	3.
4.	Industrial	2,160,094	2,184,504	2,408,469	4.
5.	Irrigation	20,972	23,777	23,878	5.
6.	Public Street and Highway Lighting	139,751	126,452	129,843	6.
7.	Other Sales to Public Authorities	2,773	2,977	3,206	7.
8.	Total Sales to Ultimate Consumers	27,781,209	28,116,982	28,902,511	8.
9.	Sales for Resale - Requirements Customers	737,142	864,353	1,150,791	9.
10.	Sales for Resale - Other Customers	3,431,100	3,241,856	3,320,600	10.
11.	Total Sales for Resale	4,168,242	4,106,209	4,471,391	11.
12.	**Total kWh Sales**	31,949,451	32,223,191	33,373,902	12.
13.	**Average Number of Customers**				13.
14.	Residential	989,989	983,539	977,944	14.
15.	Commercial	120,372	120,305	118,945	15.
16.	Industrial	3,474	3,538	3,607	16.
17.	Irrigation	310	319	326	17.
18.	Public Street and Highway Lighting	1,001	918	919	18.
19.	Other Sales to Public Authorities	163	162	164	19.
20.	Total Retail Consumers	1,115,309	1,108,781	1,101,905	20.
21.	Sales for Resale - Requirements Customers	14	14	14	21.
22.	**Total Customers**	1,115,323	1,108,795	1,101,919	22.
23.	**Average kWh Use (Annual)**				23.
24.	Residential	13,191	13,417	13,719	24.
25.	Commercial	103,006	104,594	108,629	25.
26.	Industrial	621,789	617,440	667,721	26.
27.	Irrigation	67,652	74,536	73,245	27.
28.	Public Street and Highway Lighting	139,611	137,747	141,287	28.
29.	Other Sales to Public Authorities	17,012	18,377	19,549	29.
30.	Sales for Resale - Requirements Customers	52,653,000	61,739,500	82,199,357	30.
31.	**Average Annual Revenue per Residential Customer**				31.
32.	Annual Revenue	1,520.92	1,516.12	1,489.88	32.
33.	Revenue per kWh (Cents)	11.53	11.30	10.86	33.
34.	**Direct Production Expense per kWh Sold (Cents)**	4.79	5.20	5.37	34.
35.	**Direct Transmission Expense per kWh Sold (Cents)**	0.15	0.14	0.13	35.

Supporting Schedules:
N/A

Recap Schedules:
N/A

E-8

ARIZONA PUBLIC SERVICE COMPANY
TAXES CHARGED TO OPERATIONS
TEST YEAR ENDED 12/31/2010 AND PRIOR YEARS
(Thousands of Dollars)

Line No.	Description	Test Year Ended 12/31/2010 (A)	Prior Year Ended 12/31/2009 (B)	Prior Year Ended 12/31/2008 (C)	Line No.
	Federal Taxes:				
1.	Income	$ (67,848)	$ (5,628)	$ (47,837)	1.
2.	F.I.C.A.*	25,883	24,467	23,525	2.
3.	Deferred Income Taxes	208,373	136,978	133,918	3.
4.	Total	166,408	155,817	109,606	4.
	State Taxes:				
5.	Ad Valorem	134,383	123,680	125,134	5.
6.	Sales and Use**	84	(1,322)	(1,088)	6.
7.	Income	17,953	(31,007)	18,240	7.
8.	Deferred Income Taxes	16,962	58,318	9,478	8.
9.	Total	169,382	149,669	151,764	9.
10.	Total Taxes	$ 335,790	$ 305,486	$ 261,370	10.

Notes:
* Includes payroll related taxes charged to others. These taxes are included in operations and maintenance on C-1, E-2 and F-1.
** Includes local taxes.

Supporting Schedules:
N/A

Recap Schedules:
N/A

E-9

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO FINANCIAL STATEMENTS
TEST YEAR ENDED 12/31/2010

See the attached Arizona Public Service Company Form 10-K filed with the Securities and Exchange Commission for the period ended December 31, 2010. The notes to the financial statements are contained on pages 88 through 152 and pages 161 through 167 of the document.

Supporting Schedules
N/A

Recap Schedules
N/A

EDGAR Online

ARIZONA PUBLIC SERVICE CO

FORM 10-K
(Annual Report)

Filed 02/18/11 for the Period Ending 12/31/10

Address	400 N FIFTH ST
	P O BOX 53999
	PHOENIX, AZ 85004
Telephone	6022501000
CIK	0000007286
SIC Code	4931 - Electric and Other Services Combined
Fiscal Year	12/31

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission File Number	Registrants; State of Incorporation; Addresses; and Telephone Number	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	**ARIZONA PUBLIC SERVICE COMPANY** (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

Securities registered pursuant to Section 12(b) of the Act:

	Title Of Each Class	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	New York Stock Exchange
ARIZONA PUBLIC SERVICE COMPANY	None	None

Securities registered pursuant to Section 12(g) of the Act:

ARIZONA PUBLIC SERVICE COMPANY — Common Stock, Par Value $2.50 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

PINNACLE WEST CAPITAL CORPORATION	Yes ☑	No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☑	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

PINNACLE WEST CAPITAL CORPORATION	Yes ☐	No ☑
ARIZONA PUBLIC SERVICE COMPANY	Yes ☐	No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION	Yes ☑	No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☑	No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION	Yes ☑	No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☐	No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or in any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☑ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant's most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION	$3,935,855,234 as of June 30, 2010
ARIZONA PUBLIC SERVICE COMPANY	$0 as of June 30, 2010

The number of shares outstanding of each registrant's common stock as of February 15, 2011

PINNACLE WEST CAPITAL CORPORATION	108,780,623 shares
ARIZONA PUBLIC SERVICE COMPANY	Common Stock, $2.50 par value, 71,264,947 shares. Pinnacle West Capital Corporation is the sole holder of Arizona Public Service Company's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 18, 2011 are incorporated by reference into Part III hereof.

Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

TABLE OF CONTENTS

	Page
GLOSSARY OF NAMES AND TECHNICAL TERMS	1
FORWARD-LOOKING STATEMENTS	2
PART I	3
Item 1. Business	3
Item 1A. Risk Factors	27
Item 1B. Unresolved Staff Comments	38
Item 2. Properties	39
Item 3. Legal Proceedings	41
Executive Officers of Pinnacle West	42
PART II	44
Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	44
Item 6. Selected Financial Data	46
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	48
Item 7A. Quantitative and Qualitative Disclosures about Market Risk.	78
Item 8. Financial Statements and Supplementary Data	79
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	173
Item 9A. Controls and Procedures	173
Item 9B. Other Information	174
PART III	174
Item 10. Directors, Executive Officers and Corporate Governance of Pinnacle West	174
Item 11. Executive Compensation	174
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	174
Item 13. Certain Relationships and Related Transactions, and Director Independence	176
Item 14. Principal Accountant Fees and Services	176
PART IV	177
Item 15. Exhibits and Financial Statement Schedules	177
SIGNATURES	219

Exhibit 10.6.5
Exhibit 10.9.1C
Exhibit 10.11.4
Exhibit 12.1
Exhibit 12.2
Exhibit 12.3
Exhibit 21.1

Exhibit 23.1
Exhibit 23.2
Exhibit 31.1
Exhibit 31.2
Exhibit 31.3
Exhibit 31.4
Exhibit 32.1
Exhibit 32.2
EX-101 INSTANCE DOCUMENT
EX-101 SCHEMA DOCUMENT
EX-101 CALCULATION LINKBASE DOCUMENT
EX-101 LABELS LINKBASE DOCUMENT
EX-101 PRESENTATION LINKBASE DOCUMENT
EX-101 DEFINITION LINKBASE DOCUMENT

This combined Form 10-K is separately filed by Pinnacle West and APS. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 8 of this report includes Consolidated Financial Statements of Pinnacle West and Consolidated Financial Statements of APS. Item 8 also includes Notes to Pinnacle West's Consolidated Financial Statements, the majority of which also relates to APS, and Supplemental Notes, which only relate to APS's Consolidated Financial Statements.

GLOSSARY OF NAMES AND TECHNICAL TERMS

ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for Funds Used During Construction
ANPP	Arizona Nuclear Power Project, also known as Palo Verde
APS	Arizona Public Service Company, a subsidiary of the Company
APSES	APS Energy Services Company, Inc., a subsidiary of the Company
Base Fuel Rate	The portion of APS's retail base rates attributable to fuel and purchased power costs
Cholla	Cholla Power Plant
DOE	United States Department of Energy
El Dorado	El Dorado Investment Company, a subsidiary of the Company
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
GWh	Gigawatt-hour, one billion watts per hour
IFRS	International Financial Reporting Standards
kV	Kilovolt, one thousand volts
kWh	Kilowatt-hour, one thousand watts per hour
MMBtu	One million British Thermal Units
MW	Megawatt, one million watts
Native Load	Retail and wholesale sales supplied under traditional cost-based rate regulation
Navajo Plant	Navajo Generating Station
NRC	United States Nuclear Regulatory Commission
OCI	Other comprehensive income
Palo Verde	Palo Verde Nuclear Generating Station
Pinnacle West	Pinnacle West Capital Corporation (any use of the words "Company," "we," and "our" refer to Pinnacle West)
Pinnacle West Marketing & Trading	Pinnacle West Marketing & Trading Co., LLC, a subsidiary of the Company
PRP	Potentially responsible party under Superfund
PSA	Power supply adjustor approved by the ACC to provide for recovery or refund of variations in actual fuel and purchased power costs compared with the Base Fuel Rate
RES	Arizona Renewable Energy Standard and Tariff
Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SunCor	SunCor Development Company, a subsidiary of the Company
TCA	Transmission cost adjustor
VIE	Variable-interest entity
West Phoenix	West Phoenix Power Plant

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Item 1A and in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations," these factors include, but are not limited to:

- our ability to achieve timely and adequate rate recovery of our costs, including returns on debt and equity capital;
- our ability to manage capital expenditures and other costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant performance and outages;
- volatile fuel and purchased power costs;
- fuel and water supply availability;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to greenhouse gas emissions, renewable energy mandates and energy efficiency standards;
- our ability to meet renewable energy requirements and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- competition in retail and wholesale power markets;
- the duration and severity of the economic decline in Arizona and current real estate market conditions;
- the cost of debt and equity capital and the ability to access capital markets when required;
- changes to our credit ratings;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations;
- technological developments affecting the electric industry; and
- restrictions on dividends or other burdensome provisions in our credit agreements and ACC orders.

These and other factors are discussed in Risk Factors described in Item 1A of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

PART I

ITEM 1. BUSINESS

Pinnacle West

Pinnacle West is a holding company that conducts business through its subsidiaries. We derive substantially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

	Year Ended December 31,		
Operating Revenues (in thousands):	2010	2009	2008
APS	$ 3,180,807	$ 3,149,500	$ 3,133,496
Percentage of Pinnacle West Consolidated	97%	99%	97%

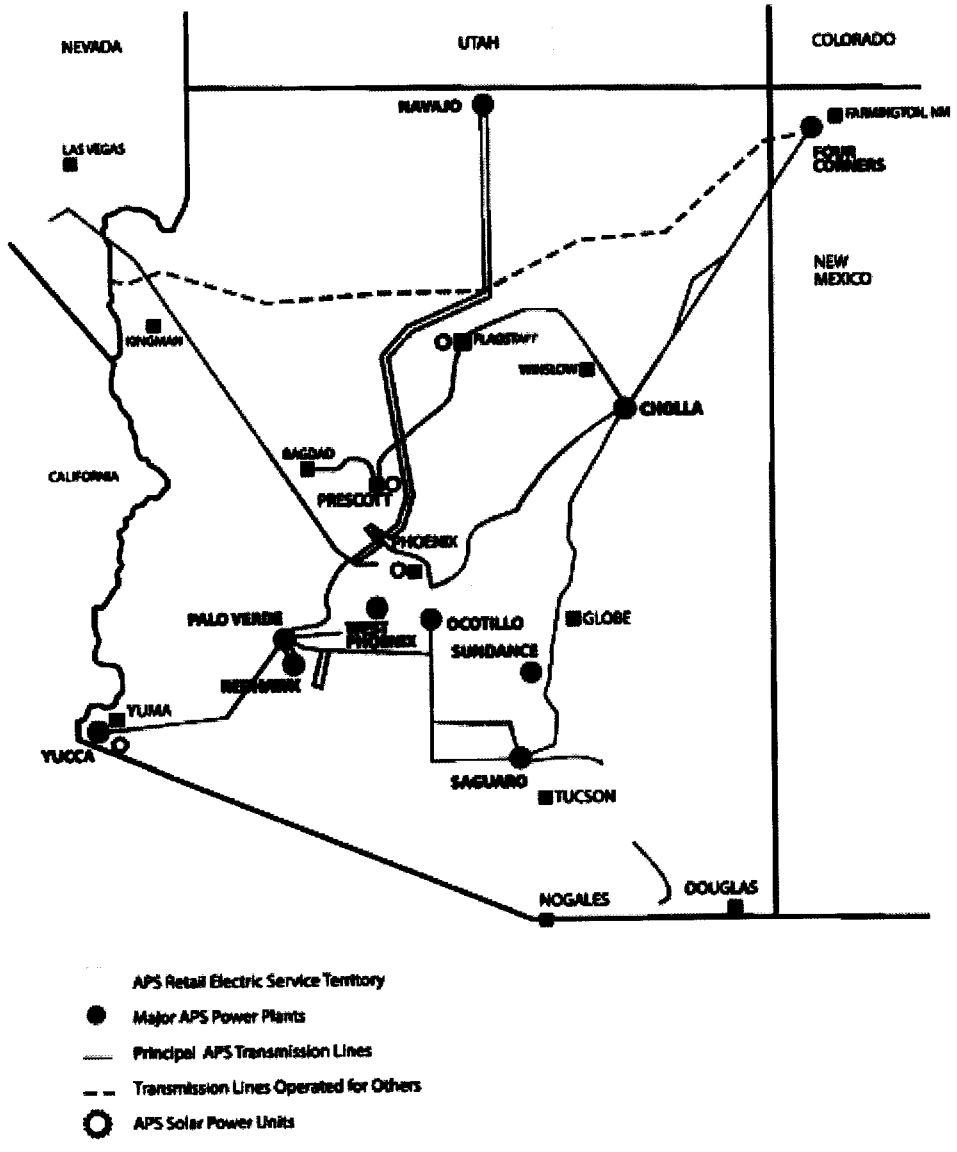
Pinnacle West's other first-tier subsidiaries are SunCor, APSES and El Dorado. Additional information related to these businesses is provided later in this report.

Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission and distribution. In 2009 our real-estate subsidiary, SunCor, began disposing of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt (see Note 23). All of SunCor's operations are reflected as discontinued operations. As a result, the real estate segment is no longer a reportable segment. See Note 17 for financial information of our business segments.

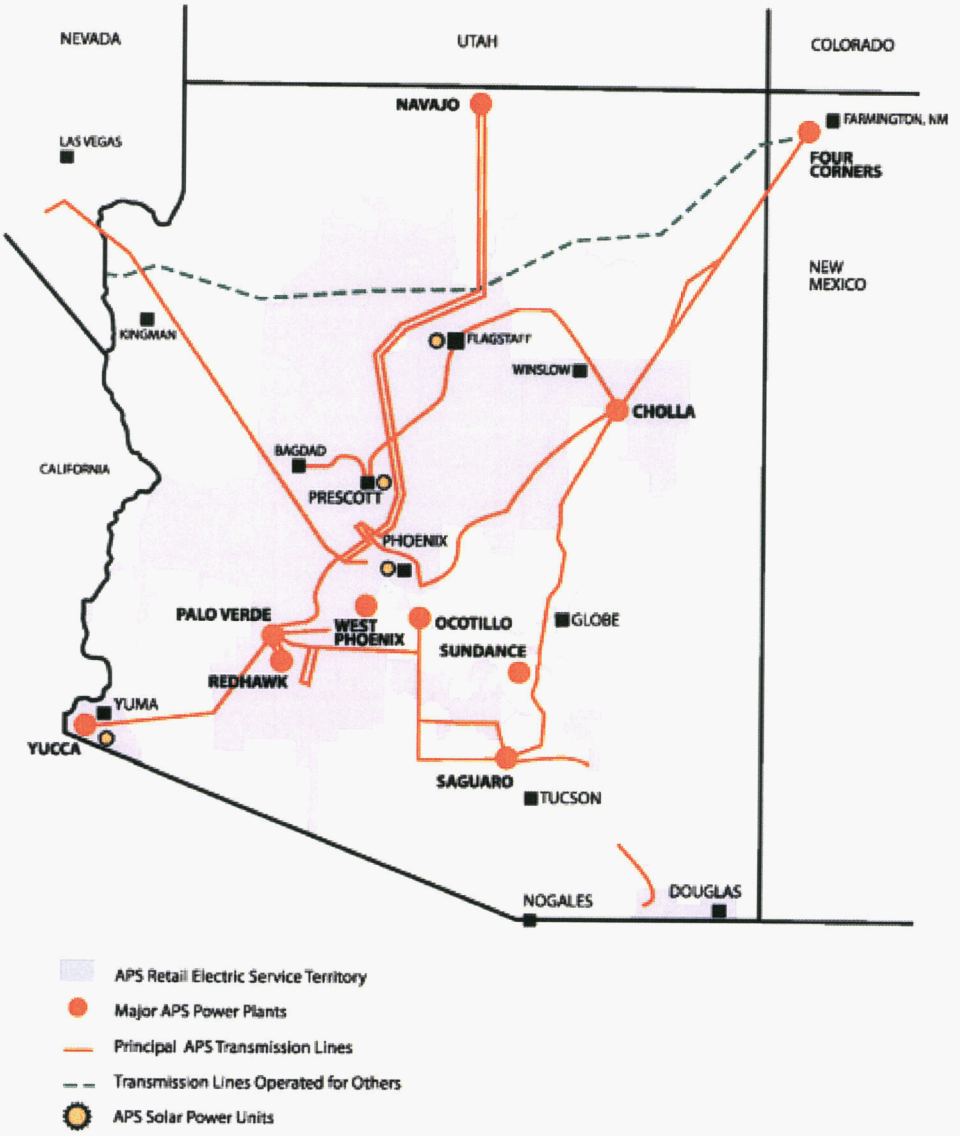
BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

APS currently provides electric service to approximately 1.1 million customers. We own or lease more than 6,290 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2010, no single purchaser or user of energy accounted for more than 1.2% of our electric revenues.

The following map shows APS's retail service territory, including the locations of its generating facilities and principal transmission lines.

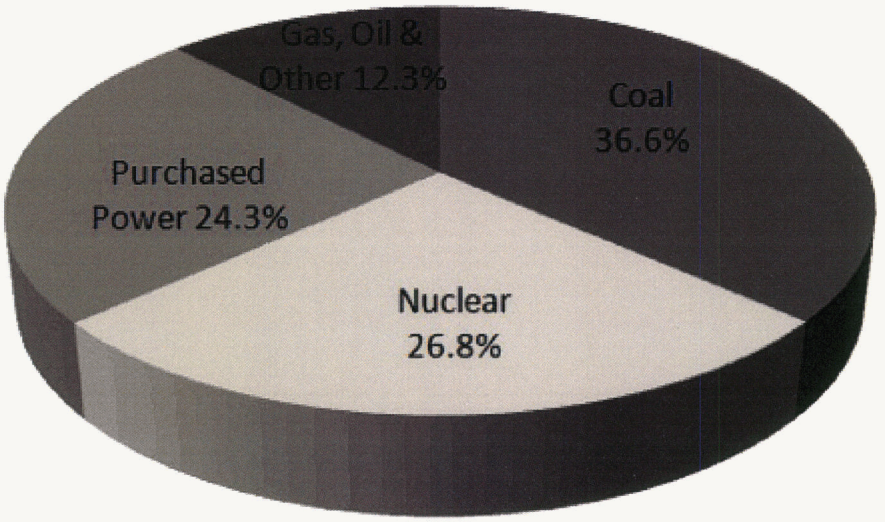


The following map shows APS's retail service territory, including the locations of its generating facilities and principal transmission lines.



Energy Sources and Resource Planning

To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. Resource planning is an important function necessary to meet Arizona's future energy needs. APS's sources of energy by fuel type during 2010 were as follows:



Generation Facilities

APS has ownership interests in or leases the coal, nuclear, gas, oil and solar generating facilities described below. For additional information regarding these facilities, see Item 2.

Coal Fueled Generating Facilities

Four Corners — Four Corners is a 5-unit coal-fired power plant located in the northwestern corner of New Mexico. APS operates the plant and owns 100% of Four Corners Units 1, 2 and 3 and 15% of Units 4 and 5. APS has a total entitlement from Four Corners of 791 MW. The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS purchases all of Four Corners' coal requirements from a supplier with a long-term lease of coal reserves with the Navajo Nation. The Four Corners coal contract runs through 2016.

On November 8, 2010, APS and Southern California Edison ("SCE") entered into an asset purchase agreement providing for the purchase by APS of SCE's 48% interest in each of Units 4 and 5 of Four Corners. If consummated, APS would acquire 739 MW from SCE unless any of the other owners of interests in Units 4 and 5 exercise their rights of first refusal prior to March 8, 2011, in which case APS would not be able to purchase SCE's entire share of the Units. Completion of the purchase by APS, which is expected to occur in the second half of 2012, is conditioned upon the receipt of regulatory approvals from the ACC, the California Public Utilities Commission and the FERC, the execution of a new coal supply contract for a lease renewal period described below, expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act and other typical closing conditions.

APS, on behalf of the Four Corners participants, has negotiated amendments to an existing facility lease with the Navajo Nation which would extend the Four Corners leasehold interest to 2041. Execution by the Navajo Nation of the lease amendments is a condition to closing of the purchase by APS of SCE's interests in Four Corners. The execution of these amendments by the Navajo Nation requires the approval of the Navajo Nation Council, which occurred on February 15, 2011 and is awaiting final signature by the Nation's President. The effectiveness of the amendments also requires the approval of the U.S. Department of the Interior ("DOI"), as does a related Federal rights-of-way grant which the Four Corners participants will pursue. A Federal environmental review will be conducted as part of the DOI review process.

APS has announced that, if APS's purchase of SCE's interests in Units 4 and 5 at Four Corners is consummated, it will close Units 1, 2 and 3 at the plant. These events will change the plant's overall generating capacity from 2,100 MW to 1,540 MW and APS's entitlement from the plant from 791 MW to 970 MW.

Cholla — Cholla is a 4-unit coal-fired power plant located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operates that Unit for PacifiCorp. APS has a total entitlement from Cholla of 647 MW. APS purchases all of Cholla's coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal government and private landholders. The Cholla coal contract runs through 2024. APS has the ability under the contract to reduce its annual coal commitment and purchase a portion of Cholla's coal requirements on the spot market to take advantage of competitive pricing options and to purchase coal required for increased operating capacity. APS believes that the current fuel contracts and competitive fuel supply options ensure the continued operation of Cholla for its useful life. In addition, APS has a long-term coal transportation contract.

Navajo Generating Station — The Navajo Plant is a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operates the plant and APS owns a 14% interest in Navajo Units 1, 2 and 3. APS has a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Plant is under contract with its coal supplier through 2011, with options to extend through 2019. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government.

These coal plants face uncertainties related to existing and potential legislation and regulation that could significantly impact their economics and operations. See "Environmental Matters" below and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview and Capital Expenditures" in Item 7 for environmental and climate change developments and lease renewal negotiations with the Navajo Nation impacting these coal facilities. See Note 11 for information regarding APS's coal mine reclamation obligations.

Nuclear

Palo Verde Nuclear Generating Station — Palo Verde is a nuclear power plant located about 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and about 17% of Unit 2. In addition, APS leases about 12.1% of Unit 2, resulting in a 29.1% combined interest in that Unit. APS has a total entitlement from Palo Verde of 1,146 MW.

Palo Verde Leases — In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back about 42% of its share of Palo Verde Unit 2 and certain common facilities. Prior to 2010, APS accounted for these arrangements as operating leases. Due to amended VIE accounting guidance, in 2010 APS began consolidating the lessor trust entities, and eliminated lease accounting for these transactions. The agreements have terms of 29.5 years and contain options to renew the leases or to purchase the property for fair market value at the end of the lease terms. APS must give notice to the respective lessor trusts between December 31, 2010 and December 31, 2012 if it wishes to exercise, or not exercise, either of these options. We are analyzing these options. See Note 20 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

Palo Verde Operating Licenses — Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987. The full power operating licenses, each valid for a period of 40 years, authorize APS, as operating agent for Palo Verde, to operate the three Palo Verde Units. On December 15, 2008, APS applied for renewed operating licenses for the Palo Verde Units for a period of 20 years beyond the expirations of the current licenses. The current NRC schedule for the applications estimates that a final NRC decision will be issued in April 2011. APS is making preparations to secure resources necessary to operate the plant for the period of extended operation, including the execution in April 2010 of a Municipal Effluent Purchase and Sale Agreement that provides effluent water rights necessary for cooling purposes at Palo Verde through 2050.

Palo Verde Fuel Cycle — The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The Palo Verde participants have contracted for all of Palo Verde's requirements for uranium concentrates through 2011 and 95% of its requirements through 2017. A new contract is currently being negotiated that will cover Palo Verde's remaining requirements for uranium concentrates through 2017. The participants have also contracted for all of Palo Verde's conversion services through 2018, all of Palo Verde's enrichment services through 2020 and all of Palo Verde's fuel assembly fabrication services through 2016.

Spent Nuclear Fuel and Waste Disposal — The Nuclear Waste Policy Act of 1982 ("NWPA") required the DOE to accept, transport, and dispose of spent nuclear fuel and high level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste ("Standard Contract") with each nuclear power plant. The DOE failed to begin accepting Palo Verde's spent nuclear fuel by 1998, and APS (on behalf of itself and the other Palo Verde participants) filed a lawsuit for DOE's breach of the Palo Verde Standard Contract in the U.S. Court of Federal Claims. The Court of Federal Claims ruled in favor of APS and in October 2010 awarded $30.2 million in damages to the Palo Verde participants for costs incurred through December 2006.

The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, DOE submitted its application to the NRC to authorize construction of the Yucca Mountain repository. In March 2010, the DOE filed a motion to dismiss with prejudice its Yucca Mountain construction authorization application that was pending before the NRC. Several interested parties have intervened in the NRC proceeding, and the proceeding has not been conclusively decided by the NRC or the courts. Additionally, a number of interested parties have filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application. None of these lawsuits have been conclusively decided by the courts.

Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation ("ISFSI") to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in December 2047 (assuming the NRC approves APS's request for renewed operating licenses, as discussed above). If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

In addition to the spent fuel stored at Palo Verde's on-site ISFSI, Palo Verde also generates certain types of low level radioactive waste that are stored on-site. Currently, the Class B and Class C waste (the higher radioactivity of the low level wastes) is stored on-site since industry access to a disposal site was eliminated several years ago. The NRC is considering regulations that would allow the industry to eliminate much of this waste by blending it with lower level Class A waste so that it can be disposed of at a facility such as the one Palo Verde utilizes in Utah.

Nuclear Decommissioning Costs — APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS's ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (one paid by all retail customers taking service from the APS system), which allows APS to maintain its external sinking fund mechanism. See Note 12 for additional information about APS's nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters — See "Palo Verde Nuclear Generating Station — Nuclear Insurance" in Note 11 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Natural Gas and Oil Fueled Generating Facilities

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near the Palo Verde Nuclear Generating Station; Ocotillo, located in Tempe; Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Saguaro and Yucca run on either gas or oil. APS has one oil only power plant, Douglas, located in the town of Douglas, Arizona. APS owns and operates each of these plants with the exception of one combustion turbine unit and one steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,389 MW. Gas for these plants is acquired through APS's hedging program. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2024. Fuel oil is acquired under short-term purchases delivered primarily to West Phoenix, where it is distributed to APS's other oil power plants by truck.

Solar Facilities

APS owns and operates more than sixty small solar systems around the state. Together they have the capacity to produce about 5 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport, a 1 MW facility located at APS's Saguaro power plant and less than 1 MW of solar photovoltaic distributed energy systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, is a pilot program through which, upon completion, APS will own, operate and receive energy from approximately 1.5 MW of solar photovoltaic distributed energy systems located within a certain test area in Flagstaff, Arizona.

Purchased Power Contracts

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A substantial portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. (See Note 18.) APS continually assesses its need for additional capacity resources to assure system reliability. APS does not expect to require new conventional generation sources sooner than 2017, due primarily to planned additions of renewable resources and energy efficiency initiatives.

Purchased Power Capacity — APS's purchased power capacity under long-term contracts, including its renewable energy portfolio, is summarized in the tables below. All capacity values are based on net capacity unless otherwise noted.

Type	Dates Available	Capacity (MW)
Purchase Agreement (a)	Year-round through December 2014	104
Purchase Agreement (b)	Year-round through June 14, 2020	60
Exchange Agreement (c)	May 15 to September 15 annually through 2020	480
Tolling Agreement	Year-round through May 2017	500
Tolling Agreement	Summer seasons through October 2019	560
Day-Ahead Call Option Agreement	Summer seasons through September 2015	500
Day-Ahead Call Option Agreement	Summer seasons through summer 2016	150
Demand Response Agreement (d)	Summer seasons through 2024	100
Renewable Energy (e)	Various	223

(a) The capacity under this agreement varies by month, with a maximum capacity of 104 MW.

(b) Up to 60 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.

(c) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).

The capacity under this agreement increases in phases over the first three years to reach the 100 MW level by the summer of 2012.

(e) Renewable energy purchased power agreements are described in detail below under "Current and Future Resources — Renewable Energy Standard — Renewable Energy Portfolio."

Current and Future Resources

Current Demand and Reserve Margin

Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APS's 2010 peak one-hour demand on its electric system was recorded on July 15, 2010 at 6,936 MW, compared to the 2009 peak of 7,218 MW recorded on July 27, 2009. APS's operable generating capacity, together with firm purchases totaling 2,974 MW, including short-term seasonal purchases and unit contingent purchases, resulted in an actual reserve margin, at the time of the 2010 peak demand, of 21.8%. The power actually available to APS from its resources fluctuates from time to time due in part to planned and unplanned plant and transmission outages.

Future Resources and Resource Plan

Under the ACC's modified resource planning rule, APS will file by April 1 st of each even year its resource plans for the next fifteen-year period. The ACC's modified rule also requires APS to file its first resource plan within 120 days after the rule becomes effective. The modified rule became effective in January 2011 and APS will likely file a resource plan in the first quarter of 2011. The modified rule also requires the ACC to issue an order with its acknowledgment of APS's resource plan within approximately ten months following its submittal. The ACC's acknowledgment of APS's resource plan will consider factors such as the total cost of electric energy services, demand management, analysis of supply-side options, system reliability and risk management.

Renewable Energy Standard

In 2006, the ACC adopted the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 3% of retail electric sales in 2011 and increases annually until it reaches 15% in 2025. In APS's 2009 retail rate case settlement agreement, APS committed to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to its 2008 renewable resource commitments. Taken together, APS's commitment is estimated to be 3,400 GWh, or approximately 10% of retail sales, by year-end 2015, which is double the existing RES target of 5% for that year. (See Note 3.) A component of the RES is focused on stimulating development of distributed energy systems (generally speaking, small-scale renewable technologies that are located on customers' properties). Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed energy requirement is 25% of the overall RES requirement of 3% in 2011 and increases to 30% of the applicable RES requirement in 2012 and subsequent years. The following table summarizes these requirement standards and their timing:

	2011	2015	2020	2025
RES as a % of retail electric sales	3%	5%	10%	15%
Percent of RES to be supplied from distributed energy resources	25%	30%	30%	30%

Renewable Energy Portfolio. APS has a diverse portfolio of existing and planned renewable resources totaling 875 MW, including wind, geothermal, solar, biomass and biogas. Of this portfolio, 288 MW are currently in operation and 587 MW are under contract for development or are under construction. Renewable resources in operation include 5 MW of facilities owned by APS, 223 MW of long-term purchased power agreements, and an estimated 60 MW of customer-sited, third-party owned distributed energy resources.

APS continues to actively consider opportunities to enhance its renewable energy portfolio, both to ensure its compliance with the RES and to meet the needs of its customer base. APS's strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. One of the key programs under which APS will own solar resources is the "AZ Sun Program." As approved by the ACC, the AZ Sun Program will allow APS to own 100 MW of solar photovoltaic power plants across Arizona by investing up to $500 million through 2014. Under this program to date, APS has executed contracts for the development of 83 MW of new solar generation, representing an investment commitment of approximately $377 million. See Note 3 for additional details about the AZ Sun Program, including the related cost recovery.

The following table summarizes APS's renewable energy sources in operation and under development. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW)	Net Capacity Planned/ Under Development (MW)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	Gila Bend, AZ	2011			17
Cotton Center	Gila Bend, AZ	2011			17
Hyder Phase 1	Hyder, AZ	2011			11
Hyder Phase 2	Hyder, AZ	2012			5
Chino Valley	Chino Valley, AZ	2012			19
Luke AFB	Glendale, AZ	2012/2013(a)			14
Subtotal AZ Sun Program (b)					83
Multiple Facilities	AZ	Various		5	
Total APS Owned				5	83
Purchased Power Agreements					
Solar:					
Solana (c)	Gila Bend, AZ	2013	30		250
RE Ajo	Ajo, AZ	2011	25		5
Sun E AZ 1	Prescott, AZ	2011	30		10
Solar 1 (d)	Tonopah, AZ	2012	30		15
Wind:					
Aragonne Mesa	Santa Rosa, NM	2006	20	90	
High Lonesome	Mountainair, NM	2009	30	100	
Perrin Ranch Wind	Williams, AZ	2011	25		99
Geothermal:					
Salton Sea	Imperial County, CA	2006	23	10	
Biomass:					
Snowflake	Snowflake, AZ	2008	15	10	
Snowflake	Snowflake, AZ	2008	1	10	
Biogas:					
Glendale Landfill	Glendale, AZ	2010	20	3	
Landfill 1 (d)	Surprise, AZ	2012	20		3
Total Purchased Power Agreements				223	382
Distributed Energy					
Solar:					
APS Owned (e)	AZ	various			1
Third-party Owned (f)	AZ	various		60	66
Agreement 1	Bagdad, AZ	2012	25		15
Agreement 2 (g)	AZ	2012-2014	20-25		40
Total Distributed Energy				60	122
Total Renewable Portfolio				288	587

(a) The timing is dependent on site preparation activities.

(b) Under the AZ Sun Program, 17 MW remains to be fulfilled.

(c) Represents contracted capacity.

(d) Details of these agreements have not yet been publicly announced.

(e) Reflects Community Power Project. See Note 3.

(f) Achieved through incentive-based programs. Includes resources with production-based incentives that have terms of 10-20 years.

(g) Agreement ramps up to 40 MW over 3 years.

Demand Side Management

Arizona regulators are placing an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. In December 2009, the ACC initiated Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This ambitious standard will likely impact Arizona's future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations resulting from APS's 2009 retail rate case settlement.)

Economic Stimulus Projects

Through the American Recovery and Reinvestment Act of 2009 ("ARRA"), the Federal government made a number of programs available for utilities to develop renewable resources, improve reliability and create jobs by using economic stimulus funding. Certain programs are also available through the State of Arizona.

In 2009, the DOE announced an ARRA commitment to fund the majority of a carbon dioxide emission reduction research and development project in the amount of $71 million, which was to be located at our Cholla power plant. Due to the increased resource and funding requirements for a project of that size, APS elected not to move forward with that award and is now in the process of closing out the project. However, APS is moving forward with work under the $3 million award from DOE for a high penetration photovoltaic generation study related to the Community Power Project in Flagstaff, Arizona. The funding under this DOE award will continue to be contingent upon meeting certain project milestones, including DOE-established budget parameters, over the next four years.

APS is also continuing its work as a sub-recipient under an ARRA award received through the State of Arizona's Department of Commerce. This approximately $4 million award is for the implementation of various distributed energy and energy efficiency programs in Arizona. APS will be implementing certain solar water heater and photovoltaic-related community projects under this award.

Competitive Environment and Regulatory Oversight

Retail

The ACC regulates APS's retail electric rates and its issuance of securities. The ACC must also approve any transfer or encumbrance of APS's property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS and their respective affiliates.

APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as roof top solar panels to meet or supplement their energy needs.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. As a result, as of January 1, 2001, all of APS's retail customers were eligible to choose alternate energy suppliers. However, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. In 2000, the Arizona Superior Court found that the rules were in part unconstitutional and in other respects unlawful, the latter finding being primarily on procedural grounds, and invalidated all ACC orders authorizing competitive electric services providers to operate in Arizona. In 2004, the Arizona Court of Appeals invalidated some, but not all of the rules and upheld the invalidation of the orders authorizing competitive electric service providers. In 2005, the Arizona Supreme Court declined to review the Court of Appeals decision.

To date, the ACC has taken no further or substantive action on either the rules or the prior orders authorizing competitive electric service providers in response to the final Court of Appeals decision. In 2008, the ACC directed the ACC staff to investigate whether such retail competition was in the public interest and what legal impediments remain to competition in light of the Court of Appeals decision referenced above. The ACC staff's report on the results of its investigation was issued on August 12, 2010. The report stated that additional analysis, discussion and study of all aspects of the issue are required in order to perform a proper evaluation. While the report did not make any specific recommendations other than to conduct more workshops, the report did state that the current retail electric competition rules are incomplete and in need of modification.

On April 14, 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. A second matter is pending with the ACC to determine whether that ruling should extend to solar providers who serve a broader customer base under the same business model. Use of such products by customers within our territory would result in some level of competition. APS cannot predict when, and the extent to which, additional electric service providers will enter or re-enter APS's service territory.

Wholesale

The FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2010, approximately 5.8% of APS's electric operating revenues resulted from such sales and services. APS's wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS's Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS markets, hedges and trades in electricity and fuels.

Environmental Matters

Climate Change

Legislative Initiatives. In the past several years, the United States Congress has considered bills that would regulate domestic greenhouse gas emissions. In 2009, the House of Representatives passed a comprehensive energy and climate change bill, but the Senate did not consider it or a similar bill in the 111 th Congress. With much focus on the economy, it is unclear when Congress will consider another global warming bill. The actual economic and operational impact of any legislation on APS depends on a variety of factors, none of which can be fully known until such legislation passes and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed emissions; whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned; the cost to reduce emissions or buy allowances in the marketplace; and the availability of offsets and mitigating factors to moderate the costs of compliance. At the present time, we cannot predict what form of legislation, if any, will ultimately pass.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has not yet enacted any state-specific legislation regarding greenhouse gas emissions, the California legislature enacted AB 32 and SB 1368 in 2006 to address greenhouse gas emissions. In December 2010, the California Air Resources Board approved regulations that will establish a cap-and-trade program for greenhouse gas emissions which is scheduled to be launched in 2012 as part of the state's program implementing AB32. In addition, the New Mexico Environmental Improvement Board recently enacted a greenhouse gas cap-and-trade program and emissions cap, to become effective in 2012 and 2013, respectively.

We are monitoring these and other state legislative developments to understand the extent to which they may affect our business, including our sales into the impacted states or the ability of our out-of-state power plant participants to continue their participation in certain coal-fired power plants. In particular, SCE, a participant in Four Corners, has indicated that SB 1368 may prohibit it from making emission control expenditures at the plant. (See "Energy Sources and Resource Planning — Generation Facilities — Coal Fueled Generating Facilities — Four Corners" above for details of the pending sale of SCE's interest in Four Corners to APS.)

Regulatory Initiatives. In December 2009, the EPA determined that greenhouse gas emissions endanger public health and welfare. This determination was made in response to a 2007 United States Supreme Court ruling that greenhouse gases fit within the Clean Air Act's broad definition of "air pollutant" and, as a result, the EPA has the authority to regulate greenhouse gas emissions of new motor vehicles under the Clean Air Act. As a result of the endangerment finding, the EPA determined that the Clean Air Act required new regulatory requirements for new and modified major greenhouse gas emitting sources, including power plants. On June 3, 2010, the EPA issued a rule under the Clean Air Act, known as the "tailoring rule," establishing new greenhouse gas emissions thresholds that determine when sources, including power plants, must obtain air operating permits or New Source Review permits. New Source Review is a pre-construction permitting program under the Clean Air Act that requires analysis of pollution controls prior to building a new stationary source or making major modifications to an existing stationary source. The tailoring rule became effective on August 2, 2010 and it became applicable to power plants on January 2, 2011. Several groups have filed lawsuits challenging the EPA's endangerment finding and the tailoring rule.

APS does not expect the tailoring rule to have a significant impact on its current operations. The rule will require APS to consider the impact of greenhouse gas emissions as part of its traditional New Source Review analysis for new sources and major modifications to existing plants. At the present time, we cannot predict what other rules or regulations may ultimately result from the EPA's endangerment finding, whether the parties challenging the endangerment finding or the tailoring rule will be successful, and what impact other potential rules or regulations will have on APS's operations.

On December 30, 2010, pursuant to its authority under the Clean Air Act, the EPA finalized a greenhouse gas Federal Implementation Plan ("FIP") for Arizona relating to pre-construction permits for construction of new sources or major modifications of existing sources. As a result of this action, effective January 2, 2011, the EPA assumed responsibility for acting on permit applications for only the greenhouse gas portion of such pre-construction permits. State permitting authorities will continue to retain responsibility for the remaining parts of pre-construction permits that are unrelated to emissions of greenhouse gasses. To the extent Arizona seeks and receives from the EPA a delegation of permitting authority for greenhouse gas emissions, the state will assume responsibility for issuing both the greenhouse gas and non-greenhouse gas portions of pre-construction permits. The greenhouse gas FIP will remain in place until such time as the EPA approves a State Implementation Plan that applies pre-construction permit requirements to greenhouse gas-emitting stationary sources in Arizona. APS does not expect the greenhouse gas FIP to have a significant impact on its current operations.

The EPA also recently announced its intent to promulgate New Source Performance Standards ("NSPS") for greenhouse gas emissions from certain industrial facilities, under the Clean Air Act. The EPA intends to propose the new standards by July 2011 and finalize them by May 2012. The EPA has indicated that the rules will apply to coal-fired electric generating units ("EGUs") and will establish NSPS for new and modified EGUs and emission guidelines for existing EGUs. The rules are expected to apply to the Four Corners, Cholla and the Navajo Plant. We cannot currently predict the impact of these rules on APS's operations.

If any emission reduction legislation or additional regulations are enacted, we will assess our compliance alternatives, which may include replacement of existing equipment, installation of additional pollution control equipment, purchase of allowances, retirement or suspension of operations at certain coal-fired facilities, or other actions. Although associated capital expenditures or operating costs resulting from greenhouse gas emission regulations or legislation could be material, we believe that we would be able to recover the costs of these environmental compliance initiatives through our rates.

Regional Initiative . In 2007, six western states (Arizona, California, New Mexico, Oregon, Utah and Washington) and two Canadian provinces (British Columbia and Manitoba) entered into an accord, the Western Climate Initiative ("WCI"), to reduce greenhouse gas emissions from automobiles and certain industries, including utilities. Montana, Quebec and Ontario have also joined WCI. WCI participants set a goal of reducing greenhouse gas emissions 15% below 2005 levels by 2020. After soliciting public comment, in September 2008 WCI issued the design of a cap-and-trade program for greenhouse gas emissions. Due in part to the recent activity at the federal level discussed above, the initiative's momentum and the movement toward detailed proposed rules has slowed. On February 2, 2010, Arizona's Governor issued an executive order stating that Arizona will continue to be a member of WCI to monitor its advancements in this area, but it will not implement the WCI regional cap-and-trade program. As a result, while we continue to monitor the progress of WCI, at the present time we do not believe it will have a material impact on our operations.

Company Response to Climate Change Initiatives . We have undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use and energy efficiency. (See "Energy Sources and Resource Planning — Current and Future Resources" above for details of these plans and initiatives.) APS currently has a diverse portfolio of renewable resources, including wind, geothermal, solar and biomass and we are focused on increasing the percentage of our energy that is produced by renewable resources.

In January 2008, APS joined the Climate Registry as a Founding Reporter. Founding Reporters are companies that voluntarily joined the non-profit organization before May 2008 to measure and report greenhouse gas emissions in a common, accurate and transparent manner consistent across industry sectors and borders. Beginning in 2010, APS stopped participating in the Climate Registry because APS began reporting substantially the same information under the mandatory greenhouse gas reporting rule issued by the EPA on September 22, 2009. Pinnacle West prepares an annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com*) . The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West's website, including the Corporate Responsibility Report, is not incorporated by reference into this report.

Climate Change Lawsuits. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against nine oil companies, fourteen power companies (including Pinnacle West), and a coal company, alleging that the defendants' emissions of carbon dioxide contribute to global warming and constitute a public and private nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village and they are seeking an unspecified amount of monetary damages. In June 2008, the defendants filed motions to dismiss the action, which were granted. The plaintiffs filed an appeal with the Ninth Circuit Court of Appeals in November 2009, and Pinnacle West filed its reply on June 30, 2010. The court has not yet scheduled oral arguments on the plaintiffs' appeal. We believe the action is without merit and intend to continue to defend against the claims.

A similar nuisance lawsuit, *American Electric Power Co., Inc. v. Connecticut,* is currently pending in the United States Supreme Court. Another such lawsuit was dismissed by the Fifth Circuit on procedural grounds. Both cases, as well as the Kivalina case, raise political and legal considerations, including whether the courts can or should be making climate change policy decisions. The outcome of the *American Electric Power* case is particularly significant because the issues being considered by the Supreme Court closely overlap with the main issues presented in the *Kivalina* appeal. We are not a party to either of these two lawsuits, but are monitoring these developments and their potential industry impacts.

EPA Environmental Regulation

Regional Haze Rules. Over a decade ago, the EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, the EPA) to determine what pollution control technologies constitute the "best available retrofit technology" ("BART") for certain older major stationary sources. The EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

Cholla. In 2007, ADEQ required APS to perform a BART analysis for Cholla pursuant to the Clean Air Visibility Rule. APS completed the BART analysis for Cholla and submitted its BART recommendations to ADEQ on February 4, 2008. The recommendations include the installation of certain pollution control equipment that APS believes constitutes BART. ADEQ has reviewed APS's recommendations and is expected to submit to EPA Region 9 its proposed BART State Implementation Plan ("SIP") for Cholla and other sources within the state in the near future. On January 19, 2011, a group of environmental organizations notified EPA of its intent to sue the agency as a result of EPA's alleged failure to promulgate a Federal Implementation Plan for states that have not yet submitted all or part of the required BART SIPs, including Arizona.

Once APS receives a final determination as to what constitutes BART for Cholla, we will have five years to complete the installation of the equipment and to achieve the emission limits established by ADEQ. However, in order to coordinate with the plant's other scheduled activities, APS is currently implementing portions of its recommended plan for Cholla on a voluntary basis. Costs related to the implementation of these portions of our recommended plan are included in our environmental expenditure estimates (see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Expenditures" in Item 7).

Four Corners and the Navajo Plant. EPA Region 9 previously requested that APS, as the operating agent for Four Corners, and SRP, as the operating agent for the Navajo Plant, perform a BART analysis for Four Corners and the Navajo Plant, respectively. APS and SRP each submitted an analysis to the EPA concluding that certain combustion control equipment constitutes BART for these plants. Based on the analyses and comments received through EPA's rulemaking process, the EPA will determine what it believes constitutes BART for each plant.

On October 6, 2010, the EPA issued its proposed BART determination for Four Corners. The proposed rule would require the installation of post-combustion controls on each of Units 1-5 at Four Corners to reduce nitrogen oxides (NOx) emissions. Current estimates indicate that APS's total costs for these controls could be up to approximately $400 million for Four Corners. If APS's purchase of SCE's interest in Units 4 and 5 is consummated and Units 1-3 are closed, APS's total costs for these controls would be approximately $300 million. (See "Energy Sources and Resource Planning — Generation Facilities — Coal Fueled Generating Facilities — Four Corners" for details of this proposed transaction.) The EPA also indicated in the proposal that it may require the installation of electrostatic precipitators or baghouses on Units 1, 2 and 3 to reduce particulate matter emissions. APS estimates that its total costs for such particulate removal equipment is approximately $220 million, which may also be required under the anticipated mercury rules. (See "Environmental Matters — Mercury and Other Hazardous Air Pollutants" below for additional information on these anticipated rules.) The EPA proposed a 10% stack opacity limitation for all five units and a 20% opacity limitation on certain fugitive dust emissions, although the proposed fugitive dust provision is unrelated to BART.

On November 24, 2010, APS submitted a letter to the EPA proposing an alternative to the EPA's October BART proposal. Specifically, APS proposed to close Four Corners Units 1, 2 and 3 by 2014 and to install post-combustion pollution controls for NOx on Units 4 and 5 by the end of 2018, provided that the EPA agrees to a contemporaneous resolution of Four Corners' obligations or liability, if any, under the regional haze and reasonably attributable visibility impairment programs, the New Source Review program and NSPS programs of the Clean Air Act.

On February 10, 2011, the EPA signed a Supplemental Notice Requesting Comment, related to the BART rulemaking for Four Corners. In the Supplemental Notice, the EPA proposed to find that a different alternative emission control strategy, based upon APS's November 2010 proposal, would achieve more progress than the EPA's October 2010 BART proposal. The Supplemental Notice proposes that Units 1, 2 and 3 would close by 2014, post-combustion pollution controls for NOx would be installed on Units 4 and 5 by July 31, 2018, and the NOx emission limitation for Units 4 and 5 would be 0.098 lbs/MMBtu, rather than the 0.11 lbs/MMBtu proposed by the EPA in October 2010. The EPA extended the comment deadline for both the October 2010 proposal and the Supplemental Notice to May 2, 2011. We are currently evaluating both proposals and will be providing comments to the EPA on both.

The EPA has not yet issued a proposed rule for the Navajo Plant. SRP's recommended plan for the Navajo Plant includes the installation of combustion control equipment, with an estimated cost to APS of approximately $6 million based on APS's Navajo Plant ownership interest. If the EPA determines that post-combustion controls are required, APS's total costs could be up to approximately $93 million for the Navajo Plant. The Four Corners and the Navajo Plant participants will have five years after the EPA issues its final determinations to achieve compliance with their respective BART requirements.

In addition, on February 16, 2010, a group of environmental organizations filed a petition with the Departments of Interior and Agriculture requesting those agencies to certify to the EPA that visibility impairment in sixteen national park and wilderness areas is reasonably attributable to emissions from Four Corners, the Navajo Plant and other non-APS plants. If the agencies certify impairment, the EPA is required to evaluate and, if necessary, determine BART for Four Corners and the Navajo Plant under a different haze program known as "Reasonably Attributable Visibility Impairment." On January 19, 2011, a similar group of environmental organizations filed a lawsuit against the Departments of Interior and Agriculture, alleging among other things that the agencies failed to act on the February 2010 petition "without unreasonable delay" and requesting the court to order the agencies to act on the petition within 30 days. We are currently evaluating the potential impact of this lawsuit on APS.

The Four Corners and Navajo Plant participants' obligations to comply with the EPA's final BART determinations, coupled with the financial impact of future climate change legislation, other environmental regulations, the result of the lawsuit mentioned above and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

In order to coordinate with each plant's other scheduled activities, the plants are currently implementing portions of their recommended plans described above on a voluntary basis. APS's share of the costs related to the implementation of these portions of the recommended plans are included in our environmental expenditure estimates (see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Expenditures" in Item 7).

Mercury and other Hazardous Air Pollutants. In early 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the Clean Air Mercury Rule ("CAMR"), which was adopted by the EPA to regulate mercury emissions from coal-fired power plants. As a result, the law in effect prior to the adoption of the CAMR became the applicable law, and the EPA is now required to adopt final maximum achievable control technology emissions ("MACT") standards. Under a consent decree that was finalized on April 15, 2010, the EPA has agreed to issue final MACT standards for mercury and other hazardous air pollutants by November 2011. Under the terms of the consent decree, APS will have three years after the EPA issues its final rule to achieve compliance, which would likely require APS to install additional pollution control equipment.

APS has installed, and continues to install, certain of the equipment necessary to meet the anticipated standards. APS estimates that the cost for equipment necessary to meet these anticipated standards is approximately $220 million for Four Corners Units 1-3 and $89 million for Cholla Units 1-3. The estimated costs for Four Corners Units 1-3 are not included in our current environmental expenditure estimates since our estimates assume the consummation of APS's purchase of SCE's interest in Four Corners Units 4 and 5 and the subsequent shut down of Units 1-3. Cholla's estimated costs for the next three years are included in our environmental expenditure estimates. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Expenditures" in Item 7 for details of our capital expenditure estimates).

Coal Combustion Waste. On June 21, 2010, the EPA released its proposed regulations governing the handling and disposal of coal combustion residuals ("CCRs"), such as fly ash and bottom ash. APS currently disposes of CCRs in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. The EPA proposes regulating CCRs as either non-hazardous waste or hazardous waste and requested comments on three different alternatives. The hazardous waste proposal would phase out the use of ash ponds for disposal of CCRs. The other two proposals regulate CCRs as non-hazardous waste and impose performance standards for ash disposal. One of these proposals would require retrofitting or closure of currently unlined ash ponds, while the other proposal would not require the installation of liners or pond closures. The EPA has not yet indicated a preference for any of the alternatives.

APS filed comments on the proposed rule during the public comment period, which ended on November 19, 2010. We do not know when the EPA will issue a final rule, including required compliance dates. We cannot currently predict the outcome of the EPA's actions or whether such actions will have a material adverse impact on our financial position, results of operations or cash flows.

Ozone National Ambient Air Quality Standards. In March 2008, the EPA adopted new, more stringent eight-hour ozone standards, known as national ambient air quality standards or NAAQS. In January 2010, the EPA proposed to adopt even more stringent eight-hour ozone NAAQS. As ozone standards become more stringent, our fossil generation units may come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds and/or to generate emission offsets for new projects or facility expansions. At this time, APS is unable to predict what impact the adoption of these standards may have on its operations.

New Source Review . On April 6, 2009, APS received a request from the EPA under Section 114 of the Clean Air Act seeking detailed information regarding projects at and operations of Four Corners. This request is part of an enforcement initiative that the EPA has undertaken under the Clean Air Act. The EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the New Source Review provisions of the Clean Air Act. Other electric utilities have received and responded to similar Section 114 requests, and several of them have been the subject of notices of violation and lawsuits by the EPA. APS responded to the EPA's request in August 2009 and is currently unable to predict the timing or content of the EPA's response, if any, or any resulting actions.

On May 7, 2010, APS received a Notice of Intent to Sue from Earthjustice, on behalf of several environmental organizations, related to alleged violations of the Clean Air Act at Four Corners (the "Notice"). The Notice alleges New Source Review-related violations and NSPS violations. Under the Clean Air Act, a citizens group is required to provide 60 days advance notice of its intent to file a lawsuit. Within that 60-day time period, the EPA may step in and file a lawsuit regarding the allegations. If the EPA does so, the citizens group is precluded from filing its own lawsuit, but it may still intervene in the EPA's lawsuit, if it so desires. The 60-day period lapsed in early July 2010, and the EPA did not take any action. At this time, we cannot predict whether or when Earthjustice might file a lawsuit.

Endangered Species Act. On January 30, 2011, the Center for Biological Diversity, Dine Citizens Against Running Our Environment, and San Juan Citizens Alliance field a lawsuit against the Office of Surface Mining Reclamation and Enforcement ("OSM") and the Department of the Interior, alleging that OSM failed to engage in mandatory Endangered Species Act ("ESA") consultation with the Fish and Wildlife Service prior to authorizing the renewal of an operating permit for the mine that serves Four Corners. The lawsuit alleges that activities at the mine, including mining and the disposal of coal combustion residue, will adversely affect several endangered species and their critical habitats. The lawsuit requests the court to vacate and remand the mining permit and enjoin all activities carried out under the permit until OSM has complied with the ESA. Although we are not a party to the lawsuit, we are evaluating the lawsuit to determine its potential impact on plant operations.

Superfund . The Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, the EPA advised APS that the EPA considers APS to be a PRP in the Motorola 52 nd Street Superfund Site, Operable Unit 3 ("OU3") in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with the EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with the EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan. APS estimates that its costs related to this investigation and study will be approximately $1 million, which is reserved as a liability on its financial statements. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time we cannot accurately estimate our total expenditures.

By letter dated April 25, 2008, the EPA informed APS that it may be a PRP in the Gila River Indian Reservation Superfund Site in Maricopa County, Arizona. APS, along with three other electric utility companies, owns a parcel of property on which a transmission pole and a portion of a transmission line are located. The property abuts the Gila River Indian Community boundary and, at one time, may have been part of an airfield where crop dusting took place. Currently, the EPA is only seeking payment from APS and four other PRPs for past cleanup-related costs involving contamination from the crop dusting. Based upon the total amount of cleanup costs reported by the EPA in its letter to APS, we do not expect that the resolution of this matter will have a material adverse impact on APS's financial position, results of operations, or cash flows.

Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations, cash flows or liquidity.

Navajo Nation Environmental Issues

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. See "Energy Sources and Resource Planning — Generation Facilities — Coal Fueled Generating Facilities" above for additional information regarding these plants.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the "Navajo Acts"). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, Salt River Project, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its needs. However, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future operations of the plant. The effect of the drought cannot be fully assessed at this time, and APS cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS operations.

San Juan River Adjudication. Both groundwater and surface water in areas important to APS's operations have been the subject of inquiries, claims and legal proceedings, which will require a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss.

Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County, Arizona, Superior Court. Palo Verde is located within the geographic area subject to the summons. APS's rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As operating agent of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Five of APS's other power plants are also located within the geographic area subject to the summons. APS's claims dispute the court's jurisdiction over its groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS's water rights claims has been set in this matter.

Little Colorado River Adjudication. APS has also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS's groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS's claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. A number of parties are in the process of settlement negotiations with respect to certain claims in this matter. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning APS's water rights claims has been set in this matter.

Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial position, results of operations, cash flows or liquidity.

BUSINESS OF OTHER SUBSIDIARIES

The operations of our other first-tier subsidiaries (described below) are not expected to contribute in any material way to our future financial performance nor will they require any material amounts of capital over the next three years.

APSES

APSES provides energy-related products and services (such as energy master planning, energy use consultation and facility audits, cogeneration analysis and installation, and project management) with a focus on energy efficiency and renewable energy to commercial and industrial retail customers in the western United States. On June 22, 2010, APSES sold its district cooling business consisting of operations in downtown Phoenix, Tucson, and on certain Arizona State University campuses. This sale resulted in an after-tax gain of approximately $25 million.

Financial Summary.

	2010	2009	2008
		(dollars in millions)	
Net income (loss)	$ 30	$ (2)	$ (1)
Total assets at December 31	$ 43	$ 74	$ 70

SunCor

SunCor was a developer of residential, commercial and industrial real estate projects in Arizona, Idaho, New Mexico and Utah. Due to the continuing distressed conditions in the real estate markets, in 2009 SunCor undertook a program to dispose of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to eliminate its outstanding debt.

Financial Summary.

	2010	2009	2008
		(dollars in millions)	
Revenues (a)	$ 102	$ 158	$ 242
Net loss attributable to common shareholders (b)	$ (9)	$ (279)	$ (26)
Total assets at December 31 (c)	$ 16	$ 166	$ 547

(a) All reported as discontinued operations on Pinnacle West's Consolidated Statements of Income. (See Note 22).

(b) These amounts include $266 million (pre-tax) and $53 million (pre-tax) real estate impairment charges for 2009 and 2008, respectively.

(c) The reduction in assets in 2010 is primarily due to asset sales. The $16 million of assets at December 31, 2010 consists primarily of $8 million of intercompany receivables, $3 million of assets held for sale and $5 million of other assets.

In 2010 and 2009, income tax benefits related to SunCor operations were recorded by Pinnacle West in accordance with an intercompany tax sharing agreement. See "Liquidity and Capital Resources — Other Subsidiaries — SunCor" in Item 7 for a discussion of SunCor's long-term debt, liquidity and capital requirements, and the SunCor-related risk factor in Item 1A for a discussion of risks facing SunCor.

El Dorado

El Dorado owns minority interests in several energy-related investments and Arizona community-based ventures. El Dorado's short-term goal is to prudently realize the value of its existing investments. On a long-term basis, Pinnacle West may use El Dorado, when appropriate, for investments that are strategic to the business of generating, distributing and marketing electricity.

Financial Summary.

	2010	2009	2008
		(dollars in millions)	
Net income (loss)	$ 2	$ (7)	$ (10)
Total assets at December 31	$ 19	$ 19	$ 28

Income taxes related to El Dorado are recorded by Pinnacle West.

OTHER INFORMATION

Pinnacle West, APS and Pinnacle West's other first-tier subsidiaries are all incorporated in the State of Arizona. Additional information for each of these companies is provided below:

	Principal Executive Office Address	Year of Incorporation	Approximate Number of Employees at December 31, 2010
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	80
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,600
APSES	60 E. Rio Salado Parkway Suite 1001 Tempe, AZ 85281	1998	5
SunCor	80 East Rio Salado Parkway Suite 410 Tempe, AZ 85281	1965	10
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—
Total			6,740

The APS number includes employees at jointly-owned generating facilities (approximately 3,100 employees) for which APS serves as the generating facility manager. Approximately 1,940 APS employees are union employees. The collective bargaining agreement with union employees in the fossil generation, energy delivery and customer service business areas expires in April 2011, and the parties began negotiating a successor agreement in February 2011. The agreement with union employees serving as Palo Verde security officers expires in 2013.

WHERE TO FIND MORE INFORMATION

We use our website *www.pinnaclewest.com* as a channel of distribution for material Company information. The following filings available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC: Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. Our board and committee charters, Code of Ethics for Financial Executives, Ethics Policy and Standards of Business Practices and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Ethics Policy and Standards of Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange, on its website. The information on Pinnacle West's website is not incorporated by reference into this report.

You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Secretary, Station 9068, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-3252).

ITEM 1A. RISK FACTORS

In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS.

REGULATORY RISKS

Our financial condition depends upon APS's ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy.

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity, results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS's retail electric rates and the FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS retail rate proceedings and ancillary matters which may come before the ACC and the FERC. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify final orders under certain circumstances. The ACC must also approve APS's issuance of securities and any transfer of APS property used to provide retail electric service, and must approve or receive prior notification of certain transactions between us, APS and our respective affiliates. Decisions made by the ACC and the FERC could have a material adverse impact on our financial condition, results of operations or cash flows.

APS's ability to conduct its business operations and avoid fines and penalties depends upon compliance with federal, state or local statutes and regulations, and obtaining and maintaining certain regulatory permits, approvals and certificates.

APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of agencies that regulate APS's business, including the FERC, the NRC, the EPA and state and local governmental agencies. These agencies regulate many aspects of APS's utility operations, including safety and performance, emissions, siting and construction of facilities, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, the FERC can impose penalties (up to one million dollars per day per violation) for failure to comply with mandatory electric reliability standards. In addition, APS is required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS's business is conducted in accordance with applicable laws in all material respects. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies .

The operation of APS's nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose monetary civil penalties or a progressively increased inspection regime that could ultimately result in the shut down of a unit, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APS's financial condition, results of operations and cash flows.

APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APS's cost of operations or impact its business plans.

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, wastewater discharges, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash and air pollution control wastes. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if APS fails to obtain, maintain or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise.

Environmental Clean Up. APS has been named as a PRP for a Superfund site in Phoenix, Arizona and it could be named a PRP in the future for other environmental clean up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

Regional Haze. APS is currently awaiting a final rulemaking from the EPA that could impose new requirements on Four Corners and the Navajo Plant. APS is also awaiting a final rulemaking from ADEQ that could impose new requirements on Cholla. The EPA and ADEQ will require these plants to install pollution control equipment that constitutes the best available retrofit technology to lessen the impacts of emissions on visibility surrounding the plants. Depending upon the agencies' final determinations of what constitutes BART for these plants, the financial impact of installing the required pollution control equipment could jeopardize the economic viability of the plants or the ability of individual participants to continue their participation in these plants.

Coal Ash. The EPA released proposed regulations governing the disposal of CCRs, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The EPA proposed regulating CCRs as either non-hazardous or hazardous waste. APS currently disposes of CCRs in ash ponds and dry storage areas at Four Corners and Cholla, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete products. If the EPA regulates CCRs as a hazardous solid waste or phases out APS's ability to dispose of CCRs through the use of ash ponds, APS could incur significant costs for CCR disposal and may be unable to continue its sale of fly ash for beneficial reuse.

New Source Review. The EPA has taken the position that many projects electric utilities have performed are major modifications that trigger New Source Review requirements under the Clean Air Act. The utilities generally have taken the position that these projects are routine maintenance and did not result in emissions increases, and thus are not subject to New Source Review. In 2009, APS received and responded to a request from the EPA regarding projects and operations of Four Corners. A civilian organization notified the Four Corners participants that it intends to file a citizen suit against the participants for alleged violations of New Source Review and the NSPS program of the Clean Air Act. If the EPA seeks to impose New Source Review requirements at Four Corners or any other APS plant, or if the citizen suit is filed and the citizens' group prevails, significant capital investments could be required to install new pollution control technologies. The EPA could also seek civil penalties.

Mercury and other Hazardous Air Pollutants. The EPA is required to adopt maximum achievable control technology emissions standards for mercury and other hazardous air pollutants by November 2011. Compliance with the new standards will be required three years after the EPA issues its final rule. Depending on the compliance requirements contained in the final rule, APS may need to make significant capital investments to install additional pollution control equipment to meet these new standards.

APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APS's customers, could have a material adverse effect on its financial condition, results of operations or cash flows.

APS faces physical and operational risks related to climate change, and potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit greenhouse gas emissions.

Concern over climate change, deemed by many to be induced by rising levels of greenhouse gases in the atmosphere, has led to significant legislative and regulatory efforts to limit CO_2, which is a major byproduct of the combustion of fossil fuel, and other greenhouse gas emissions. In addition, lawsuits have been filed against companies that emit greenhouse gases, including a lawsuit filed by the Native Village of Kivalina and the City of Kivalina, Alaska against us and several other utilities seeking damages related to climate change, which was dismissed but has been appealed.

Financial Risks — Potential Legislation and Regulation . In the past several years, the United States Congress has considered bills that would regulate domestic greenhouse gas emissions. It is possible that some form of legislation may occur in the future at the federal level with respect to greenhouse gas emissions.

If the United States Congress, or individual states or groups of states in which APS operates, ultimately pass legislation regulating the emissions of greenhouse gases, any resulting limitations on CO_2 and other greenhouse gas emissions could result in the creation of substantial additional capital expenditures and operating costs in the form of taxes, emissions allowances or required equipment upgrades and could have a material adverse impact on all fossil fuel fired generation facilities (particularly coal-fired facilities, which constitute approximately 28% of APS's generation capacity).

At the state level, the California legislature enacted legislation to address greenhouse gas emissions and the California Air Resources Board approved regulations that will establish a cap-and-trade program for greenhouse gas. This legislation, regulation and other state-specific initiatives may affect APS's business, including sales into the impacted states or the ability of its out-of-state power plant participants to continue their participation in certain coal-fired power plants, including Four Corners following expiration of the current lease term in 2016.

In addition, the EPA has determined that greenhouse gas emissions endanger public health and welfare. This determination was made in response to a 2007 United States Supreme Court ruling that greenhouse gases fit within the Clean Air Act's broad definition of "air pollutant" and, as a result, the EPA has the authority to regulate greenhouse gas emissions of new motor vehicles under the Clean Air Act. As a result of the endangerment finding, the EPA determined that the Clean Air Act required new regulatory requirements for new and modified major greenhouse gas emitting sources, including power plants. Several groups have filed lawsuits challenging the EPA's endangerment finding. APS cannot predict what rules or regulations may ultimately result from the EPA's endangerment finding, whether the parties challenging the endangerment finding will be successful, or what impact other potential rules or regulations will have on APS's operations. Excessive costs to comply with future legislation or regulations could force APS and other similarly-situated electric power generators to retire or suspend operations at certain coal-fired facilities.

Physical and Operational Risks. Assuming that the primary physical and operational risks to APS from climate change are increased potential for drought or water shortage, and a mild to moderate increase in ambient temperatures, APS believes it is taking the appropriate steps to respond to these risks. Weather extremes such as drought and high temperature variations are common occurrences in the Southwest's desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and represent a greater challenge.

If APS cannot meet or maintain the level of renewable energy required under Arizona's increasing Renewable Energy Standards, APS may be subject to penalties or fines for non-compliance.

The RES requires APS to supply an increasing percentage of renewable energy each year, so that the amount of retail electricity sales from eligible renewable resources is at least 3% of total retail sales by 2011. This amount increases annually to 15% by 2025. In its 2009 retail rate case settlement agreement, APS agreed to exceed these standards and committed to an interim renewable energy target of 1,700 GWh of renewable resources to be in service by year end 2015 in addition to its 2008 renewable resource commitments. Taken together, APS's commitment is estimated to be 3,400 GWh, or approximately 10% of retail sales, by year end 2015. A portion of this total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement is 25% of the overall RES requirement of 3% in 2011 and increases to 30% of the applicable RES requirement in 2012 and subsequent years. If APS fails to implement any of its annual ACC-approved renewable implementation plans, it may be subject to penalties imposed by the ACC, including APS's inability to recover certain costs. Compliance with the distributed resource requirement is contingent upon customer participation. The development of any renewable generation facilities resulting from the RES is subject to many other risks, including risks relating to financing, permitting, technology, fuel supply, and the construction of sufficient transmission capacity to support these facilities.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on APS's business and its results of operations.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APS's service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS's customers. As a result, APS cannot predict if, when, and the extent to which, additional competitors may re-enter APS's service territory.

In 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not "public service corporations" under the Arizona Constitution, and are therefore not regulated by the ACC. A second matter is pending with the ACC to determine whether that ruling should extend to solar providers who serve a broader customer base under the same business model. The use of such products by customers within our territory would result in some level of competition. APS cannot predict whether the ACC will deem these vendors "public service corporations" subject to ACC regulation and when, and the extent to which, additional service providers will enter APS's service territory, increasing the level of competition in the market.

OPERATIONAL RISKS

APS's results of operations can be adversely affected by various factors impacting demand for electricity.

Weather Conditions. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APS's overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APS's results of operations.

Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of forest fires. Forest fires could threaten APS's communities and electric transmission lines. Any damage caused as a result of forest fires could negatively impact APS's results of operations.

Effects of Energy Conservation Measures and Distributed Energy. The ACC has enacted rules regarding energy efficiency that mandate a 22% annual energy savings requirement by 2020. This will likely increase participation by APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn will impact the demand for electricity. The rules also include a requirement for the ACC to review and address financial disincentives, recovery of fixed costs and the recovery of net lost income/revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the ACC passed a policy statement on per customer revenue decoupling in December of 2010. The policy statement will have no effect on APS's rates unless implemented in a rate case. The 2009 retail rate case settlement agreement also establishes energy efficiency goals for APS that begin in 2010 that extend through 2012, subjecting APS to energy efficiency requirements slightly greater for those years than required under the rules described above.

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement is 25% of the overall RES requirement of 3% in 2011 and increases to 30% of the applicable RES requirement in 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some or all of their own energy needs.

Reduced demand due to these energy efficiency and distributed energy requirements, unless offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

The operation of power generation facilities involves risks that could result in unscheduled power outages or reduced output, which could materially affect APS's results of operations .

The operation of power generation facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS's business. If APS's facilities operate below expectations, especially during its peak seasons, it may lose revenue or incur additional expenses, including increased purchased power expenses.

The lack of access to sufficient supplies of water could have a material adverse impact on APS's business and results of operations.

Assured supplies of water are important for APS's generating plants. Water in the southwestern United States is limited and various parties have made conflicting claims regarding the right to access and use such limited supply of water. Both groundwater and surface water in areas important to APS's generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS's inability to access sufficient supplies of water could have a material adverse impact on our business and results of operations.

The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements and rights-of-way, which could have a significant impact on our business.

Certain APS power plants, including Four Corners, and portions of the transmission lines that carry power from these plants are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is currently unable to predict the final outcome of discussions with the appropriate Indian tribes and approval by their respective governing bodies with respect to renewals of these leases, easements and rights-of-way.

There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack.

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde is subject to environmental, health and financial risks such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $118 million (but not more than $18 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power plant in the United States. Although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

The operation of Palo Verde requires licenses that need to be periodically renewed and/or extended. In December 2008, APS applied for renewed operating licenses for all three Palo Verde units for 20 years beyond the expirations of the current licenses. APS does not anticipate any problems renewing these licenses. However, as a result of potential terrorist threats and increased public scrutiny of utilities, the licensing process could result in increased licensing or compliance costs that are difficult to predict.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

APS's operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas and coal to the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), which was signed into law in July 2010, contains measures aimed at increasing the transparency and stability of the over-the counter, or OTC, derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations yet to be developed, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APS's trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period.

Changes in technology could create challenges for APS's existing business.

Research and development activities are ongoing to assess alternative technologies that produce power or reduce power consumption, including clean coal and coal gasification, renewable technologies including photovoltaic (solar) cells, customer-sited generation (solar) and efficiency technologies, and improvements in traditional technologies and equipment, such as more efficient gas turbines. Advances in these, or other technologies could reduce the cost of power production, making APS's existing generating facilities less economical. In addition, advances in technology could reduce the demand for power supply, which could adversely affect APS's business.

APS is pursuing and implementing smart grid technologies, including advanced transmission and distribution system technologies, digital meters enabling two-way communications between the utility and its customers, and electric usage monitoring devices for customers' homes and businesses. Many of the products and processes resulting from these and other alternative technologies have not yet been widely used or tested, and their use on large-scale systems is not as advanced and established as APS's existing technologies and equipment. Uncertainties and unknowns related to these and other advancements in technology and equipment could adversely affect APS's business if national standards develop that do not embrace the current technologies or if the technologies and equipment fail to perform as expected. In addition, widespread installation and acceptance of these devices could enable the entry of new market participants, such as technology companies, into the interface between APS and its customers.

We are subject to employee workforce factors that could adversely affect our business and financial condition.

Like most companies in the electric utility industry, our workforce is aging and a number of our employees will become eligible to retire within the next few years. Although we have undertaken efforts to recruit and train new employees, we may not be successful. We are subject to other employee workforce factors, such as the availability of qualified personnel, the need to negotiate collective bargaining agreements with union employees and potential work stoppages. Exposure to these or other employee workforce factors could negatively impact our business, financial condition or results of operations.

We are subject to information security risks.

In the regular course of our business we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or the inappropriate release of certain types of information, including confidential customer information or system operating information could have a material adverse impact on our business and financial condition.

FINANCIAL RISKS

Financial market disruptions may increase our financing costs or limit our access to the credit and capital markets, which may adversely affect our liquidity and our ability to implement our financial strategy.

We rely on access to short-term money markets, longer-term capital markets and the bank market as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions may increase our cost of borrowing or adversely affect our ability to access one or more financial markets. Such disruptions could include:

- continuation of the current economic downturn;
- terrorist attacks or threatened attacks;
- mergers among financial institutions and the overall health of the banking industry; or
- the overall health of the utility industry.

In addition, the credit commitments of our lenders under our bank facilities may not be satisfied for a variety of reasons, including unexpected periods of financial distress affecting our lenders, which could materially adversely affect the adequacy of our liquidity sources.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- reducing our credit ratings;
- increasing the cost of future debt financing and refinancing;
- increasing our vulnerability to adverse economic and industry conditions; and
- requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes.

A reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

Our current ratings are set forth in "Liquidity and Capital Resources — Credit Ratings" in Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle West's and APS's securities, limit our access to capital and increase our borrowing costs, which would diminish our financial results. We would be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under certain of our existing credit facilities depend on our credit ratings. A downgrade would also require us to provide substantial additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could completely eliminate any possible future access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

Market performance, changing interest rates and other economic factors could decrease the value of our benefit plan assets and nuclear decommissioning trust funds and increase our related obligations, resulting in significant additional funding that could negatively impact our business.

Disruptions in the capital markets and/or decline in market value may adversely affect the values of fixed income and equity investments held in our employee benefit plan trusts and nuclear decommissioning trusts. We have significant obligations in these areas and hold substantial assets in these trusts. A decline in the market value of the investments in these trusts may increase our funding requirements. Additionally, the pension plan and other postretirement benefit liabilities are impacted by the discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates impact the discount rate, and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to other comprehensive income. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension and other postretirement benefit plans. A significant portion of the pension costs and other postretirement benefit costs and all of the nuclear decommissioning costs are recovered in regulated electricity prices. Our inability to fully recover these costs in a timely manner or any increased funding obligations could negatively impact our financial condition, results of operations or cash flows.

We may be required to adopt IFRS. The ultimate adoption of such standards could negatively impact our business, financial condition or results of operations.

IFRS is a comprehensive series of accounting standards published by the International Accounting Standards Board ("IASB") that is being considered by the SEC to replace accounting principles generally accepted in the United States of America ("GAAP") for use in preparation of financial statements. If the SEC requires mandatory adoption of IFRS, we may lose our ability to use regulatory accounting treatment, and would follow IFRS rather than GAAP for the preparation of our financial statements beginning in 2014. In the meantime, the FASB and the IASB are working on several accounting standards jointly to converge certain accounting differences before 2014. The implementation and adoption of these new standards and the inability to use regulatory accounting could negatively impact our business, financial condition or results of operations.

Our cash flow largely depends on the performance of APS.

We conduct our operations primarily through our subsidiary, APS. Substantially all of our consolidated assets are held by APS. Accordingly, our cash flow is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us.

APS's debt agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

Pinnacle West's ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries.

Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their assets and cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

The market price of our common stock may be volatile.

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;

- developments generally affecting industries in which we operate, particularly the energy distribution and energy generation industries;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts.

These provisions, which could preclude our shareholders from receiving a change of control premium, include the following:

- restrictions on our ability to engage in a wide range of "business combination" transactions with an "interested shareholder" (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;
- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;
- the ability of the Board of Directors to increase the size of the Board and fill vacancies on the Board, whether resulting from such increase, or from death, resignation, disqualification or otherwise; and
- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

While these provisions have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

SunCor's continuing wind-down of its real estate business may give rise to various claims.

Since 2009, SunCor has been engaged in a program to dispose of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt. As of December 31, 2010, SunCor had no existing bank debt and had total assets remaining on its books of $16 million, consisting of $8 million of intercompany receivables, $3 million of assets held for sale and $5 million of other assets. SunCor is focusing on concluding an orderly wind-down of its business. This effort includes addressing contingent liabilities, such as warranty and construction claims that may be brought by property owners and potential funding obligations to local taxing districts that financed infrastructure at certain of its real estate developments.

Pinnacle West has not guaranteed any of SunCor's obligations. SunCor's remaining business operations, and its ability to generate cash from operations, are minimal. As a result, SunCor may seek judicial protection to effectuate a resolution of any claims that cannot be successfully addressed by other means. In such event, Pinnacle West could be exposed to the uncertainties and complexities inherent for parent companies in such proceedings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2010 fiscal year and that remain unresolved .

ITEM 2. PROPERTIES

Generation Facilities

APS's portfolio of owned and leased generating facilities is provided in the table below:

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1%	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 1, 2, 3	3		Coal	Base Load	560
Four Corners 4, 5 (c)	2	15%	Coal	Base Load	231
Cholla	3		Coal	Base Load	647
Navajo (d)	3	14%	Coal	Base Load	315
Ocotillo	2		Gas	Peaking	220
Saguaro	2		Gas/Oil	Peaking	210
Total Steam					2,183
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo	2		Gas	Peaking	110
Saguaro 1, 2	2		Gas/Oil	Peaking	110
Saguaro 3	1		Gas	Peaking	79
Douglas	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas/Oil	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Multiple facilities			Solar	As Available	5
Total Solar					5
Total Capacity					6,293

(a) 100% unless otherwise noted.

(b) See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Nuclear" in Item 1 for details regarding leased interests in Palo Verde. The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso Electric Company (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.

(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), SCE (48%), Tucson Electric Power Company (7%) and El Paso Electric Company (7%). The plant is operated by APS. As discussed under "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal Fueled Generating Facilities — Four Corners" in Item 1, APS and SCE have entered into an agreement by which APS would acquire SCE's interest in Units 4 and 5, after which APS would close Units 1, 2 and 3.

(d) The other participants are Salt River Project (21.7%), Nevada Power Company (11.3%), the United States Government (24.3%), Tucson Electric Power Company (7.5%) and Los Angeles Department of Water & Power (21.2%). The plant is operated by Salt River Project.

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 with respect to matters having a possible impact on the operation of certain of APS's generating facilities.

See "Business of Arizona Public Service Company" in Item 1 for a map detailing the location of APS's major power plants and principal transmission lines.

Transmission and Distribution Facilities

Current Facilities . APS's transmission facilities consist of approximately 5,992 pole miles of overhead lines and approximately 49 miles of underground lines, 5,769 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,098 miles of overhead lines and approximately 17,417 miles of underground primary cable, all of which are located in Arizona. APS shares ownership of some of its transmission facilities with other companies. The following table shows APS's jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2010:

	Percent Owned (Weighted Average)
North Valley System	71.2%
Palo Verde — Estrella 500KV System	50.0%
Round Valley System	50.0%
ANPP 500KV System	34.0%
Navajo Southern System	26.1%
Four Corners Switchyards	47.5%
Palo Verde — Yuma 500KV System	43.5%
Phoenix — Mead System	17.5%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2011 plan, APS projects it will invest approximately $450 million in new transmission over the next ten years, which includes 258 miles of new lines. This investment will increase the import capability into metropolitan Phoenix by approximately 6% and will increase the import capability into the Yuma area by approximately 39%. One significant project presently nearing completion is the Morgan — Pinnacle Peak project, which consists of 26 miles of 500kV and 230kV lines.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which are included in APS's 2011 transmission plan, are the Delany to Palo Verde line and the North Gila to Palo Verde line, both of which are intended to support the transmission of renewable energy to Phoenix and California.

Plant and Transmission Line Leases and Easements on Indian Lands

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under easements from the federal government. The easement and lease for the Navajo Plant expire in 2019 and the easement and lease for Four Corners expire in 2016. Each of the leases contains an option to extend for an additional 25-year period from the end of the existing lease term, for a rental amount tied to the original rent payment adjusted based on an index. The easements do not contain an express renewal option and it is unclear what conditions to renewal or extension of the easements may be imposed. APS is currently working with the Navajo Nation to extend the Four Corners leases and the transmission rights-of-way discussed below for an additional twenty-five years. (See "Business of Arizona Public Service Company — Energy Sources and Resource Planning — Generation Facilities — Coal Fueled Generating Facilities" in Item 1 for details of this extension and the related required approvals.) The ultimate cost of renewal of the Navajo Plant and Four Corners leases and easements is uncertain. The coal contracted for use in these plants is also located on Indian reservations.

Certain portions of the transmission lines that carry power from several of our power plants are located on Indian lands pursuant to easements or other rights-of-way that are effective for specified periods. Some of these rights-of-way have expired and our renewal applications have not yet been acted upon by the appropriate Indian tribes. Other rights expire at various times in the future and renewal action by the applicable tribe will be required at that time. The majority of our transmission lines residing on Indian lands are on the Navajo Nation. The Four Corners and Navajo Plant leases provide Navajo Nation consent to certain of the rights-of-way for transmission lines related to those plants at a specified rental rate for the original term of the rights-of-way and for a like payment in any renewal period. In addition, a 1985 amendment to the leases provides a formula for calculating payments for certain new and renewal rights-of-way. However, some of our rights-of-way are not covered by the leases, or are granted by other Indian tribes. In recent negotiations with other utilities or companies for renewal of similar rights-of-way, certain of the affected Indian tribes have required payments substantially in excess of amounts that we have paid in the past for such rights-of-way or that are typical for similar permits across non-Indian lands; however, we are unaware of the underlying agreements and/or specific circumstances surrounding these renewals. The ultimate cost of renewal of the rights-of-way for our transmission lines is uncertain. We are monitoring these rights-of-way and easement issues and have had extensive discussions with the Navajo Nation regarding them. We are currently unable to predict the outcome of this matter.

ITEM 3. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 11 for information relating to the FERC proceedings on Pacific Northwest energy market issues, liability associated with the Motorola 52 nd Street Superfund Site and for information regarding the bankruptcy proceeding involving the landlord for our corporate headquarters building.

EXECUTIVE OFFICERS OF PINNACLE WEST

Pinnacle West's executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The executive officers, their ages at February 18, 2011, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	56	Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS	2009-Present
		President of Pinnacle West	2008-Present
		Chief Executive Officer of APS	2008-Present
		Chief Operating Officer of Pinnacle West	2008-2009
		President of APS	2006-2009
		Executive Vice President of Pinnacle West; Chief Financial Officer of APS	2003-2008
		Chief Financial Officer of Pinnacle West	2002-2008
		Executive Vice President of APS	2003-2006
Donald G. Robinson	57	President and Chief Operating Officer of APS	2009-Present
		Senior Vice President, Planning and Administration of APS	2007-2009
		Vice President, Planning of APS	2003-2007
Denise R. Danner	55	Vice President, Controller and Chief Accounting Officer of Pinnacle West; Chief Accounting Officer of APS	2010-Present
		Vice President and Controller of APS	2009-Present
		Senior Vice President, Controller and Chief Accounting Officer of Allied Waste Industries, Inc.	2007-2008
		Vice President, Controller and Chief Accounting Officer of Phelps Dodge Corporation	2004-2007
Randall K. Edington	57	Executive Vice President and Chief Nuclear Officer of APS	2007-Present
		Senior Vice President and Chief Nuclear Officer of APS	2007
		Site Vice President and Chief Nuclear Officer of Cooper Generating Station with Entergy Corporation	2003-2007
David P. Falck	57	Executive Vice President, General Counsel and Secretary of Pinnacle West and APS	2009-Present
		Senior Vice President — Law of Public Service Enterprise Group Inc.	2007-2009
		Partner — Pillsbury Winthrop Shaw Pittman LLP	1987-2007

Name	Age	Position	Period
James R. Hatfield	53	Senior Vice President and Chief Financial Officer of Pinnacle West and APS	2008-Prese
		Treasurer of Pinnacle West and APS	2009-201
		Senior Vice President and Chief Financial Officer of OGE Energy Corp.	1999-2008
John Hatfield	45	Vice President, Communications of APS	2010-Present
		Director, Corporate Communications of Southern California Edison	2004-2010
Lee R. Nickloy	44	Vice President and Treasurer of Pinnacle West and APS	2010-Present
		Assistant Treasurer and Director Corporate Finance of Ameren Corporation	2000-2010
Mark A. Schiavoni	55	Senior Vice President, Fossil Operations of APS	2009-Present
		Senior Vice President of Exelon Generation and President of Exelon Power	2004-2009
Lori S. Sundberg	47	Senior Vice President, Human Resources and Ethics of APS	2011-Present
		Vice President, Human Resources and Ethics of APS	2010-2011
		Vice President, Human Resources of APS	2007-2010
		Vice President, Employee Relations, Safety, Compliance & Embrace of American Express Company	2007
		Vice President, HR Relationship Leader, Global Corporate Travel Division of American Express Company	2003-2007

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Pinnacle West's common stock is publicly held and is traded on the New York Stock Exchange. At the close of business on February 15, 2011, Pinnacle West's common stock was held of record by approximately 26,953 shareholders.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE STOCK SYMBOL: PNW

2010	High	Low	Close	Dividends Per Share
1st Quarter	$ 38.37	$ 34.62	$ 37.73	$ 0.525
2nd Quarter	39.10	32.31	36.36	0.525
3rd Quarter	41.75	35.71	41.27	0.525
4th Quarter	42.68	39.97	41.45	0.525

2009	High	Low	Close	Dividends Per Share
1st Quarter	$ 35.13	$ 22.32	$ 26.56	$ 0.525
2nd Quarter	30.30	25.28	30.15	0.525
3rd Quarter	33.71	28.87	32.82	0.525
4th Quarter	37.96	31.08	36.58	0.525

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for APS's common stock.

The chart below sets forth the dividends paid on APS's common stock for each of the four quarters for 2010 and 2009.

Common Stock Dividends
(Dollars in Thousands)

Quarter	2010	2009
1 st Quarter	$ 42,500	$ 42,500
2 nd Quarter	56,900	42,500
3 rd Quarter	56,900	42,500
4 th Quarter	26,100	42,500

The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. As of December 31, 2010, APS did not have any outstanding preferred stock.

Issuer Purchases of Equity Securities

The following table contains information about our purchases of our common stock during the fourth quarter of 2010.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 – October 31, 2010	—	—	—	—
November 1 – November 30, 2010	—	—	—	—
December 1 – December 31, 2010	1,994	$ 41.39	—	—
Total	1,994	$ 41.39	—	—

(1) Represents shares of common stock repurchased for rescission of director stock grant.

ITEM 6. SELECTED FINANCIAL DATA
PINNACLE WEST CAPITAL CORPORATION — CONSOLIDATED

	2010	2009	2008	2007	2006
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	$ 3,180,678	$ 3,149,187	$ 3,127,383	$ 2,918,163	$ 2,635,036
Marketing and trading	—	—	66,897	138,247	136,748
Other revenues	82,967	26,723	25,407	34,375	24,282
Total operating revenues	$ 3,263,645	$ 3,175,910	$ 3,219,687	$ 3,090,785	$ 2,796,066
Income from continuing operations	$ 350,598	$ 252,558	$ 278,335	$ 299,218	$ 279,586
Discontinued operations — net of income taxes (a)	19,611	(179,794)	(18,715)	23,773	61,935
Net income	370,209	72,764	259,620	322,991	341,521
Less: Net income attributable to noncontrolling interests	20,156	4,434	17,495	15,848	14,266
Net income attributable to common shareholders	$ 350,053	$ 68,330	$ 242,125	$ 307,143	$ 327,255
COMMON STOCK DATA					
Book value per share — year-end	$ 33.93	$ 32.69	$ 34.16	$ 35.15	$ 34.48
Earnings per weighted-average common share outstanding:					
Continuing operations attributable to common shareholders — basic	$ 3.10	$ 2.31	$ 2.59	$ 2.83	$ 2.67
Net income attributable to common shareholders — basic	$ 3.28	$ 0.68	$ 2.40	$ 3.06	$ 3.29
Continuing operations attributable to common shareholders — diluted	$ 3.08	$ 2.30	$ 2.58	$ 2.81	$ 2.65
Net income attributable to common shareholders — diluted	$ 3.27	$ 0.67	$ 2.40	$ 3.05	$ 3.27
Dividends declared per share	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.025
Weighted-average common shares outstanding — basic	106,573,348	101,160,659	100,690,838	100,255,807	99,417,008
Weighted-average common shares outstanding — diluted	107,137,785	101,263,795	100,964,920	100,834,871	100,010,108
BALANCE SHEET DATA					
Total assets	$ 12,362,703	$ 11,986,324	$ 11,805,967	$ 11,355,788	$ 11,019,185
Liabilities and equity:					
Current liabilities	$ 1,310,736	$ 1,108,943	$ 1,527,683	$ 1,365,192	$ 943,497
Long-term debt less current maturities	3,045,794	3,496,524	3,183,386	3,300,663	3,426,914
Deferred credits and other	4,230,947	3,952,853	3,523,929	3,029,866	3,131,901
Total liabilities	8,587,477	8,558,320	8,234,998	7,695,721	7,502,312
Total equity	3,775,226	3,428,004	3,570,969	3,660,067	3,516,873
Total liabilities and equity	$ 12,362,703	$ 11,986,324	$ 11,805,967	$ 11,355,788	$ 11,019,185

(a) Amounts primarily related to SunCor's real estate impairment charges (see Note 23) and APSES discontinued operations (see Note 22).

SELECTED FINANCIAL DATA
ARIZONA PUBLIC SERVICE COMPANY — CONSOLIDATED

	2010	2009	2008	2007	2006
			(dollars in thousands)		
OPERATING RESULTS					
Electric operating revenues	$ 3,180,807	$ 3,149,500	$ 3,133,496	$ 2,936,277	$ 2,658,513
Fuel and purchased power costs	1,046,815	1,178,620	1,289,883	1,151,392	969,767
Other operating expenses	1,584,955	1,501,081	1,376,257	1,326,934	1,258,848
Operating income	549,037	469,799	467,356	457,951	429,898
Other income (deductions)	20,138	13,893	836	20,870	27,584
Interest deductions — net of AFUDC	213,349	213,258	188,353	179,033	173,486
Net income	355,826	270,434	279,839	299,788	283,996
Less: Net income attributable to noncontrolling interests	20,163	19,209	17,495	15,848	14,266
Net income attributable to common shareholder	$ 335,663	$ 251,225	$ 262,344	$ 283,940	$ 269,730
BALANCE SHEET DATA					
Total assets	$ 12,241,582	$ 11,681,571	$ 11,149,451	$ 10,514,981	$ 10,150,051
Liabilities and equity:					
Total equity	$ 3,916,037	$ 3,527,679	$ 3,416,751	$ 3,425,328	$ 3,278,230
Long-term debt less current maturities	2,948,991	3,180,406	2,850,242	2,876,881	2,877,502
Palo Verde sale leaseback lessor notes less current maturities	96,803	126,000	151,783	173,538	194,281
Total capitalization	6,961,831	6,834,085	6,418,776	6,475,747	6,350,013
Current liabilities	1,095,897	900,625	1,289,523	1,076,449	826,715
Deferred credits and other	4,183,854	3,946,861	3,441,152	2,962,785	2,973,323
Total liabilities and equity	$ 12,241,582	$ 11,681,571	$ 11,149,451	$ 10,514,981	$ 10,150,051

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Consolidated Financial Statements and APS's Consolidated Financial Statements and the related Notes that appear in Item 8 of this report. For information on the broad factors that may cause our actual future results to differ from those we currently seek or anticipate, see "Forward-Looking Statements" at the front of this report and "Risk Factors" in Item 1A.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for substantially all of our revenues and earnings, and is expected to continue to do so.

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. In 2010, Palo Verde achieved its best generation year ever, producing over 31 million megawatt-hours, with an overall station capacity factor of 90.5%. The generation from each Palo Verde operating unit directly reflects the station's currently effective 18-month refueling cycle. In 2010, Palo Verde successfully refueled both Unit 1 and Unit 3. As part of the 2010 refueling outages, Palo Verde installed new reactor vessel closure heads and simplified head assembly modifications. These projects are designed to provide safety benefits, eliminate costly inspections and reduce the duration of future outages.

Coal and Related Environmental Matters. APS-operated coal plants, Four Corners and Cholla, achieved net capacity factors of 82% and 79%, respectively, in 2010. APS is focused on the impacts on its coal fleet that may result from potential legislation and increased regulation concerning greenhouse gas emissions. Recent concern over climate change and other emission-related issues could have a significant impact on our capital expenditures and operating costs in the form of taxes, emissions allowances or required equipment upgrades for these plants. APS is closely monitoring its long range capital management plans, understanding that any resulting legislation and regulation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to fund any such equipment upgrades. In particular, on October 6, 2010, the EPA issued its proposed determination for "Best Available Retrofit Technology" (BART) requirements for Four Corners that, as proposed, would require installation of additional pollution control equipment on all five of the plant's units. Based on APS's current ownership share of Four Corners, APS currently estimates that its total costs for the proposed controls could be up to approximately $400 million for nitrogen oxide controls and about $220 million for particulate removal equipment. It is currently evaluating the impacts of the proposed determination and intends to submit comments during the EPA's comment period. See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 and environmental and climate change-related risks described in Item 1A for additional environmental and climate change developments and risks facing APS.

In addition, SCE, a participant in Four Corners, has indicated that certain California legislation may prohibit it from making emission control expenditures at the plant. On November 8, 2010, APS and SCE entered into an asset purchase agreement, providing for the purchase by APS of SCE's 48% interest in each of Units 4 and 5 of Four Corners. The purchase price is $294 million, subject to certain adjustments. Completion of the purchase by APS, which is expected to occur in the second half of 2012, is subject to the receipt of approvals by the ACC, the California Public Utilities Commission and the FERC. APS and SCE filed applications with their respective commissions seeking requisite authority or approvals to complete the transaction. Closing is also conditioned on the execution of a new coal supply contract for the lease renewal period described below, expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act and other typical closing conditions.

APS, on behalf of the Four Corners participants, has negotiated amendments to an existing facility lease with the Navajo Nation which would extend the Four Corners leasehold interest to 2041. Execution by the Navajo Nation of the lease amendments is a condition to closing of the purchase by APS of SCE's interests in Four Corners. The execution of these amendments by the Navajo Nation requires the approval of the Navajo Nation Council, which occurred on February 15, 2011 and is awaiting final signature by the Nation's President. The effectiveness of the amendments also requires the approval of the DOI, as does a related Federal rights-of-way grant which the Four Corners participants will pursue. A Federal environmental review will be conducted as part of the DOI review process.

Pursuant to a Co-Tenancy Agreement among the Four Corners participants, the other participants have a right of first refusal to purchase shares of SCE's interests proportional to their current ownership percentages. The exercise of this purchase right by any of the other participants must be exercised by March 8, 2011. If any of the purchase rights are exercised, the amount available for purchase by APS would be reduced. At this time APS does not know whether any of the other participants will exercise the right of first refusal.

APS has announced that, if APS's purchase of SCE's interests in Units 4 and 5 at Four Corners is consummated, it will close Units 1, 2 and 3 at the plant. These events will change the plant's overall generating capacity from 2,100 MW to 1,540 MW and APS's entitlement from the plant from 791 MW to 970 MW. When applying for approval to purchase Units 4 and 5, APS also requested from the ACC recovery of any unrecovered costs associated with the closure of Units 1, 2 and 3.

Transmission and Delivery. In the area of transmission and delivery to its customers, APS ranked favorably during 2010, with top quartile performance for average customer outage time and its best reliability year to date. During 2010, APS undertook several significant transmission projects, including the Morgan to Pinnacle Peak transmission line scheduled for completion in 2011. APS's 2011 transmission plan projects that it will invest approximately $450 million in new transmission over the next ten years, which includes 258 miles of new lines. The first three years of these additions are included in the capital expenditures table presented in the "Liquidity" section below along with other transmission costs for upgrades and replacements. APS is working closely with regulators to identify and plan for transmission needs resulting from the current focus on renewable energy. APS is also working to establish and expand smart grid technology throughout its service territory designed to provide long-term benefits both to APS and its customers. APS is piloting and deploying a variety of technologies that are intended to allow customers to better monitor their energy use and needs, minimize system outage durations and the number of customers that experience outages, and facilitate cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

Renewable Energy . The ACC approved the RES in 2006, recognizing the importance of renewable energy to our state. The renewable energy requirement is 3% of retail electric sales in 2011 and increases annually until it reaches 15% in 2025. In the 2009 retail rate case settlement agreement, APS agreed to exceed the RES standards, committing to 1,700 GWh of new renewable resources to be in service by year-end 2015 in addition to its 2008 renewable resource commitments. Taken together, APS's commitment is estimated to be 3,400 GWh or approximately 10% of APS's retail energy sales by year-end 2015, which is double the existing RES target of 5% for that year. See Note 3. A component of the RES is focused on stimulating development of distributed energy systems (generally speaking, small-scale renewable technologies that are located on customers' properties).

APS has a diverse portfolio of existing and planned renewable resources totaling 875 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 288 MW are currently in operation and 587 MW are under contract for development or are under construction. Renewable resources in operation include 5 MW of utility-scale facilities owned by APS, 223 MW of long-term purchased power agreements, and an estimated 60 MW of customer-sited, third-party owned distributed energy resources.

To achieve our RES requirements, as mentioned above, to date APS has entered into contracts for 587 MW of renewable resources that are planned, in development or under construction. APS's strategy to procure these resources includes new facilities to be owned by APS, purchased power contracts for new facilities and ongoing development of distributed energy resources. Through the AZ Sun Program, approved by the ACC on March 3, 2010, APS plans to own 100 MW of solar photovoltaic power plants across Arizona by investing up to $500 million through 2014. Under this program, APS has executed contracts for the development of 83 MW of new solar generation, representing an investment commitment of approximately $377 million. See Note 3 for additional details of the AZ Sun Program, including the related cost recovery. APS has also entered into long-term purchased power agreements for 382 MW from solar, wind and biogas facilities currently planned, in development or under construction, and 122 MW from distributed energy resources. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the project to the electric grid.

APS continues to actively consider opportunities to enhance its renewable energy portfolio, both to ensure its compliance with the Renewable Energy Standard and to meet the needs of its customer base .

Demand Side Management. Arizona regulators are placing an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. In December 2009, the ACC initiated Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. On July 27, 2010, the proposed Energy Efficiency Standard was adopted by the ACC, approved by the Arizona Attorney General and became effective on January 1, 2011. This ambitious standard will likely impact Arizona's future energy resource needs.

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain adequate financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by the FERC. At the end of 2009, the ACC approved a settlement agreement entered into by APS and twenty-one of the twenty-three other parties to APS's general retail rate case, with modifications that did not materially affect the overall economic terms of the agreement. The rate case settlement authorizes and requires equity infusions into APS of at least $700 million prior to the end of 2014. The settlement demonstrated cooperation among APS, the ACC staff, the Residential Utility Consumer Office (RUCO) and other intervenors to the rate case, and establishes a future rate case filing plan that allows APS the opportunity to help shape Arizona's energy future outside of continual rate cases. See Note 3 for a detailed discussion of the settlement agreement terms and information on APS's FERC rates.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand-side management and renewable energy efforts and customer programs. These mechanisms are described more fully in Note 3.

On October 18, 2010, the Chairman of the ACC issued a draft decoupling policy statement for consideration by the commission. On December 15, 2010 the ACC unanimously approved a slightly modified decoupling policy statement supportive of using a revenue-per-customer methodology, which is the mechanism APS and a number of other parties support. Decoupling refers to a ratemaking design which reduces or removes the linkage between sales and utility revenues and/or profits, reducing utility disincentives to the adoption of programs that benefit customers by saving energy. Mechanically, decoupling compares actual versus authorized revenues or revenue per customer over a period and either credits or collects any differences from customers in a subsequent period. The policy permits regulated utilities to file a decoupling proposal in their next general rate case. APS intends to include a decoupling model consistent with the policy statement for consideration in its upcoming general rate case, currently expected to be filed in June 2011.

Financial Strength and Flexibility. Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities and have been able to access these facilities, ensuring adequate liquidity for each company. In early February 2010, APS entered into a $500 million revolving credit facility, replacing its $377 million revolving credit facility that would have otherwise terminated in December 2010. At that same time, Pinnacle West entered into a $200 million revolving credit facility that replaced its $283 million facility that also would have otherwise terminated in December 2010. Since March 2010, Pinnacle West and APS have accessed the commercial paper market, which neither company had utilized since the third quarter of 2008 due to negative market conditions.

In April 2010, Pinnacle West issued 6,900,000 shares of common stock at an offering price of $38.00 per share, resulting in net proceeds of approximately $253 million. Pinnacle West contributed all of the net proceeds from this offering into APS in the form of equity infusions. APS has used these capital contributions to repay short-term indebtedness, to finance capital expenditures and for other general corporate purposes.

In early February 2011, APS entered into a $500 million revolving credit facility, replacing its $489 million revolving credit facility that would have otherwise terminated in September 2011.

SunCor Real Estate Operations. As a result of the continuing distressed conditions in the real estate markets, during 2009 SunCor undertook a program to dispose of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt. At December 31, 2010, SunCor had total remaining assets of about $16 million, which includes approximately $3 million of assets held for sale. See "Liquidity and Capital Resources — Other Subsidiaries — SunCor" below for information regarding 2010 asset sales and liquidity matters.

District Cooling Business Sale . On June 22, 2010, APSES sold its district cooling business consisting of operations in downtown Phoenix, Tucson, and on certain Arizona State University campuses. The sale resulted in an after-tax gain of approximately $35 million. APSES is now focused on its core business of energy conservation and renewable energy contracting services.

Subsidiaries. The operations of APSES and our other first tier subsidiary, El Dorado, are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

Key Financial Drivers

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company's current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

Electric Operating Revenues. For the years 2008 through 2010, retail electric revenues comprised approximately 93% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. Off-system sales of excess generation output, purchased power and natural gas are included in regulated electricity segment revenues and related fuel and purchased power because they are credited to APS's retail customers through the PSA. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Customer and Sales Growth. Customer growth in APS's service territory for the year ended December 31, 2010 was 0.6% compared with the prior year. For the three years 2008 through 2010, APS's customer growth averaged 0.9% per year. We currently expect customer growth to average about 1.7% per year for 2011 through 2013 due to anticipated improving economic conditions both nationally and in Arizona. Retail sales in kilowatt-hours, adjusted to exclude the effects of weather variations, for 2010 declined 1.0% compared to the prior year, reflecting the poor economic conditions in 2010 and the effects of our energy efficiency programs. For the three years 2008 through 2010, APS's actual retail electricity sales in kilowatt-hours, adjusted to exclude the effects of weather variations, declined at an average annual rate of 0.9%. We currently estimate that total retail electricity sales in kilowatt-hours will remain flat on average per year during 2011 through 2013, including the effects of APS's energy efficiency programs, but excluding the effects of weather variations. A continuation of the economic downturn, or the failure of the Arizona economy to rebound in the near future, could further impact these estimates. The customer and sales growth referred to in this paragraph apply to Native Load customers.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns, impacts of energy efficiency programs and responses to retail price changes. Our experience indicates that a reasonable range of variation in our kilowatt-hour sales projection attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to $10 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historical extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses . Operations and maintenance expenses are impacted by growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, higher-trending pension and other postretirement benefit costs, renewable energy and demand side management related expenses (which are offset by the same amount of regulated electricity segment operating revenues) and other factors. In its 2009 retail rate case settlement, APS committed to operational expense reductions from 2010 through 2014 and received approval to defer certain pension and other postretirement benefit cost increases to be incurred in 2011 and 2012.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities. We have also applied to the NRC for renewed operating licenses for each of the Palo Verde units. If the NRC grants the extension, we estimate that our annual pretax depreciation expense will decrease by approximately $34 million at the later of the license extension date or January 1, 2012.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate for APS, which currently owns the majority of our property, was 8.0% of the assessed value in 2010, 7.5% of the assessed value in 2009 and 7.8% of the assessed value in 2008. We expect property taxes to increase as we add new utility plants (including new generation, transmission and distribution facilities described below under "Capital Additions") and as we improve our existing facilities.

Income Taxes . Income taxes are affected by the amount of pre-tax book income, income tax rates, and certain non-taxable items, such as the AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 6.) The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Our reportable business segments reflect a change from previously reported information. As of December 31, 2010, our real estate activities are no longer considered a segment requiring separate reporting or disclosure. In 2009 our real estate subsidiary, SunCor, began disposing of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt (see Note 23). At December 31, 2010, SunCor had total remaining assets of about $16 million, which includes approximately $3 million of assets held for sale. Additionally, all of SunCor's operations are reflected in discontinued operations.

Operating Results — 2010 compared with 2009

Our consolidated net income attributable to common shareholders for 2010 was $350 million, compared with $68 million for the comparable prior-year period. The improved results were primarily due to lower real estate impairment charges recorded in 2010 compared with the prior-year period by SunCor.

In addition, regulated electricity segment net income increased approximately $82 million from the prior-year period due to increased revenues related to APS's retail rate increases and other factors. Our consolidated results for 2010 also include a gain of $25 million after income taxes related to the sale of APSES' district cooling business. The following table presents net income (loss) attributable to common shareholders by business segment compared with the prior-year period:

	Year Ended December 31, 2010	2009	Net Change
		(dollars in millions)	
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,134	$ 1,970	$ 164
Operations and maintenance	(870)	(822)	(48)
Depreciation and amortization	(415)	(407)	(8)
Taxes other than income taxes	(135)	(123)	(12)
Other income (expenses), net	(4)	(2)	(2)
Interest charges, net of allowance for funds used during construction	(204)	(212)	8
Income taxes	(161)	(142)	(19)
Noncontrolling interests (Note 20)	(20)	(19)	(1)
Regulated electricity segment net income	325	243	82
All other (a)	5	(10)	15
Income from Continuing Operations Attributable to Common Shareholders	**330**	**233**	**97**
Discontinued real estate activities, primarily impairment charges at SunCor (Note 23)	(6)	(167)	161
All other discontinued operations (b)	26	2	24
Income (Loss) from Discontinued Operations Attributable to Common Shareholders	**20**	**(165)**	**185**
Net Income Attributable to Common Shareholders	**$ 350**	**$ 68**	**$ 282**

(a) Includes activities related to APSES and El Dorado. None of the activities of either of these companies constitutes a reportable segment.

(b) Income from discontinued operations for 2010 includes a gain of $25 million after income taxes related to the sale of APSES' district cooling business.

Regulated electricity segment

This section includes a discussion of major variances in income and expense amounts for the regulated electricity segment.

Operating revenues less fuel and purchased power expenses Regulated electricity segment operating revenues less fuel and purchased power expenses were $164 million higher for the year ended 2010 compared with the prior year. The following table describes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Retail regulatory settlement effective January 1, 2010:			
Retail base rate increases, net of deferrals	$ 269	$ 128	$ 141
Line extension revenues (Note 3)	19		19
Transmission rate increases	6		6
Higher demand-side management and renewable energy surcharges (substantially offset in operations and maintenance expense)	33	2	31
Higher fuel and purchased power costs offset by the effects of higher off-system sales, net of related PSA deferrals	28	26	2
Lower retail revenues related to recovery of PSA deferrals, substantially offset by lower amortization of fuel and purchased power expense	(270)	(276)	6
Lower retail sales primarily due to lower usage per customer, including the effects of the Company's energy efficiency programs, but excluding the effects of weather	(28)	(9)	(19)
Effects of weather on retail sales, primarily due to milder weather in the second quarter 2010	(20)	(6)	(14)
Miscellaneous items, net	(5)	3	(8)
Total	$ 32	$ (132)	$ 164

Operations and maintenance Operations and maintenance expenses increased $48 million for the year ended 2010 compared with the prior year primarily because of:

- An increase of $25 million related to demand-side management and renewable energy programs, which are primarily offset in operating revenues;
- An increase of $18 million related to employee benefits costs; and
- An increase of $5 million related to other miscellaneous factors.

Depreciation and Amortization Depreciation and amortization expenses were $8 million higher for the year ended 2010 compared with the prior year primarily because of increased plant in service partially offset by lower depreciation rates.

Taxes other than income taxes Taxes other than income taxes increased $12 million for the year ended 2010 compared with the prior year primarily because of higher property tax rates in the current year.

Interest charges, net of allowance for funds used during construction Interest charges, net of allowance for funds used during construction, decreased $8 million for the year ended 2010 compared with the prior year primarily because of higher rates in the current year for the allowance for equity and borrowed funds used during construction, partially offset by higher interest charges due to higher debt balances. Interest charges, net of allowance for funds used during construction are comprised of the regulated electricity segment portions of the line items interest expense and allowance for equity and borrowed funds used during construction from the Consolidated Statements of Income.

Income taxes Income taxes were $19 million higher for the year ended 2010 compared with the prior year primarily because of higher pretax income in the current-year period, partially offset by $17 million of income tax benefits related to prior years that were resolved in the current year. See Note 4.

All other

All other revenues increased $56 million partially offset by increased other expenses of $41 million resulting primarily from improved margins from APSES' products and services business. In addition, other income was higher due to investment losses at El Dorado in 2009.

Discontinued Operations

Real estate activities During the first quarter of 2009, SunCor's Board of Directors authorized a series of strategic transactions to dispose of SunCor's assets. This decision resulted in impairment charges of approximately $161 million after income taxes in 2009. As of December 31, 2010, all of SunCor's operations have been reclassified to discontinued operations (see Note 22). The after-tax impacts of the $6 million loss from real estate activities for the year ended 2010 includes real estate impairment charges of approximately $10 million (see Note 23) and other costs of $6 million, partially offset by a gain from debt restructuring of approximately $10 million (see Note 6).

All other All other earnings from discontinued operations were $24 million higher for the year ended 2010 compared to the prior-year period primarily because of a gain of $25 million after income taxes related to the sale of APSES' district cooling business in 2010.

Operating Results — 2009 Compared with 2008

Our consolidated net income attributable to common shareholders for 2009 was $68 million, compared with $242 million for the prior year period. The decrease in net income was primarily due to 2009 real estate impairment charges recorded by SunCor, the Company's real estate subsidiary.

In addition, regulated electricity segment net income decreased approximately $13 million from the prior year primarily due to lower retail sales resulting from lower usage per customer; higher interest charges, net of capitalized financing costs; higher depreciation and amortization expenses; and the absence of income tax benefits related to prior years recorded in 2008. These negative factors were partially offset by increased revenues due to an interim rate increase effective January 1, 2009 and transmission rate increases.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

	Year Ended December 31, 2009	2008	Net Change
		(dollars in millions)	
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 1,970	$ 1,843	$ 127
Operations and maintenance	(822)	(756)	(66)
Depreciation and amortization	(407)	(391)	(16)
Taxes other than income taxes	(123)	(125)	2
Other income (expenses), net	(2)	(21)	19
Interest charges, net of allowance for funds used during construction	(212)	(185)	(27)
Income taxes	(142)	(92)	(50)
Noncontrolling interests (Note 20)	(19)	(17)	(2)
Regulated electricity segment net income	243	256	(13)
All other (a)	(10)	5	(15)
Income from Continuing Operations Attributable to Common Shareholders	**233**	**261**	**(28)**
Discontinued real estate activities, primarily impairment charges at SunCor (Note 23)	(167)	(26)	(141)
All other discontinued operations (a)	2	7	(5)
Loss from Discontinued Operations Attributable to Common Shareholders	**(165)**	**(19)**	**(146)**
Net Income Attributable to Common Shareholders	**$ 68**	**$ 242**	**$ (174)**

(a) Includes activities related to marketing and trading, APSES and El Dorado. Income for 2008 includes income from discontinued operations of $8 million related to the resolution of certain tax issues associated with the sale of Silverhawk Power Station ("Silverhawk") in 2005. None of these segments is a reportable segment.

Regulated electricity segment

This section includes a discussion of major variances in income and expense amounts for the regulated electricity segment.

Operating revenues less fuel and purchased power expenses Regulated electricity segment operating revenues less fuel and purchased power expenses were $127 million higher for the year ended 2009 compared with the prior year. The following table describes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Higher renewable energy and demand-side management surcharges (substantially offset in operations and maintenance expense)	$ 63	$	$ 63
Interim retail rate increases effective January 1, 2009	61		61
Transmission rate increases	21		21
Increased mark-to-market valuations of fuel and purchased power contracts related to favorable changes in market prices, net of related PSA deferrals		(18)	18
Effects of weather on retail sales, primarily due to hotter weather in the third quarter of 2009	12	3	9
Lower retail sales primarily due to lower usage per customer, including the effects of the Company's energy efficiency programs, but excluding the effects of weather	(58)	(26)	(32)
Higher fuel and purchased power costs including the effects of lower off-system sales, net of related PSA deferrals	(30)	(19)	(11)
Lower retail revenues related to recovery of PSA deferrals, offset by lower amortization of the same amount recorded as fuel and purchased power expense (see Note 3)	(36)	(36)	—
Miscellaneous items, net	(11)	(9)	(2)
Total	$ 22	$ (105)	$ 127

Operations and maintenance Operations and maintenance expenses increased $66 million for the year ended 2009 compared with the prior year primarily because of:

- An increase of $62 million related to renewable energy and demand-side management programs, which are offset in operating revenues;
- An increase of $29 million in generation costs, including more planned maintenance, partially offset by lower costs at Palo Verde due to cost efficiency measures; and
- A decrease of $25 million associated with cost saving measures and other factors, including the absence of employee severance costs in 2009.

Depreciation and amortization Depreciation and amortization expenses increased $16 million for the year ended 2009 compared with the prior year primarily because of increases in utility plant in service. The increases in utility plant in service are the result of various improvements to APS's existing fossil and nuclear generating plants and distribution and transmission infrastructure additions and upgrades.

Interest charges, net of allowance for funds used during construction Interest charges, net of allowance for funds used during construction increased $27 million for the year ended 2009 compared with the prior year primarily because of higher debt balances, partially offset by the effects of lower interest rates (see discussion related to APS's debt issuances in "Pinnacle West Consolidated — Liquidity and Capital Resources" below). Interest charges, net of allowance for funds used during construction are comprised of the regulated electricity segment portions of the line items interest expense and allowance for equity and borrowed funds used during construction from the Consolidated Statements of Income.

Other income (expenses), net Other income (expenses), net improved $19 million for the year ended 2009 compared with the prior year primarily because of improved investment gains. Other income (expenses), net is comprised of the regulated electricity segment portions of the line items other income and other expense from the Consolidated Statements of Income.

Income taxes Income taxes were $50 million higher for the year ended 2009 compared with the prior year primarily because of $30 million of income tax benefits related to prior years recorded in 2008 and higher pretax income. See Note 4.

All other

All other earnings from continuing operations were $15 million lower for the year ended 2009 compared with the prior year primarily because of planned reductions of marketing and trading activities.

Discontinued operations

Real estate activities During the first quarter of 2009, we decided to sell substantially all of SunCor's assets to reduce its outstanding debt. The loss from real estate activities attributable to common shareholders was $141 million higher for the year ended 2009 compared with the prior year primarily because of an increase in real estate impairment charges of $213 million before income taxes (see Note 23 for details of the impairment charges).

All other All other earnings from discontinued operations were $5 million lower for the year ended 2009 compared with the prior year primarily because of the absence of the 2008 resolution of certain tax issues associated with the sale of Silverhawk in 2005.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows — Pinnacle West Consolidated

The following table presents net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2010, 2009 and 2008 (dollars in millions):

	2010	2009	2008
Net cash flow provided by operating activities	$ 750	$ 1,067	$ 848
Net cash flow used for investing activities	(576)	(705)	(815)
Net cash flow provided by (used for) financing activities	(209)	(322)	16
Net increase (decrease) in cash and cash equivalents	$ (35)	$ 40	$ 49

2010 Compared with 2009

The decrease of approximately $317 million in net cash provided by operating activities is primarily due to voluntary pension contributions in 2010 of approximately $200 million, changes in collateral and margin cash provided as a result of changes in commodity prices and other changes in working capital.

The decrease of approximately $129 million in net cash used for investing activities is primarily due to approximately $100 million of proceeds from the sale of the district cooling business in June 2010 and the increase in proceeds from the sale of commercial real estate investments of approximately $29 million.

The decrease of approximately $113 million in net cash used for financing activities is primarily due to lower repayments of short-term borrowings in 2010 due to lower short-term debt balances partially offset by lower net sources of equity and long-term debt financing, including the proceeds of approximately $253 million from the issuance of equity in April 2010 and APS's issuance of $500 million of unsecured senior notes in 2009.

2009 Compared with 2008

The increase of approximately $219 million in net cash provided by operating activities is primarily due to a reduction of collateral and margin cash required as a result of changes in commodity prices and a 2009 income tax refund (see Note 4).

The decrease of approximately $110 million in net cash used for investing activities is primarily due to lower levels of capital expenditures net of contributions (see table and discussion below), partially offset by lower real estate sales primarily due to a commercial property sale in 2008.

The increase of approximately $338 million in net cash used for financing activities is primarily due to repayments of short-term borrowings, partially offset by APS's issuance of $500 million of unsecured senior notes.

Cash Flows — Arizona Public Service Company

The following table presents APS's net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2010, 2009 and 2008 (dollars in millions):

	2010	2009	2008
Net cash flow provided by operating activities	$ 695	$ 995	$ 820
Net cash flow used for investing activities	(747)	(738)	(879)
Net cash flow provided by (used for) financing activities	31	(208)	79
Net increase (decrease) in cash and cash equivalents	$ (21)	$ 49	$ 20

2010 Compared with 2009

The decrease of approximately $300 million in net cash provided by operating activities is primarily due to voluntary pension contributions in 2010 of approximately $200 million, increased collateral and margin cash provided as a result of changes in commodity prices, and the payment of income taxes in 2010. These were partially offset by other changes in working capital.

The increase of approximately $9 million in net cash used for investing activities is primarily due to lower contributions in aid of construction and other cash flows.

The decrease of approximately $239 million in net cash used for financing activities is primarily due to the repayment of short-term borrowings in 2009, partially offset by lower net sources of equity and long-term debt financing including the proceeds of approximately $253 million from the infusion of equity from Pinnacle West in 2010 and by APS's issuance of $500 million of unsecured senior notes in 2009.

2009 Compared with 2008

The increase of approximately $175 million in net cash provided by operating activities is primarily due to a reduction of collateral and margin cash required as a result of changes in commodity prices.

The decrease of approximately $141 million in net cash used for investing activities is primarily due to lower levels of capital expenditures net of contributions.

The increase of approximately $287 million in net cash used for financing activities is primarily due to repayments of short-term borrowings, partially offset by APS's issuance of $500 million of unsecured senior notes (see Note 6).

Liquidity

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for 2008, 2009 and 2010 and estimated capital expenditures for the next three years:

CAPITAL EXPENDITURES
(dollars in millions)

	Actual			Estimated		
	2008	2009	2010	2011	2012	2013
APS						
Generation:						
Nuclear Fuel	$ 47	$ 64	$ 63	$ 65	$ 68	$ 69
Renewables	—	—	6	236	179	90
Environmental	96	33	11	11	22	122
Four Corners Units 4 and 5	—	—	—	—	294	—
Other Generation	167	144	172	144	152	107
Distribution	340	246	232	284	350	285
Transmission	163	193	120	143	220	248
Other (a)	43	52	62	78	49	41
Total APS	856	732	666	961	1,334	962
Other	48	13	4	—	—	—
Total	$ 904	$ 745	$ 670	$ 961	$ 1,334	$ 962

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. Included under Renewables is the AZ Sun Program, which is a significant component of the increase in capital expenditures from 2010 to 2011. For purposes of this table, we have assumed the consummation of APS's purchase of SCE's interest in Four Corners Units 4 and 5 and the subsequent shut down of Units 1-3, as discussed in the "Overview" section above. As a result, we included the $294 million purchase price under Generation and have not included environmental expenditures for Units 1-3. We are also monitoring the status of certain environmental matters, which, depending on their final outcome, could require modification to our environmental expenditures. (See "Business of Arizona Public Service Company — Environmental Matters — EPA Environmental Regulation — Regional Haze Rules, Mercury and Other Hazardous Air Pollutants and Coal Combustion Waste" in Item 1.)

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, new customer construction, related information systems and facility costs. Examples of the types of projects included in the forecast include power lines, substations, line extensions to new residential and commercial developments and upgrades to customer information systems.

Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders and principal and interest payments on our short-term and long-term debt. The level of our common stock dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

On January 19, 2011, the Pinnacle West Board of Directors declared a quarterly dividend of $0.525 per share of common stock, payable on March 1, 2011, to shareholders of record on February 1, 2011.

Our primary sources of cash are dividends from APS, external debt and equity financings. For the years 2008 through 2010, total distributions from APS were $522 million and there were no distributions from SunCor. For 2010, cash distributions from APS were $182 million.

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2010, APS's common equity ratio, as defined, was 53%. Its total shareholder equity was approximately $3.8 billion, and total capitalization was approximately $7.2 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $2.9 billion, assuming APS's total capitalization remains the same. Based on the discussion above, this restriction does not materially affect Pinnacle West's ability to meet its ongoing capital requirements.

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for the commercial paper programs. During the first quarter of 2010, Pinnacle West and APS refinanced existing credit facilities that would have otherwise matured in December 2010.

On February 12, 2010, Pinnacle West refinanced its $283 million revolving credit facility that would have matured in December 2010, and decreased the size of the facility to $200 million. The new facility matures in February 2013. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Pinnacle West will use the facility for general corporate purposes, commercial paper program support and for the issuance of letters of credit. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings. As a result of the downsized credit facility, the Company also reduced the size of its commercial paper program to $200 million from $250 million.

At December 31, 2010, the $200 million credit facility was available to support the issuance of up to $183 million in commercial paper or for bank borrowings, including issuances of letters of credit up to $183 million. At December 31, 2010, Pinnacle West had no outstanding borrowings under this credit facility, $17 million of commercial paper borrowings and no outstanding letters of credit.

In April 2010, Pinnacle West issued 6,900,000 shares of common stock at an offering price of $38.00 per share, resulting in net proceeds of approximately $253 million. Pinnacle West contributed all of the net proceeds from this offering into APS in the form of equity infusions. APS has used these contributions to repay short-term indebtedness, to finance capital expenditures and for other general corporate purposes. Pinnacle West intends to issue equity to provide most of the funds for the equity infusions into APS required by the retail rate case settlement. Such equity issuances may occur at any time in the period through 2014, at Pinnacle West's discretion. See Note 3.

In June 2010, Pinnacle West received approximately $100 million related to the sale of APSES' district cooling business. The net proceeds were used to repay short-term indebtedness.

Pinnacle West expects to receive approximately $132 million of cash tax benefits related to SunCor's strategic asset sales (see Note 23), a majority of which have been realized as of December 31, 2010. Approximately $7 million of these benefits were recorded in 2010 as reductions to income tax expense related to the current impairment charges. The additional $125 million of tax benefits were recorded as reductions to income tax expense related to SunCor impairment charges recorded on or before December 31, 2009.

The $68 million income tax receivables on the Consolidated Balance Sheets represent the anticipated refunds related to an APS tax accounting method change approved by the IRS in the third quarter of 2009 and the current year tax benefits related to the SunCor strategic asset sales that closed in 2010.

The Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 includes provisions making qualified property placed into service after September 8, 2010 and before January 1, 2012 eligible for 100% bonus depreciation for federal income tax purposes. In addition, qualified property placed into service in 2012 is eligible for 50% bonus depreciation for federal income tax purposes. These provisions of the recent tax legislation are expected to generate approximately $450-500 million of cash tax benefits for APS through accelerated depreciation. It is anticipated that these cash benefits will be fully realized by APS by the end of 2013, with a majority of the benefit realized in 2012 and 2013. The cash generated is an acceleration of tax benefits that APS would have otherwise received over 20 years.

Pinnacle West sponsors a qualified defined benefit and account balance pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. IRS regulations require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension obligation. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. During 2010, we made voluntary contributions of $200 million to our pension plan. The required minimum contribution to our pension plan is zero in 2011 and approximately $85 million in 2012. The contribution to our other postretirement benefit plans in 2010 was approximately $17 million. The contributions to our other postretirement benefit plans for 2011 and 2012 are expected to be approximately $20 million each year. APS and other subsidiaries fund their share of the contributions. APS's share is approximately 98% of both plans.

APS

APS's capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West. See "Pinnacle West (Parent Company)" above for a discussion of the common equity ratio that APS must maintain in order to pay dividends to Pinnacle West.

On February 12, 2010, APS refinanced its $377 million credit facility that would have matured in December 2010, and increased the size of the facility to $500 million. The new credit facility terminates in February 2013. APS may increase the amount of the facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use the facility for general corporate purposes, commercial paper program support and for the issuance of letters of credit. Interest rates are based on APS's senior unsecured debt credit ratings.

On February 14, 2011, APS refinanced its $489 million credit facility that would have matured in September 2011, and increased the size of the facility to $500 million. The new credit facility terminates in February 2015. APS may increase the amount of the facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use the facility for general corporate purposes, commercial paper program support and for the issuance of letters of credit. Interest rates are based on APS's senior unsecured debt credit ratings.

At December 31, 2010, APS had two credit facilities totaling $989 million, consisting of the $500 million and $489 million credit facilities described above. These facilities were available either to support the issuance of up to $250 million in commercial paper, or for bank borrowings, including issuances of letters of credit up to $989 million. At December 31, 2010, APS had no borrowings outstanding under any of its credit facilities and no outstanding commercial paper. A $20 million letter of credit was issued under APS's $489 million credit facility in the second quarter of 2010.

On July 13, 2010, APS changed the interest rate mode for the approximately $33 million of Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Bonds (Arizona Public Service Company Navajo Project) 1994 Series A, due 2029. The rate period for the bonds changed from a daily rate mode, supported by a letter of credit, to a three-year term rate mode that will bear interest at a rate of 3.625% per annum for three years. The letter of credit was terminated in connection with this change, and there is no bank or other third-party credit support for the bonds in the term rate mode.

On August 10, 2010, APS changed the letter of credit supporting the approximately $17 million of Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Bonds (Arizona Public Service Company Project) Series 1998, due 2033. The bonds were in a daily rate mode supported by a prior letter of credit and remain in a daily rate mode, supported by a new three-year letter of credit expiring in August 2013.

On October 12, 2010, APS changed the interest rate mode for the approximately $147 million of City of Farmington, New Mexico Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Four Corners Project) 1994 Series A and 1994 Series B, due 2024 and City of Farmington, New Mexico Pollution Control Revenue Bonds (Arizona Public Service Company Four Corners Project) 1994 Series C, due 2024. The rate period for the 1994 Series A bonds and the 1994 Series B bonds changed from a daily rate mode, supported by letters of credit, to a term rate mode to maturity, subject to optional redemption after year ten, that will bear interest at a rate of 4.70% per annum until maturity in 2024 unless the optional redemption is exercised by APS. The rate period for the 1994 Series C bonds changed from a daily rate mode, supported by a letter of credit, to a three-year term rate mode that will bear interest at a rate of 2.875% per annum until October 2013. The letters of credit supporting each of these three series of bonds were terminated in connection with these changes, and there is no bank or other third-party credit support for any of these bonds.

On January 1, 2010, due to the adoption of amended accounting guidance relating to VIEs, APS began consolidating the Palo Verde Lessor Trusts (see Note 20) and, as a result of consolidation of these VIEs, APS has reported the Lessor Trusts' long-term debt on its Consolidated Balance Sheets. Interest rates on these debt instruments are 8% and are fixed for the remaining life of the debt. As of December 31, 2010 approximately $29 million was classified as current maturities of long-term debt and $97 million was classified as long-term debt relating to these VIEs. These debt instruments mature on December 30, 2015 and have sinking fund features that are serviced by the lease payments. See Note 20 for additional discussion of the VIEs.

Other Financing Matters — See Note 3 for information regarding the PSA approved by the ACC. Although APS defers actual retail fuel and purchased power costs on a current basis, APS's recovery of the deferrals from its ratepayers is subject to annual and, if necessary, periodic PSA adjustments.

See Note 3 for information regarding the retail rate case settlement, which includes ACC authorization and requirements of equity infusions into APS of at least $700 million by December 31, 2014.

See Note 18 for information related to the change in our margin accounts.

Other Subsidiaries

SunCor —In 2010, SunCor sold land parcels, commercial assets and master planned home-building communities for approximately $72 million, which approximated the carrying value of these assets, resulting in a net gain of zero. In connection with these sales, SunCor negotiated a restructuring of certain of its credit facilities. The debt restructuring resulted in an after-tax gain of approximately $10 million. At December 31, 2010, SunCor had total remaining assets of about $16 million, which includes approximately $3 million of assets held for sale. At December 31, 2010, SunCor had no debt outstanding.

El Dorado — El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments.

APSES —APSES expects minimal capital expenditures over the next three years.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant and each anticipates it will continue to meet this and other significant covenant requirements. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2010, the ratio was approximately 49% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facilities borrowings.

See Notes 5 and 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 17, 2011 are shown below. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient liquidity to cover a downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Senior unsecured (a)	Baa3 (P)	BB+ (prelim)	N/A
Commercial paper	P-3	A-3	F3
Outlook	Stable	Positive	Stable
APS			
Senior unsecured	Baa2	BBB-	BBB
Secured lease obligation bonds	Baa2	BBB-	BBB
Commercial paper	P-2	A-3	F3
Outlook	Stable	Positive	Stable

(a) Pinnacle West has a shelf registration under SEC Rule 415. Pinnacle West currently has no outstanding, rated senior unsecured securities. However, Moody's assigned a provisional (P) rating and Standard & Poor's assigned a preliminary (prelim) rating to the senior unsecured securities that can be issued under such shelf registration.

Off-Balance Sheet Arrangements

On January 1, 2010 we adopted amended accounting guidance relating to VIEs and, as a result, we have consolidated certain entities which were previously not consolidated. The consolidation of these entities has impacted our consolidated financial statements. See Notes 1, 2 and 20 for a discussion of these impacts.

Guarantees and Surety Bonds

We have issued parental guarantees and obtained surety bonds on behalf of our subsidiaries including credit support instruments enabling APSES to offer energy-related products and surety bonds at APS, principally related to self-insured workers' compensation. Non-performance or non-payment under the underlying contract by our subsidiaries would result in a payment liability on our part under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to such instruments. At December 31, 2010, we had no outstanding claims for payment under any of these instruments. Our guarantees and surety bonds have no recourse or collateral provisions to allow us to recover amounts paid under these instruments or surety bonds from our subsidiaries. We generally agree to indemnification provisions related to liabilities arising from or related to certain of our agreements, with limited exceptions depending on the particular agreement. See Note 21 for additional information regarding guarantees and letters of credit.

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2010 (dollars in millions):

	2011	2012-2013	2014-2015	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$ 673	$ 949	$ 1,071	$ 2,587	$ 5,280
Pinnacle West	177	—	—	—	177
Total long-term debt payments, including interest and capital lease obligations	850	949	1,071	2,587	5,457
Short-term debt payments, including interest (b)	17	—	—	—	17
Fuel and purchased power commitments (c)	381	824	1,070	7,084	9,359
Operating lease payments	24	38	27	9	98
Nuclear decommissioning funding requirements	24	49	49	137	259
Renewable energy credits (d)	57	40	40	196	333
Purchase obligations (e)	214	125	—	117	456
Noncontrolling interests	10	28	55	—	93
Total contractual commitments	$ 1,577	$ 2,053	$ 2,312	$ 10,130	$ 16,072

(a) The long-term debt matures at various dates through 2038 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2010 (see Note 6).

(b) The short-term debt represents commercial paper borrowings at Pinnacle West (see Note 5).

Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy and nuclear fuel (see Notes 3 and 11).

(d) Contracts to purchase renewable energy credits in compliance with the Renewable Energy Standard.

(e) These contractual obligations include commitments for capital expenditures and other obligations. These amounts do not include the purchase of SCE's interest in Four Corners Units 4 and 5 due to additional approvals required. See discussion in "Overview."

This table excludes $133 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. This table also excludes $85 million in estimated minimum pension contributions in 2012 (see Note 8).

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $1.0 billion of regulatory assets and $753 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2010.

Included in the balance of regulatory assets at December 31, 2010 is a regulatory asset of $669 million for pension and other postretirement benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2010 reported pension liability on the Consolidated Balance Sheets and our 2010 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	Impact on Pension Liability	Impact on Pension Expense
Discount rate:		
Increase 1%	$ (261)	$ (8)
Decrease 1%	294	10
Expected long-term rate of return on plan assets:		
Increase 1%	—	(7)
Decrease 1%	—	7

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2010 reported other postretirement benefit obligation on the Consolidated Balance Sheets and our 2010 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	Impact on Other Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	$ (118)	$ (5)
Decrease 1%	138	6
Health care cost trend rate (b):		
Increase 1%	134	9
Decrease 1%	(107)	(7)
Expected long-term rate of return on plan assets — pretax:		
Increase 1%	—	(2)
Decrease 1%	—	2

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

(b) This assumes a 1% change in the initial and ultimate health care cost trend rate.

See Note 8 for further details about our pension and other postretirement benefit plans.

Derivative Accounting

Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, determines whether we use accrual accounting (for contracts designated as normal) or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in the fair value are recognized periodically in income unless certain hedge criteria are met. For cash flow hedges, the effective portion of changes in the fair value of the derivative is recognized in common stock equity (as a component of other comprehensive income (loss)) and the ineffective portion is recognized in current earnings.

See "Market Risks — Commodity Price Risk" below for quantitative analysis. See "Fair Value Measurements" below for additional information on valuation. See Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative accounting.

Fair Value Measurements

We apply recurring fair value measurements to derivative instruments, nuclear decommissioning trusts, certain cash equivalents and plan assets held in our retirement and other benefit plans. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use inputs, or assumptions that market participants would use, to determine fair market value. The significance of a particular input determines how the instrument is classified in the fair value hierarchy. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value sometimes requires subjective and complex judgment. Our assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy. Actual results could differ from our estimates of fair value. See Note 14 for further fair value measurement discussion, Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative accounting.

Our nuclear decommissioning trusts invest in fixed income securities and equity securities. The fair values of these securities are based on observable inputs for identical or similar assets. See Note 14 for further discussion of our nuclear decommissioning trusts.

Real Estate Investment Impairments

While we do not have any real estate investments or home inventory at December 31, 2010, we did have real estate investments of $120 million and $3 million of home inventory on our Consolidated Balance Sheets at December 31, 2009. For purposes of evaluating impairment, in accordance with guidance on the impairment and disposal of long-lived assets, we classified our real estate assets, such as land under development, land held for future development, and commercial property, as "held and used." When events or changes in circumstances indicated that the carrying value of real estate assets considered held and used were not recoverable, we compared the undiscounted cash flows that we estimated would be generated by each asset to its carrying amount. If the carrying amount exceeded the undiscounted cash flows, we adjusted the asset to fair value and recognized an impairment charge. The adjusted value became the new book value (carrying amount) for held and used assets. We may have had real estate assets classified as held and used with fair values that were lower than their carrying amounts, but were not deemed to be impaired because the undiscounted cash flows exceeded the carrying amounts.

Real estate home inventory was considered to be held for sale for the purposes of evaluating impairment. Home inventories were reported at the lower of carrying amount or fair value less cost to sell. Fair value less cost to sell was evaluated each period to determine if it had changed. Losses (and gains not to exceed any cumulative loss previously recognized) were reported as adjustments to the carrying amount.

We determined fair value for our real estate assets primarily based on the future cash flows that we estimated would be generated by each asset discounted for market risk. Our impairment assessments and fair value determinations required significant judgment regarding key assumptions such as future sales prices, future construction and land development costs, future sales timing, and discount rates. The assumptions were specific to each project and may have varied among projects. The discount rates we used to determine fair values at December 31, 2009 ranged from 11% to 29%. Due to the judgment and assumptions applied in the estimation process, with regard to impairments, it is possible that actual results could have differed from those estimates.

OTHER ACCOUNTING MATTERS

On January 1, 2010 we adopted amended accounting guidance relating to VIEs and, as a result, we have consolidated certain entities which were previously not consolidated. The consolidation of these entities has impacted our consolidated financial statements. See Notes 1, 2 and 20 for a discussion of these impacts.

The FASB is currently working on several significant projects with the desire to converge GAAP with IFRS. These projects include accounting for leases, revenue recognition, and financial instruments, among other items. Concurrently, the SEC is considering mandating IFRS for U.S. companies. See Note 2 for a discussion of these potential changes.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund.

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 14). The nuclear decommissioning trust fund also has risks associated with the changing market value of its investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2010 and 2009. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2010 and 2009 (dollars in thousands):

Pinnacle West — Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2010	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2011	0.84%	$ 16,600	0.32%	$ 26,710	6.32%	$ 605,169
2012	—	—	—	—	6.41%	477,435
2013	—	—	0.32%	16,870	4.94%	122,828
2014	—	—	—	—	5.91%	502,274
2015	—	—	—	—	4.79%	313,420
Years thereafter	—	—	—	—	6.69%	1,619,150
Total		$ 16,600		$ 43,580		$3,640,276
Fair value		$ 16,600		$ 43,580		$3,869,681

Pinnacle West — Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2009	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2010	1.09%	$ 153,715	1.66%	$ 276,636	7.90%	$ 26,840
2011	—	—	2.00%	39,967	6.32%	605,425
2012	—	—	5.25%	38	6.41%	477,674
2013	—	—	5.25%	1,774	6.77%	58,912
2014	—	—	—	—	5.91%	502,499
Years thereafter	—	—	—	—	6.46%	1,817,420
Total		$ 153,715		$ 318,415		$3,488,770
Fair value		$ 153,715		$ 318,415		$3,631,585

The tables below present contractual balances of APS's long-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2010 and 2009. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2010 and 2009 (dollars in thousands):

APS — Consolidated

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2010	Interest Rates	Amount	Interest Rates	Amount
2011	0.32%	$ 26,710	6.48%	$ 430,169
2012	—	—	6.41%	477,435
2013	0.32%	16,870	4.94%	122,828
2014	—	—	5.91%	502,274
2015	—	—	4.79%	313,420
Years thereafter	—	—	6.69%	1,619,150
Total		$ 43,580		$ 3,465,276
Fair value		$ 43,580		$ 3,693,276

APS — Consolidated

	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2009	Interest Rates	Amount	Interest Rates	Amount
2010	0.25%	$ 196,170	7.91%	$ 26,789
2011	0.26%	26,710	6.48%	430,398
2012	—	—	6.41%	477,654
2013	—	—	6.77%	58,910
2014	—	—	5.91%	502,499
Years thereafter	—	—	6.46%	1,817,420
Total		$ 222,880		$ 3,313,670
Fair value		$ 222,880		$ 3,451,255

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

The following table shows the net pretax changes in mark-to-market of our derivative positions in 2010 and 2009 (dollars in millions):

	2010	2009
Mark-to-market of net positions at beginning of year	$ (169)	$ (282)
Recognized in earnings:		
Change in mark-to-market losses for future period deliveries	(7)	(4)
Mark-to-market losses realized including ineffectiveness during the period	5	11
Decrease (increase) in regulatory asset	(36)	76
Recognized in OCI:		
Change in mark-to-market losses for future period deliveries (a)	(155)	(155)
Mark-to-market losses realized during the period	123	185
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$ (239)	$ (169)

(a) The changes in mark-to-market recorded in OCI are due primarily to changes in forward natural gas prices.

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2010 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Derivative Accounting" and "Fair Value Measurements," for more discussion of our valuation methods.

Source of Fair Value	2011	2012	2013	2014	2015	Years thereafter	Total fair value
Prices actively quoted	$ (1)	$ —	$ —	$ —	$ —	$ —	$ (1)
Prices provided by other external sources	(139)	(47)	(14)	—	—	—	(200)
Prices based on models and other valuation methods	(7)	(4)	(7)	(6)	(6)	(8)	(38)
Total by maturity	$ (147)	$ (51)	$ (21)	$ (6)	$ (6)	$ (8)	$ (239)

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2010 and 2009 (dollars in millions):

	December 31, 2010 Gain (Loss)		December 31, 2009 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Earnings				
Electricity	$ —	$ —	$ 1	$ (1)
Natural gas	1	(1)	1	(1)
Regulatory asset (liability) or OCI (a)				
Electricity	13	(13)	21	(21)
Natural gas	42	(42)	59	(59)
Total	$ 56	$ (56)	$ 82	$ (82)

(a) These contracts are hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 18 for a discussion of our credit valuation adjustment policy.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Market and Credit Risks" in Item 7 above for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND
FINANCIAL STATEMENT SCHEDULES

	Page
Management's Report on Internal Control Over Financial Reporting (Pinnacle West Capital Corporation)	80
Report of Independent Registered Public Accounting Firm	81
Pinnacle West Consolidated Statements of Income for 2010, 2009 and 2008	83
Pinnacle West Consolidated Balance Sheets as of December 31, 2010 and 2009	84
Pinnacle West Consolidated Statements of Cash Flows for 2010, 2009 and 2008	86
Pinnacle West Consolidated Statements of Changes in Equity for 2010, 2009 and 2008	87
Notes to Pinnacle West's Consolidated Financial Statements	88
Management's Report on Internal Control Over Financial Reporting (Arizona Public Service Company)	153
Report of Independent Registered Public Accounting Firm	154
APS Consolidated Statements of Income for 2010, 2009 and 2008	156
APS Consolidated Balance Sheets as of December 31, 2010 and 2009	157
APS Consolidated Statements of Cash Flows for 2010, 2009 and 2008	159
APS Consolidated Statements of Changes in Equity for 2010, 2009 and 2008	160
Supplemental Notes to APS's Consolidated Financial Statements	162
Financial Statement Schedules for 2010, 2009 and 2008	
Pinnacle West Schedule I — Condensed Statements of Income for 2010, 2009 and 2008	168
Pinnacle West Schedule I — Condensed Balance Sheets as of December 31, 2010 and 2009	169
Pinnacle West Schedule I — Condensed Statements of Cash Flows for 2010, 2009 and 2008	170
Pinnacle West Schedule II — Reserve for Uncollectibles for 2010, 2009 and 2008	171
APS Schedule II — Reserve for Uncollectibles for 2010, 2009 and 2008	172

See Note 13 and S-2 for the selected quarterly financial data (unaudited) required to be presented in this Item.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (PINNACLE WEST CAPITAL CORPORATION)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Pinnacle West Capital Corporation. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework,* our management concluded that our internal control over financial reporting was effective as of December 31, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's consolidated financial statements.

February 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2010 and 2009 and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As disclosed in Note 2 to the consolidated financial statements, the Company adopted amended accounting guidance related to the consolidation of variable interest entities on January 1, 2010.

/s/ DELOITTE & TOUCHE LLP

Phoenix, Arizona
February 18, 2011

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars and shares in thousands, except per share amounts)

	Year Ended December 31,		
	2010	2009	2008
OPERATING REVENUES			
Regulated electricity segment	$ 3,180,678	$ 3,149,187	$ 3,127,383
Marketing and trading	—	—	66,897
Other revenues	82,967	26,723	25,407
Total	3,263,645	3,175,910	3,219,687
OPERATING EXPENSES			
Regulated electricity segment fuel and purchased power	1,046,815	1,178,620	1,284,116
Marketing and trading fuel and purchased power	—	—	45,572
Operations and maintenance	877,406	831,863	765,277
Depreciation and amortization	414,555	407,463	391,190
Taxes other than income taxes	135,334	123,277	124,853
Other expenses	65,651	24,534	26,032
Total	2,539,761	2,565,757	2,637,040
OPERATING INCOME	723,884	610,153	582,647
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	22,066	14,999	18,636
Other income (Note 19)	6,368	5,278	9,541
Other expense (Note 19)	(9,764)	(14,269)	(31,576)
Total	18,670	6,008	(3,399)
INTEREST EXPENSE			
Interest charges	244,174	237,527	219,916
Allowance for borrowed funds used during construction (Note 1)	(16,539)	(10,430)	(14,547)
Total	227,635	227,097	205,369
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	514,919	389,064	373,879
INCOME TAXES (Note 4)	164,321	136,506	95,544
INCOME FROM CONTINUING OPERATIONS	350,598	252,558	278,335
INCOME (LOSS) FROM DISCONTINUED OPERATIONS			
Net of income tax expense (benefit) of $12,808, $(107,596) and $(11,648) (Note 22)	19,611	(179,794)	(18,715)
NET INCOME	370,209	72,764	259,620
Less: Net income attributable to noncontrolling interests (Note 20)	20,156	4,434	17,495
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 350,053	$ 68,330	$ 242,125
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	106,573	101,161	100,691
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	107,138	101,264	100,965
EARNINGS PER WEIGHTED — AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations attributable to common shareholders — basic	$ 3.10	$ 2.31	$ 2.59
Net income attributable to common shareholders — basic	3.28	0.68	2.40
Income from continuing operations attributable to common shareholders — diluted	3.08	2.30	2.58
Net income attributable to common shareholders — diluted	3.27	0.67	2.40
DIVIDENDS DECLARED PER SHARE	$ 2.10	$ 2.10	$ 2.10
AMOUNTS ATTRIBUTABLE TO COMMON SHAREHOLDERS:			
Income from continuing operations, net of tax	$ 330,435	$ 233,349	$ 260,840
Discontinued operations, net of tax	19,618	(165,019)	(18,715)
Net income attributable to common shareholders	$ 350,053	$ 68,330	$ 242,125

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 110,188	$ 145,378
Customer and other receivables	324,207	301,915
Accrued unbilled revenues	103,292	110,971
Allowance for doubtful accounts	(7,981)	(6,153)
Materials and supplies (at average cost)	181,414	176,020
Fossil fuel (at average cost)	21,575	39,245
Deferred income taxes (Note 4)	94,602	53,990
Income tax receivable (Note 4)	2,483	26,005
Assets from risk management activities (Note 18)	73,788	50,619
Other current assets	28,362	30,747
Total current assets	931,930	928,737
INVESTMENTS AND OTHER ASSETS		
Real estate investments — net (Notes 1, 6 and 23)	—	119,989
Assets from risk management activities (Note 18)	39,032	28,855
Nuclear decommissioning trust (Note 14)	469,886	414,576
Other assets	116,216	110,091
Total investments and other assets	625,134	673,511
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6, 9 and 10)		
Plant in service and held for future use	13,201,960	12,848,138
Accumulated depreciation and amortization	(4,514,204)	(4,340,645)
Net	8,687,756	8,507,493
Construction work in progress	459,361	467,700
Palo Verde sale leaseback, net of accumulated depreciation of $213,094 and $204,328 (Note 20)	137,956	146,722
Intangible assets, net of accumulated amortization of $330,584 and $294,724	184,952	164,380
Nuclear fuel, net of accumulated amortization of $85,270 and $64,544	108,794	118,243
Total property, plant and equipment	9,578,819	9,404,538
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,048,656	813,161
Income tax receivable (Note 4)	65,103	65,103
Other	113,061	101,274
Total deferred debits	1,226,820	979,538
TOTAL ASSETS	$ 12,362,703	$ 11,986,324

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 236,354	$ 240,637
Accrued taxes (Note 4)	104,711	104,011
Accrued interest	54,831	54,596
Short-term borrowings (Note 5)	16,600	153,715
Current maturities of long-term debt (Note 6)	631,879	303,476
Customer deposits	68,322	71,026
Liabilities from risk management activities (Note 18)	58,976	55,908
Other current liabilities	139,063	125,574
Total current liabilities	1,310,736	1,108,943
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)		
Long-term debt less current maturities	2,948,991	3,370,524
Palo Verde sale leaseback lessor notes less current maturities (Note 20)	96,803	126,000
Total long-term debt less current maturities	3,045,794	3,496,524
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,833,566	1,496,095
Deferred fuel and purchased power regulatory liability (Note 3)	58,442	87,291
Other regulatory liabilities (Notes 1 and 3)	694,589	679,072
Liability for asset retirements (Note 12)	328,571	301,783
Liabilities for pension and other postretirement benefits (Note 8)	813,121	811,338
Liabilities from risk management activities (Note 18)	65,390	62,443
Customer advances	121,645	136,595
Coal mine reclamation	117,243	92,060
Unrecognized tax benefits (Note 4)	66,349	142,099
Other	132,031	144,077
Total deferred credits and other	4,230,947	3,952,853
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY (Note 7)		
Common stock, no par value; authorized 150,000,000 shares; issued 108,820,067 at end of 2010 and 101,527,937 at end of 2009	2,421,372	2,153,295
Treasury stock at cost; 50,410 shares at end of 2010 and 93,239 at end of 2009	(2,239)	(3,812)
Total common stock	2,419,133	2,149,483
Retained earnings	1,423,961	1,298,213
Accumulated other comprehensive loss:		
Pension and other postretirement benefits (Note 8)	(59,420)	(50,892)
Derivative instruments	(100,347)	(80,695)
Total accumulated other comprehensive loss	(159,767)	(131,587)
Total shareholders' equity	3,683,327	3,316,109
Noncontrolling interests (Note 20)	91,899	111,895
Total equity	3,775,226	3,428,004
TOTAL LIABILITIES AND EQUITY	$ 12,362,703	$ 11,986,324

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 370,209	$ 72,764	$ 259,620
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of district cooling business	(41,973)	—	—
Depreciation and amortization including nuclear fuel	472,807	450,864	431,672
Deferred fuel and purchased power	93,631	(51,742)	(80,183)
Deferred fuel and purchased power amortization	(122,481)	147,018	183,126
Allowance for equity funds used during construction	(22,066)	(14,999)	(18,636)
Real estate impairment charge	16,731	280,188	53,250
Gain on real estate debt restructuring	(16,755)	—	—
Deferred income taxes	260,411	105,492	158,024
Change in mark-to-market valuations	2,688	(6,939)	9,074
Changes in current assets and liabilities:			
Customer and other receivables	(67,943)	12,292	73,446
Accrued unbilled revenues	7,679	(10,882)	7,388
Materials, supplies and fossil fuel	12,276	(12,261)	(25,453)
Other current assets	5,246	24,647	56,775
Accounts payable	9,125	(27,328)	(69,439)
Accrued taxes and income tax receivable — net	24,222	(31,792)	(13,149)
Other current liabilities	5,204	29,274	(5,130)
Expenditures for real estate investments	(622)	(2,957)	(21,168)
Other changes in real estate assets	4,068	(4,216)	18,211
Change in margin and collateral accounts — assets	(9,937)	(12,806)	17,450
Change in margin and collateral accounts — liabilities	(88,315)	35,654	(132,416)
Change in long term income tax receivable	—	(131,984)	—
Change in unrecognized tax benefits	(73,621)	137,898	(94,551)
Change in other regulatory liabilities	54,518	110,642	(12,129)
Change in other long-term assets	(43,189)	(47,899)	6,104
Change in other long-term liabilities	(101,456)	16,377	46,207
Net cash flow provided by operating activities	750,457	1,067,305	848,093
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(748,374)	(764,609)	(935,577)
Contributions in aid of construction	32,754	53,525	60,292
Allowance for borrowed funds used during construction	(16,778)	(10,745)	(18,820)
Proceeds from the sale of district cooling business	100,300	—	—
Proceeds from nuclear decommissioning trust sales	560,469	441,242	317,619
Investment in nuclear decommissioning trust	(584,885)	(463,033)	(338,361)
Proceeds from sale of commercial real estate investments	72,038	43,370	94,171
Other	8,576	(4,667)	5,517
Net cash flow used for investing activities	(575,900)	(704,917)	(815,159)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	—	867,469	96,934
Repayment of long-term debt	(106,572)	(456,882)	(202,234)
Short-term borrowings and payments — net	(137,115)	(516,754)	331,741
Dividends paid on common stock	(216,979)	(205,076)	(204,247)
Common stock equity issuance	255,971	3,302	3,687
Noncontrolling interests	(11,403)	(14,485)	(13,782)
Other	6,351	171	3,891
Net cash flow provided by (used for) financing activities	(209,747)	(322,255)	15,990
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(35,190)	40,133	48,924
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	145,378	105,245	56,321

CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 110,188	$ 145,378	$ 105,245
Supplemental disclosure of cash flow information Cash paid during the period for:			
Income taxes, net of (refunds)	$ (23,447)	$ (52,776)	$ 24,233
Interest, net of amounts capitalized	$ 221,728	$ 216,608	$ 205,546

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
COMMON STOCK (Note 7)			
Balance at beginning of year	$ 2,153,295	$ 2,151,323	$ 2,135,787
Issuance of common stock	263,297	10,620	10,845
Other	4,780	(8,648)	4,691
Balance at end of year	2,421,372	2,153,295	2,151,323
TREASURY STOCK (Note 7)			
Balance at beginning of year	(3,812)	(2,854)	(2,054)
Purchase of treasury stock	(82)	(2,156)	(1,387)
Reissuance of treasury stock used for stock compensation	1,655	1,198	587
Balance at end of year	(2,239)	(3,812)	(2,854)
RETAINED EARNINGS			
Balance at beginning of year	1,298,213	1,444,208	1,413,741
Net income attributable to common shareholders	350,053	68,330	242,125
Common stock dividends	(224,305)	(212,386)	(211,405)
Other	—	(1,939)	(253)
Balance at end of year	1,423,961	1,298,213	1,444,208
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)			
Balance at beginning of year	(131,587)	(146,698)	(15,863)
Pension and other postretirement benefits (Note 8):			
Unrealized actuarial loss, net of tax benefit of $(7,738), $(4,223) and $(7,801)	(11,795)	(6,350)	(11,053)
Amortization to income:			
Actuarial loss, net of tax benefit of $1,870, $1,705 and $1,578	2,868	2,615	2,437
Prior service cost, net of tax benefit of $201, $215 and $222	308	329	343
Transition obligation, net of tax benefit of $59, $39 and $40	91	61	62
Derivative instruments:			
Net unrealized loss, net of tax benefit of $(61,348), $(61,329) and $(54,490)	(93,939)	(93,996)	(83,093)
Reclassification of net realized (gain) loss to income, net of tax (expense) benefit of $48,453, $72,877 and $(24,776)	74,287	112,452	(39,531)
Balance at end of year	(159,767)	(131,587)	(146,698)
NONCONTROLLING INTERESTS			
Balance at beginning of year	111,895	124,990	128,456
Net income attributable to noncontrolling interests	20,156	4,434	17,495
Net capital activities by noncontrolling interests	(40,152)	(17,529)	(20,961)
Balance at end of year	91,899	111,895	124,990
TOTAL EQUITY	$ 3,775,226	$ 3,428,004	$ 3,570,969
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS			
Net income attributable to common shareholders	$ 350,053	$ 68,330	$ 242,125
Other comprehensive income (loss)	(28,180)	15,111	(130,835)
Comprehensive income attributable to common shareholders	$ 321,873	$ 83,441	$ 111,290

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Consolidation and Nature of Operations

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, SunCor, APSES, El Dorado and Pinnacle West Marketing & Trading. APS's consolidated financial statements include the accounts of APS and the Palo Verde sale leaseback VIEs. Intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for substantially all of our revenues and earnings, and is expected to continue to do so. SunCor was a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico, Idaho and Utah. All activities for SunCor are now reported as discontinued operations (see Note 22). APSES provides energy-related projects to commercial and industrial retail customers in competitive markets in the western United States. In 2008, APSES discontinued its commodity-related energy services (see Note 22). El Dorado is an investment firm. Pinnacle West Marketing & Trading began operations in early 2007. These operations were previously conducted by a division of Pinnacle West through the end of 2006. By the end of 2008, substantially all the contracts were transferred to APS or expired.

In preparing the consolidated financial statements, we have evaluated the events that have occurred after December 31, 2010 through the date the financial statements were issued.

Our consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented. These consolidated financial statements and notes have been prepared consistently with the exception of the reclassification of certain prior year amounts on our Consolidated Statements of Income and Consolidated Balance Sheets in accordance with accounting requirements for reporting discontinued operations (see Note 22), and amended accounting guidance related to VIEs (see Note 2).

Certain line items are presented in more detail on the Consolidated Statements of Cash Flows than was presented in the prior years. Other line items are more condensed than the previous presentation. The prior year amounts were reclassified to conform to the current year presentation. These reclassifications had no impact on total net cash flow provided by operating activities.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables show the impact of the reclassifications of prior years (previously reported) amounts (dollars in thousands):

Statement of Income for the Year Ended December 31, 2009	As previously reported	Reclassifications as a result of the adoption of new VIE accounting guidance	Reclassifications for discontinued operations	Amount reported after adoption of amended VIE accounting guidance and discontinued operations
Operating Revenues				
Real estate segment	$ 103,152	$ —	$ (103,152)	$ —
Other revenues	44,762	—	(18,039)	26,723
Operating Expenses				
Real estate segment operations	102,381	—	(102,381)	—
Real estate impairment charge	258,453	—	(258,453)	—
Operations and maintenance	875,357	(39,660)	(3,834)	831,863
Depreciation and amortization	404,331	7,704	(4,572)	407,463
Taxes other than income taxes	123,663	—	(386)	123,277
Other expenses	32,523	—	(7,989)	24,534
Other				
Other income	5,669	—	(391)	5,278
Interest Expense				
Interest charges	233,859	12,747	(9,079)	237,527
Allowance for borrowed funds used during construction	(10,745)	—	315	(10,430)
Income Taxes	37,827	—	98,679	136,506
[illegible]ome From Continuing Operations	67,231	19,209	166,118	252,558
[illegible]ss From Discontinued Operations	(13,676)	—	(166,118)	(179,794)
Net Income	53,555	19,209	—	72,764
Net Income (Loss) Attributable To Noncontrolling Interests	(14,775)	19,209	—	4,434

Statement of Income for the Year Ended December 31, 2008				
Operating Revenues				
Real estate segment	$ 74,549	$ —	$ (74,549)	$ —
Other revenues	41,729	—	(16,322)	25,407
Operating Expenses				
Real estate segment operations	100,102	—	(100,102)	—
Real estate impairment charge	18,108	—	(18,108)	—
Operations and maintenance	807,852	(39,660)	(2,915)	765,277
Depreciation and amortization	390,093	7,704	(6,607)	391,190
Taxes other than income taxes	125,336	—	(483)	124,853
Other expenses	34,171	—	(8,139)	26,032
Other				
Other income	12,797	—	(3,256)	9,541
Interest Expense				
Interest charges	215,684	14,461	(10,229)	219,916
Allowance for borrowed funds used during construction	(18,820)	—	4,273	(14,547)
Income Taxes	76,897	—	18,647	95,544
Income From Continuing Operations	231,304	17,495	29,536	278,335
Income (Loss) From Discontinued Operations	10,821	—	(29,536)	(18,715)
[illegible]et Income	242,125	17,495	—	259,620
[illegible] Income Attributable To Noncontrolling Interests	—	17,495	—	17,495

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheets – December 31, 2009	As previously reported	Reclassifications as a result of the adoption of the new VIE accounting guidance	Amounts reported after adoption of amended VIE accounting guidance
Property, Plant and Equipment — Palo Verde sale leaseback, net of accumulated depreciation	$ —	$ 146,722	$ 146,722
Deferred Debits — Regulatory assets	781,714	31,447	813,161
Current Liabilities — Current maturities of long-term debt	277,693	25,783	303,476
Long-Term Debt Less Current Maturities Palo Verde sale leaseback lessor notes	—	126,000	126,000
Deferred Credits and Other — Other	200,015	(55,938)	144,077
Equity — Noncontrolling interests	29,571	82,324	111,895

Statement of Cash Flows for the Year Ended December 31, 2009	As previously reported	Reclassifications as a result of the adoption of the new VIE accounting guidance and to conform to current year presentation	Amounts reported after adoption of amended VIE accounting guidance and to conform to current year presentation
Cash Flows from Operating Activities			
Net income	$ 53,555	$ 19,209	$ 72,764
Depreciation and amortization including nuclear fuel	443,160	7,704	450,864
Other current assets	(9,186)	33,833	24,647
Home inventory	33,833	(33,833)	—
Other long-term liabilities	7,050	9,327	16,377
Cash Flows from Financing Activities			
Repayment of long-term debt	(435,127)	(21,755)	(456,88
Noncontrolling interests	—	(14,485)	(14,485
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest, net of amounts capitalized	203,860	12,748	216,608

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Statement of Cash Flows for the Year Ended December 31, 2008	As previously reported	Reclassifications as a result of the adoption of the new VIE accounting guidance and to conform to current year presentation	Amounts reported after adoption of amended VIE accounting guidance and to conform to current year presentation
Cash Flows from Operating Activities			
Net income	$ 242,125	$ 17,495	$ 259,620
Depreciation and amortization including nuclear fuel	423,969	7,703	431,672
Other current assets	8,734	48,041	56,775
Home inventory	48,041	(48,041)	—
Other long-term liabilities	36,880	9,327	46,207
Cash Flows from Financing Activities			
Repayment of long-term debt	(181,491)	(20,743)	(202,234)
Noncontrolling interests	—	(13,782)	(13,782)
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest, net of amounts capitalized	191,085	14,461	205,546

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. See Note 18 for additional information about our derivative accounting policies.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Measurements

We determine and disclose the fair value of certain assets and liabilities in accordance with fair value guidance. Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using actively-quoted prices for identical instruments when available. When actively quoted prices are not available for the identical instruments we use prices for similar instruments or other corroborative market information or prices provided by other external sources. For options, long-term contracts and other contracts for which price quotes are not available, we use unobservable inputs, such as models and other valuation methods, to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our structured activities are hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by our executive risk committee.

See Note 14 for additional information about fair value measurements.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment and recent rate orders applicable to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

See Note 3 for additional information.

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it can recover in regulated rates the costs capitalized in accordance with this accounting guidance.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2010 were as follows:

- Fossil plant — 18 years;
- Nuclear plant — 17 years;
- Other generation — 25 years;
- Transmission — 40 years;
- Distribution — 35 years; and
- Other — 7 years.

For the years 2008 through 2010, the depreciation rates ranged from a low of 1.30% to a high of 10.20%. The weighted-average rate was 2.98% for 2010, 3.06% for 2009 and 3.08% for 2008. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 34 years.

estments

El Dorado accounts for its investments using either the equity method (if significant influence) or the cost method (if less than 20% ownership).

Our investments in the nuclear decommissioning trust fund are accounted for in accordance with guidance on accounting for certain investments in debt and equity securities. See Note 14 for more information on these investments.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statement of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 9.2% for 2010, 5.9% for 2009 and 7.0% for 2008. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Electric Revenues

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated by applying an average revenue/kWh to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and fuel and purchased power costs.

Effective January 1, 2010, electric revenues also include proceeds for line extension payments for new or upgraded service in accordance with the 2009 retail rate case settlement agreement (see Note 3). This revenue treatment continues through 2012, or until new rates are established in APS's next general retail rate case, if that is before year end 2012. Certain proceeds received under previous versions of the line extension policy, or for activities not involving an extension or upgrade of service (e.g., service relocations at the request of governmental entities or undergrounding of overhead facilities) will continue to be treated as contributions in aid of construction and will not impact electric revenues.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including accrued utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Real Estate Investments

Real estate investments primarily included SunCor's land, home inventory, commercial property and investments in joint ventures. Land included acquisition costs, infrastructure costs, capitalized interest and property taxes directly associated with the acquisition and development of each project. Home inventory consisted of construction costs, improved lot costs, capitalized interest and property taxes on homes and condos under construction. Homes under construction were classified as "real estate investments" on the Consolidated Balance Sheets; upon completion of construction they transferred to "home inventory" with the expectation that they would be sold in a timely manner.

For the purposes of evaluating impairment, in accordance with the provisions on accounting for the impairment or disposal of long-lived assets, we classified our real estate assets, such as land under development, land held for future development, and commercial property as "held and used." When events or changes in circumstances indicated that the carrying values of real estate assets considered held and used would not be recoverable, we compared the undiscounted cash flows that we estimated would be generated by each asset to its carrying amount. If the carrying amount exceeded the undiscounted cash flows, we adjusted the asset to fair value and recognized an impairment charge. The adjusted value became the new book value (carrying amount) for held and used assets. Our internal models used inputs that we believe were consistent with those that would be used by market participants.

Real estate home inventory was considered to be held for sale for purposes of evaluating impairment in accordance with the provisions of accounting guidance for impairment or disposal of long-lived assets. Home inventories were reported at the lower of carrying amount or fair value less costs to sell. Fair value less costs to sell was evaluated each period to determine if it had changed. Losses (and gains not to exceed any cumulative loss previously recognized) were reported as adjustments to the carrying amount.

Investments in joint ventures for which SunCor did not have a controlling financial interest were not consolidated, but were accounted for using the equity method of accounting. In addition, see Note 22 and Note 23.

Cash and Cash Equivalents

We consider all highly liquid investments with a maturity of three months or less at acquisition to be cash equivalents.

Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charges APS $0.001 per kWh of nuclear generation. See Note 11 for information on spent nuclear fuel disposal and Note 14 for information on nuclear decommissioning costs.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes. We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. The income tax liability accounts reflect the tax and interest associated with management's estimate of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement for all known and measurable tax exposures. See Note 4.

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS's software, on Pinnacle West's Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $45 million in 2010, $35 million in 2009 and $33 million in 2008. Estimated amortization expense on existing intangible assets over the next five years is $40 million in 2011, $36 million in 2012, $29 million in 2013, $23 million in 2014 and $15 million in 2015. At December 31, 2010, the weighted average remaining amortization period for intangible assets was 7 years.

2. New Accounting Standards

Variable Interest Entities

On January 1, 2010 we adopted amended accounting guidance relating to the consolidation of VIEs. This amended guidance significantly changed the consolidation model for VIEs. Under the prior guidance the consolidation model considered risk absorption using a quantitative approach when determining the primary beneficiary. The consolidation model under the new guidance requires a qualitative assessment and focuses on the power to direct activities of the VIE when determining the primary beneficiary. As a result of applying this qualitative assessment, we have determined that APS is the primary beneficiary of certain VIEs relating to the Palo Verde Unit 2 sale leaseback transactions, and is therefore required to consolidate these VIEs. Prior to adopting this new guidance, APS was not considered the primary beneficiary of these VIEs and did not consolidate these entities. We have adopted this guidance using retrospective application and have adjusted prior periods presented to reflect consolidation of the VIEs in those periods (see Note 1). See Note 20 for additional discussion and disclosures.

Future Accounting Changes

The FASB is currently working on several projects with the desire to converge GAAP with IFRS. These projects include accounting for leases, revenue recognition, and financial instruments, among other items. The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on our financial statements that may result from any such future changes.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Concurrent with these convergence projects, the SEC is considering mandating IFRS for U.S. companies. At this time, the impacts and timing of potential conversion to IFRS are uncertain and cannot be determined until final conversion requirements are mandated. The potential preparation of our financial statements in accordance with IFRS could have a significant impact on our reported financial statement results.

3. Regulatory Matters

2008 General Retail Rate Case Impacts

On December 30, 2009, the ACC issued an order approving a settlement agreement entered into by APS and twenty-one other parties to its general retail rate case, which was originally filed in March 2008. The settlement agreement included a net retail rate increase of $207.5 million, which represented a base rate increase of $344.7 million less a reclassification of $137.2 million of fuel and purchased power revenues from the then-existing PSA to base rates. The new rates were effective January 1, 2010. The settlement agreement also contained on-going requirements, commitments and authorizations, including the following:

- Revenue accounting treatment for line extension payments received for new or upgraded service from January 1, 2010 through year end 2012 (or until new rates are established in APS's next general rate case, if that is before the end of 2012);
- An authorized return on common equity of 11%;
- A capital structure comprised of 46.2% debt and 53.8% common equity;
- A commitment from APS to reduce average annual operational expenses by at least $30 million from 2010 through 2014;
- Authorization and requirements of equity infusions into APS of at least $700 million during the period beginning June 1, 2009 through December 31, 2014 ($253 million of which was infused into APS from proceeds of a Pinnacle West equity issuance in the second quarter of 2010); and
- Various modifications to the existing energy efficiency, demand-side management and renewable energy programs that require APS to, among other things, expand its conservation and demand-side management programs and its use of renewable energy, as well as allow for concurrent recovery of renewable energy expenses and provide for more concurrent recovery of demand-side management costs and incentives.

The parties also agreed to a rate case filing plan in which APS is prohibited from filing its next two general rate cases until on or after June 1, 2011 and June 1, 2013, respectively, unless certain extraordinary events occur. Subject to the foregoing, APS may not request its next general retail rate increase to be effective prior to July 1, 2012. On February 1, 2011, APS filed a 120-day advanced notice of its intent to file its next rate case on June 1, 2011. The parties agreed to use good faith efforts to process these subsequent rate cases within twelve months of sufficiency findings from the ACC staff, which generally occur within 30 days after the filing of a rate case.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year's RES budget.

During 2009, APS filed its annual RES implementation plan, covering the 2010-2014 timeframe and requesting 2010 RES funding approval. The plan provided for the acquisition of renewable generation in compliance with requirements through 2014, and requested RES funding of $87 million for 2010, which was later approved by the ACC. APS also sought various other determinations in its plan, including approval of the AZ Sun Program and the Community Power Project in Flagstaff, Arizona described below.

On March 3, 2010, the ACC approved the AZ Sun Program, which contemplates the addition of 100 MW of APS-owned solar resources through 2014. Through this program, APS plans to invest up to $500 million in solar photovoltaic projects across Arizona, which APS will acquire through competitive procurement processes. The costs associated with the first 50 MW under this program will be recovered initially through the RES until such time as the costs are recovered in base rates or other mechanisms. The costs of the second 50 MW will be recovered through a mechanism to be determined in APS's next retail rate case.

On April 1, 2010, the ACC approved the Community Power Project, a pilot program in which APS will own, operate and receive energy from approximately 1.5 MW of solar panels on the rooftops of up to 200 residential and business customers located within a certain test area in Flagstaff, Arizona. The capital carrying costs of the program will be recovered through the RES until such time as these costs are recovered in base rates.

On July 1, 2010, APS filed its annual RES implementation plan, covering the 2011-2015 timeframe and requesting 2011 RES funding of $96 million. The 2011 Plan addressed enhancements to the residential distributed energy incentive program based on high customer participation, among other things. On October 13, 2010, APS filed an adjusted RES implementation plan to reflect the following items, among others: 1) increased clarity relating to customer project in-service dates and related budget revisions; 2) AZ Sun Program updates; and 3) the addition of 10 MW of biomass capacity. On December 10, 2010, the ACC approved the 2011 Plan and associated funding request. In January 2011, the ACC voted to reconsider four aspects of the approved 2011 Plan, including: (a) approval to proceed with a feed-in tariff filing; (b) approval for APS to participate in the ownership of distributed energy facilities in the Schools and Government program; (c) denial of a Rapid Reservation program that allows customers to receive priority in the incentive reservation process in exchange for receipt of a reduced incentive amount; and (d) allocation of the budget among various programs and studies. Hearings were held on January 24, 2011 and January 28, 2011. The ACC amended its original decision that approved the 2011 Plan as follows: the ACC (a) reversed its approval of a feed-in tariff program; (b) restricted APS's ownership of facilities to only economically challenged, rural schools and only after a school has received a bid from a third-party solar installer; (c) approved the Rapid Reservation program; and (d) maintained the original approved budget with some timing modifications.

Demand-Side Management Adjustor Charge ("DSMAC"). The 2009 retail rate case settlement agreement requires APS to submit an annual Energy Efficiency Implementation Plan for review by and approval of the ACC. On July 15, 2009, APS filed its initial Energy Efficiency Implementation Plan, requesting approval by the ACC of programs and program elements for which APS had estimated a budget in the amount of $50 million for 2010. APS received ACC approval of all of its proposed programs and implemented the new DSMAC on March 1, 2010. A surcharge was added to customer bills in order to recover these estimated amounts for use on certain demand-side management programs. The surcharge allows for the recovery of energy efficiency expenses and any earned incentives.

The ACC approved recovery of all 2009 program costs plus incentives. The change from program cost recovery on a historical basis to recovery on a concurrent basis, as authorized in the settlement agreement, resulted in this one-time need to address two years (2009 and 2010) of cost recovery. As requested by APS, 2009 program cost recovery is to be spread over a three-year period.

On June 1, 2010, APS filed its 2011 Energy Efficiency Implementation Plan. In order to meet the energy efficiency goal for 2011 established by the settlement agreement of annual energy savings of 1.25%, expressed as a percent of total energy resources to meet retail load, APS proposed a total budget for 2011 of $79 million. On February 17, 2011, a total budget for 2011 of $80 million was approved and when added to the amortization of 2009 costs discussed above less the $10 million already being recovered in general rates, the DSMAC would recover approximately $75 million over a twelve month period beginning March 1, 2011. These amounts do not include approximately $1 million for an electric vehicle charging station program submitted to the ACC for approval on September 30, 2010.

PSA Mechanism and Balance. The PSA, which the ACC initially approved in 2005 as a part of APS's 2003 rate case, and which was modified by the ACC in 2007, provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
- under a 90/10 sharing arrangement, APS defers 90% of the difference between retail fuel and purchased power costs (excluding certain costs, such as renewable energy resources and the capacity components of long-term purchased power agreements acquired through competitive procurement) and the Base Fuel Rate; APS absorbs 10% of the retail fuel and purchased power costs above the Base Fuel Rate and retains 10% of the benefit from the retail fuel and purchased power costs that are below the Base Fuel Rate;

- an adjustment to the PSA rate is made annually each February 1 st (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);
- the PSA rate includes (a) a "Forward Component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "Historical Component," under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and
- the PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2010 and 2009 (dollars in millions):

	Year Ended December 31,	
	2010	2009
Beginning balance	$ (87)	$ 8
Deferred fuel and purchased power costs-current period	(93)	52
Amounts recovered through revenues	122	(147)
Ending balance	$ (58)	$ (87)

The PSA rate for the PSA year beginning February 1, 2011 is ($0.0057) per kWh as compared to ($0.0045) per kWh for the prior year. The regulatory liability at December 31, 2010 reflects lower average prices, primarily for natural gas and gas-based generation. Any uncollected (overcollected) deferrals during the 2011 PSA year will be included in the historical component of the PSA rate for the PSA year beginning February 1, 2012.

Transmission Rates and Transmission Cost Adjustor . In July 2008, the FERC approved an Open Access Transmission Tariff for APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS's retail customers ("Retail Transmission Charges"). In order to recover the Retail Transmission Charges, APS must file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and have a significant effect on the Retail Transmission Charge because any adjustment, though applied prospectively, may be calculated to account for previously over-collected amounts.

Effective June 1, 2010, APS's annual wholesale transmission rates for all users of its transmission system were reduced by approximately $12 million in accordance with the FERC-approved formula as a result of lower costs reflected in the formula. Approximately $10 million of this revenue reduction relates to transmission services used for APS's retail customers. On May 20, 2010, APS filed with the ACC an application for the related reduction of its TCA rate. The ACC approved the TCA reduction on July 27, 2010.

Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in millions):

	December 31,	
	2010	2009
Pension and other postretirement benefits (Note 8)	$ 669	$ 532
Deferred fuel and purchased power — mark-to-market (Note 18)	77	41
Deferred income taxes (Note 4)	72	59
Transmission vegetation management	46	34
Coal reclamation	38	16
Palo Verde VIE (Note 20)	33	31
Deferred compensation	32	31
Tax expense of Medicare subsidy (Note 8)	23	—
Loss on reacquired debt	22	23
Demand side management (a)	18	18
Other	19	28
Total regulatory assets (b)	$ 1,049	$ 813

(a) See Cost Recovery Mechanisms discussion above.

(b) There are no regulatory assets for which regulators have allowed recovery of costs but not allowed a return by exclusion from rate base.

Included in the balance of regulatory assets at December 31, 2010 and 2009 is a regulatory asset for pension and other postretirement benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The detail of regulatory liabilities is as follows (dollars in millions):

	December 31, 2010	December 31, 2009
Removal costs (Note 1) (a)	$ 379	$ 385
Asset retirement obligations (Note 12)	184	156
Deferred fuel and purchased power (b)(c)	58	87
Renewable energy standard (b)	50	51
Spent nuclear fuel (Note 11)	45	34
Deferred gains on utility property	18	20
Tax benefit of Medicare subsidy (Note 8)	—	17
Other	19	16
Total regulatory liabilities	$ 753	$ 766

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal.

(b) See Cost Recovery Mechanisms discussion above.

(c) Subject to a carrying charge.

4. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction and pension and other postretirement benefits. The regulatory liabilities relate to deferred taxes resulting primarily from investment tax credits. APS amortizes these amounts as the differences reverse.

Pinnacle West expects to recognize approximately $132 million of cash tax benefits related to SunCor's strategic asset sales (see Note 23), a majority of which have been realized as of December 31, 2010. Approximately $7 million of these benefits were recorded in 2010 as reductions to income tax expense related to the current impairment charges. The additional $125 million of tax benefits were recorded as reductions to income tax expense related to SunCor impairment charges recorded on or before December 31, 2009.

The $68 million income tax receivables on the Consolidated Balance Sheets represent the anticipated refunds related to an APS tax accounting method change approved by the IRS in the third quarter of 2009 and the current year tax benefits related to the SunCor strategic asset sales that closed in 2010. A majority of this amount is classified as long-term, as cash refunds are not expected to be received in the next twelve months.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	2010	2009	2008
Total unrecognized tax benefits, January 1	$ 201,216	$ 63,318	$ 157,869
Additions for tax positions of the current year	7,551	44,094	12,923
Additions for tax positions of prior years	—	98,942	32,510
Reductions for tax positions of prior years for:			
Changes in judgment	(11,017)	—	(4,454)
Settlements with taxing authorities	(62,199)	(4,089)	(35,812)
Lapses of applicable statute of limitations	(7,956)	(1,049)	(99,718)
Total unrecognized tax benefits, December 31	$ 127,595	$ 201,216	$ 63,318

During the first quarter of 2010, the Company reached a settlement with the IRS with regard to the examination of tax returns for the years ended December 31, 2005 through 2007. As a result of this settlement, net uncertain tax positions decreased $62 million, including approximately $3 million which decreased our effective tax rate. Additionally, the settlement resulted in the recognition of net interest benefits of approximately $4 million through the effective tax rate.

Included in the balances of unrecognized tax benefits at December 31, 2010, 2009 and 2008 were approximately $7 million, $16 million and $16 million, respectively, of tax positions that, if recognized, would decrease our effective tax rate.

As of the balance sheet date, the tax year ended December 31, 2008 and all subsequent tax years remain subject to examination by the IRS. With few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 1999. We do not anticipate that there will be any significant increases or decreases in our unrecognized tax benefits within the next twelve months.

We reflect interest and penalties, if any, on unrecognized tax benefits in the Consolidated Statements of Income as income tax expense. The amount of interest recognized in the Consolidated Statement of Income related to unrecognized tax benefits was a pre-tax benefit of $2 million for 2010, a pre-tax expense of $2 million for 2009 and a pre-tax benefit of $51 million for 2008.

The total amount of accrued liabilities for interest recognized in the consolidated Balance Sheets related to unrecognized tax benefits was $6 million as of December 31, 2010, $8 million as of December 31, 2009 and $6 million as of December 31, 2008. To the extent that matters are settled favorably, this amount could reverse and decrease our effective tax rate. Additionally, as of December 31, 2010, we have recognized $5 million of interest income to be received on the overpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of income tax expense are as follows (dollars in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ (108,827)	$ (38,502)	$ (85,866)
State	25,545	(38,080)	11,738
Total current	(83,282)	(76,582)	(74,128)
Deferred:			
Income from continuing operations	271,147	105,492	158,024
Discontinued operations	(10,736)	—	—
Total deferred	260,411	105,492	158,024
Total income tax expense	177,129	28,910	83,896
Less: income tax expense (benefit) on discontinued operations	12,808	(107,596)	(11,648)
Income tax expense — continuing operations	$ 164,321	$ 136,506	$ 95,544

The following chart compares pretax income from continuing operations at the 35% federal income tax rate to income tax expense — continuing operations (dollars in thousands):

	Year Ended December 31,		
	2010	2009	2008
Federal income tax expense at 35% statutory rate	$ 180,222	$ 136,172	$ 130,858
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	17,878	14,837	12,640
Credits and favorable adjustments related to prior years resolved in current year	(17,300)	—	(28,873)
Medicare Subsidy Part-D (see Note 8)	1,311	(2,095)	(1,993)
Allowance for equity funds used during construction (see Note 1)	(6,563)	(4,265)	(5,755)
Palo Verde VIE noncontrolling interest (see Note 20)	(7,057)	(6,723)	(6,123)
Other	(4,170)	(1,420)	(5,210)
Income tax expense — continuing operations	$ 164,321	$ 136,506	$ 95,544

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	December 31, 2010	December 31, 2009
Current asset	$ 94,602	$ 53,990
Long-term liability	(1,833,566)	(1,496,095)
Deferred income taxes — net	$ (1,738,964)	$ (1,442,105)

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31, 2010	December 31, 2009
DEFERRED TAX ASSETS		
Risk management activities	$ 124,731	$ 87,404
Regulatory liabilities:		
Asset retirement obligation and removal costs	222,448	213,814
Deferred fuel and purchased power	23,089	34,463
Renewable energy standard	18,749	—
Other	28,360	21,613
Pension and other postretirement liabilities	321,182	306,515
Real estate investments and assets held for sale	19,855	113,082
Renewable energy incentives	37,327	—
Credit and loss carryforwards	42,971	3,423
Other	68,684	57,015
Total deferred tax assets	907,396	837,329
DEFERRED TAX LIABILITIES		
Plant-related	(2,210,976)	(1,951,262)
Risk management activities	(30,125)	(20,863)
Regulatory assets:		
Allowance for equity funds used during construction	(28,276)	(23,285)
Deferred fuel and purchased power — mark-to-market	(30,276)	(16,167)
Pension and other postretirement benefits	(264,313)	(210,080)
Other	(77,078)	(57,210)
Other	(5,316)	(567)
Total deferred tax liabilities	(2,646,360)	(2,279,434)
Deferred income taxes — net	$ (1,738,964)	$ (1,442,105)

A majority of the deferred tax assets for credit and loss carryforwards relate to federal general business credits and federal net operating losses. These federal credits and losses first begin to expire in 2029.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for the commercial paper programs. During the first quarter of 2010, Pinnacle West and APS refinanced revolving credit facilities existing at the time that would have otherwise matured in December 2010. Since March 2010, Pinnacle West and APS have accessed the commercial paper markets, which neither company had utilized since the third quarter of 2008 due to negative market conditions.

The table below presents these credit facilities and amounts available and outstanding and other short-term borrowings as of December 31, 2010 (dollars in millions):

Credit Facility	Expiration	Amount Committed	Letters of Credit Used	Short-Term Borrowings	Unused Amount	Weighted Average Interest Rate	Commitment Fees
PNW Revolving Credit Facility	February 2013	$ 200	$ —	$ —	$ 183	—	0.625%
PNW Commercial Paper	January 2011	—	—	17	—	0.840%	—
APS Revolving Credit Facility	February 2013	500	—	—	500	—	0.500%
APS Revolving Credit Facility	September 2011	489	20	—	469	—	0.100%
Total		$ 1,189	$ 20	$ 17	$ 1,152		

Pinnacle West

On February 12, 2010, Pinnacle West refinanced its $283 million revolving credit facility that would have matured in December 2010, and decreased the size of the facility to $200 million. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. Pinnacle West will use the facility for general corporate purposes, commercial paper program support of up to $200 million, or for the issuance of letters of credit. Interest rates are based on Pinnacle West's senior unsecured debt credit ratings.

APS

On February 12, 2010, APS refinanced its $377 million credit facility that would have matured in December 2010, and increased the size of the facility to $500 million. APS may increase the amount of the facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use the facility for general corporate purposes, commercial paper program support and for the issuance of letters of credit. Interest rates are based on APS's senior unsecured debt credit ratings.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On February 14, 2011, APS refinanced its $489 million revolving credit facility that would have matured in September 2011, and increased the size of the facility to $500 million. The new revolving credit facility terminates in February 2015. APS may increase the amount of the facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use the facility for general corporate purposes, commercial paper program support and for the issuance of letters of credit. Interest rates are based on APS's senior unsecured debt credit ratings.

At December 31, 2010, APS had two credit facilities totaling $989 million, consisting of the $500 million and $489 million credit facilities described above. These facilities were available either to support the issuance of up to $250 million in commercial paper, or for bank borrowings, including issuances of letters of credit. See Note 21 for discussion of APS's letters of credit.

SunCor

SunCor had no short-term borrowings at December 31, 2010 and approximately $5 million at December 31, 2009.

The table below presents the consolidated credit facilities and amounts available and outstanding and other short-term borrowings as of December 31, 2009 (dollars in millions):

Credit Facility	Expiration	Amount Committed	Short-Term Borrowings	Unused Amount	Weighted Average Interest Rate	Commitment Fees
PNW Revolving Credit Facility	December 2010	$ 283	$ 149	$ 134	0.982%	0.15%
APS Revolving Credit Facility	December 2010	377	—	377	—	0.11%
APS Revolving Credit Facility	September 2011	489	—	489	—	0.10%
SunCor Short-term Borrowings	January 2010	—	5	—	LIBOR plus 2.50%	—
Total		$ 1,149	$ 154	$ 1,000		

Pinnacle West

At December 31, 2009, the Pinnacle West credit facility was available to support the issuance of up to $250 million in commercial paper or bank borrowings, including issuances of letters of credit, up to $94 million. At December 31, 2009, Pinnacle West had borrowings of approximately $149 million under its credit facility, no letters of credit and no other short-term borrowings.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

APS

At December 31, 2009, the APS credit facilities were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including issuances of letters of credit, up to $583 million. At December 31, 2009, APS had no borrowings or letters of credit under its revolving credit facilities or other short-term borrowings.

Debt Provisions

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On October 30, 2007, the ACC issued a financing order in which it approved APS's request, subject to specified parameters and procedures, to increase (a) APS's short-term debt authorization from 7% of APS's capitalization to (i) 7% of APS's capitalization plus (ii) $500 million (which is required to be used for purchases of natural gas and power) and (b) APS's long-term debt authorization from approximately $3.2 billion to $4.2 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs. This financing order expires December 31, 2012; however, all debt previously authorized and outstanding on December 31, 2012 will remain authorized and valid obligations of APS.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Long-Term Debt and Liquidity Matters

Substantially all of Pinnacle West's and APS's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2010 and 2009 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2010	December 31, 2009
APS				
Pollution control bonds — Variable	2024-2038	(b)	$ 43,580	$ 222,880
Pollution control bonds — Fixed	2029-2034	(c)	522,275	342,975
Pollution control bonds with senior notes	2029	5.05%	90,000	90,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2014	5.80%	300,000	300,000
Unsecured notes	2015	4.650%	300,000	300,000
Unsecured notes	2016	6.25%	250,000	250,000
Unsecured notes	2019	8.75%	500,000	500,000
Unsecured notes	2033	5.625%	200,000	200,000
Unsecured notes	2035	5.50%	250,000	250,000
Unsecured notes	2036	6.875%	150,000	150,000
Secured note	2014	6.00%	—	1,075
Palo Verde sale leaseback lessor notes	2015	8.00%	126,000	151,783
Unamortized discount			(6,183)	(7,185)
Capitalized lease obligations	2011-2012	(d)	2,001	2,837
Subtotal (e)			3,502,673	3,529,365
SUNCOR				
Notes payable	2011	(f)	—	95,535
Capitalized lease obligations	2011-2012	(g)	—	100
Subtotal			—	95,635
PINNACLE WEST				
Senior notes	2011	5.91%	175,000	175,000
Total long-term debt			3,677,673	3,800,000
Less current maturities:				
APS			456,879	222,959
SunCor			—	80,517
Pinnacle West			175,000	—
Total			631,879	303,476
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 3,045,794	$ 3,496,524

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.

(b) The weighted-average rate for the variable rate pollution control bonds was 0.32% at December 31, 2010 and 0.25% at December 31, 2009.

(c) The bonds fixed rate of interest ranged from 2.875% to 6.00% at December 31, 2010. The bonds fixed interest ranged from 5.00% to 6.00% at December 31, 2009. Approximately $343 million are subject to mandatory tender dates. See discussion of the refinancing of pollution control bonds below.

(d) The weighted-average interest rate was 5.29% at December 31, 2010 and 5.50% at December 31, 2009.

(e) APS's long-term debt less current maturities was $3.046 billion at December 31, 2010 and $3.306 billion at December 31, 2009.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(f) SunCor had no debt outstanding at December 31, 2010 and $57 million outstanding at December 31, 2009 under its secured revolver that matured on January 30, 2010. The weighted average interest rate at December 31, 2009 was 5.00%. SunCor had no debt outstanding at December 31, 2010 and $39 million at December 31, 2009 of other debt under other long-term facilities. At December 31, 2009, the remaining debt was primarily classified as current maturities of long-term debt and consisted of multiple notes with variable interest rates of prime plus 2.00% and LIBOR plus 1.70%, 2.00%, 2.25% and 2.50%.

(g) The weighted-average interest rate was 4.90% December 31, 2009.

Credit Facilities and Debt Issuances

Pinnacle West

In June 2010, Pinnacle West received approximately $100 million related to the sale of APSES' district cooling business. The net proceeds were used to repay short-term indebtedness.

APS

On July 13, 2010, APS changed the interest rate mode for the approximately $33 million of Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Bonds (Arizona Public Service Company Navajo Project) 1994 Series A, due 2029. The rate period for the bonds changed from a daily rate mode, supported by a letter of credit, to a three-year term rate mode that will bear interest at a rate of 3.625% per annum for three years. The letter of credit was terminated in connection with this change, and there is no bank or other third-party credit support for the bonds in the term rate mode.

On August 10, 2010, APS changed the letter of credit supporting the approximately $17 million of Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Bonds (Arizona Public Service Company Project) Series 1998, due 2033. The bonds were in a daily rate mode supported by a prior letter of credit and remain in a daily rate mode, supported by a new three-year letter of credit expiring in August 2013.

On October 12, 2010, APS changed the interest rate mode for the approximately $147 million of City of Farmington, New Mexico Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Four Corners Project) 1994 Series A and 1994 Series B, due 2024 and City of Farmington, New Mexico Pollution Control Revenue Bonds (Arizona Public Service Company Four Corners Project) 1994 Series C, due 2024. The rate period for the 1994 Series A bonds and the 1994 Series B bonds changed from a daily rate mode, supported by letters of credit, to a term rate mode to maturity, subject to optional redemption after year ten, that will bear interest at a rate of 4.70% per annum until maturity in 2024 unless the optional redemption is exercised by APS. The rate period for the 1994 Series C bonds changed from a daily rate mode, supported by a letter of credit, to a three-year term rate mode that will bear interest at a rate of 2.875% per annum until October 2013. The letters of credit supporting each of these three series of bonds were terminated in connection with these changes, and there is no bank or other third-party credit support for any of these bonds.

On January 1, 2010, due to the adoption of amended accounting guidance relating to VIEs, APS began consolidating the Palo Verde Sale Leaseback Trusts. As a result of consolidation of these VIEs, APS has reported the Lessor Trusts' long-term debt on its Consolidated Balance Sheets. Interest rates on these debt instruments are 8% and are fixed for the remaining life of the debt. As of December 31, 2010, approximately $29 million was classified as current maturities of long-term debt and approximately $97 million was classified as long-term debt relating to these VIEs. These debt instruments mature on December 30, 2015 and have sinking fund features that are serviced by the lease payments. See Note 20 for additional discussion of the VIEs.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SunCor

In 2010, SunCor sold land parcels, commercial assets and master planned home-building communities for approximately $72 million, which approximated the carrying value of these assets, resulting in a net gain of zero. In connection with these sales, SunCor negotiated a restructuring of certain of its credit facilities. The debt restructuring resulted in an after-tax gain of approximately $10 million. At December 31, 2010, SunCor had no debt outstanding.

Debt Provisions

Pinnacle West's and APS's debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant and each anticipates it will continue to meet this and other significant covenant requirements. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2010, the ratio was approximately 49% for Pinnacle West and 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

Neither Pinnacle West's nor APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS's bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2010, APS's common equity ratio, as defined, was 53%. Its total shareholder equity was approximately $3.8 billion, and total capitalization was approximately $7.2 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $2.9 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing capital requirements.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows principal payments due on Pinnacle West's and APS's total long-term debt and capitalized lease requirements (dollars in millions):

Year	Consolidated Pinnacle West	Consolidated APS
2011	$ 632	$ 457
2012	477	477
2013	140	140
2014	502	502
2015	313	313
Thereafter	1,620	1,620
Total	$ 3,684	$ 3,509

7. Common Stock and Treasury Stock

Our common stock and treasury stock activity during each of the three years 2010, 2009 and 2008 is as follows (dollars in thousands):

	Common Stock		Treasury Stock	
	Shares	Amount	Shares	Amount
Balance at December 31, 2007	100,525,470	$ 2,135,787	(39,505)	$ (2,054)
Common stock issuance	422,966	10,845	—	—
Purchase of treasury stock (a)	—	—	(39,022)	(1,387)
Reissuance of treasury stock for stock compensation	—	—	18,700	587
Other	—	4,691	—	—
Balance at December 31, 2008	100,948,436	2,151,323	(59,827)	(2,854)
Common stock issuance	579,501	10,620	—	—
Purchase of treasury stock (a)	—	—	(66,173)	(2,156)
Reissuance of treasury stock for stock compensation	—	—	32,761	1,198
Other	—	(8,648)	—	—
Balance at December 31, 2009	101,527,937	2,153,295	(93,239)	(3,812)
Common stock issuance (b)	7,292,130	263,297	—	—
Purchase of treasury stock (a)	—	—	(1,994)	(82)
Reissuance of treasury stock for stock compensation	—	—	44,823	1,655
Other	—	4,780	—	—
Balance at December 31, 2010	108,820,067	$ 2,421,372	(50,410)	$ (2,239)

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

(b) In April 2010, Pinnacle West issued 6,900,000 shares of common stock at an offering price of $38.00 per share, resulting in net proceeds of approximately $253 million. Pinnacle West contributed all of the net proceeds from this offering into APS in the form of equity infusions. APS has used these contributions to repay short-term indebtedness, to finance capital expenditures and for other general corporate purposes.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Retirement Plans and Other Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. Generally, we calculate the benefits based on age, years of service and pay.

We also sponsor other postretirement benefits for the employees of Pinnacle West and our subsidiaries. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 14 for discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset. In its 2009 retail rate case settlement, APS received approval to defer a portion of pension and other postretirement benefit cost increases incurred in 2011 and 2012.

On March 23, 2010, the President signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act (the "Act"). One feature of the Act is the elimination of the tax deduction for prescription drug costs that are reimbursed as part of the Medicare Part D subsidy. Although this tax increase does not take effect until 2013, we are required to recognize the full accounting impact in our financial statements in the period in which the Act is signed. In accordance with accounting for regulated companies, the loss of this deduction is substantially offset by a regulatory asset that will be recovered through future electric revenues. In the first quarter of 2010, Pinnacle West charged regulatory assets and liabilities for a total of $42 million, with a corresponding increase in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants) (dollars in thousands):

	Pension			Other Benefits		
	2010	2009	2008	2010	2009	2008
Service cost-benefits earned during the period	$ 59,064	$ 54,288	$ 54,576	$ 19,236	$ 18,285	$ 17,793
Interest cost on benefit obligation	122,724	118,282	110,207	42,428	39,180	37,897
Expected return on plan assets	(124,161)	(116,535)	(118,309)	(39,257)	(34,428)	(43,609)
Amortization of:						
Transition obligation	—	—	—	452	3,005	3,005
Prior service cost (credit)	1,705	2,080	2,455	(539)	(125)	(125)
Net actuarial loss	18,833	14,216	11,145	10,317	10,320	2,372
Net periodic benefit cost	$ 78,165	$ 72,331	$ 60,074	$ 32,637	$ 36,237	$ 17,333
Portion of cost charged to expense	$ 37,933	$ 36,484	$ 28,854	$ 15,839	$ 18,278	$ 8,325
APS share of cost charged to expense	$ 36,840	$ 34,850	$ 27,491	$ 15,382	$ 17,459	$ 7,932

The following table shows the plans' changes in the benefit obligations and funded status for the years 2010 and 2009 (dollars in thousands):

	Pension		Other Benefits	
	2010	2009	2010	2009
Change in Benefit Obligation				
Benefit obligation at January 1	$ 2,074,131	$ 1,884,656	$ 700,535	$ 655,265
Service cost	59,064	54,288	19,236	18,285
Interest cost	122,724	118,282	42,428	39,180
Benefit payments	(93,776)	(77,577)	(20,421)	(18,959)
Actuarial loss	183,365	94,482	98,094	6,764
Plan amendments	(448)	—	(11,975)	—
Benefit obligation at December 31	2,345,060	2,074,131	827,897	700,535
Change in Plan Assets				
Fair value of plan assets at January 1	1,461,808	1,430,372	490,455	429,306
Actual return on plan assets	190,380	96,511	60,255	61,101
Employer contributions	200,000	—	16,700	15,506
Benefit payments	(76,592)	(65,075)	—	(15,458)
Fair value of plan assets at December 31	1,775,596	1,461,808	567,410	490,455
Funded Status at December 31	$ (569,464)	$ (612,323)	$ (260,487)	$ (210,080)

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the projected benefit obligation and the accumulated benefit obligation for the pension plan in excess of plan assets as of December 31, 2010 and 2009 (dollars in thousands):

	2010	2009
Projected benefit obligation	$ 2,345,060	$ 2,074,131
Accumulated benefit obligation	2,065,091	1,824,661
Fair value of plan assets	1,775,596	1,461,808

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2010 and 2009 (dollars in thousands):

	Pension		Other Benefits	
	2010	2009	2010	2009
Current liability	$ (16,830)	$ (11,065)	$ —	$ —
Noncurrent liability	(552,634)	(601,258)	(260,487)	(210,080)
Net amount recognized	$ (569,464)	$ (612,323)	$ (260,487)	$ (210,080)

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2010 and 2009 (dollars in thousands):

	Pension		Other Benefits	
	2010	2009	2010	2009
Net actuarial loss	$ 502,938	$ 404,619	$ 261,071	$ 194,301
Prior service cost (credit)	5,712	7,865	(4,571)	(794)
Transition obligation	—	—	903	9,015
APS's portion recorded as a regulatory asset	(419,774)	(336,728)	(249,255)	(195,389)
Income tax benefit	(35,106)	(29,902)	(2,498)	(2,095)
Accumulated other comprehensive loss	$ 53,770	$ 45,854	$ 5,650	$ 5,038

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2011 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$ 25,660	$ 13,736
Prior service cost (credit)	1,400	(539)
Transition obligation	—	452
Total amounts estimated to be amortized from accumulated other comprehensive income and regulatory assets in 2011	$ 27,060	$ 13,649

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,		
	2010	2009	2010	2009	2008
Discount rate-pension	5.31%	5.90%	5.90%	6.11%	6.25%
Discount rate-other benefits	5.49%	6.00%	6.00%	6.13%	6.31%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	N/A	N/A	8.25%	8.25%	9.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	8.00%	8.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Number of years to ultimate trend rate	4	4	4	4	4

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2011, we are assuming a 7.75% long-term rate of return on plan assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. In selecting our health care trend rate, we consider past performance and forecasts of health care costs. A one percentage point change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 9	$ (8)
Effect on service and interest cost components of net periodic other postretirement benefit costs	12	(9)
Effect on the accumulated other postretirement benefit obligation	134	(107)

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

n Assets

The Board of Directors has delegated oversight of the plans' assets to an Investment Management Committee, which has adopted an investment policy. The investment policy's overall strategy is to achieve an adequate level of trust assets relative to the benefit obligation. To achieve this objective, the plans' investment policies provide for a mix of investments in long-term fixed income assets and return-generating assets. Long-term fixed income assets are designed to offset changes in benefit obligations due to changes in discount rates and inflation. Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. The determination of total allocation between return-generating and long-term fixed income assets is reviewed on at least an annual basis. Other investment strategies include the prohibition of investments in Pinnacle West securities and the external management of the plans' assets.

Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury, other government agencies, and corporations. Long-term fixed income assets may also include interest rate swaps, U.S. Treasury futures and other instruments. The investment policy does not provide for a specific mix of long-term fixed income assets, but does require the average credit rating of such assets to be considered upper medium grade or above. The 2010 year-end long-term fixed income asset strategy focused on investments in corporate bonds of primarily investment-grade U.S. issuers and long-term treasuries, with total long-term fixed income assets representing 41% of total pension plan assets and 39% of other benefit plans assets.

Return-generating assets in the pension plan and other benefit plans target a mix of approximately 64% U.S. equities, 27% international equities, and 9% alternative investments. The 2010 year-end U.S. equity holdings were invested primarily in large-cap companies in diverse industries. International equities include investments in emerging and developing markets. Return-generating assets also include investments in securities through commingled funds in common and collective trusts. Alternative investments primarily include investments in real estate. The 2010 year-end return-generating assets represented 59% of total pension plan assets and 61% of other benefit plans assets.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

See Note 14 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2010, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Netting and Other (a)	Balance at December 31, 2010
Pension Plan:				
Assets:				
Cash and cash equivalents	$ 2,375	$ —	$ —	$ 2,375
Debt Securities:				
Corporate	—	508,946	—	508,946
U.S. Treasury	163,313	—	—	163,313
Other (b)	—	53,358	—	53,358
Equities:				
U.S. Companies	462,973	—	—	462,973
International Companies	129,094	—	—	129,094
Other investments	—	5,549	8,071	13,620
Common and collective trusts:				
U.S. Equities	—	146,705	—	146,705
International Equities	—	177,114	—	177,114
Real estate	—	92,454	—	92,454
Short-term investments	—	25,644	—	25,644
Total Pension Plan	$ 757,755	$ 1,009,770	$ 8,071	$ 1,775,596
Other Benefits:				
Assets:				
Cash and cash equivalents	$ 243	$ —	$ —	$ 243
Debt Securities:				
Corporate	—	118,660	—	118,660
U.S. Treasury	74,049	—	—	74,049
Other (b)	—	24,456	—	24,456
Equities:				
U.S. Companies	179,655	—	—	179,655
International Companies	25,121	—	—	25,121
Other investments	—	365	2,034	2,399
Common and collective trusts:				
U.S. Equities	—	54,144	—	54,144
International Equities	—	61,455	—	61,455
Real Estate	—	7,357	—	7,357
Short-term investments	—	19,871	—	19,871
Total Other Benefits	$ 279,068	$ 286,308	$ 2,034	$ 567,410

(a) Represents netting of plan receivables and payables.

(b) This category consists primarily of municipal securities.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2009, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting and Other (a)	Balance at December 31, 2009
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 519	$ —	$ —	$ —	$ 519
Debt Securities:					
Corporate	—	590,343	—	—	590,343
Other (b)	—	66,281	—	—	66,281
Interest rate swaps	—	20,512	—	(20,103)	409
Equities:					
U.S. Companies	341,318	—	—	—	341,318
International Companies	83,492	—	—	—	83,492
Other investments	—	6,747	—	10,177	16,924
Common and collective trusts:					
U.S. Equities	—	144,016	—	—	144,016
International Equities	—	132,168	—	—	132,168
Real estate	—	—	64,212	—	64,212
Short-term investments	—	22,126	—	—	22,126
Liabilities:					
Interest rate swaps	—	(20,103)	—	20,103	—
Total Pension Plan	$ 425,329	$ 962,090	$ 64,212	$ 10,177	$ 1,461,808
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 156	$ —	$ —	$ —	$ 156
Debt Securities:					
Corporate	—	173,895	—	—	173,895
Other (b)	—	20,280	—	—	20,280
Interest rate swaps	—	2,091	—	(2,049)	42
Equities:					
U.S. Companies	170,293	—	—	—	170,293
International Companies	9,721	—	—	—	9,721
Other investments	—	383	—	(785)	(402)
Common and collective trusts:					
U.S. Equities	—	49,363	—	—	49,363
International Equities	—	52,670	—	—	52,670
Real Estate	—	—	6,504	—	6,504
Short-term investments	—	7,933	—	—	7,933
Liabilities:					
Interest rate swaps	—	(2,049)	—	2,049	—
Total Other Benefits	$ 180,170	$ 304,566	$ 6,504	$ (785)	$ 490,455

(a) Represents netting under master netting arrangements and plan receivables and payables.

(b) This category consists primarily of municipality issued debt securities, but also includes U.S. Treasuries and asset-backed securities such as collateralized mortgage obligations.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2010 and December 31, 2009 (dollars in thousands):

	Year Ended December 31, 2010		Year Ended December 31, 2009	
Common and Collective Trusts — Real Estate	Pension	Other Benefits	Pension	Other Benefits
Beginning balance at January 1	$ 64,212	$ 6,504	$ 88,379	$ 8,951
Actual return on assets still held (a)	(204)	(23)	(29,590)	(2,991)
Purchases, sales, and settlements	18,003	45	5,423	544
Transfers in and/or out of Level 3 (b)	(82,011)	(6,526)	—	—
Ending balance at December 31	$ —	$ —	$ 64,212	$ 6,504

(a) The return for December 31, 2010 represents the return on assets held as of March 31, 2010, the beginning of the period in which all the assets were transferred out of Level 3. The return for December 31, 2009 represents the return on assets held as of December 31, 2009, as no transfers occurred into or out of Level 3 during the year.

(b) Transfers into and out of Level 3 are measured at the beginning of the period in which the transfer occurs. Transfers out of Level 3 during 2010 relate to our Real Estate Common and Collective Trust being transferred to a Level 2 investment. During 2009 the Real Estate Common and Collective Trust had special redemption restrictions in place, which limited our ability to transact at the fund's net asset value. During 2010 these special redemption restrictions were lifted, and we were able to transact in the fund at the net asset value according to the fund's normal redemption policy.

Contributions

The required minimum contribution to our pension plan is zero in 2011 and approximately $85 million in 2012. In 2010, we made voluntary contributions of $200 million to our pension plan. The contribution to our other postretirement benefit plans in 2010 was approximately $17 million. The contributions to our other postretirement benefit plans for 2011 and 2012 are expected to be approximately $20 million each year. APS and other subsidiaries fund their share of the contributions. APS's share is approximately 98% of both plans.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

timated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter are estimated to be as follows (dollars in thousands):

Year	Pension	Other Benefits (a)
2011	$ 106,556	$ 23,197
2012	116,615	25,713
2013	129,031	28,619
2014	141,815	31,484
2015	154,185	34,176
Years 2016-2020	972,338	216,736

(a) The expected future other benefit payments take into account the Medicare Part D subsidy.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2010, costs related to APS's employees represented 98% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own future contributions. Pinnacle West recorded expenses for this plan of approximately $9 million for 2010, $9 million for 2009 and $8 million for 2008.

9. Leases

We lease certain vehicles, land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $23 million in 2010, $28 million in 2009 and $28 million in 2008. APS's lease expense was $19 million in 2010, $19 million in 2009 and $21 million in 2008.

Estimated future minimum lease payments for Pinnacle West's and APS's operating leases, excluding purchased power agreements, are approximately as follows (dollars in millions):

Year	Pinnacle West Consolidated	APS
2011	$ 24	$ 20
2012	21	17
2013	17	14
2014	14	11
2015	13	10
Thereafter	9	7
Total future lease commitments	$ 98	$ 79

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Nuclear Generating Station ("Palo Verde") Unit 2 and related common facilities. Prior to January 1, 2010 the arrangements were accounted for as operating leases. On January 1, 2010, due to the adoption of amended accounting guidance related to VIE's these agreements were deemed variable interests and consolidated. We adopted this accounting change using retrospective application and have adjusted prior periods presented. Consolidation of the lessor trust entities eliminates the lease accounting we previously reported and results in changes in our consolidated assets, debt, equity, and net income. The above disclosures exclude the impacts of these transactions, as lease accounting for these agreements is eliminated upon consolidation. See Note 20 for a discussion of VIEs.

10. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. Our share of operations and maintenance expense and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2010 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:				
Palo Verde Units 1 and 3	29.1%	$ 2,056,977	$ 1,112,159	$ 58,272
Palo Verde Unit 2 (a)	17.0%	705,996	342,640	28,162
Palo Verde Sale Leaseback	(a)	351,050	213,094	—
Four Corners Units 4 and 5	15.0%	167,076	102,918	1,971
Four Corners common	28.3%	11,585	5,738	531
Navajo Generating Station Units 1, 2 and 3	14.0%	260,590	163,281	11,041
Cholla common facilities (b)	63.3%(c)	140,041	48,815	3,229
Transmission facilities:				
ANPP 500KV System	34.0%(c)	85,359	27,211	4,863
Navajo Southern System	26.1%(c)	50,021	14,022	20
Palo Verde — Yuma 500KV System	43.5%(c)	9,408	4,165	1,462
Four Corners Switchyards	47.5%(c)	8,691	2,721	2,810
Phoenix — Mead System	17.5%(c)	39,153	14,670	287
Palo Verde — Estrella 500KV System	50.0%(c)	85,622	7,469	805
North Valley System	71.2%(c)	69,497	293	24,113
Round Valley System	50.0%(c)	—	—	66

(a) See Notes 9 and 20.

(b) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

(c) Weighted average of interests.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

APS currently estimates it will incur $132 million (in 2010 dollars) over the current life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. At December 31, 2010, APS had a regulatory liability of $45 million that represents amounts recovered in retail rates in excess of amounts spent for on-site interim spent fuel storage.

Nuclear Insurance

The Palo Verde participants are insured against public liability for a nuclear incident up to $12.6 billion per occurrence. As required by the Price Anderson Nuclear Industries Indemnity Act, Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by commercial insurance carriers. The remaining balance of $12.2 billion is provided through a mandatory industry wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $118 million, subject to an annual limit of $18 million per incident, to be periodically adjusted for inflation. Based on APS's interest in the three Palo Verde units, APS's maximum potential assessment per incident for all three units is approximately $103 million, with an annual payment limitation of approximately $15 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $16 million for each retrospective assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $44 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to purchase obligations and various fuel and purchased power contracts with terms expiring between 2011 and 2042 that include required purchase provisions. APS estimates the contract requirements to be approximately $594 million in 2011; $529 million in 2012; $419 million in 2013; $544 million in 2014; $526 million in 2015; and $7.2 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the various fuel and purchased power contracts mentioned above, some of those contracts have take-or-pay provisions. The contracts APS has for its coal supply include take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2024.

The following table summarizes our actual and estimated take-or-pay commitments (dollars in millions):

	Actual			Estimated (a)					
	2008	2009	2010	2011	2012	2013	2014	2015	Thereafter
Coal take-or-pay commitments	$ 81	$ 93	$ 66	$ 76	$ 78	$ 80	$ 82	$ 85	$ 204

(a) Total take-or-pay commitments are approximately $605 million. The total net present value of these commitments is approximately $435 million.

Renewable Energy Credits

APS has entered into contracts to purchase renewable energy credits to comply with the Renewable Energy Standard. APS estimates the contract requirements to be approximately $57 million in 2011; $20 million in 2012; $20 million in 2013; $20 million in 2014; $20 million in 2015; and $196 million thereafter.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS's coal mine reclamation obligation was approximately $117 million at December 31, 2010 and $92 million at December 31, 2009.

FERC Market Issues

On July 25, 2001, the FERC ordered an evidentiary proceeding to discuss and evaluate possible refunds for wholesale sales in the Pacific Northwest. The FERC affirmed the administrative law judge's conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision was appealed to the U.S. Court of Appeals for the Ninth Circuit. On August 24, 2007, the Ninth Circuit issued an opinion that remanded the proceeding to the FERC for further consideration. Although the FERC has not yet determined whether any refunds will ultimately be required, we do not expect that the resolution of these issues will have a material adverse impact on our financial position, results of operations or cash flows.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Superfund

Superfund establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, the EPA advised APS that the EPA considers APS to be a PRP in the Motorola 52 nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with the EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with the EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan. We estimate that our costs related to this investigation and study will be approximately $1 million, which is reserved as a liability on our financial statements. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time we cannot accurately estimate our total expenditures.

Landlord Bankruptcy

On April 16, 2009, the landlord for our corporate headquarters building announced that it is seeking relief under Chapter 11 of the United States Bankruptcy Code. We currently have several assets on our books related to our landlord, the most significant of which is an asset related to levelized rent payments for the building of approximately $71 million. This amount will continue to increase to approximately $93 million as a result of the lease terms until 2015, when this amount will begin to decrease over the remaining life of the lease. In November 2010, our landlord exited bankruptcy and our leases were assumed and reinstated. This matter is now closed.

12. Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets. The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing tions of those plants at the end of the plant life or lease term.

Some of APS's transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such distribution and transmission assets.

Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites. The asset retirement obligations associated with our non-regulated assets are immaterial.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following schedule shows the change in our asset retirement obligations for 2010 and 2009 (dollars in millions):

	2010	2009
Asset retirement obligations at the beginning of year	$ 302	$ 276
Changes attributable to:		
Liabilities settled	—	(1)
Accretion expense	22	20
Estimated cash flow revisions	5	7
Asset retirement obligations at the end of year	$ 329	$ 302

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

13. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2010 and 2009 is as follows (dollars in thousands, except per share amounts):

	2010 Quarter Ended				2010
	March 31, (a)	June 30,	September 30,	December 31,	Total
Operating revenues	$ 620,355	$ 820,594	$ 1,139,085	$ 683,611	$ 3,263,645
Operations and maintenance	207,842	215,104	221,469	232,991	877,406
Operating income	57,668	203,273	403,625	59,318	723,884
Income taxes	(7,172)	51,829	123,486	(3,822)	164,321
Income from continuing operations	11,983	94,584	231,828	12,203	350,598
Net income (loss) attributable to common shareholders	(6,014)	114,797	233,920	7,350	350,053
Basic earnings per share:					
Income from continuing operations attributable to common shareholders	$ 0.07	$ 0.84	$ 2.09	$ 0.07	$ 3.10
Net income (loss) attributable to common shareholders	(0.06)	1.07	2.15	0.07	3.28
Diluted earnings per share:					
Income from continuing operations attributable to common shareholders	$ 0.07	$ 0.83	$ 2.08	$ 0.06	$ 3.08
Net income (loss) attributable to common shareholders	(0.06)	1.07	2.14	0.07	3.27

(a) The March 31, 2010 results were adjusted for the effect of reclassifications for discontinued operations. The adjustments resulted in a reduction in operating revenues of $13,236, a reduction in operations and maintenance of $2,149, an increase in operating income of $20,034, an increase in income taxes of $8,308, and an increase in income from continuing operations of $12,755. The adjustments also resulted in an increase in income from continuing operations basic and diluted earnings per share of $0.13.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	2009 Quarter Ended				2009
	March 31,	June 30,	September 30,	December 31,	Total
As originally reported in the 2009 10-K:					
Operating revenues	$ 625,867	$ 835,972	$ 1,142,205	$ 693,057	$ 3,297,101
Operations and maintenance	207,531	226,245	208,769	232,812	875,357
Operating income (loss)	(204,923)	162,007	345,397	19,292	321,773
Income taxes	(95,004)	39,579	103,507	(10,255)	37,827
Income (loss) from continuing operations	(165,993)	74,027	188,065	(28,868)	67,231
Net income (loss) attributable to common shareholders	(156,510)	68,347	186,652	(30,159)	68,330
Palo Verde VIE reclassifications (see Note 20):					
Operations and maintenance	$ (9,915)	$ (9,914)	$ (9,916)	$ (9,915)	$ (39,660)
Operating income	7,989	7,989	7,989	7,989	31,956
Income from continuing operations	4,650	4,651	4,953	4,955	19,209
Discontinued operations reclassifications (see Note 22):					
Operating revenues	$ (18,489)	$ (17,384)	$ (53,169)	$ (32,149)	$ (121,191)
Operations and maintenance	(790)	(786)	(823)	(1,435)	(3,834)
Operating income	220,888	1,898	14,021	19,617	256,424
Income taxes	81,820	1,421	6,271	9,167	98,679
Income from continuing operations	140,651	2,352	10,310	12,805	166,118
After reclassifications:					
Operating revenues	$ 607,378	$ 818,588	$ 1,089,036	$ 660,908	$ 3,175,910
Operations and maintenance	196,826	215,545	198,030	221,462	831,863
Operating income	23,954	171,894	367,407	46,898	610,153
Income taxes	(13,184)	41,000	109,778	(1,088)	136,506
Income (loss) from continuing operations	(20,692)	81,030	203,328	(11,108)	252,558
Net income (loss) attributable to common shareholders	(156,510)	68,347	186,652	(30,159)	68,330

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	2009 Quarter Ended				2009
	March 31,	June 30,	September 30,	December 31,	Total
As originally reported in the 2009 10-K — Basic earnings per share:					
Income (loss) from continuing operations attributable to common shareholders	$ (1.50)	$ 0.73	$ 1.86	$ (0.29)	$ 0.81
Net income (loss) attributable to common shareholders	(1.55)	0.68	1.84	(0.30)	0.68
After reclassifications — Basic earnings per share:					
Income (loss) from continuing operations attributable to common shareholders	$ (0.25)	$ 0.76	$ 1.96	$ (0.16)	$ 2.31
Net income (loss) attributable to common shareholders	(1.55)	0.68	1.84	(0.30)	0.68
As originally reported in the 2009 10-K— Diluted earnings per share:					
Income (loss) from continuing operations attributable to common shareholders	$ (1.50)	$ 0.74	$ 1.86	$ (0.29)	$ 0.81
Net income (loss) attributable to common shareholders	(1.55)	0.68	1.84	(0.30)	0.67
After reclassifications — Diluted earnings per share:					
Income (loss) from continuing operations attributable to common shareholders	$ (0.25)	$ 0.75	$ 1.96	$ (0.16)	$ 2.30
Net income (loss) attributable to common shareholders	(1.55)	0.68	1.84	(0.30)	0.67

14. Fair Value Measurements

We disclose the fair value of certain assets and liabilities according to a fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes derivative instruments that are exchange-traded such as futures, cash equivalents invested in exchange-traded money market funds, exchange-traded equities, and nuclear decommissioning trust investments in Treasury securities.

Level 2 — Quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable. This category includes nonexchange-traded contracts such as forwards, options, and swaps. This category also includes investments, in common and commingled funds that are redeemable and valued based on the funds' net asset values.

Level 3 — Model-derived valuations with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where models are required due to the length of the transaction, options, transactions in locations where observable market data does not exist, and common and collective trusts with significant restrictions on our ability to transact in the fund. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We maximize the use of observable inputs and minimize the use of unobservable inputs. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market transactions, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market transactions, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Recurring Fair Value Measurements

We apply recurring fair value measurements to derivative instruments, nuclear decommissioning trusts, certain cash equivalents and plan assets held in our retirement and other benefit plans (see Note 8).

Cash Equivalents

Cash equivalents represent short-term investments in exchange-traded money market funds that are valued using quoted prices in active markets.

Risk Management Activities

Exchange-traded contracts are valued using quoted prices in active markets. For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

The credit valuation adjustment represents estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities, local distribution companies and financial institutions. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty.

Some of our derivative instrument transactions are valued based on unobservable inputs due to the long-term nature of contracts or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near term portion and unobservable valuations for the long-term portions of the transaction. When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions, and is not reflective of material inactive markets.

Nuclear Decommissioning Trust

The nuclear decommissioning trust invests in fixed income securities directly and equity securities indirectly through commingled funds. The commingled equity funds are valued based on the fund's net asset value ("NAV") and are classified within Level 2. We may transact in the fund on a semi-monthly basis. Our trustee provides valuation of our nuclear decommissioning trust assets by using pricing services to determine fair market value. We assess these valuations and verify that pricing can be supported by actual recent market transactions. The trust fund investments have been established to satisfy APS's nuclear decommissioning obligations.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

The following table presents the fair value at December 31, 2010 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in millions):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Counterparty Netting & Other (b)	Balance at December 31, 2010
Assets					
Cash equivalents	$ 35	$ —	$ —	$ —	$ 35
Risk management activities:					
Commodity contracts	—	80	61	(28)	113
Nuclear decommissioning trust:					
Equity securities:					
U.S. commingled funds	—	168	—	—	168
Fixed income securities:					
U.S. Treasury	50	—	—	—	50
Cash and cash equivalent funds	—	22	—	—	22
Corporate	—	60	—	—	60
Mortgage-backed	—	81	—	—	81
Municipality	—	79	—	—	79
Other	—	20	—	(10)	10
Total	$ 85	$ 510	$ 61	$ (38)	$ 618
Liabilities					
Risk management activities:					
Commodity contracts	$ (1)	$ (280)	$ (99)	$ 256	$ (124)

(a) Primarily consists of long-dated electricity contracts.

(b) Risk management activities represent netting under master netting arrangements, including margin and collateral. See Note 18. Nuclear decommissioning trust represents net pending securities sales and purchases.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2009 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in millions):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Counterparty Netting & Other (b)	Balance at December 31, 2009
Assets					
Cash equivalents	$ 97	$ —	$ —	$ —	$ 97
Risk management activities:					
Commodity contracts	1	100	42	(64)	79
Nuclear decommissioning trust:					
Equity securities:					
U.S. commingled funds	—	167	—	—	167
Fixed income securities:					
U.S. Treasury	55	—	—	—	55
Corporate	—	62	—	—	62
Mortgage-backed	—	60	—	—	60
Municipality	—	49	—	—	49
Other	—	21	—	1	22
Total	$ 153	$ 459	$ 42	$ (63)	$ 591
Liabilities					
Risk management activities:					
Commodity contracts	$ (14)	$ (246)	$ (52)	$ 194	$ (118)

(a) Primarily consists of long-dated electricity contracts.

(b) Primarily represents netting under master netting arrangements, including margin and collateral. See Note 18.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2010 and 2009 (dollars in millions):

	Year Ended December 31,	
	2010	2009
Net risk management activities at beginning of period	$ (10)	$ (7)
Total net gains (losses) realized/unrealized:		
Included in earnings	(1)	3
Included in OCI	(14)	(2)
Deferred as a regulatory asset or liability	(38)	19
Settlements	19	(2)
Transfers into Level 3 from Level 2	5	(25)
Transfers from Level 3 into Level 2	1	4
Net risk management activities at end of period	$ (38)	$ (10)
Net unrealized gains (losses) included in earnings related to instruments still held at end of period	$ (1)	$ 3

Amounts included in earnings are recorded in either regulated electricity segment revenue or regulated electricity segment fuel and purchased power depending on the nature of the underlying contract.

Transfers reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Nonrecurring Fair Value Measurements

We may be required to record other assets at fair value on a nonrecurring basis. These nonrecurring fair value measurements typically involve write-downs of individual assets due to impairment.

Financial Instruments Not Carried at Fair Value

The carrying value of our net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our long-term debt fair value estimates are based on quoted market prices of the same or similar issues. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table represents the carrying amount and estimated fair value of our long-term debt, including current maturities (dollars in millions):

	As of December 31, 2010		As of December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 175	$ 176	$ 175	$ 180
APS	3,503	3,737	3,530	3,674
SunCor	—	—	95	96
Total	$ 3,678	$ 3,913	$ 3,800	$ 3,950

Nuclear Decommissioning Trust

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per their stated investment guidelines. The trust funds are invested in fixed income securities and domestic equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Consolidated Balance Sheets. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have recorded the offsetting amount of gains or losses on investment securities in other regulatory liabilities or assets . The following table summarizes the fair value of APS's nuclear decommissioning trust fund assets at December 31, 2010 and December 31, 2009 (dollars in millions):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
2010			
Equity securities	$ 168	$ 43	$ (1)
Fixed income securities	312	12	(2)
Net payables (a)	(10)	—	—
Total	$ 470	$ 55	$ (3)

(a) Net payables relate to pending securities sales and purchases.

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
2009			
Equity securities	$ 167	$ 37	$ (6)
Fixed income securities	247	11	(1)
Net receivables (a)	1	—	—
Total	$ 415	$ 48	$ (7)

(a) Net receivables relate to pending securities sales and purchases.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in millions):

	Year Ended December 31,		
	2010	2009	2008
Realized gains	$ 17	$ 10	$ 7
Realized losses	(4)	(7)	(8)
Proceeds from the sale of securities (a)	560	441	318

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2010 is as follows (dollars in millions):

	Fair Value
Less than one year	$ 25
1 year - 5 years	58
5 years - 10 years	102
Greater than 10 years	127
Total	$ 312

15. Earnings Per Share

The following table presents earnings per weighted-average common share outstanding for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Basic earnings per share:			
Income from continuing operations attributable to common shareholders	$ 3.10	$ 2.31	$ 2.59
Income (loss) from discontinued operations	0.18	(1.63)	(0.19)
Earnings per share — basic	$ 3.28	$ 0.68	$ 2.40
Diluted earnings per share:			
Income from continuing operations attributable to common shareholders	$ 3.08	$ 2.30	$ 2.58
Income (loss) from discontinued operations	0.19	(1.63)	(0.18)
Earnings per share — diluted	$ 3.27	$ 0.67	$ 2.40

Dilutive stock options and performance shares (which are contingently issuable) increased average common shares outstanding by approximately 565,000 shares in 2010, 103,000 shares in 2009 and 274,000 shares in 2008. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 107,137,785 shares in 2010, 101,263,795 shares in 2009 and 100,964,920 shares in 2008.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Options to purchase 192,542 shares of common stock during 2010 were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 572,301 during 2009 and 687,375 during 2008.

16. Stock-Based Compensation

We have a 2007 long-term incentive plan ("2007 Plan") that allows the Company to grant restricted stock, restricted stock units, performance shares, stock grants, incentive and stock options, stock appreciation rights, performance share units, performance cash awards, dividend equivalents and stock to eligible individuals.

Restricted Stock Unit Awards and Stock Grants

Stock grants were issued to non-officer members of the Board of Directors in 2009 and 2008 under the 2007 Plan and were paid in fully transferable shares of stock. In 2010, non-officer members of the Board of Directors were given the option to elect to receive a stock grant, or to defer receipt and receive restricted stock units in lieu of the stock grant. The 2010 stock grants and deferred restricted stock units were issued under the 2007 Plan. The election to receive a stock grant or to defer, and the related elections were made on or before December 31, 2009. Participants had to elect to receive their deferred grant as of the last business day of the month following the month in which they separate service from the Board of Directors, or as of a date specified by them in 2011 or later. The deferral has the election to receive payment in either 50% cash and 50% fully transferable shares of stock, or 100% in fully transferable shares of stock, in exchange for each restricted stock unit. Each restricted stock unit payable in cash represents the right to receive a cash payment equal to the fair market value of one share of Pinnacle West's common stock. The deferral will also include dividend equivalent payments in either 50% cash and 50% fully-transferable shares of stock or in 100% fully-transferable shares of stock per the participant's election equal to the amount of dividends that they would have received if the participant had owned the stock to which the restricted stock units relate from the date of grant to the date of payment plus interest.

Restricted stock unit awards were granted to officers and key employees in 2010, 2009 and 2008 under the 2007 Plan. For 2009 and 2008 officers and key employees elected to receive payment in either cash or in fully transferable shares of stock, in exchange for each restricted stock unit on pre-established valuation dates. For the 2010 award the election for the awards is either 50% cash and 50% fully transferable shares of stock, or 100% in fully transferable shares of stock, in exchange for each restricted stock unit. Each restricted stock unit payable in cash represents the right to receive a cash payment equal to the fair market value of one share of Pinnacle West's common stock.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted stock unit awards vest and settle in annual installments over a four-year period. In addition, officers and key employees will receive a cash payment equal to the amount of dividends that they would have received if they had owned the stock to which the restricted stock units relate from the date of grant to the date of payment plus interest. For the 2010 award the officers and key employees will receive either a 50% cash payment and 50% fully transferrable shares of stock, or 100% in fully transferable shares of stock equal to the amount of dividends that they would have received if they had owned the stock to which the restricted stock units relate from the date of grant to the date of payment plus interest. The dividend equivalents payout election has to be the same as the election for the payout of restricted stock units. For any employee that was eligible to retire before the settlement date, the employee's restricted stock unit awards vest by retirement date and the compensation expense is recognized by retirement eligibility. As the restricted stock unit award is accounted for as a liability award, compensation costs, initially measured based on the Company's stock price on the grant date, are remeasured at each balance sheet date, using Pinnacle West's closing stock price.

Restricted stock unit awards were granted to a selected set of key employees of Pinnacle West on October 21, 2008, February 18, 2009, March 18, 2009, April 13, 2009, July 29, 2009, January 19, 2010, February 22, 2010, April 1, 2010 and November 2, 2010 under the 2007 Plan. The award of the restricted stock units follows the same vesting schedule as the 2007, 2008, 2009 and 2010 restricted stock unit awards.

The following table is a summary of granted restricted stock units and stock grants and the weighted average fair value for the three years ended 2010, 2009 and 2008:

	2010	2009	2008
Units granted	202,341	261,006	224,658
Grant date fair value (a)	$ 37.47	$ 30.25	$ 36.26

(a) weighted average fair value

The following table is a summary of the status of restricted stock units and stock grants, as of December 31, 2010 and changes during the year. This table represents only the stock portion of restricted stock units, per the election on payment discussed in the paragraph above:

Nonvested shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2010	145,339	$ 33.57
Granted	146,391	37.46
Vested	59,409	35.16
Forfeited	8,640	34.18
Nonvested at December 31, 2010	223,681	35.69

The amount of cash required to settle the payment for the 2007 grant on February 20, 2010, February 20, 2009 and February 20, 2008 was $0.9 million, $0.8 million and $1.0 million respectively. The amount of cash required to settle the payment for the 2008 grant on February 20, 2010 and February 20, 2009 was $1.5 million and $1.3 million respectively. The amount of cash required to settle the payment for the 2009 grant on February 20, 2010 was $1.4 million.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Performance Share Awards

Performance share awards were granted to officers and key employees in 2010, 2009 and 2008 under the 2007 Plan. Performance share awards for 2008 contain performance criteria that affect the number of shares ultimately received. Generally, each recipient of performance shares is entitled to receive shares of common stock after the end of a three-year performance period. The number of shares each recipient ultimately receives, if any, is based upon the percentile ranking of Pinnacle West's earnings per share growth rate at the end of the three-year period as compared with the earnings per share growth rate of all relevant companies in a specified utilities index.

Performance share awards for 2009 also contain performance criteria that affect the number of shares that ultimately vest; 50% of the award is based on the same percentile ranking as the 2008 award and the other 50% of the award is based on six non-financial separate performance metrics.

Performance share awards for 2010 also contain performance criteria that affects the number of shares that ultimately vest; 50% of the award is based upon the percentile ranking of Pinnacle West's total shareholder return at the end of the three-year performance period as compared with the total shareholder return of all relevant companies in a specified utilities index and the other 50% of the award is based on six non-financial separate performance metrics.

For any employee that was eligible to retire before the settlement date, the employee's performance share awards vest by retirement date and the compensation expense is recognized by retirement eligibility. Performance share awards are accounted for as liability awards, as employees are not required to withhold at the minimum statutory required rate. Compensation costs, initially measured based on the Company's stock price on the grant date, are remeasured at each balance sheet date, using Pinnacle West's closing stock price. Management also evaluates the probability of meeting the performance criteria at each balance sheet date. If the goals are not achieved, no compensation cost is recognized and any previously recognized compensation cost is reversed.

Performance shares were granted to officers and key employees of Pinnacle West on October 21, 2008, February 18, 2009, March 18, 2009, April 13, 2009, July 29, 2009, January 19, 2010, February 22, 2010, April 1, 2010 and November 2, 2010 under the 2007 Plan.

The following table is a summary of the Performance shares granted and the weighted average fair value for the three years ended 2010, 2009 and 2008:

	2010	2009	2008
Units granted	178,722	240,624	226,242
Grant date fair value (a)	$ 37.57	$ 30.19	$ 36.24

(a) weighted average grant date fair value

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table is a summary of the status of performance shares, as of December 31, 2010 and changes during the year:

Nonvested shares	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at January 1, 2010	358,943	$ 32.34
Granted	178,722	37.57
Vested	127,673	36.29
Forfeited	14,680	33.20
Nonvested at December 31, 2010	395,312	33.44

Retention Units

The retention unit awards have fully vested and settled on January 4, 2010; for any employee that was eligible to retire before that date, the employee's retention units vested by retirement date and the compensation expense was recognized by retirement eligibility. Retention unit awards were granted to key employees in 2006 and 2007. Each retention unit award represented the right to receive a cash payment equal to the fair market value of one share of Pinnacle West's common stock, determined on pre-established valuation dates. Each retention unit award vested and settled in equal annual installments over a four-year period. In addition, the employee received a cash payment equal to the amount of dividends that the employee would have received if the employee had owned the stock from the date of grant to the date of payment plus interest. As this award was accounted for as a liability award, compensation costs, initially measured based on the Company's stock price on the grant date, were remeasured at each balance sheet date, using Pinnacle West's closing stock price.

The amount of cash to settle the payment on the first business day of 2010 was $1.3 million, 2009 was $1.1 million, and 2008 was $1.3 million.

Incentive Shares

On January 21, 2009, the Human Resources Committee approved under the 2007 Plan payment of 2008 incentive awards to ficers in the form of a Pinnacle West common stock grant. A total of 138,756 shares were issued for this stock grant with a grant date fair value of $32.58 per share. The stock grant was included in stock compensation expense in 2008.

Stock Options

We have issued stock options in the past, but have not granted stock options since 2004. The term of outstanding options cannot be longer than 10 years and options cannot be repriced during their terms.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the option activity under our equity incentive plans for the year ended December 31, 2010:

Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (dollars in thousands)
Outstanding at January 1, 2010	432,699	$ 41.20		
Exercised	119,725	38.03		
Forfeited or expired	230,750	43.50		
Outstanding at December 31, 2010	82,224	39.37	1.3	$ 225
Exercisable at December 31, 2010	82,224	39.37	1.3	$ 225

Cash received from options exercised under our share-based payment arrangements was $4.6 million for 2010, $3 million for 2009, and zero for 2008. The tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements were immaterial for 2010 and 2009, and zero for 2008.

The intrinsic value of options exercised was immaterial for 2010 and 2009, and zero for 2008.

As of December 31, 2010, there was $13.5 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted under the plans. That cost is expected to be recognized over a weighted-average period of 2.0 years. The total fair value of shares vested during 2010 was $11 million, 2009 was $10 million, and 2008 was $5 million.

We have reserved 8 million shares of common stock for issuance under the 2007 Plan. Under the 2007 Plan, any shares of stock that are potentially deliverable under the 2002 long term incentive plan will be added to the number of shares available for grant under the 2007 Plan if the award is cancelled, forfeited, or terminated such that those shares are returned to the Company.

The compensation cost that has been charged against Pinnacle West's income for share-based compensation plans was $15 million in 2010, $5 million in 2009, and $8 million in 2008. The compensation cost that Pinnacle West has capitalized is immaterial for 2010, 2009 and 2008. Pinnacle West's total income tax benefit recognized in the Consolidated Statements of Income for share-based compensation arrangements was $6 million in 2010, $2 million in 2009, and $3 million in 2008. APS's share of compensation cost that has been charged against income was $15 million in 2010, $4 million in 2009, and $7 million in 2008.

Pinnacle West's current policy is to issue new shares to satisfy share requirements for stock compensation plans and it does not expect to repurchase any shares except to satisfy tax withholding obligations upon the vesting of restricted stock during 2011.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Business Segments

Pinnacle West's reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Our reportable business segments reflect a change from previously reported information. As of December 31, 2010, our real estate activities are no longer considered a segment requiring separate reporting or disclosure. In 2009 our real estate subsidiary, SunCor, began disposing of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt (see Note 23). The remaining assets held for sale at December 31, 2010 were approximately $3 million. Additionally, all of SunCor's operations are reflected in discontinued operations.

Financial data for 2010, 2009 and 2008 is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2010		
	Regulated Electricity Segment	All other (a)	Total
Operating revenues	$ 3,181	$ 83	$ 3,264
Fuel and purchased power costs	1,047	—	1,047
Other operating expenses	1,009	69	1,078
Operating margin	1,125	14	1,139
Depreciation and amortization	415	—	415
Interest expense	226	2	228
Other expense (income)	(22)	3	(19)
Income from continuing operations before income taxes	506	9	515
Income taxes	161	3	164
Income from continuing operations	345	6	351
Income from discontinued operations — net of income tax expense of $13 million (see Note 22)	—	19	19
Net income	345	25	370
Less: Net income attributable to noncontrolling interests	20	—	20
Net income attributable to common shareholders	$ 325	$ 25	$ 350
Total assets	$ 12,255	$ 108	$ 12,363
Capital expenditures	$ 666	$ 4	$ 670

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Business Segments for the Year Ended December 31, 2009		
	Regulated Electricity Segment	All other (a)	Total
Operating revenues	$ 3,149	$ 27	$ 3,176
Fuel and purchased power costs	1,179	—	1,179
Other operating expenses	948	32	980
Operating margin	1,022	(5)	1,017
Depreciation and amortization	407	—	407
Interest expense	226	1	227
Other expense (income)	(16)	10	(6)
Income (loss) from continuing operations before income taxes	405	(16)	389
Income taxes	143	(7)	136
Income (loss) from continuing operations	262	(9)	253
Loss from discontinued operations — net of income tax benefit of $108 million (see Note 22)	—	(180)	(180)
Net income (loss)	262	(189)	73
Less: Net income (loss) attributable to noncontrolling interests	19	(14)	5
Net income (loss) attributable to common shareholders	$ 243	$ (175)	$ 68
Total assets	$ 11,691	$ 295	$ 11,986
Capital expenditures	$ 732	$ 13	$ 745

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Business Segments for the Year Ended December 31, 2008		
	Regulated Electricity Segment	All other (a)	Total
Operating revenues	$ 3,127	$ 93	$ 3,220
Fuel and purchased power costs	1,284	46	1,330
Other operating expenses	888	28	916
Operating margin	955	19	974
Depreciation and amortization	391	—	391
Interest expense	204	1	205
Other expense (income)	(5)	9	4
Income from continuing operations before income taxes	365	9	374
Income taxes	92	4	96
Income from continuing operations	273	5	278
Loss from discontinued operations — net of income tax benefit of $12 million (see Note 22)	—	(19)	(19)
Net income (loss)	273	(14)	259
Less: Net income attributable to noncontrolling interests	17	—	17
Net income (loss) attributable to common shareholders	$ 256	$ (14)	$ 242
Total assets	$ 11,137	$ 669	$ 11,806
Capital expenditures	$ 856	$ 48	$ 904

(a) All other activities relate to SunCor, APSES and El Dorado. Income from discontinued operations for 2010 is primarily related to the APSES sale of its district cooling business. Loss from discontinued operations for 2009 and 2008 is primarily related to real estate impairment charges at SunCor (see Note 23). In addition, income from discontinued operations for 2008 includes the resolution of certain tax issues associated with the sale of Silverhawk in 2005. None of these segments is a reportable business segment.

18. Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various derivative instruments, including futures, forwards, options and swaps. As part of our overall risk management program, we may use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. Derivative instruments that are designated as cash flow hedges are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We may also invest in derivative instruments for trading purposes; however, for the year ended December 31, 2010, there was no material trading activity.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our derivative instruments are accounted for at fair value; see Note 14 for a discussion of fair value measurements. Derivative instruments for the physical delivery of purchase and sale quantities transacted in the normal course of business qualify for the normal purchase and sales scope exception and are accounted for under the accrual method of accounting. Due to the scope exception, these derivative instruments are excluded from our derivative instrument discussion and disclosures below.

We also enter into derivative instruments for economic hedging purposes. While we believe the economic hedges mitigate exposure to fluctuations in commodity prices, some of these instruments may not meet the specific hedge accounting requirements and are not designated as accounting hedges. Economic hedges not designated as accounting hedges are recorded at fair value on our balance sheet with changes in fair value recognized in the statement of income as incurred. These instruments are included in the "non-designated hedges" discussion and disclosure below.

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of accumulated other comprehensive income ("AOCI") and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As of December 31, 2010, we hedged the majority of certain exposures to the price variability of commodities for a maximum of 39 months.

In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and fuel and purchased power costs in our Consolidated Statements of Income, but this does not impact our financial condition, net income or cash flows.

For its regulated operations, APS defers for future rate treatment approximately 90% of unrealized gains and losses on certain derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2010, we had the following outstanding gross notional amount of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	13,530,414	megawatt hours
Gas	141,493,336	MMBtu

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments in Designated Accounting Hedging Relationships

The following table provides information about gains and losses from derivative instruments in designated accounting hedging relationships and their impact on our Consolidated Statements of Income during the year ended December 31, 2010 and December 31, 2009 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2010	Year Ended December 31, 2009
Amount of Loss Recognized in AOCI on Derivative Instruments (Effective Portion)	Accumulated other comprehensive loss-derivative instruments	$ (155,287)	$ (155,325)
Amount of Loss Reclassified from AOCI into Income (Effective Portion Realized)	Regulated electricity segment fuel and purchased power	(122,740)	(185,329)
Amount of Gain (Loss) Recognized in Income from Derivative Instruments (Ineffective Portion and Amount Excluded from Effectiveness Testing) (a)	Regulated electricity segment fuel and purchased power	3,680	(19,902)

(a) During the year ended December 31, 2009, $192 thousand was reclassified from AOCI to earnings related to discontinued cash flow hedges. This amount was zero in 2010.

During the next twelve months, we estimate that a net loss of $106 million before income taxes will be reclassified from AOCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, certain of these amounts will be recorded as either a regulatory asset or liability and have no effect on earnings.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments Not Designated as Accounting Hedges

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments and their impact on our Consolidated Statements of Income during the year ended December 31, 2010 and December 31, 2009 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2010	Year Ended December 31, 2009
Amount of Net Gain Recognized in Income from Derivative Instruments	Regulated electricity segment revenue	$ 1,436	$ 2,484
Amount of Net Loss Recognized in Income from Derivative Instruments	Regulated electricity segment fuel and purchased power expense	(107,690)	(16,740)
Total		$ (106,254)	$ (14,256)

Fair Values of Derivative Instruments in the Consolidated Balance Sheets

The following table provides information about the fair value of our derivative instruments, margin account and cash collateral reported on a gross basis. Transactions with counterparties that have master netting arrangements are reported net on the balance sheet. These amounts are located in the assets and liabilities from risk management activities lines of our Consolidated Balance Sheets. Amounts are as of December 31, 2010 (dollars in thousands):

Commodity Contracts	Current Assets	Investments and Other Assets	Current Liabilities	Deferred Credits and Other	Total Assets (Liabilities)
Derivatives designated as accounting hedging instruments:					
Assets	$ 1,234	$ 142	$ 9,062	$ 4,913	$ 15,351
Liabilities	(602)	(1,933)	(107,784)	(71,109)	(181,428)
Total hedging instruments	632	(1,791)	(98,722)	(66,196)	(166,077)
Derivatives not designated as accounting hedging instruments:					
Assets	36,831	40,927	27,322	19,886	124,966
Liabilities	(312)	(33)	(112,535)	(85,473)	(198,353)
Total non-hedging instruments	36,519	40,894	(85,213)	(65,587)	(73,387)
Total derivatives	37,151	39,103	(183,935)	(131,783)	(239,464)
Margin account	24,579	—	997	—	25,576
Collateral provided to counterparties	11,556	—	125,367	66,393	203,316
Collateral provided from counterparties	(1,750)	—	(1,250)	—	(3,000)
Prepaid option premiums and other	2,252	(71)	(155)	—	2,026
Balance Sheet Total	$ 73,788	$ 39,032	$ (58,976)	$ (65,390)	$ (11,546)

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides information about the fair value of our derivative instruments, margin account and cash collateral reported on a gross basis at December 31, 2009 (dollars in thousands):

Commodity Contracts	Current Assets	Investments and Other Assets	Current Liabilities	Deferred Credits and Other	Total Assets (Liabilities)
Derivatives designated as accounting hedging instruments:					
Assets	$ 329	$ —	$ 3,242	$ 75	$ 3,646
Liabilities	(3,436)	(256)	(72,899)	(77,953)	(154,544)
Total hedging instruments	(3,107)	(256)	(69,657)	(77,878)	(150,898)
Derivatives not designated as accounting hedging instruments:					
Assets	31,220	29,807	34,645	44,631	140,303
Liabilities	(4,123)	(696)	(81,722)	(71,408)	(157,949)
Total non-hedging instruments	27,097	29,111	(47,077)	(26,777)	(17,646)
Total derivatives	23,990	28,855	(116,734)	(104,655)	(168,544)
Margin account	8,643	—	12,464	104	21,211
Collateral provided to counterparties	17,986	—	49,412	42,108	109,506
Collateral provided from counterparties	—	—	(1,050)	—	(1,050)
Balance Sheet Total	$ 50,619	$ 28,855	$ (55,908)	$ (62,443)	$ (38,877)

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including two counterparties for which our exposure represents approximately 44% of Pinnacle West's $113 million of risk management assets as of December 31, 2010. This exposure relates to long-term traditional wholesale contracts with counterparties that have very high credit quality. Our risk management process assesses and monitors the financial exposure of all counterparties. Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position on December 31, 2010 was $349 million, for which we had posted collateral of $192 million in the normal course of business.

For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's), which would be a violation of the credit rating provisions. If the investment grade contingent features underlying these agreements had been triggered on December 31, 2010, after off-setting asset positions under master netting arrangements we would have been required to post approximately an additional $125 million of collateral to our counterparties; this amount includes those contracts which qualify for scope exceptions, which are excluded from the derivative details in the above footnote. We also have energy related non-derivative instrument contracts with investment grade credit-related contingent features which could also require us to post additional collateral of approximately $205 million if our debt credit ratings were to fall below investment grade.

19. Other Income and Other Expense

The following table provides detail of other income and other expense for 2010, 2009 and 2008 (dollars in thousands):

	2010	2009	2008
Other income:			
Interest income	$ 3,255	$ 1,617	$ 7,539
Investment gains — net	2,778	2,516	—
Miscellaneous	335	1,145	2,002
Total other income	$ 6,368	$ 5,278	$ 9,541
Other expense:			
Non-operating costs	$ (6,649)	$ (6,593)	$ (13,030)
Investment losses — net	—	—	(17,702)
Miscellaneous	(3,115)	(7,676)	(844)
Total other expense	$ (9,764)	$ (14,269)	$ (31,576)

20. Variable-Interest Entities

See Note 2 for a discussion of the amended accounting guidance relating to VIEs adopted on January 1, 2010.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Palo Verde Sale Leaseback Trusts

In 1986, APS entered into agreements with three separate VIE lessor trusts in order to sell and lease back interests in Palo Verde Nuclear Generating Station ("Palo Verde") Unit 2 and related common facilities. The VIE lessor trusts are single-asset leasing entities. APS will pay approximately $49 million per year for the years 2010 to 2015 related to these leases. The leases do not contain fixed price purchase options or residual value guarantees. However, the lease agreements include fixed rate renewal periods which may have a significant impact on the VIEs' economic performance. We have concluded that these fixed rate renewal periods may give APS the ability to utilize the asset for a significant portion of the asset's economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. In addition to the fixed rate renewal periods, our primary beneficiary analysis also considered that APS is the operating agent for Palo Verde, is obligated to decommission the leased assets and has fair value purchase options.

Under the previous quantitative VIE consolidation model, APS was not considered the primary beneficiary of the lessor trusts, as APS did not absorb the majority of the entities' expected losses or did not receive a majority of the residual returns. Prior to January 1, 2010 the arrangements were accounted for as operating leases.

Consolidation of these VIEs eliminates the lease accounting we previously reported and results in changes in our consolidated assets, debt, equity, and net income. Assets of the VIEs are restricted and may only be used to settle the VIEs' debt obligations and for payment to the noncontrolling interest holders. Other than the VIEs' assets now reported on our consolidated financial statements, the creditors of the VIEs have no other recourse to the assets of APS or Pinnacle West, except in certain circumstances such as a default by APS under the lease. As a result of consolidation we have eliminated rent expense, and have recognized depreciation and interest expense, resulting in an increase in net income for 2010 of $20 million entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders remains the same. Consolidation of these VIEs also results in changes to our Consolidated Statements of Cash Flows, but does not impact net cash flows.

Our Consolidated Balance Sheets at December 31, 2010 and December 31, 2009 include the following amounts relating to the VIEs (in millions):

	December 31, 2010	December 31, 2009
Property plant and equipment, net of accumulated depreciation	$ 138	$ 147
Long-term debt including current maturities	126	152
Equity- Noncontrolling interests	91	82

For regulatory ratemaking purposes the leases continue to be treated as operating leases and, as a result, we have recorded a regulatory asset of $33 million as of December 31, 2010 and $31 million at December 31, 2009.

APS is exposed to losses relating to these lessor trust VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants, assume the VIEs' debt, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2010, APS would have been required to pay the noncontrolling equity participants approximately $146 million and assume $126 million of debt. Since APS now consolidates the VIEs, the debt APS would be required to assume is already reflected in our Consolidated Balance Sheets.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We also have certain long-term purchased power agreements to purchase substantially all of an entity's output from a specified facility for a specified period. We have evaluated these arrangements under the VIE accounting guidance and have determined that these agreements do not represent variable interests. If these agreements had been deemed variable interests, we would not be considered the primary beneficiary, as we do not have the power to direct the entities' activities in a manner that would significantly impact their economic performance and, therefore, would not consolidate the entities. The adoption of the amended VIE accounting guidance has not changed how we account for these arrangements.

21. Guarantees and Surety Bonds

We have issued parental guarantees and obtained surety bonds on behalf of our subsidiaries, including credit support instruments enabling APSES to offer energy-related products and surety bonds at APS, principally related to self-insured workers' compensation. Non-performance or non-payment under the underlying contract by our subsidiaries would result in a payment liability on our part under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to such instruments. At December 31, 2010, we had no outstanding claims for payment under any of these instruments. Our guarantees and surety bonds have no recourse or collateral provisions to allow us to recover amounts paid under these instruments. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2010 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
APSES	$ 5	1	$ 48	1
APS	3	1	9	1
Total	$ 8		$ 57	

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2010, approximately $44 million of letters of credit were outstanding to support existing pollution control bonds of similar amounts. The letters of credit are available to fund the payment of principal and interest of such debt obligations. These letters of credit expire in 2011 and 2013. APS has also entered into approximately $61 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 7 for further details on the Palo Verde sale leaseback transactions). These letters of credit were amended and extended in April 2010, and will expire in 2013.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements; most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Discontinued Operations

SunCor (real estate segment) — In 2009, our real estate subsidiary, SunCor, began disposing of its homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce its outstanding debt. All activity for the 2010 income statement and prior comparative period income statement amounts were reclassified to discontinued operations. In 2008, 2009 and 2010, SunCor recorded real estate impairment charges (see Note 23). SunCor's asset sales resulted in no gain for 2010 and 2009 due to the impairment charges discussed above, and a $24 million after tax gain in 2008. At December 31, 2010, SunCor had approximately $3 million of assets on its balance sheet classified as assets held for sale which are included in other current assets.

Silverhawk — Includes activities related to the resolution of certain tax issues in 2008 associated with the sale of Silverhawk in 2005.

APSES (other) — In 2010, our subsidiary, APSES, sold its district cooling business consisting of operations in downtown Phoenix, Tucson, and on certain Arizona State University campuses. As a result of the sale, we recorded an after-tax gain from discontinued operations of approximately $25 million in June 2010. Prior period income statement amounts related to this sale and the associated revenues and costs are reflected in discontinued operations in 2010, 2009, and 2008. APSES also includes activities related to the APSES discontinued commodity-related energy services in 2008, and the associated revenues and costs that were reclassified to discontinued operations in 2008.

The following table provides revenue, income (loss) before income taxes and income (loss) after taxes classified as discontinued operations in Pinnacle West's Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008 (dollars in millions):

	2010	2009	2008
Revenue:			
SunCor	$ 30	$ 114	$ 129
Other (primarily APSES)	52	18	83
Total revenue	$ 82	$ 132	$ 212
Income (loss) before taxes:			
SunCor	$ (10)	$ (276)	$ (43)
Silverhawk	—	—	13
Other (primarily APSES)	42	3	(1)
Total income (loss) before taxes	$ 32	$ (273)	$ (31)
Income (loss) after taxes:			
SunCor	$ (6)	$ (167)	$ (26)
Silverhawk	—	—	8
Other (primarily APSES)	26	2	(1)
Total income (loss) after taxes (a)	$ 20	$ (165)	$ (19)

(a) Includes a tax benefit recognized by the parent company in accordance with an intercompany tax sharing agreement of $4 million for the year ended December 31, 2010, and $113 million for the year ended December 31, 2009.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

23. Real Estate Impairment Charge

In 2009, SunCor undertook and completed a review of its assets and strategies within its various markets as a result of the distressed conditions in real estate and credit markets. Based on the results of the review, on March 27, 2009, SunCor's Board of Directors authorized a series of strategic transactions to dispose of SunCor's homebuilding operations, master-planned communities, land parcels, commercial assets and golf courses in order to reduce SunCor's outstanding debt. As a result, SunCor took impairment charges in 2008, 2009 and 2010. All SunCor's operations are reflected in discontinued operations (see Note 22). The detail of the impairment charge is as follows (dollars in millions, and before income taxes):

	2010	2009	2008
Discontinued Operations:			
Homebuilding and master-planned communities	$ 1	$ 170	$ 21
Land parcels and commercial assets	11	87	25
Golf courses	1	23	7
Other	4	—	—
Subtotal	17	280	53
Less noncontrolling interests	—	(14)	—
Total	$ 17	$ 266	$ 53

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING (ARIZONA PUBLIC SERVICE COMPANY)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Arizona Public Service Company. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework,* our management concluded that our internal control over financial reporting was effective as of December 31, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company's financial statements.

February 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiary (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As disclosed in Note 2 to the consolidated financial statements of Pinnacle West Capital Corporation, the Company adopted amended accounting guidance related to the consolidation of variable interest entities on January 1, 2010.

/s/ DELOITTE & TOUCHE LLP
Phoenix, Arizona
February 18, 2011

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
ELECTRIC OPERATING REVENUES	$ 3,180,807	$ 3,149,500	$ 3,133,496
OPERATING EXPENSES			
Fuel and purchased power	1,046,815	1,178,620	1,289,883
Operations and maintenance	860,712	812,903	747,610
Depreciation and amortization	414,336	407,159	390,802
Income taxes (Notes 4 and S-1)	175,440	158,661	113,799
Taxes other than income taxes	134,467	122,358	124,046
Total	2,631,770	2,679,701	2,666,140
OPERATING INCOME	549,037	469,799	467,356
OTHER INCOME (DEDUCTIONS)			
Income taxes (Notes 4 and S-1)	4,975	6,087	6,538
Allowance for equity funds used during construction (Note 1)	22,066	14,999	18,636
Other income (Note S-3)	8,956	10,808	6,231
Other expense (Note S-3)	(15,859)	(18,001)	(30,569)
Total	20,138	13,893	836
INTEREST DEDUCTIONS			
Interest on long-term debt	217,002	212,654	184,532
Interest on short-term borrowings	8,267	6,315	13,432
Debt discount, premium and expense	4,559	4,675	4,702
Allowance for borrowed funds used during construction (Note 1)	(16,479)	(10,386)	(14,313)
Total	213,349	213,258	188,353
NET INCOME	355,826	270,434	279,839
Less: Net income attributable to noncontrolling interests (Note 20)	20,163	19,209	17,495
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 335,663	$ 251,225	$ 262,344

See Notes to Pinnacle West's Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2010	December 31, 2009
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6, 9 and 10)		
Plant in service and held for future use	$ 13,197,254	$ 12,781,256
Accumulated depreciation and amortization	(4,510,591)	(4,326,908)
Net	8,686,663	8,454,348
Construction work in progress	459,316	460,748
Palo Verde sale leaseback, net of accumulated depreciation of $213,094 and $204,328 (Note 20)	137,956	146,722
Intangible assets, net of accumulated amortization of $329,444 and $293,450	184,768	164,183
Nuclear fuel, net of accumulated amortization of $85,270 and $64,544	108,794	118,243
Total property, plant and equipment	9,577,497	9,344,244
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 14)	469,886	414,576
Assets from risk management activities (Note 18)	39,032	28,855
Other assets	71,428	68,839
Total investments and other assets	580,346	512,270
CURRENT ASSETS		
Cash and cash equivalents	99,937	120,798
Customer and other receivables	288,323	280,226
Accrued unbilled revenues	103,292	110,971
Allowance for doubtful accounts	(7,646)	(6,063)
Materials and supplies (at average cost)	181,414	176,020
Fossil fuel (at average cost)	21,575	39,245
Assets from risk management activities (Note 18)	73,788	50,619
Deferred income taxes (Notes 4 and S-1)	74,747	53,990
Other current assets	25,135	25,724
Total current assets	860,565	851,530
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, 4 and S-1)	1,048,656	813,161
Income tax receivable (Notes 4 and S-1)	65,498	65,498
Unamortized debt issue costs	20,530	20,959
Other	88,490	73,909
Total deferred debits	1,223,174	973,527
TOTAL ASSETS	$ 12,241,582	$ 11,681,571

See Notes to Pinnacle West's Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,379,696	2,126,863
Retained earnings	1,403,390	1,250,126
Accumulated other comprehensive (loss):		
Pension and other postretirement benefits (Note 8)	(35,961)	(29,114)
Derivative instruments	(100,334)	(80,682)
Total shareholder equity	3,824,953	3,445,355
Noncontrolling interests (Note 20)	91,084	82,324
Total equity	3,916,037	3,527,679
Long-term debt less current maturities (Note 6)	2,948,991	3,180,406
Palo Verde sale leaseback lessor notes less current maturities (Notes 6 and 20)	96,803	126,000
Total capitalization	6,961,831	6,834,085
CURRENT LIABILITIES		
Current maturities of long-term debt (Note 6)	456,879	222,959
Accounts payable	218,491	213,833
Accrued taxes (Notes 4 and S-1)	106,431	158,051
Accrued interest	54,638	54,099
Customer deposits	68,312	70,780
Liabilities from risk management activities (Note 18)	58,976	55,908
Other current liabilities	132,170	124,995
Total current liabilities	1,095,897	900,625
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Notes 4 and S-1)	1,865,359	1,582,945
Deferred fuel and purchased power regulatory liability (Notes 1 and 3)	58,442	87,291
Other regulatory liabilities (Notes 1, 3, 4, and S-1)	694,589	679,072
Liability for asset retirements (Note 12)	328,571	301,783
Liabilities for pension and other postretirement benefits (Note 8)	770,611	766,378
Liabilities from risk management activities (Note 18)	65,390	62,443
Customer advances	121,645	136,595
Coal mine reclamation	117,243	92,060
Unrecognized tax benefits (Notes 4 and S-1)	65,363	140,638
Other	96,641	97,656
Total deferred credits and other	4,183,854	3,946,861
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$ 12,241,582	$ 11,681,571

See Notes to Pinnacle West's Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 355,826	$ 270,434	$ 279,839
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	471,226	445,988	424,414
Deferred fuel and purchased power	93,631	(51,742)	(80,183)
Deferred fuel and purchased power amortization	(122,481)	147,018	183,126
Allowance for equity funds used during construction	(22,066)	(14,999)	(18,636)
Deferred income taxes	224,095	192,914	145,157
Change in mark-to-market valuations	2,688	(6,939)	7,792
Changes in current assets and liabilities:			
Customer and other receivables	(49,956)	2,603	40,782
Accrued unbilled revenues	7,679	(10,882)	6,784
Materials, supplies and fossil fuel	12,276	(12,261)	(25,453)
Other current assets	589	(9,427)	128
Accounts payable	18,066	(22,129)	(5,915)
Accrued taxes	(51,620)	(61,078)	(12,377)
Other current liabilities	(570)	26,907	20,527
Change in margin and collateral accounts — assets	(9,937)	(13,206)	17,850
Change in margin and collateral accounts — liabilities	(88,315)	35,654	(132,416)
Change in regulatory liabilities	54,518	110,642	(12,129)
Change in long-term income tax receivable	—	(132,379)	—
Change in unrecognized tax benefits	(73,189)	137,478	(92,064)
Change in other long-term assets	(41,989)	(53,734)	14,340
Change in other long-term liabilities	(85,136)	14,097	58,219
Net cash flow provided by operating activities	695,335	994,959	819,785
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(747,967)	(754,301)	(910,189)
Contributions in aid of construction	32,754	53,525	60,292
Allowance for borrowed funds used during construction	(16,479)	(10,386)	(14,313)
Proceeds from nuclear decommissioning trust sales	560,469	441,242	317,619
Investment in nuclear decommissioning trust	(584,885)	(463,033)	(338,361)
Other	8,576	(4,667)	5,517
Net cash flow used for investing activities	(747,532)	(737,620)	(879,435)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	—	863,780	—
Repayment of long-term debt	(27,694)	(365,696)	(48,460)
Short-term borrowings and payments — net	—	(521,684)	303,684
Equity infusion	252,833	—	7,601
Dividends paid on common stock	(182,400)	(170,000)	(170,000)
Noncontrolling interests	(11,403)	(14,485)	(13,782)
Net cash flow provided by (used for) financing activities	31,336	(208,085)	79,043
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(20,861)	49,254	19,393
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	120,798	71,544	52,151
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 99,937	$ 120,798	$ 71,544
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Income taxes, net of refunds	$ 81,339	$ 13,555	$ 56,728
Interest, net of amounts capitalized	$ 208,251	$ 194,346	$ 182,053

See Notes to Pinnacle West's Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
COMMON STOCK	$ 178,162	$ 178,162	$ 178,162
ADDITIONAL PAID-IN CAPITAL			
Balance at beginning of year	2,126,863	2,117,789	2,105,466
Equity infusion	252,833	—	7,601
Other	—	9,074	4,722
Balance at end of year	2,379,696	2,126,863	2,117,789
RETAINED EARNINGS			
Balance at beginning of year	1,250,126	1,168,901	1,076,557
Net income attributable to common shareholder	335,663	251,225	262,344
Dividends on common stock	(182,400)	(170,000)	(170,000)
Other	1	—	—
Balance at end of year	1,403,390	1,250,126	1,168,901
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)			
Balance at beginning of year	(109,796)	(125,702)	(8,744)
Pension and other postretirement benefits (Note 8):			
Unrealized actuarial loss, net of tax benefit of $(6,344), $(2,938) and $(5,075)	(9,684)	(4,571)	(7,597)
Amortization to income:			
Actuarial loss, net of tax benefit of $1,658, $1,387 and $1,393	2,541	2,126	2,130
Prior service cost, net of tax benefit of $193, $190 and $189	295	291	289
Derivative instruments:			
Net unrealized gain (loss), net of tax (benefit) of $(61,358), $(61,317) and $(56,149)	(93,929)	(94,008)	(85,670)
Reclassification of net realized (gains) losses to income, net of tax (expense) benefit of $48,462, $73,261 and $(16,890)	74,278	112,068	(26,110)
Balance at end of year	(136,295)	(109,796)	(125,702)
NONCONTROLLING INTERESTS			
Balance at beginning of year	82,324	77,601	73,887
Net income attributable to noncontrolling interests	20,163	19,209	17,495
Net capital activities by noncontrolling interests	(11,403)	(14,486)	(13,781)
Balance at end of year	91,084	82,324	77,601
TOTAL EQUITY	$ 3,916,037	$ 3,527,679	$ 3,416,751
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER			
Net income attributable to common shareholder	$ 335,663	$ 251,225	$ 262,344
Other comprehensive income (loss)	(26,499)	15,906	(116,958)
Total comprehensive income attributable to common shareholders	$ 309,164	$ 267,131	$ 145,386

See Notes to Pinnacle West's Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Consolidated Financial Statements.

Certain notes to Arizona Public Service Company's consolidated financial statements are combined with the notes to Pinnacle West Capital Corporation's consolidated financial statements. Listed below are the consolidated notes to Pinnacle West Capital Corporation's consolidated financial statements, the majority of which also relate to Arizona Public Service Company's consolidated financial statements. In addition, listed below are the supplemental notes which are required disclosures for Arizona Public Service Company and should be read in conjunction with Pinnacle West Capital Corporation's Consolidated Notes.

	Consolidated Footnote Reference	APS's Supplemental Footnote Reference
Summary of Significant Accounting Policies	Note 1	—
New Accounting Standards	Note 2	—
Regulatory Matters	Note 3	—
Income Taxes	Note 4	Note S-1
Lines of Credit and Short-Term Borrowings	Note 5	—
Long-Term Debt and Liquidity Matters	Note 6	—
Common Stock and Treasury Stock	Note 7	—
Retirement Plans and Other Benefits	Note 8	—
Leases	Note 9	—
Jointly-Owned Facilities	Note 10	—
Commitments and Contingencies	Note 11	—
Asset Retirement Obligations	Note 12	—
Selected Quarterly Financial Data (Unaudited)	Note 13	Note S-2
Fair Value Measurements	Note 14	—
Earnings Per Share	Note 15	—
Stock-Based Compensation	Note 16	—
Business Segments	Note 17	—
Derivative Accounting	Note 18	—
Other Income and Other Expense	Note 19	Note S-3
Variable Interest Entities	Note 20	—
Guarantees and Surety Bonds	Note 21	—
Discontinued Operations	Note 22	—
Real Estate Impairment Charge	Note 23	—

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

S-1. Income Taxes

APS is included in Pinnacle West's consolidated tax return. However, when Pinnacle West allocates income taxes to APS, it is done based upon APS's taxable income computed on a stand-alone basis, in accordance with the tax sharing agreement.

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction and pension and other postretirement benefits. The regulatory liabilities relate to deferred taxes resulting primarily from investment tax credits. APS amortizes these amounts as the differences reverse.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	2010	2009	2008
Total unrecognized tax benefits, January 1	$ 199,887	$ 62,409	$ 154,473
Additions for tax positions of the current year	7,551	44,094	12,893
Additions for tax positions of prior years	—	98,269	32,481
Reductions for tax positions of prior years for:			
Changes in judgment	(10,964)	—	(4,547)
Settlements with taxing authorities	(61,820)	(4,089)	(35,812)
Lapses of applicable statute of limitations	(7,956)	(796)	(97,079)
Total unrecognized tax benefits, December 31	$ 126,698	$ 199,887	$ 62,409

During the first quarter of 2010, the Company reached a settlement with the IRS with regard to the examination of tax returns for the years ended December 31, 2005 through 2007. As a result of this settlement, net uncertain tax positions decreased $62 million, including approximately $3 million which decreased our effective tax rate. Additionally, the settlement resulted in the recognition of net interest benefits of approximately $4 million through the effective tax rate.

Included in the balance of unrecognized tax benefits at December 31, 2010, 2009 and 2008 were approximately $6 million, $15 million and $15 million, respectively, of tax positions that, if recognized, would decrease our effective tax rate.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of the balance sheet date, the tax year ended December 31, 2008 and all subsequent tax years remain subject to examination by the IRS. With few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 1999. We do not anticipate that there will be any significant increases or decreases in our unrecognized tax benefits within the next twelve months.

We reflect interest and penalties, if any, on unrecognized tax benefits in the statement of income as income tax expense. The amount of interest recognized in the Statement of Income related to unrecognized tax benefits was a pre-tax benefit of $2 million for 2010, a pre-tax expense of $2 million for 2009 and a pre-tax benefit of $51 million for 2008.

The total amount of accrued liabilities for interest recognized in the Balance Sheets related to unrecognized tax benefits was $6 million as of December 31, 2010, $8 million as of December 31, 2009 and $5 million as of December 31, 2008. To the extent that matters are settled favorably, this amount could reverse and decrease our effective tax rate. Additionally, as of December 31, 2010, we have recognized $5 million of interest income to be received on the overpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

The components of APS's income tax expense are as follows (dollars in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ (71,036)	$ (8,667)	$ (54,719)
State	17,406	(31,673)	16,823
Total current	(53,630)	(40,340)	(37,896)
Deferred	224,095	192,914	145,157
Total income tax expense	$ 170,465	$ 152,574	$ 107,261

On the APS Statements of Income, federal and state income taxes are allocated between operating income and other income.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following chart compares APS's pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

	Year Ended December 31,		
	2010	2009	2008
Federal income tax expense at 35% statutory rate	$ 184,202	$ 148,053	$ 135,485
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	19,186	16,691	14,956
Credits and favorable adjustments related to prior years resolved in current year	(17,300)	—	(28,873)
Medicare Subsidy Part-D (see Note 8)	889	(2,025)	(1,921)
Allowance for equity funds used during construction (see Note 1)	(6,563)	(4,265)	(5,755)
Palo Verde VIE noncontrolling interest (see Note 20)	(7,057)	(6,723)	(6,123)
Other	(2,892)	843	(508)
Income tax expense	$ 170,465	$ 152,574	$ 107,261

The following table shows the net deferred income tax liability recognized on the APS Balance Sheets (dollars in thousands):

	December 31,	
	2010	2009
Current asset	$ 74,747	$ 53,990
Long-term liability	(1,865,359)	(1,582,945)
Deferred income taxes — net	$ (1,790,612)	$ (1,528,955)

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31, 2010	December 31, 2009
DEFERRED TAX ASSETS		
Regulatory liabilities:		
Asset retirement obligation and removal costs	$ 222,448	$ 213,814
Deferred fuel and purchased power	23,089	34,463
Renewable Energy Standard	18,749	—
Other	28,360	21,613
Risk management activities	124,731	87,404
Pension and other postretirement liabilities	303,055	288,769
Renewable energy incentives	37,327	—
Other	97,989	104,416
Total deferred tax assets	855,748	750,479
DEFERRED TAX LIABILITIES		
Plant-related	(2,210,976)	(1,951,262)
Risk management activities	(30,125)	(20,863)
Regulatory assets:		
Allowance for equity funds used during construction	(28,276)	(23,285)
Deferred fuel and purchased power — mark-to-market	(30,276)	(16,167)
Pension and other postretirement benefits	(264,313)	(210,080)
Other	(77,078)	(57,210)
Other	(5,316)	(567)
Total deferred tax liabilities	(2,646,360)	(2,279,434)
Deferred income taxes — net	$ (1,790,612)	$ (1,528,955)

A majority of the deferred tax assets for credit and loss carryforwards relate to federal general business credits and federal net operating losses. These federal credits and losses first begin to expire in 2029.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

S-2. Selected Quarterly Financial Data (Unaudited)

Quarterly financial information for 2010 and 2009 is as follows (dollars in thousands):

	2010 Quarter Ended,				2010
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$ 611,476	$ 799,467	$ 1,116,220	$ 653,644	$ 3,180,807
Operations and maintenance	203,881	211,310	217,044	228,477	860,712
Operating income	65,435	146,249	277,009	60,344	549,037
Net income (Loss) attributable to common shareholders	10,984	90,220	226,648	7,811	335,663

	2009 Quarter Ended,				2009
	March 31,	June 30,	September 30,	December 31,	Total
As originally reported in the 2009 10-K:					
Operating revenues	$ 602,660	$ 812,587	$ 1,083,825	$ 650,428	$ 3,149,500
Operations and maintenance	201,100	221,128	203,446	226,889	852,563
Operating income	29,125	122,385	245,104	41,229	437,843
Net income (Loss)	(15,479)	78,544	197,065	(8,905)	251,225

	2009 Quarter Ended,				2009
	March 31,	June 30,	September 30,	December 31,	Total
Palo Verde VIE reclassifications:					
Operations and maintenance	$ (9,915)	$ (9,914)	$ (9,916)	(9,915)	$ (39,660)
Operating income	7,989	7,989	7,989	7,989	31,956
Net income attributable to noncontrolling interests	4,650	4,651	4,953	4,955	19,209

	2009 Quarter Ended,				2009
	March 31,	June 30,	September 30,	December 31,	Total
After Palo Verde VIE reclassifications (see Note 20):					
Operating revenues	$ 602,660	$ 812,587	$ 1,083,825	$ 650,428	$ 3,149,500
Operations and maintenance	191,185	211,214	193,530	216,974	812,903
Operating income	37,114	130,374	253,093	49,218	469,799
Net income attributable to noncontrolling interests	4,650	4,651	4,953	4,955	19,209
Net income (Loss) attributable to common shareholders	(15,479)	78,544	197,065	(8,905)	251,225

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

. Other Income and Other Expense

The following table provides detail of APS's other income and other expense for 2010, 2009 and 2008 (dollars in thousands):

	2010	2009	2008
Other income:			
Interest income	$ 668	$ 502	$ 3,863
SO2 emission allowance sales and other (a)	—	1,439	392
Investment gains — net	2,334	6,673	—
Miscellaneous	5,954	2,194	1,976
Total other income	$ 8,956	$ 10,808	$ 6,231
Other expense:			
Non-operating costs (a)	$ (9,855)	$ (7,368)	$ (10,538)
Asset dispositions	(612)	(656)	(5,779)
Investment losses — net	—	—	(9,438)
Miscellaneous	(5,392)	(9,977)	(4,814)
Total other expense	$ (15,859)	$ (18,001)	$ (30,569)

(a) As defined by the FERC, includes below-the-line non-operating utility income and expense (items excluded from utility rate recovery).

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF INCOME
(in thousands)

	Year Ended December 31,		
	2010	**2009**	**2008**
Operating revenues	$ 2,810	$ 1,156	$ 52
Operating expenses			
Fuel and purchased power	—	—	(19,970)
Other operating expenses	9,880	10,420	8,979
Total	9,880	10,420	(10,991)
Operating income (loss)	(7,070)	(9,264)	11,043
Other			
Equity in earnings (losses) of subsidiaries	358,527	(37,214)	226,893
Other income	883	2,776	1,248
Total	359,410	(34,438)	228,141
Interest expense	14,346	14,129	17,550
Income (loss) from continuing operations	337,994	(57,831)	221,634
Income tax benefit	(9,015)	(13,885)	(12,374)
Income (loss) from continuing operations — net of income taxes	347,009	(43,946)	234,008
Income from discontinued operations — net of income taxes	3,044	112,276	8,117
Net income attributable to common shareholders	$ 350,053	$ 68,330	$ 242,125

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(in thousands)

	Balance at December 31, 2010	Balance at December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 7,725	$ 17,284
Customer and other receivables	75,745	77,570
Current deferred income taxes	19,855	—
Income tax receivable	3,736	64,317
Other current assets	61	49
Total current assets	107,122	159,220
Investments and other assets		
Investments in subsidiaries	3,901,935	3,572,472
Deferred income taxes	—	89,842
Other assets	58,071	22,520
Total investments and other assets	3,960,006	3,684,834
Total Assets	$ 4,067,128	$ 3,844,054
Liabilities and Equity		
Current liabilities		
Accounts payable	$ 4,981	$ 10,923
Accrued taxes	4,216	5,157
Short-term borrowings	16,600	149,086
Current maturities of long-term debt	175,000	—
Other current liabilities	28,101	9,950
Total current liabilities	228,898	175,116
Long-term debt less current maturities	—	175,000
Deferred credits and other		
Pension and other postretirement liabilities	28,607	29,343
Other	34,397	36,591
Total deferred credits and other	63,004	65,934
Common stock equity		
Common stock	2,419,133	2,149,483
Accumulated other comprehensive loss	(159,767)	(131,587)
Retained earnings	1,423,961	1,298,213
Total Pinnacle West Shareholders' equity	3,683,327	3,316,109
Noncontrolling interests	91,899	111,895
Total Equity	3,775,226	3,428,004
Total Liabilities and Equity	$ 4,067,128	$ 3,844,054

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION HOLDING COMPANY
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2010	**2009**	**2008**
Cash flows from operating activities			
Net income	$ 350,053	$ 68,330	$ 242,125
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries — net	(358,527)	37,214	(226,893)
Depreciation and amortization	143	127	210
Deferred income taxes	40,342	(106,536)	31,954
Change in mark-to-market valuations	—	—	(19,975)
Customer and other receivables	(18,175)	(2,303)	38,938
Accounts payable	7,468	466	(14,134)
Accrued taxes and income tax receivables — net	59,640	44,625	(5,230)
Change in margin and collateral accounts — net	—	—	—
Dividends received from subsidiaries	207,000	170,000	170,000
Other net	423	(2,379)	(7,914)
Net cash flow provided by operating activities	288,367	209,544	209,081
Cash flows from investing activities			
Investments in subsidiaries	(183,544)	(4,967)	(18,765)
Repayments of loans from subsidiaries	98,406	25,240	10,194
Advances of loans to subsidiaries	(119,293)	(21,587)	(22,554)
Net cash flow used for investing activities	(204,431)	(1,314)	(31,125)
Cash flows from financing activities			
Short-term borrowings and payments — net	(132,487)	4,566	28,729
Dividends paid on common stock	(216,979)	(205,076)	(204,247)
Repayment of long-term debt	—	—	—
Common stock equity issuance	255,971	3,302	3,687
Net cash flow used for financing activities	(93,495)	(197,208)	(171,831)
Net increase (decrease) in cash and cash equivalents	(9,559)	11,022	6,125
Cash and cash equivalents at beginning of year	17,284	6,262	137
Cash and cash equivalents at end of year	$ 7,725	$ 17,284	$ 6,262

See Notes to Pinnacle West's Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2010	$ 4,573	$ 6,905	$ —	$ 6,769	$ 4,709
2009	3,383	7,617	—	6,427	4,573
2008	4,782	6,177	—	7,576	3,383

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE II — RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of period
Reserve for uncollectibles:					
2010	$ 4,483	$ 6,756	$ —	$ 6,863	$ 4,376
2009	3,155	7,062	—	5,734	4,483
2008	4,265	5,924	—	7,034	3,155

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934 (the "Exchange Act") (15 U.S.C. 78a *et seq* .) is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of December 31, 2010. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of APS's disclosure controls and procedures as of December 31, 2010. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Management's Annual Reports on Internal Control Over Financial Reporting

Reference is made to "Management's Report on Internal Control Over Financial Reporting (Pinnacle West Capital Corporation)" on page 80 of this report and "Management's Report on Internal Control Over Financial Reporting (Arizona Public Service Company)" on page 153 of this report.

(c) Attestation Reports of the Registered Public Accounting Firm

Reference is made to "Report of Independent Registered Public Accounting Firm" on page 81 of this report and "Report of Independent Registered Public Accounting Firm" on page 154 of this report on the internal control over financial reporting of Pinnacle West and APS, respectively.

(d) Changes In Internal Control Over Financial Reporting

The term "internal control over financial reporting" (defined in SEC Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended December 31, 2010 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF PINNACLE WEST

Reference is hereby made to "Information About Our Board and Corporate Governance," "Proposal 1 — Election of Directors" and to "Section 16(a) Beneficial Ownership Reporting Compliance" in the Pinnacle West Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 18, 2011 (the "2011 Proxy Statement") and to the "Executive Officers of Pinnacle West" section in Part I of this report.

Pinnacle West has adopted a Code of Ethics for Financial Executives that applies to financial executives including Pinnacle West's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller, Treasurer, and persons holding substantially equivalent positions at Pinnacle West's subsidiaries. The Code of Ethics for Financial Executives is posted on Pinnacle West's website at *www.pinnaclewest.com* . Pinnacle West intends to satisfy the requirements under Item 5.05 of Form 8-K regarding disclosure of amendments to, or waivers from, provisions of the Code of Ethics for Financial Executives by posting such information on Pinnacle West's website.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Directors' Compensation," "Report of the Human Resources Committee," "Executive Compensation," "Overall Compensation Program" and "Human Resources Committee Interlocks and Insider Participation" in the 2011 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Reference is hereby made to "Shares of Pinnacle West Stock Owned by Management and Large Shareholders" in the 2011 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth information as of December 31, 2010 with respect to our compensation plans and individual compensation arrangements under which our equity securities are authorized for issuance.

EQUITY COMPENSATION PLAN INFORMATION

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) [1]	Weighted-average exercise price of outstanding options, warrants and rights (b) [2]	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) [3]
Equity compensation plans approved by security holders	1,406,262	$ 39.37	5,782,718
Equity compensation plans not approved by security holders	—	—	—
Total	1,406,262	$ 39.37	5,782,718

1 This amount includes shares subject to outstanding options as well as shares subject to outstanding performance share awards and restricted stock unit awards at the maximum amount of shares issuable under such awards. However, payout of the performance share awards is contingent on the Company reaching certain levels of performance during a three-year performance period. If the performance criteria for these awards are not fully satisfied, the award recipient will receive less than the maximum number of shares available under these grants and may receive nothing from these grants.

2 The weighted average exercise price in this column does not take performance share awards or restricted stock unit awards into account, as those awards have no exercise price.

3 Awards can take the form of options, stock appreciation rights, restricted stock, performance shares, performance share units, performance cash, stock grants, dividend equivalents, and restricted stock units.

Equity Compensation Plans Approved By Security Holders

Amounts in column (a) in the table above include shares subject to awards outstanding under three equity compensation plans that were approved by our shareholders: (a) the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan, under which no new stock awards may be granted; (b) the Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan (the "2002 Plan"), under which no new stock awards may be granted; and (c) the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan (the "2007 Plan"), which was approved by our shareholders at our 2007 annual meeting of shareholders. Although we cannot issue additional awards under the 2002 Plan, shares subject to outstanding awards under the 2002 Plan that expire or are cancelled or terminated will be available for issuance under the 2007 Plan. See Note 16 of the Notes to Consolidated Financial Statements for additional information regarding these plans.

Equity Compensation Plans Not Approved By Security Holders

The Company does not have any equity compensation plans under which shares can still be issued that have not been approved by shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Reference is hereby made to "Information About Our Board and Corporate Governance" and "Related Party Transactions" in the 2011 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pinnacle West

Reference is hereby made to "Proposal 3 — Ratification of the Selection of Deloitte & Touche LLP as Independent Accountants of the Company — Audit Fees and — Pre-Approval Policies" in the 2011 Proxy Statement.

APS

The following fees were paid to APS's independent registered public accountants, Deloitte & Touche LLP, for the last two fiscal years:

Type of Service	2009	2010
Audit Fees (1)	$ 1,698,325	$ 1,330,173
Audit-Related Fees (2)	380,695	138,247
Tax Fees	—	—

(1) The aggregate fees billed for services rendered for the audit of annual financial statements and for review of financial statements included in Reports on Form 10-Q.

(2) The aggregate fees billed for assurance services that are reasonably related to the performance of the audit or review of the financial statements that are not included in Audit Fees reported above, which primarily consist of fees for an IFRS Assessment for work performed in 2009 and employee benefit plan audits performed in 2010 and 2009.

Pinnacle West's Audit Committee pre-approves each audit service and non-audit service to be provided by APS's registered public accounting firm. The Audit Committee has delegated to the Chairman of the Audit Committee the authority to pre-approve audit and non-audit services to be performed by the independent public accountants if the services are not expected to cost more than $50,000. The Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting. All of the services performed by Deloitte & Touche LLP for APS were pre-approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

See the Index to Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

The documents listed below are being filed or have previously been filed on behalf of Pinnacle West or APS and are incorporated herein by reference from the documents indicated and made a part hereof. Exhibits not identified as previously filed are filed herewith.

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
3.1	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8-7-08
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010	3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8-3-10
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form 18 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9-29-93
3.4	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File No. 1-4473	2-20-09
4.1	Pinnacle West	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.12 to Pinnacle West April 29, 2005 Form 8-K Report, File No. 1-8962	5-2-05

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
4.2	Pinnacle West APS	Indenture dated as of January 1, 1995 among APS and The Bank of New York Mellon, as Trustee	4.6 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1-11-95
4.2a	Pinnacle West APS	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS's Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report, File No. 1-4473	1-11-95
4.3	Pinnacle West APS	Indenture dated as of November 15, 1996 between APS and The Bank of New York, as Trustee	4.5 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11-22-96
4.3a	Pinnacle West APS	First Supplemental Indenture dated as of November 15, 1996	4.6 to APS's Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report, File No. 1-4473	11-22-96
4.3b	Pinnacle West APS	Second Supplemental Indenture dated as of April 1, 1997	4.10 to APS's Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report, File No. 1-4473	4-9-97
4.3c	Pinnacle West APS	Third Supplemental Indenture dated as of November 1, 2002	10.2 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5-15-03

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Senior Unsecured Debt Securities	4.1 to Pinnacle West's Registration Statement No. 333-52476	12-21-00
4.5	Pinnacle West	Indenture dated as of December 1, 2000 between the Company and The Bank of New York, as Trustee, relating to Subordinated Unsecured Debt Securities	4.2 to Pinnacle West's Registration Statement No. 333-52476	12-21-00
4.6	Pinnacle West APS	Indenture dated as of January 15, 1998 between APS and The Bank of New York Mellon Trust Company N.A. (successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank), as Trustee	4.10 to APS's Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report, File No. 1-4473	1-16-98
4.6a	Pinnacle West APS	Fifth Supplemental Indenture dated as of October 1, 2001	4.1 to APS's September 30, 2001 Form 10-Q, File No. 1-4473	11-6-01
4.6b	Pinnacle West APS	Sixth Supplemental Indenture dated as of March 1, 2002	4.1 to APS's Registration Statement Nos. 333-63994 and 333-83398 by means of February 26, 2002 Form 8-K Report, File No. 1-4473	2-28-02
4.6c	Pinnacle West APS	Seventh Supplemental Indenture dated as of May 1, 2003	4.1 to APS's Registration Statement No. 333-90824 by means of May 7, 2003 Form 8-K Report, File No. 1-4473	5-9-03

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
4.6d	Pinnacle West APS	Eighth Supplemental Indenture dated as of June 15, 2004	4.1 to APS's Registration Statement No. 333-106772 by means of June 24, 2004 Form 8-K Report, File No. 1-4473	6-28-04
4.6e	Pinnacle West APS	Ninth Supplemental Indenture dated as of August 15, 2005	4.1 to APS's Registration Statements Nos. 333-106772 and 333-121512 by means of August 17, 2005 Form 8-K Report, File No. 1-4473	8-22-05
4.6f	APS	Tenth Supplemental Indenture dated as of August 1, 2006	4.1 to APS's July 31, 2006 Form 8-K Report, File No. 1-4473	8-3-06
4.6g	Pinnacle West APS	Eleventh Supplemental Indenture dated as of February 26, 2009	4.1 to Pinnacle West's/APS's February 23, 2009 Form 8-K Report, File Nos. 1-8962 and 1-4473	2-25-09
4.7	Pinnacle West	Second Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of June 23, 2004	4.4 to Pinnacle West's June 23, 2004 Form 8-K Report, File No. 1-8962	8-9-04
4.7a	Pinnacle West	Third Amended and Restated Pinnacle West Capital Corporation Investors Advantage Plan dated as of November 25, 2008	4.1 to Pinnacle West's Form S-3 Registration Statement No. 333-155641, File No. 1-8962	11-25-08
4.8	Pinnacle West	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to Pinnacle West's 1987 Form 10-K Report, File No. 1-8962	3-30-88

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
a	Pinnacle West APS	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS's total assets	4.1 to APS's 1993 Form 10-K Report, File No. 1-4473	3-30-94
10.1.1	Pinnacle West APS	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS's September 30, 1991 Form 10-Q Report, File No. 1-4473	11-14-91
10.1.1a	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS's 1994 Form 10-K Report, File No. 1-4473	3-30-95
10.1.1b	Pinnacle West APS	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS's 1994 Form 10-K Report, File No. 1-4473	3-30-95
10.1.1c	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS's 1996 Form 10-K Report, File No. 1-4473	3-28-97

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.1.1d	Pinnacle West APS	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS's 1996 Form 10-K Report, File No. 1-4473	3-28-97
10.1.1e	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002	10.2 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5-15-02
10.1.1f	Pinnacle West APS	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002	10.4 to Pinnacle West's March 2002 Form 10-Q Report, File No. 1-8962	5-15-02
10.1.1g	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 19, 2003	10.3 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3-15-04
10.1.1h	Pinnacle West APS	Amendment No. 4 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 19, 2003	10.5 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3-15-04
10.1.1i	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of May 1, 2007	10.1 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-9-07
10.1.1j	Pinnacle West APS	Amendment No. 5 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of May 1, 2007	10.2 to Pinnacle West/APS March 31, 2007 Form 10-Q Report, File Nos. 1-8962 and 104473	5-9-07

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.1.2	Pinnacle West APS	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West's 1991 Form 10-K Report, File No. 1-8962	3-26-92
10.1.2a	Pinnacle West APS	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
10.1.2b	Pinnacle West APS	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.3 to APS's 1994 Form 10-K Report, File No. 1-4473	3-30-95
10.1.2c	Pinnacle West APS	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 20, 1996	10.1 to APS's June 30, 1996 Form 10-Q Report, File No. 1-4473	8-9-96

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.1.2d	Pinnacle West APS	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of December 16, 1996	APS 10.5 to APS's 1996 Form 10-K Report, File No. 1-4473	3-28-97
10.1.2e	Pinnacle West APS	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000	10.1 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5-15-02
10.1.2f	Pinnacle West APS	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002	10.3 to Pinnacle West's March 31, 2002 Form 10-Q Report, File No. 1-8962	5-15-02
10.1.2g	Pinnacle West APS	Amendment No. 7 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of December 19, 2003	10.4 to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3-15-04
10.1.2h	Pinnacle West APS	Amendment No. 8 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of April 1, 2007	10.1.2h to Pinnacle West's 2007 Form 10-K Report, File No. 1-8962	2-27-08

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.2.1 [b]	Pinnacle West APS	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987 respectively	10.4 to APS's 1988 Form 10-K Report, File No. 1-4473	3-8-89
10.2.1a [b]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3A to APS's 1993 Form 10-K Report, File No. 1-4473	3-30-94
10.2.1b [b]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11-10-94
10.2.1c [b]	Pinnacle West APS	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 1997	10.3A to APS's 1996 Form 10-K Report, File No. 1-4473	3-28-97
10.2.1d [b]	Pinnacle West APS	Sixth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective January 1, 2001	10.8A to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3-14-01

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.2.2 [b]	Pinnacle West APS	Arizona Public Service Company Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS's June 30, 1986 Form 10-Q Report, File No. 1-4473	8-13-86
10.2.2a [b]	Pinnacle West APS	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2A to APS's 1993 Form 10-K Report, File No. 1-4473	3-30-94
10.2.2b [b]	Pinnacle West APS	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS's September 30, 1994 Form 10-Q Report, File No. 1-4473	11-10-94
10.2.2c [b]	Pinnacle West APS	Fourth Amendment to the Arizona Public Service Company Directors Deferred Compensation Plan, effective as of January 1, 1999	10.8A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00
10.2.3 [b]	Pinnacle West APS	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
2.3a [b]	Pinnacle West APS	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00
10.2.4 [b]	Pinnacle West APS	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10A to APS's 1995 Form 10-K Report, File No. 1-4473	3-29-96
10.2.4a [b]	Pinnacle West APS	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.7A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.2.4b [b]	Pinnacle West APS	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00
10.2.4c [b]	Pinnacle West APS	Third Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective as of January 1, 2002	10.3 to Pinnacle West's March 31, 2003 Form 10-Q Report, File No. 1-8962	5-15-03
10.2.4d [b]	Pinnacle West APS	Fourth Amendment to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan, effective January 1, 2003	10.64 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06
10.2.5 [b]	Pinnacle West APS	Schedules of William J. Post and Jack E. Davis to Arizona Public Service Company Deferred Compensation Plan, as amended	10.3A to Pinnacle West 2002 Form 10-K Report, File No. 1-8962	3-31-03

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.2.6 [b]	Pinnacle West APS	Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates	10.2.6 to Pinnacle West/APS 2008 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-20-09
10.2.6a [b]	Pinnacle West APS	First Amendment to the Deferred Compensation Plan of 2005 for Employees of Pinnacle West Capital Corporation and Affiliates	10.2.6a to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-19-10
10.3.1 [b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplement Excess Benefit Retirement Plan, amended and restated as of January 1, 2003	10.7A to Pinnacle West's 2003 Form 10-K Report, File No. 1-8962	3-15-04
10.3.1a [b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 18, 2003	10.48b to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06
10.3.2 [b]	Pinnacle West APS	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan of 2005	10.3.2 to Pinnacle West/APS 2008 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-20-09
10.4.1 [b]	Pinnacle West APS	Letter Agreement dated December 21, 1993, between APS and William L. Stewart	10.6A to APS's 1994 Form 10-K Report, File No. 1-4473	3-30-95
10.4.2 [b]	Pinnacle West APS	Letter Agreement dated August 16, 1996 between APS and William L. Stewart	10.8 to APS's 1996 Form 10-K Report, File No. 1-4473	3-28-97

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.4.3 [b]	Pinnacle West APS	Letter Agreement dated October 3, 1997 between APS and William L. Stewart	10.2 to APS's September 30, 1997 Form 10-Q Report, File No. 1-4473	11-12-97
10.4.4 [b]	Pinnacle West APS	Letter Agreement dated December 13, 1999 between APS and William L. Stewart	10.9A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00
10.4.4a [b]	Pinnacle West APS	Amendment to Letter Agreement, effective as of January 1, 2002, between APS and William L. Stewart	10.1 to Pinnacle West's June 30, 2002 Form 10-Q Report, File No. 1-8962	8-13-02
10.4.5 [b]	Pinnacle West APS	Letter Agreement dated June 28, 2001 between Pinnacle West Capital Corporation and Steve Wheeler	10.4A to Pinnacle West's 2002 Form 10-K Report, File No. 1-8962	3-31-03
10.4.6 [b]	APS	Letter Agreement dated December 20, 2006 between APS and Randall K. Edington	10.78 to Pinnacle West/APS 2006 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-28-07
10.4.7 [b]	APS	Letter Agreement dated July 22, 2008 between APS and Randall K. Edington	10.3 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-4473	8-07-08
10.4.8 [b]	Pinnacle West APS	Letter Agreement dated June 17, 2008 between Pinnacle West/APS and James R. Hatfield	10.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8-07-08
10.4.9 [b]	APS	Description of 2008 Palo Verde Specific Compensation Opportunity for Randall K. Edington	10.7 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-4473	8-07-08

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.4.10 [b]	APS	Supplemental Agreement dated December 26, 2008 between APS and Randall K. Edington	10.4.10 to Pinnacle West/APS 2008 Form 10-K Report, File No. 1-4473	2-20-09
10.4.11 [b]	APS	Description of 2009 Palo Verde Specific Compensation Opportunity for Randall K. Edington	10.2 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File No. 1-4473	5-5-09
10.4.12 [b]	Pinnacle West APS	Career Recognition Award Agreement dated April 14, 2009 between Pinnacle West Capital Corporation and William J. Post	10.1 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-5-09
10.4.13 [b]	APS	Description of 2010 Palo Verde Specific Compensation Opportunity for Randall K. Edington	10.4.13 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-19-10
10.4.14 [b]	Pinnacle West	Letter Agreement dated May 21, 2009, between Pinnacle West Capital Corporation and David P. Falck	10.4 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File No. 1-8962	5-6-10

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.5.1 [bd]	Pinnacle West APS	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.77 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06
10.5.1a [bd]	Pinnacle West APS	Form of Amended and Restated Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.4 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11-6-07
10.5.2 [bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.3 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File Nos. 1-8962 and 1-4473	11-6-07
10.5.3 [bd]	Pinnacle West APS	Form of Key Executive Employment and Severance Agreement between Pinnacle West and certain officers of Pinnacle West and its subsidiaries	10.5.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-19-10
10.6.1 [b]	Pinnacle West APS	Pinnacle West Capital Corporation 1994 Long- Term Incentive Plan, effective as of March 23, 1994	Appendix A to the Proxy Statement for the Plan Report for Pinnacle West's 1994 Annual Meeting of Shareholders, File No. 1-8962	4-15-94

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.6.1a [b]	Pinnacle West APS	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan	10.12A to Pinnacle West's 1999 Form 10-K Report, File No. 1-8962	3-30-00
10.6.2 [b]	Pinnacle West APS	Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.5A to Pinnacle West's 2002 Form 10-K Report	3-31-03
10.6.2a [bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.1 to Pinnacle West/APS December 9, 2005 Form 8-K Report, File Nos. 1-8962 and 1-4473	12-15-05
10.6.2b [bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.1 to Pinnacle West/APS December 31, 2005 Form 8-K Report, File Nos. 1-8962 and 1-4473	2-1-06
10.6.2c [d]	Pinnacle West APS	Performance Accelerated Stock Option Agreement under Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.98 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05
10.6.2d [bd]	Pinnacle West APS	Stock Ownership Incentive Agreement under Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.99 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05
10.6.2e [bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.91 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.6.2f [bd]	Pinnacle West APS	Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.3 to Pinnacle West/APS March 31, 2009 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-5-09
10.6.2g [bd]	Pinnacle West	Form of Performance Share Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8-3-10
10.6.2h [bd]	Pinnacle West	Form of Restricted Stock Unit Agreement under the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File No. 1-8962	8-3-10
10.6.3 [b]	Pinnacle West	Pinnacle West Capital Corporation 2000 Director Equity Plan	99.1 to Pinnacle West's Registration Statement on Form S-8 (No. 333-40796), File No. 1-8962)	7-3-00
10.6.4 [b]	Pinnacle West	Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	Appendix B to the Proxy Statement for Pinnacle West's 2007 Annual Meeting of Shareholders, File No. 1-8962	4-20-07
10.6.4a [b]	Pinnacle West	First Amendment to the Pinnacle West Capital Corporation 2007 Long-Term Incentive Plan	10.2 to Pinnacle West/APS April 18, 2007 Form 8-K Report, File No. 1-8962	4-20-07
10.6.4b [b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.1 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11-6-07
10.6.4c [b]	Pinnacle West	Description of Stock Grant to W. Douglas Parker	10.2 to Pinnacle West/APS September 30, 2007 Form 10-Q Report, File No. 1-8962	11-6-07

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
6.4d [b]	Pinnacle West	Description of Annual Stock Grants to Non-Employee Directors	10.2 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File No. 1-8962	8-07-08
10.6.5 [bd]	Pinnacle West APS	Summary of 2011 CEO Variable Incentive Plan and Officer Variable Incentive Plan		
10.7.1	Pinnacle West APS	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS's Form S-7 Registration Statement, File No. 2-59644	9-1-77
10.7.1a	Pinnacle West APS	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS's Form S-7 Registration Statement, File No. 2-59644	9-1-77
10.7.1b	Pinnacle West APS	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to Pinnacle West's Registration Statement on Form 8-B Report, File No. 1-8962	7-25-85
10.7.2	Pinnacle West APS	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS's Form S-7 Registration Statement, File No. 2-59644	9-1-77
10.7.2a	Pinnacle West APS	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.37 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7-25-85

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.7.3	Pinnacle West APS	Application and Grant of Arizona Public Service Company rights- of-way and easements, Four Corners Plant Site	5.05 to APS's Form S-7 Registration Statement, File No. 2-59644	9-1-77
10.7.3a	Pinnacle West APS	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.38 to Pinnacle West's Registration Statement on Form 8-B, File No. 1-8962	7-25-85
10.7.4	Pinnacle West APS	Four Corners Project Co-Tenancy Agreement Amendment No. 6	10.7 to Pinnacle West's 2000 Form 10-K Report, File No. 1-8962	3-14-01
10.8.1	Pinnacle West APS	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS's Form S-7 Registration Statement, File No. 2-36505	3-23-70
10.8.2	Pinnacle West APS	Application of Grant of rights-of-way and easements, Navajo Plant	5(h) to APS Form S-7 Registration Statement, File No. 2-36505	3-23-70
10.8.3	Pinnacle West APS	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS's Form S-7 Registration Statement, File No. 2-394442	3-16-71

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.8.4	Pinnacle West APS	Navajo Project Co-Tenancy Agreement dated as of March 23, 1976, and Supplement No. 1 thereto dated as of October 18, 1976, Amendment No. 1 dated as of July 5, 1988, and Amendment No. 2 dated as of June 14, 1996; Amendment No. 3 dated as of February 11, 1997; Amendment No. 4 dated as of January 21, 1997; Amendment No. 5 dated as of January 23, 1998; Amendment No. 6 dated as of July 31, 1998	10.107 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06
10.8.5	Pinnacle West APS	Navajo Project Participation Agreement dated as of September 30, 1969, and Amendment and Supplement No. 1 dated as of January 16, 1970, and Coordinating Committee Agreement No. 1 dated as of September 30, 1971	10.108 to Pinnacle West/APS 2005 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-13-06

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.9.1	Pinnacle West APS	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10. 1 to APS's 1988 Form 10-K Report, File No. 1-4473	3-8-89
10.9.1a	Pinnacle West APS	Amendment No. 13, dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS's March 31, 1991 Form 10-Q Report, File No. 1-4473	5-15-91

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
9.1b	Pinnacle West APS	Amendment No. 14 to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	99.1 to Pinnacle West's June 30, 2000 Form 10-Q Report, File No. 1-8962	8-14-00
10.9.1c	Pinnacle West APS	Amendment No. 15, dated November 29, 2010, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles		

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.10.1	Pinnacle West APS	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8-8-91
10.10.2	Pinnacle West APS	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS's June 30, 1991 Form 10-Q Report, File No. 1-4473	8-8-91
10.10.2a	Pinnacle West APS	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS's 1995 Form 10-K Report, File No. 1-4473	3-29-96
10.10.3	Pinnacle West APS	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS's 1995 Form 10-K Report, File No. 1-4473	3-29-96
10.10.4	Pinnacle West APS	Contract among PacifiCorp, APS and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS's 1995 Form 10-K Report, File No. 1-4473	3-29-96

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
10.5	Pinnacle West APS	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS's 1995 Form 10-K Report, File No. 1-4473	3-29-96
10.11.1	Pinnacle West APS	Three-Year Credit Agreement dated as of February 12, 2010 between APS, as Borrower, Wells Fargo Bank, National Association, as Agent, and the lenders and other parties thereto	10.11.3 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-19-10
10.11.2	Pinnacle West	$200,000,000 Senior Notes Uncommitted Master Shelf Agreement dated as of February 28, 2006	10.96 to Pinnacle West 2005 Form 10-K Report, File No. 1-8962	3-13-06
10.11.3	Pinnacle West	Three-Year Credit Agreement dated as of February 12, 2010 among Pinnacle West Capital Corporation, as Borrower, Bank of America, N.A, as Agent, and the lenders and other parties thereto	10.11.5 to Pinnacle West/APS 2009 Form 10-K Report, File Nos. 1-8962 and 1-4473	2-19-10

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.11.4	APS	$500,000,000 Four-Year Credit Agreement dated as of February 14, 2011 among Arizona Public Service Company as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, Credit Suisse Securities (USA) LLC, as Syndication Agent, Credit Suisse AG, Cayman Islands Branch, as Issuing Bank, Bank of America, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents and the other parties thereto		
10.11.5	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.2 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-6-10
10.11.6	Pinnacle West APS	Reimbursement Agreement among APS, the Banks party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, dated as of April 16, 2010	10.3 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-6-10

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
12.1 [c]	Pinnacle West APS	Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS's Form 18 Registration Statement, File No. 33-9480	10-24-86
10.12.1a [c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12-4-86
10.12.1b [c]	Pinnacle West APS	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1988 Form 10-K Report, File No. 1-4473	3-8-89

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.12.1c [c]	Pinnacle West APS	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
10.12.2	Pinnacle West APS	Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1-20-87
10.12.2a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8-24-87

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
12.2b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
10.13.1	Pinnacle West APS	Agreement between Pinnacle West Energy Corporation and Arizona Public Service Company for Transportation and Treatment of Effluent by and between Pinnacle West Energy Corporation and APS dated as of the 10 th day of April, 2001	10.102 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05
10.13.2	Pinnacle West APS	Agreement for the Transfer and Use of Wastewater and Effluent by and between APS, SRP and PWE dated June 1, 2001	10.103 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05
10.13.3	Pinnacle West APS	Agreement for the Sale and Purchase of Wastewater Effluent dated November 13, 2000, by and between the City of Tolleson, Arizona, APS and SRP	10.104 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
10.13.4	Pinnacle West APS	Operating Agreement for the Co-Ownership of Wastewater Effluent dated November 16, 2000 by and between APS and SRP	10.105 to Pinnacle West/APS 2004 Form 10-K Report, File Nos. 1-8962 and 1-4473	3-16-05
10.13.5	Pinnacle West APS	Municipal Effluent Purchase and Sale Agreement dated April 29, 2010, by and between City of Phoenix, City of Mesa, City of Tempe, City of Scottsdale, City of Glendale, APS and Salt River Project Agricultural Improvement and Power District	10.1 to Pinnacle West/APS March 31, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	5-6-10
10.14.1	Pinnacle West APS	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement, File No. 2-96386	3-13-85
10.15.1	Pinnacle West APS	Territorial Agreement between APS and Salt River Project	10.1 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5-15-98
10.15.2	Pinnacle West APS	Power Coordination Agreement between APS and Salt River Project	10.2 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5-15-98
10.15.3	Pinnacle West APS	Memorandum of Agreement between APS and Salt River Project	10.3 to APS's March 31, 1998 Form 10-Q Report, File No. 1-4473	5-15-98

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
15.3a	Pinnacle West APS	Addendum to Memorandum of Agreement between APS and Salt River Project dated as of May 19, 1998	10.2 to APS's May 19, 1998 Form 8-K Report, File No. 1-4473	6-26-98
10.16	Pinnacle West APS	Purchase and Sale Agreement dated November 8, 2010 by and between Southern California Edison Company and APS	10.1 to Pinnacle West/APS November 8, 2010 Form 8-K Report, File Nos. 1-8962 and 1-4473	11-8-10
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges		
12.2	APS	Ratio of Earnings to Fixed Charges		
12.3	Pinnacle West	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements		
21.1	Pinnacle West	Subsidiaries of Pinnacle West		
23.1	Pinnacle West	Consent of Deloitte & Touche LLP		
23.2	APS	Consent of Deloitte & Touche LLP		
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
31.2	Pinnacle West	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
31.4	APS	Certificate of James R. Hatfield, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended		
32.1	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
32.2	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
4.1	Pinnacle West APS	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.1a	Pinnacle West APS	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.2 [c]	Pinnacle West APS	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11-9-92

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit: [a]*	*Date Filed*
99.2a [c]	Pinnacle West APS	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8, File No. 1-4473	12-4-86
99.2b [c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
4.3 [c]	Pinnacle West APS	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS's Form 18 Registration Statement, File No. 33-9480	10-24-86
99.3a [c]	Pinnacle West APS	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12-4-86

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
99.3b [c]	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.4 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.4 [c]	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS's Form 18 Registration Statement, File No. 33-9480	10-24-86
99.4a [c]	Pinnacle West APS	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS's September 30, 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8, File No. 1-4473	12-4-86

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
4b [c]	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.5	Pinnacle West APS	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS's September 30, 1992 Form 10-Q Report, File No. 1-4473	11-9-92

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
99.5a	Pinnacle West APS	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8-10-87
99.5b	Pinnacle West APS	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
6	Pinnacle West APS	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to APS's November 18, 1986 Form 10-K Report, File No. 1-4473	1-20-87
99.6a	Pinnacle West APS	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS's Form 18 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report, File No. 1-4473	8-24-87

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
99.6b	Pinnacle West APS	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.5 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.7	Pinnacle West APS	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS's November 18, 1986 Form 8-K Report, File No. 1-4473	1-20-87
99.7a	Pinnacle West APS	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93
99.8 [c]	Pinnacle West APS	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS's 1992 Form 10-K Report, File No. 1-4473	3-30-93

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
99	Pinnacle West APS	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS's Form 18 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report, File No. 1-4473	8-10-87
99.10	Pinnacle West APS	Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to APS's September 30, 1999 Form 10-Q Report, File No. 1-4473	11-15-99
99.11	Pinnacle West	Purchase Agreement by and among Pinnacle West Energy Corporation and GenWest, L.L.C. and Nevada Power Company, dated June 21, 2005	99.5 to Pinnacle West/APS June 30, 2005 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8-9-05
101.INS	Pinnacle West APS	XBRL Instance Document		
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document		
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document		
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document		

Exhibit No.	*Registrant(s)*	*Description*	*Previously Filed as Exhibit:* [a]	*Date Filed*
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document		
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document		

[a] Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[b] Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 15(b) of Form 10-K.

[c] An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d] Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION

(Registrant)

Date: February 18, 2011

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Pinnacle West Capital Corporation, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors, President and Chief Executive Officer)	Principal Executive Officer and Director	February 18, 2011
James R. Hatfield (James R. Hatfield, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 18, 2011
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 18, 2011

Signature	Title	Date
/s/ Edward N. Basha, Jr. (Edward N. Basha, Jr.)	Director	February 18, 2011
/s/ Susan Clark-Johnson (Susan Clark-Johnson)	Director	February 18, 2011
/s/ Denis A. Cortese (Denis A. Cortese)	Director	February 18, 2011
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 18, 2011
/s/ Pamela Grant (Pamela Grant)	Director	February 18, 2011
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr.)	Director	February 18, 2011
/s/ Dale E. Klein (Dale E. Klein)	Director	February 18, 2011
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 18, 2011
 (Kathryn L. Munro)	Director	February 18, 2011
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 18, 2011
/s/ W. Douglas Parker (W. Douglas Parker)	Director	February 18, 2011

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this ort to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: February 18, 2011

/s/ Donald E. Brandt
(Donald E. Brandt, Chairman of the Board of Directors and Chief Executive Officer)

Power of Attorney

We, the undersigned directors and executive officers of Arizona Public Service Company, hereby severally appoint James R. Hatfield and David P. Falck, and each of them, our true and lawful attorneys with full power to them and each of them to sign for us, and in our names in the capacities indicated below, any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Donald E. Brandt (Donald E. Brandt, Chairman of the Board of Directors and Chief Executive Officer)	Principal Executive Officer and Director	February 18, 2011
/s/ James R. Hatfield (James R. Hatfield, Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 18, 2011
/s/ Denise R. Danner (Denise R. Danner, Vice President, Controller and Chief Accounting Officer)	Principal Accounting Officer	February 18, 2011

Signature	Title	Date
/s/ Edward N. Basha, Jr. (Edward N. Basha, Jr.)	Director	February 18, 2011
/s/ Susan Clark-Johnson (Susan Clark-Johnson)	Director	February 18, 2011
/s/ Denis A. Cortese (Denis A. Cortese)	Director	February 18, 2011
/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	February 18, 2011
/s/ Pamela Grant (Pamela Grant)	Director	February 18, 2011
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr.)	Director	February 18, 2011
/s/ Dale E. Klein (Dale E. Klein)	Director	February 18, 2011
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	February 18, 2011
 (Kathryn L. Munro)	Director	February 18, 2011
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	February 18, 2011
/s/ W. Douglas Parker (W. Douglas Parker)	Director	February 18, 2011

Summary of 2011 Incentive Plans

On December 14, 2010, the Human Resources Committee (the "Committee") of the Pinnacle West Capital Corporation ("Pinnacle West") Board of Directors (the "Board") approved the Pinnacle West 2011 Annual Incentive Award Plan (the "PNW Plan"), which provides an incentive award opportunity for Donald E. Brandt, the Chairman of the Board, President, and Chief Executive Officer of Pinnacle West and the Chairman of the Board and Chief Executive Officer of Arizona Public Service Company ("APS"). On December 15, 2010, the Board, acting on the recommendation of the Committee, approved the APS 2011 Annual Incentive Award Plan (the "APS Plan") and the APS 2011 Annual Incentive Award Plan for PVNGS Employees (the "Palo Verde Plan"), which provide incentive award opportunities for Pinnacle West and APS employees, including the following "named executive officers" from the 2010 Proxy Statement: James R. Hatfield, Senior Vice President, Chief Financial Officer and Treasurer; Randall K. Edington, Executive Vice President and Chief Nuclear Officer of APS; David P. Falck, Executive Vice President, General Counsel and Secretary; and Donald G. Robinson, President and Chief Operating Officer of APS. The PNW Plan, the APS Plan, and the Palo Verde Plan are referred to collectively herein as the "2011 Plans."

No incentive payments will be awarded under the PNW Plan or the APS Plan unless Pinnacle West, with respect to Mr. Brandt, and APS, with respect to Messrs. Hatfield, Falck and Robinson, achieves a specified threshold earnings level. No incentive payment will be awarded under the Palo Verde Plan with respect to Mr. Edington unless the Palo Verde Nuclear Generating Station ("Palo Verde") achieves specified threshold business unit performance goals. The Committee may evaluate the impacts of unusual or nonrecurring adjustments to earnings in determining whether any earnings level has been met for purposes of the 2011 Plans, and the impacts of any sale or disposal of real estate development operations will be excluded for purposes of the PNW Plan.

The award opportunity for Mr. Brandt under the PNW Plan is based on the achievement of specified 2011 Pinnacle West earnings levels and the award opportunity for Mr. Robinson under the APS Plan is based on the achievement of specified 2011 APS earnings levels. The awards achieved may be further adjusted by the Committee based upon its evaluation of each officer's individual performance. Mr. Brandt has an award opportunity of up to 50% of his base salary if the threshold earnings level is met, up to 100% of his base salary if a target earnings level is met, and up to 150% of his base salary if a maximum earnings level is met, before adjustment for individual performance. Mr. Robinson has an award opportunity of up to 37.5% of his base salary if the threshold earnings level is met, up to 75% of his base salary if a target earnings level is met, and up to 150% of his base salary if a maximum earnings level is met, before adjustment for individual performance. In considering each officer's individual performance, the Committee may take into account factors such as shareholder value creation, customer service, financial strength, operating performance and safety.

The award opportunities for Messrs. Hatfield and Falck under the APS Plan and for Mr. Edington under the Palo Verde Plan are based on the achievement of specified 2011 APS earnings levels and specified business unit performance goals. The awards achieved may be further adjusted by the Committee, with input from the Chief Executive Officer, based upon its evaluation of each officer's individual performance. Messrs. Hatfield and Falck have a target award opportunity of up to 50% of their base salary. Messrs. Hatfield and Falck may earn less than the target amount or more, up to a maximum award opportunity of up to 100% of their base salary, depending on the achievement of the earnings and business unit performance goals separately or in combination, and before adjustment for individual performance. Mr. Edington has an award opportunity of 12.5% of his base salary up to 100% of his base salary depending on the achievement of the earnings and business unit performance goals, separately or in combination, and before adjustment for individual performance. The business unit performance measures that will be considered for Messrs. Hatfield and Falck are derived from APS' critical areas of focus as provided in its Strategic Framework: customers and communities, employees, operational excellence and shareholder value. In considering each officer's individual performance, with input from the Chief Executive Officer, the Committee may take into account factors such as shareholder value creation, customer service, financial strength, operational performance and safety. The business unit performance indicators that will be considered for Mr. Edington are in the areas of safety, employee performance, achievement of operational metrics for Palo Verde, performance improvement in key areas, and cost management.

AMENDMENT NUMBER 15
TO THE ARIZONA NUCLEAR POWER PROJECT
PARTICIPATION AGREEMENT

PARTIES :

The Parties to this Amendment Number 15 to the Arizona Nuclear Power Project Participation Agreement, hereinafter referred to as "Amendment Number 15," are: ARIZONA PUBLIC SERVICE COMPANY, a corporation organized and existing under and by virtue of the laws of the State of Arizona, hereinafter referred to as "Arizona"; SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, an agricultural improvement district organized and existing under and by virtue of the laws of the State of Arizona, hereinafter referred to as "Salt River Project"; SOUTHERN CALIFORNIA EDISON COMPANY, a corporation organized. and existing under and by virtue of the laws of the State of California, hereinafter referred to as "Edison"; PUBLIC SERVICE COMPANY OF NEW MEXICO, a corporation organized and existing under and by virtue of the laws of the State of New Mexico, hereinafter referred to as "PNM"; EL PASO ELECTRIC COMPANY, a corporation organized and existing under and by virtue of the laws of the State of Texas, hereinafter referred to as "El Paso"; SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY, a joint powers agency organized and existing under and by virtue of the laws of the State of California, doing business in the State of Arizona as SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY ASSOCIATION, hereinafter referred to as "SCPPA"; and DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, a municipal corporation organized and existing under and by virtue of the laws of the State of California, hereinafter referred to as "LADWP;" all hereinafter individually referred to as "Party" and collectively as "Parties."

2. **RECITALS** :

2.1. Arizona, Salt River Project, Edison, PNM, El Paso, SCPPA and LADWP are parties to a certain agreement entitled Arizona Nuclear Power Project Participation Agreement, dated as of August 23, 1973, as amended by: Amendment Number 1, dated as of January 1, 1974; Amendment Number 2, dated as of August 28, 1975; Amendment Number 3, dated as of July 22, 1976; Amendment Number 4, dated as of December 15, 1977; Amendment Number 5, dated as of December 5, 1979; Amendment Number 6, effective as of October 16, 1981; Amendment Number 7, effective as of April 1, 1982; Amendment Number 8, executed as of September 12, 1983; Amendment Number 9, executed as of June 12, 1984 Amendment Number 10, executed as of November 21, 1985; Amendment Number 11, effective January 10, 1987; Amendment Number 12, effective August 5, 1988; Amendment Number 13, effective June 15, 1991; and, Amendment Number 14, effective June 20, 2000, retroactive to January 1, 1993, hereinafter, as so amended, referred to as the "Participation Agreement."

2.2. Pursuant to and in accordance Section E.11 of Appendix E to the Participation Agreement, El Paso and PNM filed protests regarding the allocation of certain overhead expenses of Arizona, and its corporate parent Pinnacle West Capital Corporation, to the Arizona Nuclear Power Project Participants, as specified in the Participation Agreement, Appendix E, (the "Protests").

2.3. After analysis and consideration of the Protests by the appropriate Palo Verde Participant committees, the Participants were not able to resolve the Protests to the satisfaction of all of the Participants.

2.4. Prior to the call for submission of the Protests to arbitration as specified in Sections 24 and E.11.2 of the Participation Agreement, the Participants referred the Protests to *higher authority* within each of the respective Participants' organizations in accordance with Section 6.10 of the Participation Agreement.

2.5. In December 2009 and January 2010, the Participants' *higher authority* (*i.e.* the Chief Executive Officers, or the positional equivalent) met and conferred in an attempt to resolve the Protests. Following these meetings, PNM agreed to withdraw its protest, and Arizona proposed modifications to certain provisions of the Participation Agreement, Appendix E, to resolve El Paso's protest; El Paso agreed to Arizona's proposed settlement, and agreed to withdraw its protest provided that all Participants execute this Amendment No. 15.

3. **AGREEMENT** :

For and in consideration of the premises and the mutual obligations of and undertakings by the Parties as hereinafter provided in this Amendment Number 15 to the Participation Agreement, the Parties agree as follows.

4. **EFFECTIVE DATE** :

This Amendment Number 15 shall become effective forty-five (45) days after the date that the Party which last in time executes this Amendment Number 15. The amended procedures for allocating costs that are associated with this Amendment Number 15 shall be applied retroactively to January 1, 2010.

5. **DEFINED TERMS** :

5.1. The Capitalized and *italicized* words and phrases used in this Amendment Number 15 shall have meanings ascribed to them in the Participation Agreement as amended by this Amendment Number 15.

5.2. All references to a "Section" or "Sections" in this Amendment Number 15 shall mean a Section or Sections of the Participation Agreement unless the text expressly states otherwise.

6. **AMENDMENTS TO THE ARIZONA NUCLEAR POWER PROJECT MADE BY THIS AMENDMENT NUMBER 15**

6.1. Delete Section E.1.9.

6.2. Delete Section E.2.3.

6.3. Amend Section E.3.1.4, by deleting the strikethrough text and substituting therefor the underlined text :

A portion of the expenses incurred by the Operating Agent's System Electric Operations Department, such portion to be determined by multiplying the total of such expenses by a ratio, the numerator of which is ~~the total payroll for ANPP and the denominator of which is the total payroll supervised by the Executive Vice President, Engineering and Operations~~ the annual total net megawatt-hour generation of the ANPP (known and referred to as the Palo Verde Nuclear Generating Station), and the denominator of which is the annual total net megawatt-hour generation of all Arizona-operated electric generating facilities plus Arizona megawatt-hour power purchases plus Arizona megawatt-hour transmission of power for others . Such expenses shall include, but not be limited to, the following:

6.4. Amend Section E.6.1, by deleting the strikethrough text:

The Operation and Maintenance A & G Ratio shall be the percentage computed by dividing (i) the sum of (a) the total amounts charged to FPC Accounts 920 and 921 multiplied by the O & M Ratio computed in accordance with Section E.8 hereof, (b) the total amounts charged to FPC Accounts 923 (except any amounts directly chargeable to ANPP) and 935 (formerly 932), (c) the product of the portion of labor charges included within (a) and (b) above multiplied by the Payroll Tax Ratio computed in accordance with Section E.4 hereof (d) the product of the labor charges included within (a) and (b) above multiplied by the Benefits Ratio computed in accordance with Section E.5 hereof, and (e) the product of the labor charges included within (a) and (b) above multiplied by the Compensation Insurance Ratio computed in accordance with Section E.7 hereof, ~~less (f) the one percent (1%) portion of the administrative and general expenses charged to FPC Accounts 920 and 921 allocable to contract operation and maintenance~~ by (ii) the direct labor (i.e. total labor less labor charge to clearing accounts) chargeable to operation and maintenance accounts (exclusive of A & G), to include O & M labor billed to Participants and the labor portion of Start-Up and Pre-Operation Costs subject to the Operation and Maintenance A & G Ratio pursuant to Section L.1.3, and to exclude the labor portion of Start-Up and Pre-Operation Costs subject to the construction administrative and general expense percentage of one percent (1%) pursuant to Section L.1.3.

6.5. Amend Section E.6.2, by deleting the strikethrough text and substituting therefor the underlined text :

The following example sets forth the method to be employed by the Operating Agent to determine the Operation and Maintenance A & G Ratio:

EXAMPLE COMPUTATION OF OPERATIONS

AND MAINTENANCE A & G RATIO

(Based on the Operating Agent's 1984 Experience)

Labor	Total
Administrative and General Salaries	

charged to FPC Account 920	$ 17,408,542	$ 17,406,779
Office Supplies and Expenses charged to FPC Account 921		7,208,084
[Line 7] Total	$ 17,408,542	$ 24,614,863
Total FPC Accounts 920 and 921, multiplied by O & M Ratio @ 68.48%	$ 11,921,544	$ 16,856,504
FPC Account 923		919,166
FPC Account 932 (presently 935)	1,555,913	3,127,002
[Line 11] Subtotal	$ 13,477,457	$ 20,902,672
Payroll Taxes @ 7.126%		960,404
Pensions and Benefits @ 13.512%		1,821,074
Compensation Insurance @ 0.451%		60,783
~~Less that 1% portion of A & G allocable to Contract Operation and Maintenance~~		~~1,483,314~~
Total administrative and general expenses allocable to operations and maintenance	~~$ 22,261,619~~	$ 23,744,933

Labor Base

Direct labor charged to system operations and maintenance, as further defined in Section E.6.1	$148,557,953
Less direct labor charged to administrative and general expenses (FPC Accounts 920-931 and 935)	13,160,635
Labor Base	$135,397,318

~~Operation and Maintenance~~

~~A & G Ratio for 1984 $22,261,619 ÷ $135,397,318 = 16.442%~~

Operation and Maintenance

A & G Ratio for 1984 $23,744,933 ÷ $135,397,318 = 17.537%

Note: All labor figures include loading for allowed time.

6.6. Amend Section E.9.1, by deleting the strikethrough text:

The Capital A & G Ratio shall be the percentage computed by dividing (i) the amounts equal to ~~(A)~~ the sum of (a) the total amounts charged to FPC Accounts 920 and 921 multiplied by the Construction Ratio computed in accordance with Section E.8 hereof, and (b) the product of the portion of labor charges included in (a) above multiplied by the sum of the Payroll Tax Ratio, the Benefits Ratio and the Compensation Insurance Ratio ~~less (B) the one percent (1%) portion of administrative and general expenses charged to FPC Accounts 920 and 921 allocable to contract construction (including the administrative and general expenses (i) recovered on Start-Up and Pre-Operation Costs subject to the construction administrative and general expense percentage of one percent (1%) pursuant to Section L.1.3, (ii) recovered on ANPP construction expenses, and (iii) allocable to other contract construction)~~ by (ii) the direct labor in construction accounts (exclusive of A & G), to include construction labor billed to Participants, excluding the labor portion of Start-Up and Pre-Operation Costs subject to the Operation and Maintenance A & G Ratio pursuant to Section L.1.3, less the labor portion of construction expenses to which the one percent (1%) portion of administrative and general expenses is applicable, and less the labor portion of Start-Up and Pre-Operation Costs subject to the construction administrative and general expense percentage of one percent (1%) pursuant to Section L.1.3.

6.7. Amend Section E.9.2, by deleting the strikethrough text and substituting therefor the underlined text :

The following example sets forth the method to be employed by the Operating Agent to determine the Capital A & G Ratio:

EXAMPLE COMPUTATION OF CAPITAL A & G RATIO

(Based on the Operating Agent's 1984 Experience)

Labor		Total
Administrative and General Salaries charged to FPC Account 920	$ 17,408,542	$ 17,406,779
Office Supplies and Expenses charged to FPC Account 921		7,208,084
[Line 7] Total	$ 17,408,542	$ 24,614,863
Total FPC Accounts 920 and 921, multiplied [Line 9] by Construction Ratio @ 28.355%	$ 4,936,192	$ 6,979,544
Payroll Taxes @ 7.126%		351,753
Pensions and Benefits @ 13.512%		666,978
mpensation Insurance @ 0.451%		22,262
~~ss that 1% portion of A & G allocable~~		

~~to Contract Construction, as further defined in Section E.9.1~~		~~3,634,919~~
Total A & G Expense allocable to Construction	~~$ 4,385,618~~	8,020,537
Construction Direct Labor		56,061,726
Less the labor portion of Construction Work, Start-Up and Pre-Operation Costs subject to the construction administrative and general expense percentage of one percent (1%)		13,496,824
Total Construction Direct Labor Base		$ 42,564,902

~~Capital A & G Ratio for 1984 $4,385,618 ÷ $42,564,902 = 10.303%~~

Capital A & G Ratio for 1984 $8,020,537 ÷ $42,564,902 = 18.843%

Note: All labor figures include loading for allowed time.

7. **EXECUTION BY COUNTERPARTS** :

This Amendment Number 15 may be executed in any number of counterparts, and upon execution by all Participants, each executed counterpart shall have the same force and effect as an original instrument and as if all Participants had signed the same instrument. Any signature page of this Amendment Number 15 may be detached from any counterpart of the Amendment Number 15 without impairing the legal effect of any signature thereon, and may be attached to another counterpart of this Amendment Number 15 identical in form hereto but having attached to it one or more signature pages.

[Remainder of page intentionally left blank. This page is followed by seven consecutive execution pages.]

8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

ARIZONA PUBLIC SERVICE COMPANY

By: _____

Its: President + COO

Date: 11/29/10

STATE OF ARIZONA)
) ss.
County of Maricopa)

On this 29 day of November, 2010, before me, the undersigned Notary Public, personally appeared Donald Robinson who acknowledged him/herself to be the President + COO of ARIZONA PUBLIC SERVICE COMPANY, an Arizona corporation, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such President + COO.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

KAREN McLOUGHLIN
Notary Public—Arizona
Maricopa County
Expires 10/15/2014

_____
Notary Public

My Commission Expires:

10/15/2014

8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

Reviewed by SRP Legal Services Dept.

(Signed Name)

Ken Lee

(Printed Name)

Date: 6/14/10

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

By: _____

Its: VP President

Date: 6/14/2010

ATTEST AND COUNTERSIGN:

By: _____

Its: Corporate Secretary

Date: 6/14/10

STATE OF ARIZONA)
) ss.
County of Maricopa)

On this 14th day of June, 2010, before me, the undersigned Notary Public, personally appeared John R. Hoopes who acknowledged him/~~herself~~ to be the SRP Vice President of SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, an Arizona corporation, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such SRP Vice President.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

_____
Notary Public

My Commission Expires:
Aug 5, 2011

STEPHANIE K. REED
Notary Public - Arizona
Maricopa County
My Comm. Expires Aug 5, 2011

8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

SOUTHERN CALIFORNIA EDISON COMPANY

By: _____

Its: Chairman & Chief Executive Officer

Date: September 2, 2010

STATE OF CALIFORNIA)
) ss.
County of Los Angeles)

On this ___ day of _____, 2010, before me, the undersigned Notary Public, personally appeared _____ who acknowledged him/herself to be the _____ of SOUTHERN CALIFORNIA EDISON COMPANY, a California corporation, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such _____.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

_____
Notary Public

My Commission Expires:

_____

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT

State of California
County of Los Angeles }

On 09.02.2010 (Date) before me, Michelle M Morales, Notary Public (Here Insert Name and Title of the Officer)

personally appeared Alan Fohrer (Name(s) of Signer(s))

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Signature _____ (Signature of Notary Public)

MICHELLE M. MORALES
Commission # 1802865
Notary Public - California
Los Angeles County
My Comm. Expires Feb 17, 2013

Place Notary Seal Above

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of Attached Document

Title or Type of Document: Amendment No. 15 APS

Document Date: _____ Number of Pages: _____

Signer(s) Other Than Named Above: _____

Capacity(ies) Claimed by Signer(s)

Signer's Name: _____
☐ Individual
☐ Corporate Officer — Title(s): _____
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: _____
Signer Is Representing: _____

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

Signer's Name: _____
☐ Individual
☐ Corporate Officer — Title(s): _____
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: _____
Signer Is Representing: _____

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

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8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

PUBLIC SERVICE COMPANY OF NEW MEXICO

Patrick Themig

By: PATRICK THEMIG

Its: VP Generation

Date: 10/4/10

STATE OF NEW MEXICO)
) ss.
County of Bernalillo)

On this 4th day of October, 2010, before me, the undersigned Notary Public, personally appeared Patrick Themig who acknowledged him/herself to be the VP Generation of PUBLIC SERVICE COMPANY OF NEW MEXICO, a New Mexico corporation, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such VP Generation.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

J. Marcella Kircher
Notary Public

My Commission Expires:

12-17-2011

8. SIGNATURE CLAUSE:

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

EL PASO ELECTRIC COMPANY

By: _____

Its: C. E. O.

Date: September 10, 2010

STATE OF TEXAS)
) ss.
County of El Paso)

On this 10 day of September, 2010, before me, the undersigned Notary Public, personally appeared David W. Stevens who acknowledged him/herself to be the C. E. O. of EL PASO ELECTRIC COMPANY, a Texas corporation, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such David W. Stevens.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

Valerie J Pugh
Notary Public

My Commission Expires:

12-9-2012

VALERIE J. PUGH
MY COMMISSION EXPIRES
December 9, 2012

8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY, doing business in the State of Arizona as SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY ASSOCIATION

By _____

Its: EXECUTIVE DIRECTOR

Date: 9/28/10

STATE OF CALIFORNIA)
) ss.
County of Los Angeles)

On this ___ day of _____, 2010, before me, the undersigned Notary Public, personally appeared _____ who acknowledged him/herself to be the _____ of SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY, (doing business in the State of Arizona as SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY ASSOCIATION), a California joint powers agency, and that he/she as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/herself as such _____.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

This is attached to a
Acknowledgement or Jurat
Sue Hasseler, NP, CNSA,TEA, MDSA

_____
Notary Public

My Commission Expires:

_____

State of California)
County of Los Angeles)

CALIFORNIA ALL-PURPOSE CERTIFICATE OF ACKNOWLEDGMENT

On September 28, 2010 before me, *Sue Hasseler, a notary public*,
(here insert name and title of the officer)

personally appeared Bill D. Carnahan

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

SUE HASSELER
COMM. # 1829011
NOTARY PUBLIC, CALIFORNIA
LOS ANGELES COUNTY
My Comm. Expires Jan 1, 2013

WITNESS my hand and official seal.

Signature _____ (Seal)

OPTIONAL INFORMATION

Although the information in this section is not required by law, it could prevent fraudulent removal and reattachment of this acknowledgment to an unauthorized document and may prove useful to persons relying on the attached document.

Description of Attached Document

The preceding Certificate of Acknowledgment is attached to a document titled/for the purpose of Amendment Number 15 to the Arizona Nuclear Power Project Participation Agreement,

containing 13 pages, and dated —.

The signer(s) capacity or authority is/are as:

- ☐ Individual(s)
- ☐ Attorney-in-Fact
- ☐ Corporate Officer(s) _____ Title(s)

...tor
...eral

...me(s) of Person(s) or Entity(ies) Signer is Representing

Additional Information

Method of Signer Identification

Proved to me on the basis of satisfactory evidence:
☑ form(s) of identification ○ credible witness(es)

Notarial event is detailed in notary journal on:
Page # _____ Entry # _____

Notary contact: _____

Other

☐ Additional Signer(s) ☐ Signer(s) Thumbprint(s)
☐ _____

Sue Hasseler,
N.P.,C.N.S.A.,T.E.A.
(020) 485-7000
Comm. Exp. 01-01-2015

8. **SIGNATURE CLAUSE:**

Each of the signatories below represents that he/she is appropriately authorized to enter into this Amendment Number 15 on behalf of the Party for which he/she signs.

DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

By: _____

Its: SR. ASST. GENERAL MGR.

Date: 06/02/10

STATE OF CALIFORNIA)
) ss.
County of Los Angeles)

On this 2nd day of June, 2010, before me, the undersigned Notary Public, personally appeared ARAM BENJAMIN who acknowledged him/~~herself~~ to be the SR. ASST. GEN. MGR. of DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, a California joint powers agency, and that he/~~she~~ as such officer, being authorized to do, executed the foregoing instrument for the purposes therein contained by signing the name of the company by him/~~herself~~ as such _____.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

_____
Notary Public

My Commission Expires:

_____

CHERE D. LOTT
Commission # 1814425
Notary Public - California
Los Angeles County
My Comm. Expires Sep 21, 2012

U.S. $500,000,000
FOUR-YEAR CREDIT AGREEMENT
Dated as of February 14, 2011

among
ARIZONA PUBLIC SERVICE COMPANY,
as Borrower ,

THE LENDERS PARTY HERETO,

BARCLAYS BANK PLC ,
as Agent and Issuing Bank ,

CREDIT SUISSE SECURITIES (USA) LLC ,
as Syndication Agent ,

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
as Issuing Bank,

BANK OF AMERICA, N.A.
and
WELLS FARGO BANK, NATIONAL ASSOCIATION ,
as Co-Documentation Agents ,

BARCLAYS CAPITAL
CREDIT SUISSE SECURITIES (USA) LLC
MERRILL LYNCH, PIERCE, FENNER & SMITH INCORPORATED
and
WELLS FARGO SECURITIES, LLC ,
as Joint Lead Arrangers

and

BARCLAYS CAPITAL,
and
CREDIT SUISSE SECURITIES (USA) LLC
as Joint Book Runners

TABLE OF CONTENTS

ARTICLE I

DEFINITIONS AND ACCOUNTING TERMS

Section 1.01 Certain Defined Terms 1
Section 1.02 Other Interpretive Provisions 19
Section 1.03 Accounting Terms 20
Section 1.04 Rounding 20
Section 1.05 Times of Day 20

ARTICLE II

AMOUNTS AND TERMS OF THE ADVANCES AND LETTERS OF CREDIT

Section 2.01 The Advances and Letters of Credit 20
Section 2.02 Making the Advances 21
Section 2.03 Letters of Credit 22
Section 2.04 Fees 30
Section 2.05 Optional Termination or Reduction of the Commitments 31
Section 2.06 Repayment of Advances 32
Section 2.07 Interest on Advances 32
Section 2.08 Interest Rate Determination 33
Section 2.09 Optional Conversion of Advances 34
Section 2.10 Prepayments of Advances 34
Section 2.11 Increased Costs 35
Section 2.12 Illegality 36
ction 2.13 Payments and Computations 37
ction 2.14 Taxes 38
Section 2.15 Sharing of Payments, Etc. 42
Section 2.16 Evidence of Debt 42
Section 2.17 Use of Proceeds 43
Section 2.18 Increase in the Aggregate Revolving Credit Commitments 43
Section 2.19 Affected Lenders 45
Section 2.20 Replacement of Lenders 46

ARTICLE III

CONDITIONS PRECEDENT

Section 3.01 Conditions Precedent to Effectiveness 47
Section 3.02 Conditions Precedent to Each Credit Extension and Commitment Increase 49
Section 3.03 Determinations Under Section 3.01 49

ARTICLE IV

REPRESENTATIONS AND WARRANTIES

Section 4.01 Representations and Warranties of the Borrower 50

ARTICLE V

COVENANTS OF THE BORROWER

Section 5.01 Affirmative Covenants 53
Section 5.02 Negative Covenants 56
Section 5.03 Financial Covenant 58

ARTICLE VI

EVENTS OF DEFAULT

Section 6.01 Events of Default 58
Section 6.02 Actions in Respect of Letters of Credit upon Default 60

ARTICLE VII

THE AGENT

Section 7.01 Appointment and Authority 61
Section 7.02 Rights as a Lender 61
Section 7.03 Exculpatory Provisions 62
Section 7.04 Reliance by Agent 62
Section 7.05 Delegation of Duties 63
Section 7.06 Resignation of Agent 63
Section 7.07 Non-Reliance on Agent and Other Lenders 63
Section 7.08 No Other Duties, Etc. 64
Section 7.09 Issuing Banks 64

ARTICLE VIII

MISCELLANEOUS

Section 8.01 Amendments, Etc. 64
Section 8.02 Notices, Etc. 65
Section 8.03 No Waiver; Cumulative Remedies; Enforcement 67
Section 8.04 Costs and Expenses; Indemnity; Damage Waiver 67
Section 8.05 Right of Set-off 69
Section 8.06 Binding Effect 70
Section 8.07 Successors and Assigns 70
Section 8.08 Confidentiality 73
Section 8.09 Governing Law 74

Section 8.10 Counterparts; Integration; Effectiveness 74
Section 8.11 Jurisdiction, Etc. 74
Section 8.12 Payments Set Aside 75
Section 8.13 Patriot Act 75
Section 8.14 Waiver of Jury Trial 75
Section 8.15 No Advisory or Fiduciary Responsibility 76
Section 8.16 Survival of Representations and Warranties 76
Section 8.17 Severability 76

Schedules

Schedule 1.01 Commitments and Ratable Shares
Schedule 4.01(j) Subsidiaries
Schedule 4.01(k) Existing Indebtedness
Schedule 8.02 Certain Address for Notices

Exhibits

Exhibit A Form of Note
Exhibit B Form of Notice of Borrowing
Exhibit C Form of Assignment and Assumption

FOUR-YEAR CREDIT AGREEMENT

Dated as of February 14, 2011

ARIZONA PUBLIC SERVICE COMPANY, an Arizona corporation (the " Borrower "), the banks, financial institutions and other institutional lenders (the " Initial Lenders ") and initial issuing banks (the " Initial Issuing Banks ") listed on the signature pages hereof, the other Lenders (as hereinafter defined), BARCLAYS BANK PLC, as Agent for the Lenders (as hereinafter defined), CREDIT SUISSE SECURITIES (USA) LLC, as Syndication Agent and BANK OF AMERICA, N.A. and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Co-Documentation Agents, agree as follows:

The Borrower has requested that the Lenders provide a revolving credit facility for the purposes set forth herein, and the Lenders are willing to do so on the terms and conditions set forth herein.

In consideration of the mutual covenants and agreements herein contained, the parties hereto covenant and agree as follows:

ARTICLE I

DEFINITIONS AND ACCOUNTING TERMS

Section 1.01 Certain Defined Terms . As used in this Agreement, the following terms shall have the following meanings:

" 2007 Order " means Decision No. 69947, dated October 30, 2007, of the Arizona Corporation Commission.

" Administrative Questionnaire " means an Administrative Questionnaire in a form supplied by the Agent.

" Advance " means an advance by a Lender to the Borrower as part of a Borrowing, including a Base Rate Advance made pursuant to Section 2.03(c), but excluding any L/C Advance made as part of an L/C Borrowing, and refers to a Base Rate Advance or a Eurodollar Rate Advance (each of which shall be a Type of Advance).

" Affected Lender " means any Lender, as reasonably determined by the Agent or if the Agent is the Affected Lender, by the Required Lenders, that (a) has defaulted in its obligation to fund any Advance or any of its other funding obligations under this Agreement, (b) has notified the Borrower, the Agent, any Issuing Bank or any Lender in writing of its intention not to fund any Advance or any of its other funding obligations under this Agreement, (c) has otherwise failed to pay over to the Agent or any other Lender any other amount required to be paid by it hereunder within three Business Days of the date when due, unless the subject of a good faith dispute, (d) has failed, within three Business Days after written request by the Agent, or if the Agent is the Affected Lender, by the Required Lenders, to confirm that it will comply with the terms of this Agreement relating to its obligations to fund prospective Advances or (e) shall (or

whose parent company shall) generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors; or shall have had any proceeding instituted by or against such Lender (or its parent company) seeking to adjudicate it as bankrupt or insolvent, or seeking liquidation, winding up, reorganization, arrangement, adjustment, protection, relief, or composition of it or its debts under any law relating to bankruptcy, insolvency or reorganization or relief of debtors, or seeking the entry of an order for relief or the appointment of a receiver, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or custodian for it or for any substantial part of its property and, in the case of any such proceeding instituted against it (but not instituted by it), either such proceeding shall remain undismissed or unstayed for a period of 30 days, or any of the actions sought in such proceeding (including, without limitation, the entry of an order for relief against, or the appointment of a receiver, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or custodian for, it or for any substantial part of its property) shall occur, or shall take (or whose parent company shall take) any corporate action to authorize any of the actions set forth above in this subsection (e), provided that a Lender shall not be deemed to be an Affected Lender solely by virtue of the ownership or acquisition of any equity interest in any Lender or any Person that directly or indirectly controls such Lender by a Governmental Authority or an instrumentality thereof.

" Affiliate " means, as to any Person, any other Person that, directly or indirectly, controls, is controlled by or is under common control with such Person or is a director or officer of such Person. For purposes of this definition, the term "control" (including the terms "controlling", "controlled by" and "under common control with") of a Person means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of Voting Stock, by contract or otherwise.

" Agent " means Barclays Bank in its capacity as administrative agent under any of the Loan Documents, or any successor administrative agent.

" Agent's Account " means the account of the Agent designated on Schedule 8.02 under the heading "Agent's Account" or such other account as the Agent may designate to the Lenders and the Borrower from time to time.

" Agent's Office " means the Agent's address and, as appropriate, the Agent's Account, or such other address or account as the Agent may from time to time notify to the Borrower and the Lenders.

" Applicable Lending Office " means, with respect to each Lender, such Lender's Domestic Lending Office in the case of a Base Rate Advance and such Lender's Eurodollar Lending Office in the case of a Eurodollar Rate Advance.

" Applicable Rate " means, from time to time, the following percentages per annum determined by reference to the Public Debt Rating as set forth below:

Public Debt Rating S&P/Moody's	Base Rate Advances	Eurodollar Rate Advances	Commitment Fee
Level 1 ≥ A/A2	0.25%	1.25%	0.125%
Level 2 < Level 1 but ≥ A-/A3	0.50%	1.50%	0.150%
Level 3 < Level 2 but ≥ BBB+/Baa1	0.75%	1.75%	0.200%
Level 4 < Level 3 but ≥ BBB/Baa2	1.00%	2.00%	0.250%
Level 5 < Level 4 but ≥ BBB-/Baa3	1.25%	2.25%	0.350%
Level 6 < Level 5	1.50%	2.50%	0.450%

" Approved Fund " means any Fund that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of any entity that administers or manages a Lender.

" Arrangers " means, collectively, Barclays Capital, the investment banking division of Barclays Bank PLC, Credit Suisse Securities (USA) LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC.

" Assignment and Assumption " means an assignment and assumption entered into by a Lender and an Eligible Assignee, and accepted by the Agent, in substantially the form of Exhibit C hereto.

" Assuming Lender " has the meaning specified in Section 2.18(d).

" Assumption Agreement " has the meaning specified in Section 2.18(d)(ii).

" Authorized Officer " means the chairman of the board, chief executive officer, chief operating officer, chief financial officer, chief accounting officer, president, any vice president, treasurer, controller or any assistant treasurer of the Borrower.

" Available Amount " of any Letter of Credit means, at any time, the maximum amount available to be drawn under such Letter of Credit at such time (assuming compliance at such time with all conditions to drawing).

" Barclays Bank " means Barclays Bank PLC.

" Base Rate " means for any day a fluctuating rate per annum equal to the highest of:

(a) the rate of interest in effect for such day as publicly announced from time to time by the Agent as its "prime rate";

(b) the Federal Funds Rate plus 0.50%; and

(c) an amount equal to (i) the Eurodollar Rate for a one month Interest Period on such day (or if such day is not a Business Day, the immediately preceding Business Day) plus (ii) 1%.

"Prime rate" means the rate of interest in effect for such day as publicly announced from time to time by the Agent as its "prime rate." The "prime rate" is a rate set by the Agent based upon various factors including the Agent's costs and desired return, general economic conditions and other factors, and is used as a reference point for pricing some loans, which may be priced at, above, or below such announced rate. Any change in the "prime rate" announced by the Agent shall take effect at the opening of business on the day specified in the public announcement of such change.

" Base Rate Advance " means an Advance that bears interest as provided in Section 2.07(a)(i).

" Borrower " has the meaning given to such term in the introductory paragraph hereof.

" Borrower Information " has the meaning specified in Section 8.08.

" Borrowing " means a borrowing consisting of simultaneous Advances of the same Type made by each of the Lenders pursuant to Section 2.01(a).

" Business Day " means a day of the year on which banks are not required or authorized by Law to close in New York City or Phoenix, Arizona and, if the applicable Business Day relates to any Advance in which interest is calculated by reference to the Eurodollar Rate, on which dealings are carried on in the London interbank market.

" Capital Lease Obligations " means as to any Person, the obligations of such Person to pay rent or other amounts under a lease of (or other agreement conveying the right to use) real and/or personal property, which obligations are required to be classified and accounted for as a capital lease on the balance sheet of such Person under GAAP and, for the purposes of this Agreement, the amount of such obligations shall be the capitalized amount thereof, determined in accordance with GAAP.

" Change in Law " means the occurrence, after the date of this Agreement, of any of the following: (a) the adoption of any Law, any change in any Law or in the administration, interpretation or application thereof by any Governmental Authority or (c) the making or issuance of any request, guideline or directive (whether or not having the force of law) by any Governmental Authority; provided, however, that notwithstanding anything herein to the contrary, the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, guidelines or directives thereunder or issued in connection therewith shall be deemed to be a "Change in Law", regardless of the date enacted, adopted or issued.

" Commitment " means a Revolving Credit Commitment or a Letter of Credit Commitment.

" Commitment Date " has the meaning specified in Section 2.18(b).

" Commitment Increase " has the meaning specified in Section 2.18(a).

" Consolidated " refers to the consolidation of accounts in accordance with GAAP.

" Consolidated Indebtedness " means, at any date, the Indebtedness of the Borrower and its Consolidated Subsidiaries determined on a Consolidated basis as of such date; provided , however , that so long as the creditors of the VIE Lessor Trusts have no recourse to the assets of the Borrower, "Consolidated Indebtedness" shall not include any Indebtedness or other obligations of the VIE Lessor Trusts.

" Consolidated Net Worth " means, at any date, the sum as of such date of (a) the par value (or value stated on the books of the Borrower) of all classes of capital stock of the Borrower and its Subsidiaries, excluding the Borrower's capital stock owned by the Borrower and/or its Subsidiaries, *plus* (or *minus* in the case of a surplus deficit) (b) the amount of the Consolidated surplus, whether capital or earned, of the Borrower, determined in accordance with GAAP as of the end of the most recent calendar month (excluding the effect on the Borrower's accumulated other comprehensive income/loss of the ongoing application of Accounting Standards Codification Topic 815).

" Consolidated Subsidiary " means, at any date, any Subsidiary or other entity the accounts of which would be Consolidated with those of the Borrower on its Consolidated financial statements if such financial statements were prepared as of such date; provided that in no event will Consolidated Subsidiaries include the VIE Lessor Trusts.

" Convert ", " Conversion " and " Converted " each refers to a conversion of Advances of one Type into Advances of the other Type pursuant to Section 2.08, Section 2.09 or Section 2.12.

" Credit Extension " means each of the following: (a) a Borrowing and (b) the issuance of a Letter of Credit.

" Debtor Relief Laws " means the Bankruptcy Code of the United States of America, and all other liquidation, conservatorship, bankruptcy, assignment for the benefit of creditors, moratorium, rearrangement, receivership, insolvency, reorganization, or similar debtor relief Laws of the United States of America or other applicable jurisdictions from time to time in effect and affecting the rights of creditors generally.

" Default " means any Event of Default or any event that would constitute an Event of Default but for the requirement that notice be given or time elapse or both.

" Dollars " or " $ " means dollars of the United States of America.

" Domestic Lending Office " means, with respect to any Lender, the office of such Lender described as such in such Lender's Administrative Questionnaire, or such other office or offices as a Lender may from time to time notify the Borrower and the Agent.

" Effective Date " has the meaning specified in Section 3.01.

" Eligible Assignee " means any Person that meets the requirements to be an assignee under Section 8.07(b)(iii), (v) and (vi) (subject to such consents, if any, as may be required under Section 8.07(b)(iii)).

" Environmental Action " means any action, suit, demand, demand letter, claim, notice of non-compliance or violation, notice of liability or potential liability, investigation, proceeding, consent order or consent agreement relating in any way to any Environmental Law, Environmental Permit or Hazardous Materials or arising from alleged injury or threat of injury to health, safety or the environment and relating to any Environmental Law, including, without limitation, (a) by any Governmental Authority for enforcement, cleanup, removal, response, remedial or other actions or damages and (b) by any Governmental Authority or any third party for damages, contribution, indemnification, cost recovery, compensation or injunctive relief.

" Environmental Law " means any federal, state, local or foreign statute, law, ordinance, rule, regulation, code, order, judgment, decree or judicial or agency interpretation, policy or guidance relating to pollution or protection of the environment, natural resources or, to the extent relating to exposure to Hazardous Materials, human health or safety, including, without limitation, those relating to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

" Environmental Permit " means any permit, approval, identification number, license or other authorization required under any Environmental Law.

" ERISA " means the Employee Retirement Income Security Act of 1974.

" ERISA Affiliate " means any trade or business (whether or not incorporated) under common control with the Borrower within the meaning of Section 414(b) or (c) of the Internal Revenue Code (and Sections 414(m) and (o) of the Internal Revenue Code for purposes of provisions relating to Section 412 of the Internal Revenue Code).

" ERISA Event " means (a) a Reportable Event with respect to a Pension Plan; (b) a withdrawal by the Borrower or any ERISA Affiliate from a Pension Plan subject to Section 4063 of ERISA during a plan year in which it was a substantial employer (as defined in Section 4001(a)(2) of ERISA) or a cessation of operations that is treated as such a withdrawal under Section 4062(e) of ERISA; (c) a complete or partial withdrawal by the Borrower or any ERISA Affiliate from a Multiemployer Plan or notification that a Multiemployer Plan is in reorganization; (d) the filing of a notice of intent to terminate, the treatment of a Plan amendment as a termination under Section 4041 or 4041A of ERISA, or the commencement of proceedings by the PBGC to terminate a Pension Plan or Multiemployer Plan; (e) an event or condition which constitutes grounds under Section 4042 of ERISA for the termination of, or the appointment of a trustee to administer, any Pension Plan or Multiemployer Plan; or (f) the imposition of any

liability under Title IV of ERISA, other than for PBGC premiums due but not delinquent under Section 4007 of ERISA, upon the Borrower or any ERISA Affiliate.

" Eurodollar Lending Office " means, with respect to any Lender, the office of such Lender described as such in such Lender's Administrative Questionnaire, or such other office or offices as a Lender may from time to time notify the Borrower and the Agent.

" Eurodollar Rate " means:

(a) for any Interest Period with respect to a Eurodollar Rate Advance, the rate per annum equal to the British Bankers Association LIBOR Rate (" BBA LIBOR "), as published by Reuters (or other commercially available source providing quotations of BBA LIBOR as designated by the Agent from time to time) at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such Interest Period, for Dollar deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period. If such rate is not available at such time for any reason, then the "Eurodollar Rate" for such Interest Period shall be the rate per annum determined by the Agent to be the rate at which deposits in dollars for delivery on the first day of such Interest Period in same day funds in the approximate amount of the Eurodollar Rate Advance being made, continued or converted by the Agent and with a term equivalent to such Interest Period would be offered by the Agent to major banks in the London interbank eurodollar market at their request at approximately 11:00 a.m. (London time) two Business Days prior to the commencement of such Interest Period; and

(b) for any interest rate calculation with respect to a Base Rate Advance, the rate per annum equal to (i) BBA LIBOR, at approximately 11:00 a.m. two Business Days prior to, London time on the date of determination (provided that if such day is not a Business Day in London, the next preceding Business Day in London) for Dollar deposits being delivered in the London interbank market for a term of one month commencing that day or (ii) if such published rate is not available at such time for any reason, the rate determined by the Agent to be the rate at which deposits in Dollars for delivery on the date of determination in same day funds in the approximate amount of the Base Rate Advance being made, continued or converted by the Agent and with a term equal to one month would be offered by the Agent's London Branch to major banks in the London interbank Eurodollar market at their request at the date and time of determination.

" Eurodollar Rate Advance " means an Advance that bears interest at a rate based on the Eurodollar Rate (other than a Base Rate Advance bearing interest at a rate based on the Eurodollar Rate).

" Events of Default " has the meaning specified in Section 6.01.

" Excluded Taxes " means, with respect to the Agent, any Lender, any Issuing Bank or any other recipient of any payment to be made by or on account of any obligation of the Borrower hereunder, (a) taxes imposed on or measured by its overall net income (however denominated), and franchise taxes imposed on it (in lieu of net income taxes), by the United States of America or the jurisdiction (or any political subdivision thereof) under the Laws of which such recipient is organized or does business or in which its principal office is located or, in the case of any

Lender, in which its Applicable Lending Office is located, (b) any branch profits taxes imposed by the United States of America or any similar tax imposed by any other jurisdiction in which the Borrower is located, (c) any backup withholding tax that is required by the Internal Revenue Code to be withheld from amounts payable to a Lender that has failed to comply with clause (A) of Section 2.14(e)(ii), and (d) in the case of a Foreign Lender (other than as agreed to between any assignee and the Borrower pursuant to a request by the Borrower under Section 2.20), any United States of America withholding tax that (i) is required to be imposed on amounts payable to such Foreign Lender pursuant to the Laws in force at the time such Foreign Lender becomes a party hereto (or designates a new Applicable Lending Office) or (ii) is attributable to such Foreign Lender's failure or inability (other than as a result of a Change in Law) to comply with clause (B) of Section 2.14(e)(ii), except to the extent that such Foreign Lender (or its assignor, if any) was entitled, at the time of designation of a new Applicable Lending Office (or assignment), to receive additional amounts from the Borrower with respect to such withholding tax pursuant to Section 2.14(a)(i) or (ii).

" Federal Funds Rate " means, for any day, the rate per annum equal to the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System arranged by federal funds brokers on such day, as published by the Federal Reserve Bank of New York on the Business Day next succeeding such day; provided that (a) if such day is not a Business Day, the Federal Funds Rate for such day shall be such rate on such transactions on the next preceding Business Day as so published on the next succeeding Business Day, and (b) if no such rate is so published on such next succeeding Business Day, the Federal Funds Rate for such day shall be the average rate (rounded upward, if necessary, to a whole multiple of 1/100 of 1%) charged to the Agent on such day on such transactions as determined by the Agent.

" Fee Letters " means (a) each of the following letters to the Borrower dated January 14, 2011: (i) the letter from Barclays Bank PLC, Credit Suisse AG, Cayman Islands Branch and Credit Suisse Securities (USA) LLC, (ii) the letter from Bank of America, N.A., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Bank, National Association and Wells Fargo Securities, LLC, and (iii) the agent fee letter from Barclays Bank PLC, as Agent, each relating to certain fees payable by the Borrower to such parties in respect of the transactions contemplated by this Agreement and (b) any letter between the Borrower and any Issuing Bank other than an Initial Issuing Bank relating to certain fees payable to such Issuing Bank in its capacity as such, each as amended, modified, restated or supplemented from time to time.

" Foreign Lender " means any Lender that is organized under the Laws of a jurisdiction other than that in which the Borrower is resident for tax purposes (including such a Lender when acting in the capacity of an Issuing Bank). For purposes of this definition, the United States of America, each State thereof and the District of Columbia shall be deemed to constitute a single jurisdiction.

" Four Corners Acquisition " means the acquisition by the Borrower from Southern California Edison Company (" SCE ") of SCE's interests in Units 4 and 5 of the Four Corners Power Plant near Farmington, New Mexico, pursuant to the Purchase and Sale Agreement, dated as of November 8, 2010, by and between SCE and the Borrower.

" Fund " means any Person (other than a natural person) that is (or will be) engaged in making, purchasing, holding or otherwise investing in commercial loans and similar extensions of credit in the ordinary course of its business.

" GAAP " has the meaning specified in Section 1.03.

" Governmental Authority " means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra-national bodies such as the European Union or the European Central Bank).

" Guarantee " means as to any Person, any obligation, contingent or otherwise, of such Person directly or indirectly guaranteeing any Indebtedness of any other Person or in any manner providing for the payment of any Indebtedness of any other Person or otherwise protecting the holder of such Indebtedness against loss (whether by virtue of partnership arrangements, agreements to keep well, to purchase assets, goods, securities or services, or to take-or-pay or otherwise), provided that the term "Guarantee" shall not include endorsements for collection or deposit in the ordinary course of business. The term " Guarantee " used as a verb has a corresponding meaning.

" Hazardous Materials " means (a) petroleum and petroleum products, byproducts or breakdown products, radioactive materials, asbestos-containing materials, polychlorinated biphenyls and radon gas and (b) any other chemicals, materials or substances designated, classified or regulated as hazardous or toxic or as a pollutant or contaminant under any Environmental Law.

" Hedge Agreement " means any interest rate swap, cap or collar agreement, interest rate future or option contract, currency swap agreement, currency future or option contract, commodity future or option contract, commodity forward contract or other similar agreement.

" Increase Date " has the meaning specified in Section 2.18(a).

" Increasing Lender " has the meaning specified in Section 2.18(b).

" Indebtedness " means as to any Person at any date (without duplication): (a) indebtedness created, issued, incurred or assumed by such Person for borrowed money or evidenced by bonds, debentures, notes or similar instruments; (b) all obligations of such Person to pay the deferred purchase price of property or services, excluding, however, trade accounts payable (other than for borrowed money) arising in, and accrued expenses incurred in, the ordinary course of business of such Person so long as such trade accounts payable are paid within 180 days (unless subject to a good faith dispute) of the date incurred; (c) all Indebtedness secured by a lien on any asset of such Person, to the extent such Indebtedness has been assumed by, or is a recourse obligation of, such Person; (d) all Guarantees by such Person; (e) all Capital Lease Obligations of such Person; and (f) the amount of all reimbursement obligations of such Person (whether contingent or otherwise) in respect of letters of credit, bankers' acceptances, surety or other bonds and similar instruments in support of Indebtedness.

" Indemnified Taxes " means Taxes other than Excluded Taxes.

" Initial Issuing Banks " has the meaning given to such term in the introductory paragraph hereof.

" Initial Lenders " has the meaning given to such term in the introductory paragraph hereof.

" Interest Period " means, for each Eurodollar Rate Advance comprising part of the same Borrowing, the period commencing on the date such Eurodollar Rate Advance is disbursed or the date of the Conversion of any Base Rate Advance into such Eurodollar Rate Advance and ending on the last day of the period selected by the Borrower pursuant to the provisions below and, thereafter, each subsequent period commencing on the last day of the immediately preceding Interest Period and ending on the last day of the period selected by the Borrower pursuant to the provisions below. The duration of each such Interest Period shall be one, two, three or six months, as the Borrower may, upon notice received by the Agent not later than 12:00 noon on the third Business Day prior to the first day of such Interest Period, select; provided , however , that:

(a) the Borrower may not select any Interest Period that ends after the Termination Date;

(b) Interest Periods commencing on the same date for Eurodollar Rate Advances comprising part of the same Borrowing shall be of the same duration;

(c) whenever the last day of any Interest Period would otherwise occur on a day other than a Business Day, the last day of such Interest Period shall be extended to occur on the next succeeding Business Day, provided , however , that, if such extension would cause the last day of such Interest Period to occur in the next following calendar month, the last day of such Interest Period shall occur on the next preceding Business Day; and

(d) whenever the first day of any Interest Period occurs on a day of an initial calendar month for which there is no numerically corresponding day in the calendar month that succeeds such initial calendar month by the number of months equal to the number of months in such Interest Period, such Interest Period shall end on the last Business Day of such succeeding calendar month.

" Internal Revenue Code " means the Internal Revenue Code of 1986, as amended from time to time, and the regulations promulgated and rulings issued thereunder.

" ISP " means, with respect to any Letter of Credit, the "International Standby Practices 1998" published by the Institute of International Banking Law & Practice, Inc. (or such later version thereof as may be in effect at the time of issuance).

" Issuing Bank " means the Initial Issuing Banks or any other Lender approved by the Borrower that may agree to issue Letters of Credit pursuant to an Assignment and Assumption or other agreement in form satisfactory to the Borrower and the Agent, so long as such Lender

expressly agrees to perform in accordance with their terms all of the obligations that by the terms of this Agreement are required to be performed by it as an Issuing Bank and notifies the Agent of its Applicable Lending Office (which information shall be recorded by the Agent in the Register), for so long as such Initial Issuing Bank or Lender, as the case may be, shall have a Letter of Credit Commitment.

" L/C Advance " means, with respect to each Lender, such Lender's funding of its participation in any L/C Borrowing in accordance with its Ratable Share.

" L/C Borrowing " means an extension of credit resulting from a drawing under any Letter of Credit which has not been reimbursed on the date when made nor refinanced as a Base Rate Advance.

" L/C Cash Deposit Account " means an interest bearing cash deposit account to be established and maintained by the Agent, over which the Agent shall have sole dominion and control, upon terms as may be satisfactory to the Agent.

" L/C Obligations " means, as at any date of determination, the aggregate Available Amount of all outstanding Letters of Credit plus the aggregate of all Unreimbursed Amounts, including all L/C Borrowings. For all purposes of this Agreement, if on any date of determination a Letter of Credit has expired by its terms but any amount may still be drawn thereunder by reason of the operation of Rule 3.14 of the ISP, such Letter of Credit shall be deemed to be "outstanding" in the amount so remaining available to be drawn.

" L/C Related Documents " means with respect to any Letter of Credit, the Letter of Credit Application, and any other document, agreement and instrument entered into by any Issuing Bank and the Borrower or in favor of any Issuing Bank and relating to such Letter of Credit.

" Laws " means, collectively, all international, foreign, Federal, state and local statutes, treaties, rules, guidelines, regulations, ordinances, codes and administrative or judicial precedents or authorities, including the interpretation or administration thereof by any Governmental Authority charged with the enforcement, interpretation or administration thereof, and all applicable administrative orders, directed duties, licenses, authorizations and permits of, and agreements with, any Governmental Authority.

" Lenders " means the Initial Lenders, each Issuing Bank, each Assuming Lender that shall become a party hereto pursuant to Section 2.18 and each Person that shall become a party hereto pursuant to Section 8.07.

" Letter of Credit " has the meaning specified in Section 2.01(b).

" Letter of Credit Application " means an application and agreement for the issuance or amendment of a Letter of Credit in the form from time to time in use by any Issuing Bank.

" Letter of Credit Commitment " means, with respect to each Issuing Bank, the obligation of such Issuing Bank to issue Letters of Credit for the account of the Borrower from time to time in an aggregate amount equal to (a) for each of the Initial Issuing Banks, $125,000,000 and (b) for any other Issuing Bank, as separately agreed to by such Issuing Bank and the Borrower.

The Letter of Credit Commitment is part of, and not in addition to, the Revolving Credit Commitments.

" Letter of Credit Expiration Date " means the day that is five Business Days prior to the Termination Date.

" Lien " means any mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance, lien (statutory or otherwise), charge or other security interest or preferential arrangement that has the practical effect of creating a security interest, including, without limitation, the lien or retained security title of a conditional vendor and any easement, right of way or other encumbrance on title to real property, and any capital lease having substantially the same economic effect as any of the foregoing.

" Loan Documents " mean this Agreement, each Note, each L/C Related Document and the Fee Letters.

" Material Adverse Effect " means a material adverse effect on (a) the financial condition, operations, business or property of the Borrower and its Subsidiaries taken as a whole, (b) the rights and remedies of the Agent or any Lender under this Agreement or any Note or (c) the ability of the Borrower to perform its obligations under this Agreement or any Note.

" Material Subsidiary " means, at any time, a Subsidiary of the Borrower which as of such time meets the definition of a "significant subsidiary" included as of the date hereof in Regulation S-X of the Securities and Exchange Commission or whose assets at such time exceed 10% of the assets of the Borrower and the Subsidiaries (on a consolidated basis).

" Moody's " means Moody's Investors Service, Inc.

" Multiemployer Plan " means any employee benefit plan of the type described in Section 4001(a)(3) of ERISA, to which the Borrower or any ERISA Affiliate makes or is obligated to make contributions, or during the preceding five plan years, has made or been obligated to make contributions.

" Note " means a promissory note of the Borrower payable to the order of any Lender, delivered pursuant to a request made under Section 2.16 in substantially the form of Exhibit A hereto.

" Notice of Borrowing " has the meaning specified in Section 2.02(a).

" Obligations " means all advances to, and debts, liabilities, obligations, covenants and duties of, the Borrower arising under any Loan Document or otherwise with respect to any Advance or Letter of Credit, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and including interest and fees that accrue under any Loan Document after the commencement by or against the Borrower of any proceeding under any Debtor Relief Laws naming such Person as the debtor in such proceeding, regardless of whether such interest and fees are allowed claims in such proceeding.

" Other Taxes " means all present or future stamp or documentary taxes or any other excise or property taxes, charges or similar levies arising from any payment made hereunder or under any other Loan Document or from the execution, delivery or enforcement of, or otherwise with respect to, this Agreement or any other Loan Document.

" PBGC " means the Pension Benefit Guaranty Corporation.

" Pension Plan " means any "employee pension benefit plan" (as such term is defined in Section 3(2) of ERISA), other than a Multiemployer Plan, that is subject to Title IV of ERISA and is sponsored or maintained by the Borrower or any ERISA Affiliate or to which the Borrower or any ERISA Affiliate contributes or has an obligation to contribute, or in the case of a multiple employer or other plan described in Section 4064(a) of ERISA, has made contributions at any time during the immediately preceding five plan years.

" Permitted Lien " of the Borrower or any Material Subsidiary means any of the following:

(i) Liens for taxes, assessments or other governmental charges or levies not at the time delinquent or thereafter payable without penalty or being contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been made;

(ii) Liens imposed by or arising by operation of law, such as Liens of carriers, warehousemen, mechanics, materialmen and landlords incurred in the ordinary course of business, including, without limitation, landlord's liens arising under Arizona Law under leases entered into by the Borrower in the 1986 sale and leaseback transactions with respect to PVNGS Unit 2 and securing the payment of rent under such leases, in each case, for sums not overdue for a period of more than 30 days or being contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been made;

(iii) Liens incurred in the ordinary course of business in connection with worker's compensation, unemployment insurance or other forms of governmental insurance or benefits or other similar statutory obligations;

(iv) Liens to secure obligations on surety or appeal bonds;

(v) Liens on cash deposits in the nature of a right of setoff, banker's lien, counterclaim or netting of cash amounts owed arising in the ordinary course of business on deposit accounts, commodity accounts or securities accounts;

(vi) easements, restrictions, reservations, licenses, covenants, and other defects of title that are not, in the aggregate, materially adverse to the use of such property for the purpose for which it is used;

(vii) Liens securing claims against or other obligations of any Person other than the Borrower or any Subsidiary of the Borrower neither assumed nor guaranteed by the Borrower or any Subsidiary of the Borrower nor on which the Borrower or any Subsidiary of the Borrower customarily pays interest, existing upon real estate or rights in

or relating to real estate acquired by the Borrower or any Subsidiary of the Borrower for use in the operation of the business of the Borrower or any Subsidiary of the Borrower, including, without limitation, for the generation, transmission or distribution of electric energy, transportation, telephonic, telegraphic, radio, wireless or other electronic communication or any other purpose;

(viii) rights reserved to or vested in and Liens on assets arising out of obligations or duties to any municipality or public authority with respect to any right, power, franchise, grant, license or permit, or by any provision of Law;

(ix) rights reserved to or vested in others to take or receive any part of the power pursuant to firm power commitment contracts, purchased power contracts, tolling agreements and similar agreements, coal, gas, oil or other minerals, timber or other products generated, developed, manufactured or produced by, or grown on, or acquired with, any property of the Borrower;

(x) rights reserved to or vested in any municipality or public authority to control or regulate any property of the Borrower, or to use such property in a manner that does not materially impair the use of such property for the purposes for which it is held by the Borrower;

(xi) security interests granted in favor of the lessors in the Borrower's Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992 (such agreement, as amended or otherwise modified from time to time, being the " Unit 2 Trust Agreement ") entered into in connection with the PVNGS Unit 2 sale leaseback transaction to secure the Borrower's obligations in respect of the decommissioning of PVNGS Unit 2 or related facilities;

(xii) Liens that may exist with respect to the Unit 2 Trust Agreement (other than as described in paragraph (xi) above) or with respect to either of the Borrower's Decommissioning Trust Agreement (PVNGS Unit 1) or Decommissioning Trust Agreement (PVNGS Unit 3), each dated as of July 1, 1991, as amended or otherwise modified from time to time, relating to the Borrower's obligation to set aside funds for the decommissioning and retirement from service of such Units;

(xiii) pledges of pollution control bonds and related rights to secure the Borrower's reimbursement obligations in respect of letters of credit, bond insurance, and other credit or liquidity enhancements supporting pollution control bond transactions, provided that such pollution control bonds are not secured by any other assets of the Borrower or any Material Subsidiary;

(xiv) rights and interests of Persons other than the Borrower or any Material Subsidiary (including, without limitation, acquisition rights), related obligations of the Borrower or any Material Subsidiary and restrictions on it or its property arising out of contracts, agreements and other instruments to which the Borrower or any Material Subsidiary is a party that relate to the common ownership or joint use of property or other use of property for the benefit of one or more third parties or that allow a third party to

purchase property of the Borrower or any Material Subsidiary and all Liens on the interests of Persons other than the Borrower or any Material Subsidiary in such property;

(xv) transfers of operational or other control of facilities to a regional transmission organization or other similar body and Liens on such facilities to cover expenses, fees and other costs of such an organization or body;

(xvi) Liens established on specified bank accounts of the Borrower to secure the Borrower's reimbursement obligations in respect of letters of credit supporting commercial paper issued by the Borrower and similar arrangements for collateral security with respect to refinancings or replacements of the same;

(xvii) rights of transmission users or any regional transmission organizations or similar entities in transmission facilities;

(xviii) Liens on property of the Borrower sold in a transaction permitted by Section 5.02(a) to another Person pursuant to a conditional sales agreement where the Borrower retains title;

(xix) Liens created under this Agreement;

(xx) Liens on cash or cash equivalents not to exceed $200,000,000 (A) deposited in margin accounts with or on behalf of futures contract brokers or paid over to other contract counterparties or (B) pledged or deposited as collateral to a contract counterparty to secure obligations with respect to (1) contracts (other than for Indebtedness) for commercial and trading activities in the ordinary course of business for the purchase, transmission, distribution, sale, storage, lease or hedge of any energy or energy related commodity or (2) Hedge Agreements;

(xxi) Liens granted on cash or cash equivalents to defease Indebtedness of the Borrower or any of its Subsidiaries;

(xxii) Liens granted on cash or cash equivalents constituting proceeds from any sale or disposition of assets that is not prohibited by Section 5.02(c) deposited in escrow accounts or otherwise withheld or set aside to secure obligations of the Borrower or any Subsidiary providing for indemnification, adjustment of purchase price or any similar obligations, in each case, in an amount not to exceed the amount of gross proceeds received by the Borrower or any Subsidiary in connection with such sale or disposition;

(xxiii) Liens, deposits and similar arrangements to secure the performance of bids, tenders or contracts (other than contracts for borrowed money), public or statutory obligations, performance bonds and other obligations of a like nature incurred in the ordinary course of business by the Borrower or any of its Subsidiaries;

(xxiv) rights of lessees arising under leases entered into by the Borrower or any of its Subsidiaries as lessor, in the ordinary course of business;

(xxv) any Liens on or reservations with respect to governmental and other licenses, permits, franchises, consents and allowances;

(xxvi) Liens on property which is the subject of a Capital Lease Obligation designating the Borrower or any of its Subsidiaries as lessee and all right, title and interest of the Borrower or any of its Subsidiaries in and to such property and in, to and under such lease agreement, whether or not such lease agreement is intended as a security;

(xxvii) licenses of intellectual property entered into in the ordinary course of business;

(xxviii) Liens solely on any cash earnest money deposits made by the Borrower or any of its Subsidiaries in connection with any letter of intent or purchase agreement permitted hereunder;

(xxix) deposits or funds established for the removal from service of operating facilities and coal mines and related facilities or other similar facilities used in connection therewith; and

(xxx) Liens on cash deposits used to secure letters of credit under defaulting lender provisions in credit or reimbursement facilities;

provided , however , that no Lien in favor of the PBGC shall, in any event, be a Permitted Lien.

" Person " means an individual, partnership, corporation (including a business trust), joint stock company, trust, unincorporated association, joint venture, limited liability company or other entity, or a government or any political subdivision or agency thereof.

" Plan " means any "employee benefit plan" (as such term is defined in Section 3(3) of ERISA) established by the Borrower or, with respect to any such plan that is subject to Section 412 of the Internal Revenue Code or Title IV of ERISA, any ERISA Affiliate.

" Public Debt Rating " means, as of any date, the rating that has been most recently announced by either S&P or Moody's, as the case may be, for any class of non-credit enhanced long-term senior unsecured debt issued by the Borrower or, if any such rating agency shall have issued more than one such rating, the lowest such rating issued by such rating agency. For purposes of the foregoing, (a) if only one of S&P and Moody's shall have in effect a Public Debt Rating, the Applicable Rate shall be determined by reference to the available rating; (b) if neither S&P nor Moody's shall have in effect a Public Debt Rating, the Applicable Rate will be in accordance with Level 6 under the definition of " Applicable Rate "; (c) if the ratings established by S&P and Moody's shall fall within different levels, the Applicable Rate shall be based upon the higher rating unless such ratings differ by two or more levels, in which case the applicable level will be deemed to be one level below the higher of such levels; (d) if any rating established by S&P or Moody's shall be changed (other than as a result of a change in the basis on which ratings are established), such change shall be effective as of the date on which such change is first announced publicly by the rating agency making such change; and (e) if S&P or Moody's

shall change the basis on which ratings are established, each reference to the Public Debt Rating announced by S&P or Moody's, as the case may be, shall refer to the then equivalent rating by S&P or Moody's, as the case may be.

" PVNGS " means the Palo Verde Nuclear Generating Station.

" PWCC " means Pinnacle West Capital Corporation, an Arizona corporation.

" Ratable Share " of any amount means, with respect to any Lender at any time but subject to the provisions of Section 2.19, the product of such amount times a fraction the numerator of which is the amount of such Lender's Revolving Credit Commitment at such time (or, if the Revolving Credit Commitments shall have been terminated pursuant to Section 2.05 or 6.01, such Lender's Revolving Credit Commitment as in effect immediately prior to such termination) and the denominator of which is the aggregate amount of all Revolving Credit Commitments at such time (or, if the Revolving Credit Commitments shall have been terminated pursuant to Section 2.05 or 6.01, the aggregate amount of all Revolving Credit Commitments as in effect immediately prior to such termination).

" Register " has the meaning specified in Section 8.07(c).

" Related Parties " means, with respect to any Person, such Person's Affiliates and the partners, directors, officers, employees, agents, trustees and advisors of such Person and of such Person's Affiliates.

" Reportable Event " means any of the events set forth in Section 4043(c) of ERISA, other than events for which the 30-day notice period has been waived under the final regulations issued under Section 4043, as in effect as of the date of this Agreement (the "Section 4043 Regulations"). Any changes made to the Section 4043 Regulations that become effective after the Effective Date shall have no impact on the definition of Reportable Event as used herein unless otherwise amended by the Borrower and the Required Lenders.

" Required Lenders " means, at any time, but subject to Section 2.19, Lenders holding in the aggregate more than 50% of (a) the Revolving Credit Commitments or (b) if the Revolving Credit Commitments have been terminated, the Total Outstandings.

" Revolving Credit Commitment " means, as to any Lender, its obligation to (a) make Advances to the Borrower pursuant to Section 2.01 and 2.03(c), and (b) purchase participations in L/C Obligations, in an aggregate principal amount at any one time outstanding not to exceed the amount set forth opposite such Lender's name on Schedule 1.01 under the column "Revolving Credit Commitment" or if such Lender has become a Lender hereunder pursuant to an Assumption Agreement or if such Lender has entered into any Assignment and Assumption, the amount set forth for such Lender in the Register, in each case as such amount may be reduced pursuant to Section 2.05 or increased pursuant to Section 2.18.

" S&P " means Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc.

" Sale Leaseback Obligation Bonds " means PVNGS II Funding Corp.'s (a) 8.00% Secured Lease Obligation Bonds, Series 1993, due 2015; (b) any other bonds issued by or on behalf of the Borrower in connection with a sale/leaseback transaction; and (c) any refinancing or refunding of the obligations specified in subclauses (a) and (b) above.

" SEC Reports " means the Borrower's (i) Form 10-K Report for the year ended December 31, 2009, (ii) Form 10-Q Reports for the quarters ended March 31, 2010, June 30, 2010 and September 30, 2010 and (iii) Form 8-K Reports filed on January 25, 2010, February 1, 2010, February 19, 2010, March 3, 2010, March 4, 2010, April 21, 2010, April 27, 2010, May 6, 2010, June 2, 2010, June 7, 2010, June 28, 2010, August 3, 2010, September 7, 2010, September 15, 2010, October 28, 2010, November 1, 2010, November 8, 2010, December 16, 2010, December 20, 2010 and February 7, 2011, as so filed.

" Subsequent Order " means any decision, order or ruling of the Arizona Corporation Commission issued after the Effective Date relating to the incurrence or maintenance of Indebtedness by the Borrower and that amends, supersedes or otherwise modifies the 2007 Order or any successor decision, order or ruling.

" Subsidiary " of any Person means any corporation, partnership, joint venture, limited liability company, trust or estate of which (or in which) more than 50% of (a) the issued and outstanding Voting Stock, (b) the interest in the capital or profits of such limited liability company, partnership or joint venture or (c) the beneficial interest in such trust or estate, is at the time directly or indirectly owned or controlled by such Person, by such Person and one or more of its other Subsidiaries or by one or more of such Person's other Subsidiaries; provided that in no event will Subsidiaries include the VIE Lessor Trusts.

" Taxes " means all present or future taxes, levies, imposts, duties, deductions, withholdings (including backup withholding), assessments, fees or other charges imposed by any Governmental Authority, including any interest, additions to tax or penalties applicable thereto.

" Termination Date " means the earlier of (a) February 13, 2015 and (b) the date of termination in whole of the Commitments pursuant to Section 2.05 or 6.01.

" Total Outstandings " means the sum of (a) the aggregate principal amount of all Advances plus (b) all L/C Obligations outstanding.

" Type " means a Base Rate Advance or a Eurodollar Rate Advance.

" Unreimbursed Amount " has the meaning specified in Section 2.03(c)(i).

" Unissued Letter of Credit Commitment " means, with respect to any Issuing Bank, the obligation of such Issuing Bank to issue Letters of Credit for the account of the Borrower in an amount equal to the excess of (a) the amount of its Letter of Credit Commitment over (b) the aggregate Available Amount of all Letters of Credit issued by such Issuing Bank.

" Unused Commitment " means, with respect to each Lender at any time, (a) such Lender's Revolving Credit Commitment at such time minus (b) the sum of (i) the aggregate principal amount of all Advances made by such Lender (in its capacity as a Lender) and

outstanding at such time and (ii) such Lender's Ratable Share of the aggregate L/C Obligations outstanding at such time.

" VIE Lessor Trusts " means the three (3) separate variable-interest entity lessor trusts that purchased from, and leased back to the Borrower certain interests in the PVNGS Unit 2 and related common facilities, as described in Note 9 of Notes to Condens Consolidated Financial Statements in the Borrower's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010.

" Voting Stock " means capital stock issued by a corporation, or equivalent interests in any other Person, the holders of which are ordinarily, in the absence of contingencies, entitled to vote for the election of directors (or persons performing similar functions) of such Person, even if the right so to vote has been suspended by the happening of such a contingency.

Section 1.02 Other Interpretive Provisions . With reference to this Agreement and each other Loan Document, unless otherwise specified herein or in such other Loan Document:

(a) The definitions of terms herein shall apply equally to the singular and plural forms of the terms defined. Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "include," "includes" and "including" shall be deemed to be followed by the phrase "without limitation." The word "will" shall be construed to have the same meaning and effect as the word "shall." Unless the context requires otherwise, (i) any definition of or reference to any agreement, instrument or other document shall be construed as referring to such agreement, instrument or other document as from time to time amended, supplemented or otherwise modified (subject to any restrictions on such amendments, supplements or modifications set forth herein or in any other Loan Document), (ii) any reference herein to any Person shall be construed to include such Person's permitted successors and permitted assigns, (iii) the words "herein," "hereof" and "hereunder," and words of similar import when used in any Loan Document, shall be construed to refer to such Loan Document in its entirety and not to any particular provision thereof, (iv) all references in a Loan Document to Articles, Sections, Exhibits and Schedules shall be construed to refer to Articles and Sections of, and Exhibits and Schedules to, the Loan Document in which such references appear, (v) any reference to any law shall include all statutory and regulatory provisions consolidating, amending, replacing or interpreting such law and any reference to any law or regulation shall, unless otherwise specified, refer to such law or regulation as amended, modified or supplemented from time to time, and (vi) the words "asset" and "property" shall be construed to have the same meaning and effect and to refer to any and all tangible and intangible assets and properties, including cash, securities, accounts and contract rights.

(b) In the computation of periods of time from a specified date to a later specified date, the word "from" means "from and including;" the words "to" and "until" each mean "to but excluding;" and the word "through" means "to and including."

(c) Section headings herein and in the other Loan Documents are included for convenience of reference only and shall not affect the interpretation of this Agreement or any other Loan Document.

Section 1.03 Accounting Terms . Unless otherwise specified herein, all accounting terms used herein shall be interpreted, all accounting determinations hereunder shall be made, and all financial statements required to be delivered hereunder shall be prepared, in accordance with generally accepted accounting principles as in effect from time to time, applied on a basis consistent (except for changes concurred in by the Borrower's independent public accountants) with the most recent audited Consolidated financial statements of the Borrower delivered to the Agent (" GAAP "). If at any time any change in GAAP or in the interpretation thereof would affect the computation of any financial ratio or requirement set forth in any Loan Document, and either the Borrower or the Required Lenders shall so request, the Agent, the Lenders and the Borrower shall negotiate in good faith to amend such ratio or requirement to preserve the original intent thereof in light of such change in GAAP or in the interpretation thereof (subject to the approval of the Required Lenders); provided that , unless and until so amended, such ratio or requirement shall continue to be computed in accordance with GAAP prior to such change therein.

Section 1.04 Rounding . Any financial ratios required to be maintained by the Borrower pursuant to this Agreement shall be calculated by dividing the appropriate component by the other component, carrying the result to one place more than the number of places by which such ratio is expressed herein and rounding the result up or down to the nearest number (with a rounding-up if there is no nearest number).

Section 1.05 Times of Day . Unless otherwise specified, all references herein to times of day shall be references to Eastern time (daylight or standard, as applicable).

ARTICLE II

AMOUNTS AND TERMS OF THE ADVANCES AND LETTERS OF CREDIT

Section 2.01 The Advances and Letters of Credit .

(a) The Advances . Each Lender severally agrees, on the terms and conditions hereinafter set forth, to make Advances in Dollars to the Borrower from time to time on any Business Day during the period from the Effective Date until the Termination Date in an amount not to exceed such Lender's Unused Commitment. Each Borrowing shall be in an aggregate amount of $5,000,000 or an integral multiple of $1,000,000 in excess thereof and shall consist of Advances of the same Type made on the same day by the Lenders ratably according to their respective Revolving Credit Commitments. Within the limits of each Lender's Revolving Credit Commitment, and subject to the other terms and conditions hereof, the Borrower may borrow under this Section 2.01(a), prepay pursuant to Section 2.10 and reborrow under this Section 2.01(a).

(b) Letters of Credit . Each Issuing Bank agrees, on the terms and conditions hereinafter set forth, in reliance upon the agreements of the other Lenders set forth in this Agreement, to issue standby letters of credit (each a " Letter of Credit ") for the account of the Borrower from time to time on any Business Day during the period from the Effective Date until 30 days before the Termination Date in an aggregate Available Amount for all Letters of Credit issued by each Issuing Bank not to exceed at any time such Issuing Bank's Letter of Credit

Commitment, provided that after giving effect to the issuance of any Letter of Credit, (i) the Total Outstandings shall not exceed the aggregate Revolving Credit Commitments and (ii) each Lender's Ratable Share of the Total Outstandings shall not exceed such Lender's Revolving Credit Commitment. No Letter of Credit shall have an expiration date (including all rights of the Borrower or the beneficiary to require renewal) later than the Letter of Credit Expiration Date. Within the limits referred to above, the Borrower may from time to time request the issuance of Letters of Credit under this Section 2.01(b). The terms "issue", "issued", "issuance" and all similar terms, when applied to a Letter of Credit, shall include any renewal, extension or amendment thereof.

Section 2.02 Making the Advances .

(a) Except as otherwise provided in Section 2.03(c), each Borrowing shall be made on notice, given not later than (x) 12:00 noon on the third Business Day prior to the date of the proposed Borrowing in the case of a Borrowing consisting of Eurodollar Rate Advances or (y) 12:00 noon on the date of the proposed Borrowing in the case of a Borrowing consisting of Base Rate Advances, by the Borrower to the Agent, which shall give to each Lender prompt notice thereof by facsimile. Each such notice of a Borrowing (a " Notice of Borrowing ") shall be in writing or by facsimile in substantially the form of Exhibit B hereto, specifying therein the requested (i) date of such Borrowing, (ii) Type of Advances comprising such Borrowing, (iii) aggregate amount of such Borrowing, and (iv) in the case of a Borrowing consisting of Eurodollar Rate Advances, initial Interest Period for each such Advance. Each Lender shall, in the case of a Borrowing consisting of Base Rate Advances, before 2:00 p.m. on the date of such Borrowing, and in the case of a Borrowing consisting of Eurodollar Rate Advances, before 11:00 a.m. on date of such Borrowing, make available for the account of its Applicable Lending Office to the Agent at the Agent's Account, in same day funds, such Lender's Ratable Share of such Borrowing. After the Agent's receipt of such funds and upon fulfillment of the applicable conditions set forth in Article III, the Agent will make such funds available to the Borrower at the Agent's address referred to in Section 8.02 or as requested by the Borrower in the applicable Notice of Borrowing.

(b) Anything in subsection (a) above to the contrary notwithstanding, (i) the Borrower may not select Eurodollar Rate Advances for any Borrowing if the aggregate amount of such Borrowing is less than $5,000,000 or if the obligation of the Lenders to make Eurodollar Rate Advances shall then be suspended pursuant to Section 2.08 or 2.12 and (ii) at no time shall there be more than fifteen different Interest Periods outstanding for Eurodollar Rate Advances.

(c) Each Notice of Borrowing shall be irrevocable and binding on the Borrower. In the case of any Borrowing that the related Notice of Borrowing specifies is to be comprised of Eurodollar Rate Advances, the Borrower shall indemnify each Lender against any loss, cost or expense reasonably incurred by such Lender as a result of any failure to fulfill on or before the date specified in such Notice of Borrowing for such Borrowing the applicable conditions set forth in Article III, including, without limitation, any loss (excluding loss of anticipated profits), cost or expense incurred by reason of the liquidation or reemployment of deposits or other funds acquired by such Lender to fund the Advance to be made by such Lender as part of such Borrowing when such Advance, as a result of such failure, is not made on such date.

(d) Unless the Agent shall have received notice from a Lender prior to the time of the applicable Borrowing that such Lender will not make available to the Agent such Lender's Ratable Share of such Borrowing, the Agent may assume that such Lender has made such portion available to the Agent on the date of such Borrowing in accordance with subsection (a) of this Section 2.02 and the Agent may, in reliance upon such assumption, make available to the Borrower on such date a corresponding amount. If and to the extent that such Lender shall not have so made such Ratable Share available to the Agent, such Lender and the Borrower severally agree to repay to the Agent within one Business Day after demand for such Lender and within three Business Days after demand for the Borrower such corresponding amount together with interest thereon, for each day from the date such amount is made available to the Borrower until the date such amount is repaid to the Agent, at (i) in the case of the Borrower, the interest rate applicable at the time to Advances comprising such Borrowing and (ii) in the case of such Lender, the Federal Funds Rate. If the Borrower and such Lender shall pay such interest to the Agent for the same or an overlapping period, the Agent shall promptly remit to the Borrower the amount of such interest paid by the Borrower for such period. If such Lender shall repay to the Agent such corresponding amount, such amount so repaid shall constitute such Lender's Advance as part of such Borrowing for purposes of this Agreement.

(e) The failure of any Lender to make the Advance to be made by it as part of any Borrowing shall not relieve any other Lender of its obligation, if any, hereunder to make its Advance on the date of such Borrowing, but no Lender shall be responsible for the failure of any other Lender to make the Advance to be made by such other Lender on the date of any Borrowing.

Section 2.03 Letters of Credit .

(a) General .

(i) No Issuing Bank shall issue any Letter of Credit, if the expiry date of such requested Letter of Credit would occur after the Letter of Credit Expiration Date, unless all the Lenders have approved such expiry date.

(ii) No Issuing Bank shall be under any obligation to issue any Letter of Credit if:

(A) any order, judgment or decree of any Governmental Authority or arbitrator shall by its terms purport to enjoin or restrain such Issuing Bank from issuing such Letter of Credit, or any Law applicable to such Issuing Bank or any request or directive (whether or not having the force of law) from any Governmental Authority with jurisdiction over such Issuing Bank shall prohibit, or request that such Issuing Bank refrain from, the issuance of letters of credit generally or such Letter of Credit in particular or shall impose upon such Issuing Bank with respect to such Letter of Credit any restriction, reserve or capital requirement (for which such Issuing Bank is not otherwise compensated hereunder) not in effect on the Effective Date, or shall impose upon such Issuing Bank any unreimbursed loss, cost or expense which was not applicable on the

Effective Date and which, in each such case, such Issuing Bank in good faith deems material to it;

(B) except as otherwise agreed by the Borrower and such Issuing Bank, such Letter of Credit is in an initial stated amount less than $350,000 in the case of a standby Letter of Credit;

(C) such Letter of Credit is to be denominated in a currency other than Dollars;

(D) such Letter of Credit contains any provisions for automatic reinstatement of the stated amount after any drawing thereunder;

(E) subject to Section 2.03(b)(iii), the expiry date of such requested Letter of Credit would occur more than twelve months after the date of issuance or last extension; or

(F) any Lender is at such time an Affected Lender hereunder, unless the applicable Issuing Bank is satisfied that the related exposure will be 100% covered by the Commitments of the non-Affected Lenders or, if not so covered, until such Issuing Bank has entered into arrangements satisfactory to it in its sole discretion with the Borrower or such Affected Lender to eliminate such Issuing Bank's risk with respect to such Affected Lender, and participating interests in any such newly issued Letter of Credit shall be allocated among non-Affected Lenders in a manner consistent with Section 2.19(c)(i) (and Affected Lenders shall not participate therein);

(iii) No Issuing Bank shall amend any Letter of Credit if such Issuing Bank would not be permitted at such time to issue such Letter of Credit in its amended form under the terms hereof.

(iv) No Issuing Bank shall be under any obligation to amend any Letter of Credit if (A) such Issuing Bank would have no obligation at such time to issue such Letter of Credit in its amended form under the terms hereof, or (B) the beneficiary of such Letter of Credit does not accept the proposed amendment to such Letter of Credit.

(b) Procedures for Issuance and Amendment of Letters of Credit; Auto-Extension Letters of Credit .

(i) Each Letter of Credit shall be issued or amended, as the case may be, upon the request of the Borrower delivered to the applicable Issuing Bank (with a copy to the Agent) in the form of a Letter of Credit Application, appropriately completed and signed by an Authorized Officer of the Borrower. Such Letter of Credit Application must be received by such Issuing Bank and the Agent not later than 11:00 a.m. at least two Business Days (or such later date and time as the Agent and such Issuing Bank may agree in a particular instance in their sole discretion) prior to the proposed issuance date or date of amendment, as the case may be. In the case of a request for an initial issuance of a Letter of Credit, such Letter of Credit Application shall specify in form and detail

satisfactory to the applicable Issuing Bank: (A) the proposed issuance date of the requested Letter of Credit (which shall be a Business Day); (B) the amount thereof; (C) the expiry date thereof; (D) the name and address of the beneficiary thereof; (E) the documents to be presented by such beneficiary in case of any drawing thereunder; (F) the full text of any certificate to be presented by such beneficiary in case of any drawing thereunder; (G) the purpose and nature of the requested Letter of Credit; and (H) such other matters as such Issuing Bank may require. In the case of a request for an amendment of any outstanding Letter of Credit, such Letter of Credit Application shall specify in form and detail satisfactory to the applicable Issuing Bank (A) the Letter of Credit to be amended; (B) the proposed date of amendment thereof (which shall be a Business Day); (C) the nature of the proposed amendment; and (D) such other matters as such Issuing Bank may require. Additionally, the Borrower shall furnish to the applicable Issuing Bank and the Agent such other documents and information pertaining to such requested Letter of Credit issuance or amendment, including any L/C Related Documents, as the applicable Issuing Bank or the Agent may require. In the event and to the extent that the provisions of any Letter of Credit Application or other L/C Related Document shall conflict with this Agreement, the provisions of this Agreement shall govern. Without limitation of the immediately preceding sentence, no such Letter of Credit Application or other L/C Related Document may impose any additional conditions on the issuance or maintenance of a Letter of Credit, any additional default provisions, collateral requirements or other obligations of the Borrower to any Issuing Bank, other than as stated in this Agreement.

(ii) Promptly after receipt of any Letter of Credit Application, the applicable Issuing Bank will confirm with the Agent (by telephone or in writing) that the Agent has received a copy of such Letter of Credit Application from the Borrower and, if not, such Issuing Bank will provide the Agent with a copy thereof. Unless the applicable Issuing Bank has received written notice from the Required Lenders, the Agent or the Borrower, at least one Business Day prior to the requested date of issuance or amendment of the applicable Letter of Credit, that one or more applicable conditions contained in Article III shall not then be satisfied, then, subject to the terms and conditions hereof, such Issuing Bank shall, on the requested date, issue a Letter of Credit for the account of the Borrower or enter into the applicable amendment, as the case may be, in each case in accordance with such Issuing Bank's usual and customary business practices. Immediately upon the issuance of each Letter of Credit, each Lender shall be deemed to, and hereby irrevocably and unconditionally agrees to, purchase from such Issuing Bank a risk participation in such Letter of Credit in an amount equal to the product of such Lender's Ratable Share times the amount of such Letter of Credit.

(iii) If the Borrower so requests in any applicable Letter of Credit Application, the applicable Issuing Bank may, in its sole and absolute discretion, agree to issue a Letter of Credit that has automatic extension provisions (each, an " Auto-Extension Letter of Credit "); provided that any such Auto-Extension Letter of Credit must permit such Issuing Bank to prevent any such extension at least once in each twelve-month period (commencing with the date of issuance of such Letter of Credit) by giving prior notice to the beneficiary thereof not later than a day (the " Non-Extension Notice Date ") in each such twelve-month period to be agreed upon at the time such Letter of Credit is issued.

Unless otherwise directed by the applicable Issuing Bank, the Borrower shall not be required to make a specific request to the applicable Issuing Bank for any such extension. Once an Auto-Extension Letter of Credit has been issued, the Lenders shall be deemed to have authorized (but may not require) the applicable Issuing Bank to permit the extension of such Letter of Credit at any time to an expiry date not later than the Letter of Credit Expiration Date; provided , however , that the applicable Issuing Bank shall not permit any such extension (or may issue a Notice of Non-Extension) if (A) such Issuing Bank has determined that it would not be permitted at such time to issue such Letter of Credit in its revised form (as extended) by reason of the provisions of clause (i) of Section 2.03(a) (or would have no obligation to issue such Letter of Credit by reason of the provisions of clause (ii) of Section 2.03(a)), or (B) it has received notice (which may be by telephone or in writing) on or before the day that is seven Business Days before the Non-Extension Notice Date (1) from the Agent that the Required Lenders have elected not to permit such extension pursuant to Section 6.02 or (2) from the Agent, the Required Lenders or the Borrower that one or more of the applicable conditions specified in Section 3.02 is not then satisfied, and in each such case directing such Issuing Bank not to permit such extension.

(iv) Promptly after its delivery of any Letter of Credit or any amendment to a Letter of Credit to an advising bank with respect thereto or to the beneficiary thereof, the applicable Issuing Bank will also deliver to the Borrower and the Agent a true and complete copy of such Letter of Credit or amendment.

(c) Drawings and Reimbursements; Funding of Participations .

(i) Subject to the provisions below, not later than 2:30 p.m. on the date (the " Honor Date ") that any Issuing Bank makes any payment on a drawing on any Letter of Credit, if the Borrower shall have received notice of such payment prior to 11:30 a.m. on such date, or, if such notice has not been received by the Borrower prior to such time on such date, then not later than 2:30 p.m. on the next Business Day, the Borrower shall reimburse such Issuing Bank through the Agent in an amount equal to the amount of such drawing together with interest thereon. If the Borrower fails to so reimburse such Issuing Bank by such time, unless the Borrower shall have advised the Agent that it does not meet the conditions specified in either clause (B) or (C) below, the Agent shall promptly notify each Lender of the Honor Date, the amount of the unreimbursed drawing (the " Unreimbursed Amount "), and the amount of such Lender's Ratable Share thereof. In such event, the Borrower shall be deemed to have requested a Base Rate Advance to be disbursed on the Honor Date in an amount equal to the Unreimbursed Amount, without regard to the minimum and multiples specified in Section 2.01(a) or the delivery of a Notice of Borrowing, but subject to (A) the amount of the aggregate Unused Commitments, (B) no Event of Default having occurred and be continuing, or resulting therefrom, and (C) the conditions specified in Sections 3.02(c) and (d) being satisfied on and as of the date of the applicable Base Rate Advance and, to the extent so financed, the Borrower's obligation to satisfy the reimbursement obligation created by such payment by the Issuing Bank on the Honor Date shall be discharged and replaced by the resulting Base Rate Advance. Any notice given by any Issuing Bank or the Agent pursuant to this Section 2.03(c)(i) may be given by telephone if immediately confirmed in writing;

provided that the lack of such an immediate confirmation shall not affect the conclusiveness or binding effect of such notice.

(ii) Each Lender shall upon any notice pursuant to Section 2.03(c)(i) make funds available to the Agent for the account of the applicable Issuing Bank at the Agent's Office in an amount equal to its Ratable Share of the Unreimbursed Amount not later than 4:00 p.m. on the Business Day specified in such notice by the Agent, whereupon, subject to the provisions of Section 2.03 (c)(iii), each Lender that so makes funds available shall be deemed to have made a Base Rate Advance to the Borrower in such amount. The Agent shall remit the funds so received to the applicable Issuing Bank.

(iii) With respect to any Unreimbursed Amount that is not fully refinanced by a Base Rate Advance because any of the conditions set forth in clauses (A), (B) or (C) of Section 2.03(c)(i) cannot be satisfied or for any other reason, then not later than 2:30 p.m. on the next Business Day after the day notice of the drawing is given to the Borrower, in the case of a failure to meet any such condition, or in any other case, after notice of the event resulting in the outstanding Unreimbursed Amount, the Borrower shall reimburse such Issuing Bank through the Agent in an amount equal to the amount of such outstanding Unreimbursed Amount with interest thereon. If the Borrower fails to so reimburse such Issuing Bank by such time, the Borrower shall be deemed to have incurred from the applicable Issuing Bank an L/C Borrowing in the amount of the Unreimbursed Amount that is not so refinanced, which L/C Borrowing shall be due and payable on demand (together with interest) and shall bear interest at the Base Rate in effect from time to time plus the Applicable Rate for Base Rate Advances in effect from time to time plus 2% per annum. In such event, each Lender's payment to the Agent for the account of the applicable Issuing Bank pursuant to Section 2.03(c)(ii) shall be deemed payment in respect of its participation in such L/C Borrowing and shall constitute an L/C Advance from such Lender in satisfaction of its participation obligation under this Section 2.03.

(iv) Until each Lender funds its Base Rate Advance or L/C Advance pursuant to this Section 2.03(c) to reimburse the applicable Issuing Bank for any amount drawn under any Letter of Credit, interest in respect of such Lender's Ratable Share of such amount shall be solely for the account of the applicable Issuing Bank.

(v) Each Lender's obligation to make Base Rate Advances or L/C Advances to reimburse the applicable Issuing Bank for amounts drawn under Letters of Credit, as contemplated by this Section 2.03(c), shall be absolute and unconditional and shall not be affected by any circumstance, including (A) any setoff, counterclaim, recoupment, defense or other right which such Lender may have against such Issuing Bank, the Borrower or any other Person for any reason whatsoever; (B) the occurrence or continuance of a Default, or (C) any other occurrence, event or condition, whether or not similar to any of the foregoing; provided, however, that each Lender's obligation to make Base Rate Advances pursuant to this Section 2.03(c) is subject to the conditions set forth in Section 2.03(c)(i). No such making of an L/C Advance shall relieve or otherwise impair the obligation of the Borrower to reimburse the applicable Issuing Bank for the

amount of any payment made by such Issuing Bank under any Letter of Credit, together with interest as provided herein.

(vi) If any Lender fails to make available to the Agent for the account of the applicable Issuing Bank any amount required to be paid by such Lender pursuant to the foregoing provisions of this Section 2.03(c) by the time specified in Section 2.03(c)(i), such Issuing Bank shall be entitled to recover from such Lender (acting through the Agent), on demand, such amount with interest thereon for the period from the date such payment is required to the date on which such payment is immediately available to such Issuing Bank at a rate per annum equal to the greater of the Federal Funds Rate and a rate determined by such Issuing Bank in accordance with banking industry rules on interbank compensation, plus any administrative, processing or similar fees customarily charged by such Issuing Bank in connection with the foregoing. If such Lender pays such amount (with interest and fees as aforesaid), the amount so paid shall constitute such Lender's Base Rate Advance included in the relevant Borrowing or L/C Advance in respect of the relevant L/C Borrowing, as the case may be. A certificate of the applicable Issuing Bank submitted to any Lender (through the Agent) with respect to any amounts owing under this clause (vi) shall be conclusive absent manifest error.

(d) Repayment of Participations .

(i) At any time after the applicable Issuing Bank has made a payment under any Letter of Credit and has received from any Lender such Lender's L/C Advance in respect of such payment in accordance with Section 2.03(c), if the Agent receives for the account of such Issuing Bank any payment in respect of the related Unreimbursed Amount or interest thereon (whether directly from the Borrower or otherwise, including proceeds of Cash Collateral (as defined in Section 2.03(h)) applied thereto by the Agent), the Agent will distribute to such Lender its Ratable Share thereof in the same funds as those received by the Agent.

(ii) If any payment received by the Agent for the account of the applicable Issuing Bank pursuant to Section 2.03(c)(i) is required to be returned under any of the circumstances described in Section 8.12 (including pursuant to any settlement entered into by such Issuing Bank in its discretion), each Lender shall pay to the Agent for the account of such Issuing Bank its Ratable Share thereof on demand of the Agent, plus interest thereon from the date of such demand to the date such amount is returned by such Lender, at a rate per annum equal to the Federal Funds Rate from time to time in effect. The obligations of the Lenders under this clause shall survive the payment in full of the Obligations and the termination of this Agreement.

(e) Failure to Make Advances . The failure of any Lender to make the Advance to be made by it on the date specified in Section 2.03(c) or any L/C Advance shall not relieve any other Lender of its obligation hereunder to make its Advance or L/C Advance, as the case may be, to be made by such other Lender on such date.

(f) Obligations Absolute . The obligation of the Borrower to reimburse the applicable Issuing Bank for each drawing under each Letter of Credit and to repay each L/C Borrowing

shall be absolute, unconditional and irrevocable, and shall be paid strictly in accordance with the terms of this Agreement under all circumstances, including the following:

(i) any lack of validity or enforceability of such Letter of Credit, this Agreement, or any other Loan Document;

(ii) the existence of any claim, counterclaim, setoff, defense or other right that the Borrower may have at any time against any beneficiary or any transferee of such Letter of Credit (or any Person for whom any such beneficiary or any such transferee may be acting), any Issuing Bank or any other Person, whether in connection with this Agreement, the transactions contemplated hereby or by such Letter of Credit or any agreement or instrument relating thereto, or any unrelated transaction;

(iii) any draft, demand, certificate or other document presented under such Letter of Credit proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue or inaccurate in any respect; or any loss or delay in the transmission or otherwise of any document required in order to make a drawing under such Letter of Credit;

(iv) any payment by the applicable Issuing Bank under such Letter of Credit against presentation of a draft or certificate that does not strictly comply with the terms of such Letter of Credit; or any payment made by the applicable Issuing Bank under such Letter of Credit to any Person purporting to be a trustee in bankruptcy, debtor-in-possession, assignee for the benefit of creditors, liquidator, receiver or other representative of or successor to any beneficiary or any transferee of such Letter of Credit, including any arising in connection with any proceeding under any Debtor Relief Law; or

(v) any other circumstance or happening whatsoever, whether or not similar to any of the foregoing, including any other circumstance that might otherwise constitute a defense available to, or a discharge of, the Borrower.

provided , however , that nothing in this Section 2.03(f) shall limit the rights of the Borrower under Section 2.03(g).

The Borrower shall promptly examine a copy of each Letter of Credit and each amendment thereto that is delivered to it and, in the event of any claim of noncompliance with the Borrower's instructions or other irregularity that is known to the Borrower in connection with any draw under such Letter of Credit of which the Borrower has reasonable notice, the Borrower will immediately notify the applicable Issuing Bank. To the extent allowed by applicable Law, Borrower shall be conclusively deemed to have waived any such claim against the applicable Issuing Bank and its correspondents unless such notice is given as aforesaid. Nothing herein shall require the Borrower to make any determination as to whether the drawing is in accordance with the requirements of the Letter of Credit, provided that the Borrower may waive any discrepancies in the drawing on any such Letter of Credit.

(g) Role of Issuing Bank . Each Lender and the Borrower agree that, in paying any drawing under a Letter of Credit, the applicable Issuing Bank shall not have any responsibility to

obtain any document (other than any sight draft, certificates and documents expressly required by the Letter of Credit) or to ascertain or inquire as to the validity or accuracy of any such document or the authority of the Person executing or delivering any such document. None of the applicable Issuing Bank, the Agent, any of their respective Related Parties nor any correspondent, participant or assignee of such Issuing Bank shall be liable to any Lender for (i) any action taken or omitted in connection herewith at the request or with the approval of the Lenders or the Required Lenders, as applicable; (ii) any action taken or omitted in the absence of gross negligence or willful misconduct; or (iii) the due execution, effectiveness, validity or enforceability of any document or instrument related to any Letter of Credit or L/C Related Document. The Borrower hereby assumes all risks of the acts or omissions of any beneficiary or transferee with respect to its use of any Letter of Credit; provided , however , that this assumption is not intended to, and shall not, preclude the Borrower's pursuing such rights and remedies as it may have against the beneficiary or transferee at Law or under any other agreement. None of the applicable Issuing Bank, the Agent, any of their respective Related Parties nor any correspondent, participant or assignee of such Issuing Bank shall be liable or responsible for any of the matters described in clauses (i) through (v) of Section 2.03(f); provided , however , that anything in such clauses to the contrary notwithstanding, the Borrower may have a claim against the applicable Issuing Bank, and such Issuing Bank may be liable to the Borrower, to the extent, but only to the extent, of any direct, as opposed to consequential or exemplary, damages suffered by the Borrower which the Borrower proves were caused by such Issuing Bank's willful misconduct or gross negligence or such Issuing Bank's willful failure to pay under any Letter of Credit after the presentation to it by the beneficiary of a sight draft and certificate(s) strictly complying with the terms and conditions of a Letter of Credit. In furtherance and not in limitation of the foregoing, the applicable Issuing Bank may accept documents that appear on its face to be in order, without responsibility for further investigation, regardless of any notice or information to the contrary, and such Issuing Bank shall not be responsible for the validity or sufficiency of any instrument transferring or assigning or purporting to transfer or assign a Letter of Credit or the rights or benefits thereunder or proceeds thereof, in whole or in part, which may prove to be invalid or ineffective for any reason.

(h) Cash Collateral . Upon the request of the Agent, if, as of the Letter of Credit Expiration Date, any L/C Obligation for any reason remains outstanding, the Borrower shall, in each case, immediately Cash Collateralize the then outstanding L/C Obligations. Section 6.02 sets forth certain additional requirements to deliver Cash Collateral hereunder. For purposes of this Section 2.03 , Section 2.19(c)(ii) and Section 6.02 , "Cash Collateralize" means to pledge and deposit with or deliver to the Agent, for the benefit of the Issuing Banks and the Lenders, as collateral for the L/C Obligations, cash or deposit account balances pursuant to documentation in form and substance satisfactory to the Agent and each Issuing Bank (which documents are hereby consented to by the Lenders). Derivatives of such term have corresponding meanings. The Borrower hereby grants to the Agent, for the benefit of the Issuing Banks and the Lenders, a security interest in all such cash, deposit accounts and all balances therein and all proceeds of the foregoing. Cash Collateral shall be maintained in blocked, non-interest bearing deposit accounts with the Agent.

(i) Applicability of ISP and UCP . Unless otherwise expressly agreed by the applicable Issuing Bank and the Borrower when a Letter of Credit is issued, the rules of the ISP shall apply to each standby Letter of Credit.

(j) Letter of Credit Reports . Each Issuing Bank shall furnish (A) to the Agent on the first Business Day of each month a written report summarizing issuance and expiration dates of Letters of Credit issued by such Issuing Bank during the preceding month and drawings during such month under all such Letters of Credit and (B) to the Agent on the first Business Day of each calendar quarter a written report setting forth the average daily aggregate Available Amount during the preceding calendar quarter of all Letters of Credit issued by such Issuing Bank.

(k) Interim Interest . Except as provided in Section 2.03(c)(ii) with respect to Unreimbursed Amounts refinanced as Base Rate Advances and Section 2.03(c)(iii) with respect to L/C Borrowings, unless the Borrower shall reimburse each payment by an Issuing Bank pursuant to a Letter of Credit in full on the Honor Date, the Unreimbursed Amount thereof shall bear interest, for each day from and including the Honor Date to but excluding the date that the Borrower reimburses such Issuing Bank for the Unreimbursed Amount in full, at the rate per annum equal to (i) the Base Rate in effect from time to time plus the Applicable Rate for Base Rate Advances in effect from time to time, to but excluding the next Business Day after the Honor Date and (ii) from and including the next Business Day after the Honor Date, the Base Rate in effect from time to time plus the Applicable Rate for Base Rate Advances in effect from time to time plus 2% per annum.

Section 2.04 Fees .

(a) Commitment Fee . The Borrower agrees to pay to the Agent for the account of each Lender a commitment fee on such Lender's Unused Commitment from the Effective Date in the case of each Initial Lender and from the effective date specified in the Assumption Agreement or in the Assignment and Assumption pursuant to which it became a Lender in the case of each other Lender until the Termination Date at a rate per annum equal to the Applicable Rate for Commitment Fees in effect from time to time, payable in arrears quarterly on the last day of each March, June, September and December, commencing March 31, 2011, and on the Termination Date, provided that no commitment fee shall accrue with respect to the Unused Commitment of an Affected Lender so long as such Lender shall be an Affected Lender.

(b) Letter of Credit Fees .

(i) The Borrower shall pay to the Agent for the account of each Lender a commission on such Lender's Ratable Share of the average daily aggregate Available Amount of all Letters of Credit outstanding from time to time at a rate per annum equal to the Applicable Rate for Eurodollar Rate Advances in effect from time to time, during such calendar quarter, payable in arrears quarterly on the last day of each March, June, September and December, commencing with the quarter ended March 31, 2011, and on the Termination Date; provided that the Applicable Rate for Eurodollar Rate Advances shall be 2% above such Applicable Rate in effect upon the occurrence and during the continuation of an Event of Default if the Borrower is required to pay default interest pursuant to Section 2.07(b).

(ii) The Borrower shall pay to each Issuing Bank, for its own account, a fronting fee with respect to each Letter of Credit issued by such Issuing Bank, payable in the amounts and at the times specified in the applicable Fee Letter between the Borrower

and such Issuing Bank, and such other commissions, issuance fees, transfer fees and other fees and charges in connection with the issuance or administration of each Letter of Credit as the Borrower and such Issuing Bank shall agree promptly following receipt of an invoice therefor.

(c) Agent's Fees . The Borrower shall pay to the Agent for its own account such fees as are agreed between the Borrower and the Agent pursuant to the Fee Letter between the Borrower and the Agent.

Section 2.05 Optional Termination or Reduction of the Commitments .

(a) The Borrower shall have the right, upon at least three Business Days' notice to the Agent, to terminate in whole or permanently reduce ratably in part the Unused Commitments or the Unissued Letter of Credit Commitments, provided that each partial reduction shall be in the aggregate amount of $10,000,000 or an integral multiple of $1,000,000 in excess thereof.

(b) So long as no Default or Event of Default shall be continuing, the Borrower shall have the right, at any time, upon at least ten Business Days' notice to an Affected Lender (with a copy to the Agent), to terminate in whole such Lender's Revolving Credit Commitment and, if applicable, its Letter of Credit Commitment, without affecting the Commitments of any other Lender. Such termination shall be effective, (x) with respect to such Lender's Unused Commitment, on the date set forth in such notice, provided , however , that such date shall be no earlier than ten Business Days after receipt of such notice and (y) with respect to each Advance outstanding to such Lender, in the case of Base Rate Advances, on the date set forth in such notice and, in the case of Eurodollar Rate Advances, on the last day of the then current Interest Period relating to such Advance. Upon termination of a Lender's Commitments under this Section 2.05(b), the Borrower will pay or cause to be paid all principal of, and interest accrued to the date of such payment on, Advances owing to such Lender and, subject to Section 2.19, pay any accrued commitment fees or Letter of Credit fees payable to such Lender pursuant to the provisions of Section 2.04, and all other amounts payable to such Lender hereunder (including, but not limited to, any increased costs or other amounts owing under Section 2.11 and any indemnification for Taxes under Section 2.14); and, if such Lender is an Issuing Bank, shall pay to such Issuing Bank for deposit in an escrow account an amount equal to the Available Amount of all Letters of Credit issued by such Issuing Bank, whereupon all Letters of Credit issued by such Issuing Bank shall be deemed to have been issued outside of this Agreement on a bilateral basis and shall cease for all purposes to constitute a Letter of Credit issued under this Agreement, and upon such payments, except as otherwise provided below, the obligations of such Lender hereunder shall, by the provisions hereof, be released and discharged; provided , however , that (i) such Lender's rights under Sections 2.11, 2.14 and 8.04, and, in the case of an Issuing Bank, Section 8.04(c), and its obligations under Section 8.04 and 8.08, in each case in accordance with the terms thereof, shall survive such release and discharge as to matters occurring prior to such date and (ii) such escrow agreement shall be in a form reasonably agreed to by the Borrower and such Issuing Bank, but in no event shall either the Borrower or such Issuing Bank require any waivers, covenants, events of default or other provisions that are more restrictive than or inconsistent with the provisions of this Agreement. Subject to Section 2.18, the aggregate amount of the Commitments of the Lenders once reduced pursuant to this Section 2.05(b) may not be reinstated. The termination of the Commitments of an Affected Lender pursuant to this

Section 2.05(b) will not be deemed to be a waiver of any right that the Borrower, the Agent, any Issuing Bank or any other Lender may have against the Affected Lender that arose prior to the date of such termination. Upon any such termination, the Ratable Share of each remaining Lender will be revised.

Section 2.06 Repayment of Advances . The Borrower shall repay to the Agent for the ratable account of the Lenders on the Termination Date the aggregate principal amount of the Advances made by such Lender and then outstanding.

Section 2.07 Interest on Advances .

(a) Scheduled Interest . The Borrower shall pay interest on the unpaid principal amount of each Advance owing to each Lender from the date of such Advance until such principal amount shall be paid in full, at the following rates per annum:

(i) Base Rate Advances . During such periods as such Advance is a Base Rate Advance, a rate per annum equal at all times to the sum of (x) the Base Rate in effect from time to time plus (y) the Applicable Rate for Base Rate Advances in effect from time to time, payable in arrears quarterly on the last day of each March, June, September and December during such periods and on the date such Base Rate Advance shall be Converted or paid in full.

(ii) Eurodollar Rate Advances . During such periods as such Advance is a Eurodollar Rate Advance, a rate per annum equal at all times during each Interest Period for such Advance to the sum of (x) the Eurodollar Rate for such Interest Period for such Advance plus (y) the Applicable Rate for Eurodollar Rate Advances in effect from time to time, payable in arrears on the last day of such Interest Period and, if such Interest Period has a duration of more than three months, on each day that occurs during such Interest Period every three months from the first day of such Interest Period and on the date such Eurodollar Rate Advance shall be Converted or paid in full.

(b) Default Interest . Upon the occurrence and during the continuance of an Event of Default under Section 6.01(a), the Agent may, and upon the request of the Required Lenders shall, require the Borrower to pay interest (" Default Interest ") on (i) the unpaid principal amount of each Advance owing to each Lender, payable in arrears on the dates referred to in clause (a)(i) or (a)(ii) above, at a rate per annum equal at all times to 2% per annum above the rate per annum required to be paid on such Advance pursuant to clause (a)(i) or (a)(ii) above and (ii) to the fullest extent permitted by Law, the amount of any interest, fee or other amount payable hereunder that is not paid when due, from the date such amount shall be due until such amount shall be paid in full, payable in arrears on the date such amount shall be paid in full and on demand, at a rate per annum equal at all times to 2% per annum above the rate per annum required to be paid on Base Rate Advances pursuant to clause (a)(i) above, provided , however , that following acceleration of the Advances pursuant to Section 6.01, Default Interest shall accrue and be payable hereunder whether or not previously required by the Agent.

(c) Interest Rate Limitation . Nothing contained in this Agreement or in any other Loan Document shall be deemed to establish or require the payment of interest to any Lender at

a rate in excess of the maximum rate permitted by applicable Law. If the amount of interest payable for the account of any Lender on any interest payment date would exceed the maximum amount permitted by applicable Law to be charged by such Lender, the amount of interest payable for its account on such interest payment date shall be automatically reduced to such maximum permissible amount. In the event of any such reduction affecting any Lender, if from time to time thereafter the amount of interest payable for the account of such Lender on any interest payment date would be less than the maximum amount permitted by applicable Law to be charged by such Lender, then the amount of interest payable for its account on such subsequent interest payment date shall be automatically increased to such maximum permissible amount, provided that at no time shall the aggregate amount by which interest paid for the account of any Lender has been increased pursuant to this sentence exceed the aggregate amount by which interest paid for its account has theretofore been reduced pursuant to the previous sentence.

Section 2.08 Interest Rate Determination .

(a) The Agent shall give prompt notice to the Borrower and the Lenders of the applicable interest rate determined by the Agent for purposes of Section 2.07(a).

(b) If the Required Lenders determine that for any reason in connection with any request for a Eurodollar Rate Advance or a Conversion to or continuation thereof that (a) Dollar deposits are not being offered to banks in the London interbank eurodollar market for the applicable amount and Interest Period of such Eurodollar Rate Advance, (b) adequate and reasonable means do not exist for determining the Eurodollar Rate for any requested Interest Period with respect to a proposed Eurodollar Rate Advance, or (c) the Eurodollar Rate for any requested Interest Period with respect to a proposed Eurodollar Rate Advance does not adequately and fairly reflect the cost to such Lenders of funding such Advance, the Agent will promptly so notify the Borrower and each Lender, whereupon each Eurodollar Rate Advance will automatically on the last day of the then existing Interest Period therefor Convert into a Base Rate Advance. Thereafter, the obligation of the Lenders to make or maintain Eurodollar Rate Advances shall be suspended until the Agent (upon the instruction of the Required Lenders) revokes such notice. Upon receipt of such notice, the Borrower may revoke any pending request for a Borrowing of, Conversion to or continuation of Eurodollar Rate Advances or, failing that, will be deemed to have Converted such request into a request for a Base Rate Advance in the amount specified therein.

(c) If the Borrower shall fail to select the duration of any Interest Period for any Eurodollar Rate Advances in accordance with the provisions contained in the definition of "Interest Period" in Section 1.01, the Agent will forthwith so notify the Borrower and the Lenders and such Advances will automatically, on the last day of the then existing Interest Period therefor, Convert into Base Rate Advances.

(d) On the date on which the aggregate unpaid principal amount of Eurodollar Rate Advances comprising any Borrowing shall be reduced, by payment or prepayment or otherwise, to less than $5,000,000, such Advances shall automatically Convert into Base Rate Advances.

(e) Upon the occurrence and during the continuance of any Event of Default,

(i) with respect to Eurodollar Rate Advances, each such Advance will automatically, on the last day of the then existing Interest Period therefor, Convert into a Base Rate Advance (or if such Advance is then a Base Rate Advance, will continue as a Base Rate Advance); and

(ii) the obligation of the Lenders to make Eurodollar Rate Advances or to Convert Advances into Eurodollar Rate Advances shall be suspended until the Agent shall notify the Borrower and the Lenders that the circumstances causing such suspension no longer exist.

Section 2.09 Optional Conversion of Advances. The Borrower may on any Business Day, upon notice given to the Agent not later than 12:00 noon on the third Business Day prior to the date of the proposed Conversion and subject to the provisions of Sections 2.08 and 2.12, Convert all Advances of one Type comprising the same Borrowing into Advances of the other Type; provided, however, that (a) any Conversion of Eurodollar Rate Advances into Base Rate Advances shall be made only on the last day of an Interest Period for such Eurodollar Rate Advances, (b) any Conversion of Base Rate Advances into Eurodollar Rate Advances shall be in an amount not less than the minimum amount specified in Section 2.02(b) and (c) no Conversion of any Advances shall result in more separate Borrowings than permitted under Section 2.02(b). Each such notice of a Conversion shall, within the restrictions specified above, specify (i) the date of such Conversion, (ii) the Advances to be Converted, and (iii) if such Conversion is into Eurodollar Rate Advances, the duration of the initial Interest Period for each such Advance. Each notice of Conversion shall be irrevocable and binding on the Borrower.

Section 2.10 Prepayments of Advances.

(a) Optional. At any time and from time to time, the Borrower shall have the right to prepay the Advances, in whole or in part, without premium or penalty (except as provided in clause (y) below), upon notice at least two Business Days' prior to the date of such prepayment, in the case of Eurodollar Rate Advances, and not later than 11:00 a.m. on the date of such prepayment, in the case of Base Rate Advances, to the Agent specifying the proposed date of such prepayment and the aggregate principal amount and Type of the Advances to be prepaid (and, in the case of Eurodollar Rate Advances, the Interest Period of the Borrowing pursuant to which made); provided, however, that (x) each partial prepayment shall be in an aggregate principal amount of $5,000,000 or an integral multiple of $1,000,000 in excess thereof, and shall be accompanied by accrued interest to the date of prepayment on the principal amount prepaid, and (y) in the event of any such prepayment of a Eurodollar Rate Advance, the Borrower shall be obligated to reimburse the Lenders in respect thereof pursuant to Section 8.04(e).

(b) Mandatory.

(i) The Borrower shall prepay the aggregate principal amount of the Advances, together with accrued interest to the date of prepayment on the principal amount prepaid, without requirement of demand therefor, or shall pay or prepay any other Indebtedness then outstanding at any time, when and to the extent required to

comply with applicable Laws of any Governmental Authority, including the 2007 Order, or applicable resolutions of the Board of Directors of the Borrower.

(ii) If for any reason the Total Outstandings at any time exceed the aggregate Commitments then in effect, the Borrower shall, within one Business Day after notice thereof, prepay Advances and/or Cash Collateralize the L/C Obligations in an aggregate amount equal to such excess; provided, however, that the Borrower shall not be required to Cash Collateralize the L/C Obligations pursuant to this Section 2.10(b) unless, after the prepayment in full of the Advances, the Total Outstandings exceed the aggregate Commitments then in effect.

Section 2.11 Increased Costs.

(a) Increased Costs Generally. If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, compulsory loan, insurance charge or similar requirement against assets of, deposits with or for the account of, or credit extended or participated in by, any Lender (except any reserve requirement contemplated by Section 2.11(e)) or any Issuing Bank; or

(ii) impose on any Lender or any Issuing Bank or the London interbank market any other condition, cost or expense affecting this Agreement or Eurodollar Rate Advances made by such Lender or any Letter of Credit or participation therein;

and the result of any of the foregoing shall be to increase the cost to such Lender of making or maintaining any Eurodollar Rate Advance (or of maintaining its obligation to make any such Advance), or to increase the cost to such Lender or such Issuing Bank of participating in, issuing or maintaining any Letter of Credit (or of maintaining its obligation to participate in or to issue any Letter of Credit), or to reduce the amount of any sum received or receivable by such Lender or such Issuing Bank hereunder (whether of principal, interest or any other amount) then, upon request of such Lender or such Issuing Bank, the Borrower will pay to such Lender or such Issuing Bank, as the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank, as the case may be, for such additional costs incurred or reduction suffered.

(b) Capital Requirements. If any Lender or any Issuing Bank determines that any Change in Law affecting such Lender or such Issuing Bank or any Applicable Lending Office of such Lender or such Lender's or such Issuing Bank's holding company, if any, regarding capital requirements has or would have the effect of reducing the rate of return on such Lender's or such Issuing Bank's capital or on the capital of such Lender's or such Issuing Bank's holding company, if any, as a consequence of this Agreement, the Commitments of such Lender or the Advances made by, or participations in Letters of Credit held by, such Lender, or the Letters of Credit issued by such Issuing Bank, to a level below that which such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company could have achieved but for such Change in Law (taking into consideration such Lender's or such Issuing Bank's policies and the policies of such Lender's or such Issuing Bank's holding company with respect to capital adequacy), then from time to time the Borrower will pay to such Lender or such Issuing Bank, as

the case may be, such additional amount or amounts as will compensate such Lender or such Issuing Bank or such Lender's or such Issuing Bank's holding company for any such reduction suffered.

(c) Certificates for Reimbursement. A certificate of a Lender or an Issuing Bank setting forth the amount or amounts necessary to compensate such Lender or such Issuing Bank or its holding company, as the case may be, as specified in subsection (a) or (b) of this Section and delivered to the Borrower shall be conclusive and binding upon all parties absent manifest error. The Borrower shall pay such Lender or such Issuing Bank, as the case may be, the amount shown as due on any such certificate within 30 days after receipt thereof.

(d) Delay in Requests. Failure or delay on the part of any Lender or any Issuing Bank to demand compensation pursuant to the foregoing provisions of this Section shall not constitute a waiver of such Lender's or such Issuing Bank's right to demand such compensation, provided that the Borrower shall not be required to compensate a Lender or an Issuing Bank pursuant to the foregoing provisions of this Section for any increased costs incurred or reductions suffered more than three months prior to the date that such Lender or such Issuing Bank, as the case may be, notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's or such Issuing Bank's intention to claim compensation therefor (except that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the three-month period referred to above shall be extended to include the period of retroactive effect thereof).

(e) Reserves on Eurodollar Rate Advances. The Borrower shall pay to each Lender, as long as such Lender shall be required to maintain reserves with respect to liabilities or assets consisting of or including Eurocurrency funds or deposits (currently known as "Eurocurrency liabilities"), additional interest on the unpaid principal amount of each Eurodollar Rate Advance equal to the actual costs of such reserves allocated to such Advance by such Lender (as determined by such Lender in good faith, which determination shall be conclusive absent manifest error), which shall be due and payable on each date on which interest is payable on such Eurodollar Rate Advance, provided the Borrower shall have received at least 30 days' prior notice (with a copy to the Agent) of such additional interest from such Lender. If a Lender fails to give notice 30 days prior to the relevant interest payment date, such additional interest shall be due and payable 30 days from receipt of such notice.

Section 2.12 Illegality. If any Lender shall have determined in good faith that the introduction of or any change in any applicable Law or in the interpretation or administration thereof by any Governmental Authority charged with the interpretation or administration thereof, or compliance with any guideline or request from any such Governmental Authority (whether or not having the force of law), for any Lender or its Applicable Lending Office to make, maintain or fund Eurodollar Rate Advances, or to determine or charge interest rates based upon the Eurodollar Rate, or any Governmental Authority has imposed material restrictions on the authority of such Lender to purchase or sell, or to take deposits of, Dollars in the London interbank market, then, on notice thereof by such Lender to the Borrower through the Agent, any obligation of such Lender to make or continue Eurodollar Rate Advances or to convert Base Rate Advances to Eurodollar Rate Advances shall be suspended until such Lender notifies the Agent and the Borrower that the circumstances giving rise to such determination no longer exist. Upon

receipt of such notice, the Borrower shall, upon demand from such Lender (with a copy to the Agent), prepay or, if applicable, convert all Eurodollar Rate Advances of such Lender to Base Rate Advances, either on the last day of the Interest Period therefor, if such Lender may lawfully continue to maintain such Eurodollar Rate Advances to such day, or immediately, if such Lender may no lawfully continue to maintain such Eurodollar Rate Advances. Upon any such prepayment or conversion, the Borrower shall also pa accrued interest on the amount so prepaid or converted.

Section 2.13 Payments and Computations .

(a) All payments to be made by the Borrower shall be made without condition or deduction for any counterclaim, defense, recoupment or setoff. The Borrower shall make each payment hereunder not later than 1:00 p.m. on the day when due in U.S. dollars to the Agent at the Agent's Account in same day funds. The Agent will promptly thereafter cause to be distributed like funds relating to the payment of principal, interest, fees or commissions ratably (other than amounts payable pursuant to Section 2.05(b), 2.11, 2.12, 2.14, 2.20 or 8.04(e)) to the Lenders for the account of their respective Applicable Lending Offices, and like funds relating to the payment of any other amount payable to any Lender to such Lender for the account of its Applicable Lending Office, in each case to be applied in accordance with the terms of this Agreement. Upon any Assuming Lender becoming a Lender hereunder as a result of a Commitment Increase pursuant to Section 2.18, and upon the Agent's receipt of such Lender's Assumption Agreement and recording of the information contained therein in the Register, from and after the applicable Increase Date, the Agent shall make all payments hereunder and under any Notes issued in connection therewith in respect of the interest assumed thereby to the Assuming Lender. Upon its acceptance of an Assignment and Assumption and recording of the information contained therein in the Register pursuant to Section 8.07(c), from and after the effective date specified in such Assignment and Assumption, the Agent shall make all payments hereunder and under the Notes in respect of the interest assigned thereby to the Lender assignee thereunder, and the parties to such Assignment and Assumption shall make all appropriate adjustments in such payments for periods prior to such effective date directly between themselves.

(b) All computations of interest based on (i) the Prime rate (as defined in the definition of "Base Rate" in Section 1.01) shall be made by the Agent on the basis of a year of 365 or 366 days, as the case may be and (ii) the Federal Funds Rate, the Eurodollar Rate and of fees and Letter of Credit commissions shall be made by the Agent on the basis of a year of 360 days, in each case for the actual number of days (including the first day but excluding the last day) occurring in the period for which such interest, fees or commissions are payable. Each determination by the Agent of an interest rate hereunder shall be conclusive and binding for all purposes, absent manifest error.

(c) Whenever any payment hereunder or under the Notes shall be stated to be due on a day other than a Business Day, such payment shall be made on the next succeeding Business Day, and such extension of time shall in such case be included in the computation of payment of interest, fees or commissions, as the case may be; provided , however , that, if such extension would cause payment of interest on or principal of Eurodollar Rate Advances to be made in the next following calendar month, such payment shall be made on the next preceding Business Day.

(d) Unless the Agent shall have received notice from the Borrower prior to the date on which any payment is due to the Lenders hereunder that the Borrower will not make such payment in full, the Agent may assume that the Borrower has made such payment in full to the Agent on such date and the Agent may, in reliance upon such assumption, cause to be distributed to each Lender on such date an amount equal to the amount then due such Lender. If and to the extent the Borrower shall not have so made such payment in full to the Agent, each Lender shall repay to the Agent forthwith on demand such amount distributed to such Lender together with interest thereon, for each day from the date such amount is distributed to such Lender until the date such Lender repays such amount to the Agent, at the Federal Funds Rate.

Section 2.14 Taxes.

(a) Payments Free of Taxes; Obligation to Withhold; Payments on Account of Taxes.

(i) Any and all payments by or on account of any obligation of the Borrower hereunder or under any other Loan Document shall to the extent permitted by applicable Laws be made free and clear of and without reduction or withholding for any Taxes. If, however, applicable Laws require the Borrower or the Agent to withhold or deduct any Tax, such Tax shall be withheld or deducted in accordance with such Laws as determined by the Borrower or the Agent, as the case may be, upon the basis of the information and documentation to be delivered pursuant to subsection (e) below.

(ii) If the Borrower or the Agent shall be required by the Internal Revenue Code to withhold or deduct any Taxes, including both United States of America Federal backup withholding and withholding taxes, from any payment, then (A) the Agent shall withhold or make such deductions as are determined by the Agent to be required based upon the information and documentation it has received pursuant to subsection (e) below, (B) the Agent shall timely pay the full amount withheld or deducted to the relevant Governmental Authority in accordance with the Internal Revenue Code, and (C) to the extent that the withholding or deduction is made on account of Indemnified Taxes or Other Taxes, the sum payable by the Borrower shall be increased as necessary so that after any required withholding or the making of all required deductions (including deductions applicable to additional sums payable under this Section) the Agent, Lender or Issuing Bank, as the case may be, receives an amount equal to the sum it would have received had no such withholding or deduction been made.

(b) Payment of Other Taxes by the Borrower. Without limiting the provisions of subsection (a) above, the Borrower shall timely pay any Other Taxes to the relevant Governmental Authority in accordance with applicable Laws.

(c) Tax Indemnifications.

(i) Without limiting the provisions of subsection (a) or (b) above, the Borrower shall, and does hereby, indemnify the Agent, each Lender and each Issuing Bank, and shall make payment in respect thereof within 30 days after written demand therefor, for the full amount of any Indemnified Taxes or Other Taxes (including Indemnified Taxes or Other Taxes imposed or asserted on or attributable to amounts

payable under this Section) withheld or deducted by the Borrower or the Agent or paid by the Agent, such Lender or such Issuing Bank, as the case may be, and any penalties, interest and reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes or Other Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. The Borrower shall also, and does hereby, indemnify the Agent, and shall make payment in respect thereof within 10 days after demand therefor, for any amount which a Lender or an Issuing Bank for any reason fails to pay indefeasibly to the Agent as required by clause (ii) of this subsection. A certificate as to the amount of any such payment or liability delivered to the Borrower by a Lender or an Issuing Bank (with a copy to the Agent), or by the Agent on its own behalf or on behalf of a Lender or an Issuing Bank, shall be conclusive absent manifest error.

(ii) Without limiting the provisions of subsection (a) or (b) above, each Lender and each Issuing Bank shall, and does hereby, indemnify the Borrower and the Agent, and shall make payment in respect thereof within 30 days after demand therefor, against any and all Taxes and any and all related losses, claims, liabilities, penalties, interest and expenses (including the fees, charges and disbursements of any counsel for the Borrower or the Agent) incurred by or asserted against the Borrower or the Agent by any Governmental Authority as a result of the failure by such Lender or such Issuing Bank, as the case may be, to deliver, or as a result of the inaccuracy, inadequacy or deficiency of, any documentation required to be delivered by such Lender or such Issuing Bank, as the case may be, to the Borrower or the Agent pursuant to subsection (e). Each Lender and each Issuing Bank hereby authorizes the Agent to set off and apply any and all amounts at any time owing to such Lender or such Issuing Bank, as the case may be, under this Agreement or any other Loan Document against any amount due to the Agent under this clause (ii). The agreements in this clause (ii) shall survive the resignation and/or replacement of the Agent, any assignment of rights by, or the replacement of, a Lender or an Issuing Bank, the termination of the Commitments and the repayment, satisfaction or discharge of all other Obligations.

(d) Evidence of Payments . Upon request by the Borrower or the Agent, as the case may be, after any payment of Taxes by the Borrower or by the Agent to a Governmental Authority as provided in this 2.14, the Borrower shall deliver to the Agent or the Agent shall deliver to the Borrower, as the case may be, the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of any return required by Laws to report such payment or other evidence of such payment reasonably satisfactory to the Borrower or the Agent, as the case may be.

(e) Status of Lenders; Tax Documentation .

(i) Each Lender shall deliver to the Borrower and to the Agent, at the time or times prescribed by applicable Laws or when reasonably requested by the Borrower or the Agent, such properly completed and executed documentation prescribed by applicable Laws or by the taxing authorities of any jurisdiction and such other reasonably requested information as will permit the Borrower or the Agent, as the case may be, to determine (A) whether or not payments made hereunder or under any other Loan Document are subject to Taxes, (B) if applicable, the required rate of withholding or

deduction, and (C) such Lender's entitlement to any available exemption from, or reduction of, applicable Taxes in respect of all payments to be made to such Lender by the Borrower pursuant to this Agreement or otherwise to establish such Lender's status for withholding tax purposes in the applicable jurisdiction.

(ii) Without limiting the generality of the foregoing, if the Borrower is resident for tax purposes in the United States of America,

(A) any Lender that is a "United States person" within the meaning of Section 7701(a)(30) of the Internal Revenue Code shall deliver to the Borrower and the Agent executed originals of Internal Revenue Service Form W-9 or such other documentation or information prescribed by applicable Laws or reasonably requested by the Borrower or the Agent as will enable the Borrower or the Agent, as the case may be, to determine whether or not such Lender is subject to backup withholding or information reporting requirements; and

(B) each Foreign Lender that is entitled under the Internal Revenue Code or any applicable treaty to an exemption from or reduction of withholding tax with respect to payments hereunder or under any other Loan Document shall deliver to the Borrower and the Agent (in such number of copies as shall be requested by the recipient) on or prior to the date on which such Foreign Lender becomes a Lender under this Agreement (and from time to time thereafter upon the request of the Borrower or the Agent, but only if such Foreign Lender is legally entitled to do so), whichever of the following is applicable:

(1) executed originals of Internal Revenue Service Form W-8BEN claiming eligibility for benefits of an income tax treaty to which the United States of America is a party,

(2) executed originals of Internal Revenue Service Form W-8ECI,

(3) executed originals of Internal Revenue Service Form W-8IMY and all required supporting documentation,

(4) in the case of a Foreign Lender claiming the benefits of the exemption for portfolio interest under section 881 (c) of the Internal Revenue Code, (x) a certificate to the effect that such Foreign Lender is not (A) a "bank" within the meaning of section 881(c)(3)(A) of the Internal Revenue Code, (B) a "10 percent shareholder" of the Borrower within the meaning of section 881(c)(3)(B) of the Internal Revenue Code, or (C) a "controlled foreign corporation" described in section 881(c)(3)(C) of the Internal Revenue Code and (y) executed originals of Internal Revenue Service Form W-8BEN, or

(5) executed originals of any other form prescribed by applicable Laws as a basis for claiming exemption from or a reduction in United States of America Federal withholding tax together with such

supplementary documentation as may be prescribed by applicable Laws to permit the Borrower or the Agent to determine the withholding or deduction required to be made.

(iii) Each Lender shall promptly (A) notify the Borrower and the Agent of any change in circumstances which would modify or render invalid any claimed exemption or reduction, and (B) take such steps as shall not be materially disadvantageous to it, in the reasonable judgment of such Lender, and as may be reasonably necessary (including the re-designation of its Applicable Lending Office) to avoid any requirement of applicable Laws of any jurisdiction that the Borrower or the Agent make any withholding or deduction for taxes from amounts payable to such Lender.

(f) Treatment of Certain Refunds. Unless required by applicable Laws, at no time shall the Agent have any obligation to file for or otherwise pursue on behalf of a Lender or an Issuing Bank, or have any obligation to pay to any Lender or any Issuing Bank, any refund of Taxes withheld or deducted from funds paid for the account of such Lender or such Issuing Bank, as the case may be. If the Agent, any Lender or any Issuing Bank determines, in its sole discretion, that it has received a refund of any Taxes or Other Taxes as to which it has been indemnified by the Borrower or with respect to which the Borrower has paid additional amounts pursuant to this Section, it shall pay to the Borrower an amount equal to such refund (but only to the extent of indemnity payments made, or additional amounts paid, by the Borrower under this Section with respect to the Taxes or Other Taxes giving rise to such refund), net of all reasonable out-of-pocket expenses incurred by the Agent, such Lender or such Issuing Bank, as the case may be, and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund), provided that the Borrower, upon the request of the Agent, such Lender or such Issuing Bank, agrees to repay the amount paid over to the Borrower (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) to the Agent, such Lender or such Issuing Bank in the event the Agent, such Lender or such Issuing Bank is required to repay such refund to such Governmental Authority. This subsection shall not be construed to require the Agent, any Lender or any Issuing Bank to make available its tax returns (or any other information relating to its taxes that it deems confidential) to the Borrower or any other Person.

(g) Payments. Failure or delay on the part of the Agent, any Lender or any Issuing Bank to demand compensation pursuant to the foregoing provisions of this Section 2.14 shall not constitute a waiver of the Agent's, such Lender's or such Issuing Bank's right to demand such compensation, provided that the Borrower shall not be required to compensate the Agent, a Lender or an Issuing Bank pursuant to the foregoing provisions of this Section 2.14 for any Indemnified Taxes or Other Taxes imposed or asserted by the relevant Governmental Authority more than three months prior to the date that the Agent, such Lender or such Issuing Bank, as the case may be, claims compensation with respect thereto (except that, if a Change in Law giving rise to such Indemnified Taxes or Other Taxes is retroactive, then the three-month period referred to above shall be extended to include the period of retroactive effect thereof).

(h) Each of the Agent, any Issuing Bank or any Lender agrees to cooperate with any reasonable request made by the Borrower in respect of a claim of a refund in respect of Indemnified Taxes as to which it has been indemnified by the Borrower or with respect to which

the Borrower has paid additional amounts pursuant to this Section 2.14 if (i) the Borrower has agreed in writing to pay all of the Agent's or such Issuing Bank's or such Lender's reasonable out-of-pocket costs and expenses relating to such claim, (ii) the Agent or such Issuing Bank or such Lender determines, in its good faith judgment, that it would not be disadvantaged, unduly burdened or prejudiced as a result of such claim and (iii) the Borrower furnishes, upon request of the Agent, or such Issuing Bank or such Lender, an opinion of tax counsel (such opinion, which can be reasoned, and such counsel to be reasonably acceptable to such Lender, or such Issuing Bank or the Agent) that the Borrower is likely to receive a refund or credit.

Section 2.15 Sharing of Payments, Etc . If any Lender shall obtain any payment (whether voluntary, involuntary, through the exercise of any right of set-off, or otherwise) on account of the Advances or L/C Advances owing to it (other than pursuant to Section 2.05(b), 2.11, 2.12, 2.14, 2.20 or 8.04(e) or any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Advances or participations in Letters of Credit to any assignee or participant, other than to the Borrower or any Subsidiary thereof if permitted hereby (as to which the provisions of this Section 2.15 shall apply) in excess of its Ratable Share of payments on account of the Advances obtained by all the Lenders, such Lender shall forthwith purchase from the other Lenders (for cash at face value) such participations in the Advances owing to them as shall be necessary to cause such purchasing Lender to share the excess payment ratably with each of them; provided , however , that if all or any portion of such excess payment is thereafter recovered from such purchasing Lender, such purchase from each Lender shall be rescinded and such Lender shall repay to the purchasing Lender the purchase price to the extent of such recovery together with an amount equal to such Lender's Ratable Share (according to the proportion of (i) the amount of such Lender's required repayment to (ii) the total amount so recovered from the purchasing Lender) of any interest or other amount paid or payable by the purchasing Lender in respect of the total amount so recovered. The Borrower agrees that any Lender so purchasing a participation from another Lender pursuant to this Section 2.15 may, to the fullest extent permitted by Law, exercise all its rights of payment (including the right of set-off) with respect to such participation as fully as if such Lender were the direct creditor of the Borrower in the amount of such participation.

Section 2.16 Evidence of Debt .

(a) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Advance owing to such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder in respect of Advances. The Borrower agrees that upon notice by any Lender to the Borrower (with a copy of such notice to the Agent) to the effect that a Note is required or appropriate in order for such Lender to evidence (whether for purposes of pledge, enforcement or otherwise) the Advances owing to, or to be made by, such Lender, the Borrower shall promptly execute and deliver to such Lender a Note payable to the order of such Lender in a principal amount up to the Revolving Credit Commitment of such Lender.

(b) The Register maintained by the Agent pursuant to Section 8.07(c) shall include a control account, and a subsidiary account for each Lender, in which accounts (taken together) shall be recorded (i) the date and amount of each Borrowing made hereunder, the Type of

Advances comprising such Borrowing and, if appropriate, the Interest Period applicable thereto, (ii) the terms of each Assumption Agreement and each Assignment and Assumption delivered to and accepted by it, (iii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iv) the amount of any sum received by the Agent from the Borrower hereunder and each Lender's share thereof.

(c) Entries made in good faith by the Agent in the Register pursuant to subsection (b) above, and by each Lender in its account or accounts pursuant to subsection (a) above, shall be prima facie evidence of the amount of principal and interest due and payable or to become due and payable from the Borrower to, in the case of the Register, each Lender and, in the case of such account or accounts, such Lender, under this Agreement, absent manifest error; provided , however , that the failure of the Agent or such Lender to make an entry, or any finding that an entry is incorrect, in the Register or such account or accounts shall not limit or otherwise affect the obligations of the Borrower under this Agreement.

Section 2.17 Use of Proceeds . The proceeds of the Advances shall be available (and the Borrower agrees that it shall use such proceeds) solely to refinance Indebtedness of the Borrower from time to time and for other general corporate purposes of the Borrower, subject to such restrictions that are imposed in the 2007 Order.

Section 2.18 Increase in the Aggregate Revolving Credit Commitments .

(a) The Borrower may, at any time prior to the Termination Date, by notice to the Agent, request that the aggregate amount of the Revolving Credit Commitments be increased by an amount of $10,000,000 or an integral multiple thereof (each a " Commitment Increase ") to be effective as of a date that is at least 90 days prior to the Termination Date (the " Increase Date ") as specified in the related notice to the Agent; provided , however that (i) in no event shall the aggregate amount of the Revolving Credit Commitments at any time exceed $700,000,000 or the aggregate amount of Commitment Increases exceed $200,000,000 and (ii) on the date of any request by the Borrower for a Commitment Increase and on the related Increase Date, the applicable conditions set forth in this Section 2.18 shall be satisfied.

(b) The Agent shall promptly notify the Lenders of a request by the Borrower for a Commitment Increase, which notice shall include (i) the proposed amount of such requested Commitment Increase, (ii) the proposed Increase Date and (iii) the date by which Lenders wishing to participate in the Commitment Increase must commit to an increase in the amount of their respective Revolving Credit Commitments (the " Commitment Date "). Each Lender that is willing to participate in such requested Commitment Increase (each an " Increasing Lender ") shall, in its sole discretion, give written notice to the Agent on or prior to the Commitment Date of the amount by which it is willing to increase its Revolving Credit Commitment. If the Lenders notify the Agent that they are willing to increase the amount of their respective Revolving Credit Commitments by an aggregate amount that exceeds the amount of the requested Commitment Increase, the requested Commitment Increase shall be allocated among the Lenders willing to participate therein in such amounts as are agreed between the Borrower and the Agent.

(c) Promptly following each Commitment Date, the Agent shall notify the Borrower as to the amount, if any, by which the Lenders are willing to participate in the requested Commitment Increase. If the aggregate amount by which the Lenders are willing to participate in any requested Commitment Increase on any such Commitment Date is less than the requested Commitment Increase, then the Borrower may extend offers to one or more Eligible Assignees to participate in any portion of the requested Commitment Increase that has not been committed to by the Lenders as of the applicable Commitment Date; provided , however , that the Revolving Credit Commitment of each such Eligible Assignee shall be in an amount of not less than $10,000,000.

(d) On each Increase Date, each Eligible Assignee that accepts an offer to participate in a requested Commitment Increase in accordance with Section 2.18(b) (each such Eligible Assignee, an " Assuming Lender ") shall become a Lender party to this Agreement as of such Increase Date and the Revolving Credit Commitment of each Increasing Lender for such requested Commitment Increase shall be so increased by the amount by which the Increasing Lender agreed to increase its Revolving Credit Commitment (or by the amount allocated to such Lender pursuant to the last sentence of Section 2.18(b)) as of such Increase Date; provided , however , that the Agent shall have received on or before such Increase Date the following, each dated such date:

(i) (A) certified copies of resolutions of the Board of Directors of the Borrower approving the Commitment Increase and the corresponding modifications to this Agreement, (B) an opinion of counsel for the Borrower (which may be in-house counsel), in form and substance reasonably acceptable to the Required Lenders and (C) a certificate from a duly authorized officer of the Borrower, stating that the conditions set forth in Section 3.02(a) and (b) are satisfied;

(ii) an assumption agreement from each Assuming Lender, if any, in form and substance satisfactory to the Borrower and the Agent (each an " Assumption Agreement "), duly executed by such Assuming Lender, the Agent and the Borrower; and

(iii) confirmation from each Increasing Lender of the increase in the amount of its Revolving Credit Commitment in a writing satisfactory to the Borrower and the Agent.

On each Increase Date, upon fulfillment of the conditions set forth in the immediately preceding sentence of this Section 2.18(d), the Agent shall notify the Lenders (including, without limitation, each Assuming Lender) and the Borrower, on or before 1:00 p.m., by telecopier, of the occurrence of the Commitment Increase to be effected on such Increase Date and shall record in the Register the relevant information with respect to each Increasing Lender and each Assuming Lender on such date. Each Increasing Lender and each Assuming Lender shall, before 2:00 p.m. on the Increase Date, make available for the account of its Applicable Lending Office to the Agent at the Agent's Account, in same day funds, in the case of such Assuming Lender, an amount equal to such Assuming Lender's Ratable Share of the Borrowings then outstanding (calculated based on its Revolving Credit Commitment as a percentage of the aggregate Revolving Credit Commitments outstanding after giving effect to the relevant Commitment Increase) and, in the case of such Increasing Lender, an amount equal to the excess of (i) such

Increasing Lender's Ratable Share of the Borrowings then outstanding (calculated based on its Revolving Credit Commitment as a percentage of the aggregate Revolving Credit Commitments outstanding after giving effect to the relevant Commitment Increase) over (ii) such Increasing Lender's Ratable Share of the Borrowings then outstanding (calculated based on its Revolving Credit Commitment (without giving effect to the relevant Commitment Increase) as a percentage of the aggregate Revolving Credit Commitments (without giving effect to the relevant Commitment Increase). After the Agent's receipt of such funds from each such Increasing Lender and each such Assuming Lender, the Agent will promptly thereafter cause to be distributed like funds to the other Lenders for the account of their respective Applicable Lending Offices in an amount to each other Lender such that the aggregate amount of the outstanding Advances owing to each Lender after giving effect to such distribution equals such Lender's Ratable Share of the Borrowings then outstanding (calculated based on its Revolving Credit Commitment as a percentage of the aggregate Revolving Credit Commitments outstanding after giving effect to the relevant Commitment Increase).

Section 2.19 Affected Lenders . Notwithstanding any provision of this Agreement to the contrary, if any Lender becomes an Affected Lender, then the following provisions shall apply for so long as such Lender is an Affected Lender:

(a) fees shall cease to accrue on the Unused Commitment of such Affected Lender pursuant to Section 2.04(a);

(b) the Revolving Credit Commitment and Advances of such Affected Lender shall not be included in determining whether the Required Lenders have taken or may take any action hereunder (including any consent to any amendment or waiver pursuant to Section 8.01), other than any waiver, amendment or modification requiring the consent of all Lenders or of each Lender affected;

(c) if there shall be any Available Amount under any outstanding Letter of Credit during any time a Lender is an Affected Lender, then:

(i) so long as no Default or Event of Default has occurred and is continuing, all or any part of the Available Amount of all such Letters of Credit shall be reallocated among the non-Affected Lenders in accordance with their respective Ratable Shares (disregarding any Affected Lender's Revolving Credit Commitment) but only to the extent that with respect to each non-Affected Lender the sum of (A) the aggregate principal amount of all Advances made by such non-Affected Lender (in its capacity as a Lender) and outstanding at such time plus (B) such non-Affected Lender's Ratable Share (after giving effect to the reallocation contemplated in this Section 2.19(c)(i)) of the outstanding L/C Obligations, does not exceed such non-Affected Lender's Revolving Credit Commitment;

(ii) if the reallocation described in clause (i) above cannot, or can only partially, be effected, the Borrower shall within one (1) Business Day following notice by the Agent Cash Collateralize for the benefit of the applicable Issuing Bank only the Borrower's obligations corresponding to such Affected Lender's Ratable Share of the Available Amount of outstanding Letters of Credit (after giving effect to any partial

reallocation pursuant to clause (i) above) (the " Affected Lender Share ") in accordance with the procedures set forth in Section 2.03(h) for so long as such there shall be any Available Amount of outstanding Letters of Credit;

(iii) if the Ratable Share of the Available Amount of outstanding Letters of Credit of the non-Affected Lenders is reallocated pursuant to this Section 2.19(c), then the fees payable to the Lenders pursuant to Section 2.04(a) and Section 2.04(b) shall be adjusted in accordance with such non-Affected Lenders' Ratable Shares;

(iv) if any Affected Lender Share is not reallocated pursuant to clause (i) above and if the Borrower fails to Cash Collateralize any portion of such Affected Lender Share pursuant to clause (ii) above, then, without prejudice to any rights or remedies of any Issuing Bank or any Lender hereunder, the fee payable under Section 2.04(b) with respect to such Affected Lender Share shall be payable to the Issuing Bank until such Affected Lender Share is reallocated; and

(v) if the Borrower Cash Collateralizes any portion of any Affected Lender Share pursuant to clause (ii) above, the Borrower shall not be required to pay any fees to such Affected Lender pursuant to Section 2.04(b)(i) or the applicable Issuing Bank pursuant to Section 2.04(b)(ii) (solely with respect to any fronting fee) with respect to such Affected Lender's Affected Lender Share during the period such Affected Lender's Affected Lender Share is Cash Collateralized;

(d) to the extent the Agent receives any payments or other amounts for the account of an Affected Lender under this Agreement, such Affected Lender shall be deemed to have requested that the Agent use such payment or other amount to fulfill such Affected Lender's previously unsatisfied obligations to fund an Advance under Section 2.03(c) or L/C Advance or any other unfunded payment obligation of such Affected Lender under this Agreement; and

(e) for the avoidance of doubt, the Borrower, each Issuing Bank, the Agent and each other Lender shall retain and reserve its other rights and remedies respecting each Affected Lender.

In the event that the Agent, the Borrower and the Issuing Banks each agrees that an Affected Lender has adequately remedied all matters that caused such Lender to be an Affected Lender, then the Ratable Shares of the Lenders shall be readjusted to reflect the inclusion of such Lender's Revolving Credit Commitment and on such date such Lender shall purchase at par such of the Advances of the other Lenders as the Agent shall determine may be necessary in order for such Lender to hold such Advances in accordance with its Ratable Share. In addition, at such time as the Affected Lender is replaced by another Lender pursuant to Section 2.20, the Ratable Shares of the Lenders will be readjusted to reflect the inclusion of the replacing Lender's Commitment in accordance with tion 2.20. In either such case, this Section 2.19 will no longer apply.

Section 2.20 Replacement of Lenders . If any Lender requests compensation under Section 2.11, or if the Borrower is required to pay any additional amount to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.14, or if any Lender

is an Affected Lender, then the Borrower may, at its sole expense and effort, upon notice to such Lender and the Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in, and consents required by, Section 8.07), all of its interests, rights and obligations under this Agreement and the related Loan Documents to one or more assignees that shall assume such obligations (which any such assignee may be another Lender, if a Lender accepts such assignment); provided that:

(a) the Borrower shall have paid to the Agent the assignment fee specified in Section 8.07(b);

(b) such Lender shall have received payment of an amount equal to the outstanding principal of its Advances and L/C Advances, accrued interest thereon, accrued fees and all other amounts payable to it hereunder and under the other Loan Documents (including any amounts under Section 8.04(e)) from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts);

(c) in the case of any such assignment resulting from a claim for compensation under Section 2.11 or payments required to be made pursuant to Section 2.14, such assignment will result in a reduction in such compensation or payments thereafter; and

(d) such assignment does not conflict with applicable Laws.

A Lender shall not be required to make any such assignment or delegation if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment and delegation cease to apply.

ARTICLE III

CONDITIONS PRECEDENT

Section 3.01 Conditions Precedent to Effectiveness. This Agreement shall become effective on and as of the first date (the "Effective Date") on which the following conditions precedent have been satisfied:

(a) The Lenders shall have been given such access to the management, records, books of account, contracts and properties of the Borrower and its Subsidiaries as they shall have requested.

(b) The Borrower shall have paid all accrued fees and agreed expenses of the Agent, the Arrangers and the Lenders and the reasonable accrued fees and expenses of counsel to the Agent that have been invoiced at least one Business Day prior to the Effective Date.

(c) On the Effective Date, the following statements shall be true and the Agent shall have received a certificate signed by a duly authorized officer of the Borrower, dated the Effective Date, stating that:

(i) The representations and warranties contained in Section 4.01 are true and correct on and as of the Effective Date, and

(ii) No event has occurred and is continuing that constitutes a Default.

(d) The Agent shall have received on or before the Effective Date the following, each dated such day, in form and substance satisfactory to the Agent and the Lenders:

(i) Receipt by the Agent of executed counterparts of this Agreement properly executed by a duly authorized officer of the Borrower and by each Lender.

(ii) The Notes, payable to the order of the Lenders to the extent requested by any Lender pursuant to Section 2.16.

(iii) The articles of incorporation of the Borrower certified to be true and complete as of a recent date by the appropriate governmental authority of the state or other jurisdiction of its incorporation and certified by a secretary, assistant secretary or associate secretary of the Borrower to be true and correct as of the Effective Date.

(iv) The bylaws of the Borrower certified by a secretary, assistant secretary or associate secretary of the Borrower to be true and correct as of the Effective Date.

(v) Certified copies of the resolutions of the Board of Directors of the Borrower approving this Agreement and the Notes, and of all documents evidencing other necessary corporate action and governmental approvals, if any, with respect to this Agreement and the Notes.

(vi) A certificate of the secretary, assistant secretary or associate secretary of the Borrower certifying the names and true signatures of the officers of the Borrower authorized to sign this Agreement and the Notes and the other documents to be delivered hereunder.

(vii) A certificate as of a recent date from the Borrower's state of incorporation evidencing that the Borrower is in good standing in its state of organization or formation.

(viii) A favorable opinion of counsel for the Borrower, in form and substance reasonably acceptable to the Lenders.

(ix) A favorable opinion of Sidley Austin LLP, counsel for the Agent, in form and substance reasonably acceptable to the Lenders.

(e) Concurrently with or before the Effective Date, (i) all principal, interest and other amounts outstanding under the Borrower's existing Five-Year Credit Agreement dated as of September 28, 2006 (the " Existing Senior Credit Agreement ") shall be repaid and satisfied in full, (ii) all commitments to extend credit under the Existing Senior Credit Agreement shall be terminated and (iii) any letters of credit outstanding under the Existing Senior Credit Agreement shall have been terminated, canceled, transferred or replaced; and the Agent shall have received

evidence of the foregoing satisfactory to it, including an escrow agreement or payoff letter executed by the lenders or the agent under the Existing Senior Credit Agreement if applicable.

Section 3.02 Conditions Precedent to Each Credit Extension and Commitment Increase . The obligation of each Lender to make an Advance (other than an L/C Advance or a Base Rate Advance made pursuant to Section 2.03(c)) on the occasion of each Borrowing, the obligation of each Issuing Bank to issue a Letter of Credit, and each Commitment Increase shall be subject to the conditions precedent that the Effective Date shall have occurred and on the date of such Borrowing or such issuance (as the case may be), or the applicable Increase Date, the following statements shall be true (and each of the giving of the applicable Notice of Borrowing or request for issuance and the acceptance by the Borrower of the proceeds of such Borrowing shall constitute a representation and warranty by the Borrower that on the date of such Borrowing or date of such issuance such statements are true):

(a) the representations and warranties contained in Section 4.01 (other than Section 4.01(k), and in the case of a Borrowing or issuance of a Letter of Credit, Section 4.01(e)(ii) and 4.01(f)(ii)) are correct on and as of such date, before and after giving effect to such Borrowing or issuance of a Letter of Credit, or such Commitment Increase and to the application of the proceeds therefrom, as though made on and as of such date;

(b) no event has occurred and is continuing, or would result from such Borrowing or issuance of a Letter of Credit, or such Commitment Increase or from the application of the proceeds therefrom, that constitutes a Default;

(c) all required regulatory authorizations including the 2007 Order and/or any Subsequent Order in respect of such Credit Extension have been obtained and are in full force and effect and, before and after giving effect to such Borrowing or such issuance of a Letter of Credit and to the application of the proceeds therefrom, the Borrower is in compliance with the provisions of the applicable order; and

(d) before and after giving effect to such Credit Extension and to the application of the proceeds therefrom, as though made on and as of such date, the Indebtedness of the Borrower does not exceed that permitted by (i) applicable resolutions of the Board of Directors of the Borrower, (ii) applicable Arizona Law, or (iii) the 2007 Order or any Subsequent Order, whichever is in force and effect at such time.

Each request for Credit Extension (which shall not include a Conversion or a continuation of Eurodollar Rate Advances) submitted by the Borrower shall be deemed to be a representation and warranty that the conditions specified in Sections 3.02(a) through (d) have been satisfied on and as of the date of the applicable Credit Extension.

Section 3.03 Determinations Under Section 3.01 . For purposes of determining compliance with the conditions specified in Section 3.01 and the satisfaction of each Lender with respect to letters delivered to it from the Borrower as set forth in Sections 4.01 (a), 4.01(e) and 4.01(f), each Lender that has signed this Agreement shall be deemed to have consented to, approved or accepted or to be satisfied with each document or other matter required thereunder to be consented to or approved by or acceptable or satisfactory to the Lenders unless an officer of

the Agent responsible for the transactions contemplated by this Agreement shall have received notice from such Lender prior to the date that the Borrower designates as the proposed Effective Date, specifying its objection thereto. The Agent shall promptly notify the Lenders and the Borrower of the occurrence of the Effective Date.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES

Section 4.01 Representations and Warranties of the Borrower. The Borrower represents and warrants as follows:

(a) Each of the Borrower and each Material Subsidiary: (i) is a corporation or other entity duly organized and validly existing under the Laws of the jurisdiction of its incorporation or organization; (ii) has all requisite corporate or if the Material Subsidiary is not a corporation, other comparable power necessary to own its assets and carry on its business as presently conducted; (iii) has all governmental licenses, authorizations, consents and approvals necessary to own its assets and carry on its business as presently conducted, if the failure to have any such license, authorization, consent or approval is reasonably likely to have a Material Adverse Effect and except as disclosed to the Agent in the SEC Reports or by means of a letter from the Borrower to the Lenders (such letter, if any, to be delivered to the Agent for prompt distribution to the Lenders) delivered prior to the execution and delivery of this Agreement (which, in each case, shall be satisfactory to each Lender in its sole discretion) and except that (A) the Borrower from time to time may make minor extensions of its lines, plants, services or systems prior to the time a related franchise, certificate of convenience and necessity, license or permit is procured, (B) from time to time communities served by the Borrower may become incorporated and considerable time may elapse before such a franchise is procured, (C) certain such franchises may have expired prior to the renegotiation thereof, (D) certain minor defects and exceptions may exist which, individually and in the aggregate, are not material and (E) certain franchises, certificates, licenses and permits may not be specific as to their geographical scope); and (iv) is qualified to do business in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary and where failure so to qualify is reasonably likely to have a Material Adverse Effect.

(b) The execution, delivery and performance by the Borrower of this Agreement and the other Loan Documents, and the consummation of the transactions contemplated hereby and thereby, are within the Borrower's corporate powers, have been duly authorized by all necessary corporate action, and do not or did not (i) contravene the Borrower's articles of incorporation or by-laws, (ii) contravene any Law (including without limitation the 2007 Order), decree, writ, injunction or determination of any Governmental Authority, in each case applicable to or binding upon the Borrower or any of its properties, (iii) contravene any contractual restriction binding on or affecting the Borrower or (iv) cause the creation or imposition of any Lien upon the assets of the Borrower or any Material Subsidiary, except for Liens created under this Agreement and except where such contravention or creation or imposition of such Lien is not reasonably likely to have a Material Adverse Effect.

(c) No authorization or approval or other action by, and no notice to or filing with, any Governmental Authority is required for the due execution, delivery and performance by the Borrower of this Agreement or the Notes to be delivered by it, except for the 2007 Order or any Subsequent Order, which has been duly obtained and is in full force and effect, and any notices or compliance filings required therein.

(d) This Agreement has been, and each of the other Loan Documents upon execution and delivery will have been, duly executed and delivered by the Borrower. This Agreement is, and each of the other Loan Documents upon execution and delivery will be, the legal, valid and binding obligation of the Borrower enforceable against the Borrower in accordance with their respective terms, subject, however, to the application by a court of general principles of equity and to the effect of any applicable bankruptcy, insolvency, reorganization, moratorium or similar Laws affecting creditors' rights generally.

(e) (i) The Consolidated balance sheet of the Borrower as of December 31, 2009, and the related Consolidated statements of income and cash flows of the Borrower for the fiscal year then ended, accompanied by an opinion thereon of Deloitte & Touche LLP, independent registered public accountants, and the Consolidated balance sheet of the Borrower as of September 30, 2010, and the related Consolidated statements of income and cash flows of the Borrower for the nine months then ended, duly certified by the chief financial officer of the Borrower, copies of which have been furnished to the Agent, fairly present in all material respects, subject, in the case of said balance sheet as of September 30, 2010, and said statements of income and cash flows for the nine months then ended, to year-end audit adjustments, the Consolidated financial condition of the Borrower as at such dates and the Consolidated results of the operations of the Borrower for the periods ended on such dates, all in accordance with GAAP (except as disclosed therein). (ii) Except as disclosed to the Agent in the SEC Reports or by means of a letter from the Borrower to the Lenders (such letter, if any, to be delivered to the Agent for prompt distribution to the Lenders) delivered prior to the execution and delivery of this Agreement (which, in each case, shall be satisfactory to each Lender in its sole discretion), since December 31, 2009, there has been no Material Adverse Effect.

(f) There is no pending or, to the knowledge of an Authorized Officer of the Borrower, threatened action, suit, investigation, litigation or proceeding, including, without limitation, any Environmental Action, affecting the Borrower or any of its Subsidiaries before any court, governmental agency or arbitrator that (i) purports to affect the legality, validity or enforceability of this Agreement or any other Loan Document or the consummation of the transactions contemplated hereby or (ii) would be reasonably likely to have a Material Adverse Effect (except as disclosed to the Agent in the SEC Reports or by means of a letter from the Borrower to the Lenders (such letter, if any, to be delivered to the Agent for prompt distribution to the Lenders) delivered prior to the execution and delivery of this Agreement (which, in each case, shall be satisfactory to each Lender in its sole discretion)) and there has been no adverse change in the status, or financial effect on the Borrower or any of its Subsidiaries, of such disclosed litigation that would be reasonably likely to have a Material Adverse Effect.

(g) No proceeds of any Advance will be used to acquire any equity security not issued by the Borrower of a class that is registered pursuant to Section 12 of the Securities Exchange Act of 1934.

(h) The Borrower is not engaged in the business of extending credit for the purpose of purchasing or carrying margin stock (within the meaning of Regulation U issued by the Board of Governors of the Federal Reserve System), and no proceeds of any Advance will be used to purchase or carry any margin stock or to extend credit to others for the purpose of purchasing or carrying any margin stock, in any case in violation of Regulation U. After application of the proceeds of any Advance, not more than 25% of the value of the assets subject to any restriction under this Agreement on the right to sell, pledge, transfer, or otherwise dispose of such assets is represented by margin stock.

(i) The Borrower and its Subsidiaries have filed all United States of America Federal income tax returns and all other material tax returns which are required to be filed by them and have paid all taxes due pursuant to such returns or pursuant to any assessment received by the Borrower or any of its Subsidiaries, except to the extent that (i) such taxes are being contested in good faith and by appropriate proceedings and that appropriate reserves for the payment thereof have been maintained by the Borrower and its Subsidiaries in accordance with GAAP or (ii) the failure to make such filings or such payments is not reasonably likely to have a Material Adverse Effect. The charges, accruals and reserves on the books of the Borrower and its Material Subsidiaries as set forth in the most recent financial statements of the Borrower delivered to the Agent pursuant to Section 4.01(e) or Section 5.01(h)(i) or (ii) hereof in respect of taxes and other governmental charges are, in the opinion of the Borrower, adequate.

(j) Set forth on Schedule 4.01(j) hereto (as such schedule may be modified from time to time by the Borrower by written notice to the Agent) is a complete and accurate list of all the Subsidiaries of the Borrower and, as of the Effective Date, no such Subsidiary of the Borrower is a Material Subsidiary.

(k) Set forth on Schedule 4.01(k) hereto is a complete and accurate list identifying any Indebtedness of the Borrower outstanding in a principal amount equal to or exceeding $5,000,000 and which is not described in the financial statements referred to in Section 4.01(e).

(l) The Borrower is not an "investment company", or a company "controlled" by an "investment company", within the meaning of the Investment Company Act of 1940, as amended.

(m) No report, certificate or other written information furnished by the Borrower or any of its Subsidiaries to any Agent or any Lender in connection with the transactions contemplated hereby and the negotiation of this Agreement or delivered hereunder or any other Loan Document (as modified or supplemented by other information so furnished) at the time so furnished, when taken together as a whole with all such written information so furnished, contains an untrue statement of a material fact or omits to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading, except as would not reasonably be expected to result in a Material Adverse Effect; provided that with respect to any projected financial information, forecasts, estimates or forward-looking information, the Borrower represents only that such information and materials have been prepared in good faith on the basis of assumptions believed to be reasonable at the time of preparation of such forecasts, and no representation or warranty is made as to the actual attainability of any such projections, forecasts, estimates or forward-looking information.

ARTICLE V

COVENANTS OF THE BORROWER

Section 5.01 Affirmative Covenants . So long as any Advance shall remain unpaid, any Letter of Credit shall remain outstanding or any Lender shall have any Commitment hereunder, the Borrower shall:

(a) Compliance with Laws, Etc . (i) Comply, and cause each of its Material Subsidiaries to comply, in all material respects, with all applicable Laws of Governmental Authorities, such compliance to include, without limitation, compliance with ERISA and Environmental Laws, unless the failure to so comply is not reasonably likely to have a Material Adverse Effect and (ii) comply at all times with the 2007 Order, any Subsequent Order, Arizona Revised Statutes, Section 40-302 and all similar or comparable Laws, orders, decrees, writs, injunctions or determinations of any Governmental Authority relating to the incurrence or maintenance of Indebtedness by the Borrower, unless the failure to so comply is not reasonably likely to have a Material Adverse Effect.

(b) Payment of Taxes, Etc . Pay and discharge, and cause each of its Subsidiaries to pay and discharge, before the same shall become delinquent, all taxes, assessments and governmental charges or levies imposed upon it or upon its property; provided , however , that neither the Borrower nor any of its Subsidiaries shall be required to pay or discharge any such tax, assessment, charge or levy (i) that is being contested in good faith and by proper proceedings and as to which appropriate reserves are being maintained in accordance with GAAP or (ii) if the failure to pay such tax, assessment, charge or levy is not reasonably likely to have a Material Adverse Effect.

(c) Maintenance of Insurance . Maintain, and cause each of its Material Subsidiaries to maintain, insurance with responsible and reputable insurance companies or associations in such amounts and covering such risks as is usually carried by companies engaged in similar businesses and owning similar properties in the same general areas in which the Borrower or such Subsidiary operates; provided , however , that the Borrower and its Subsidiaries may self-insure to the same extent as other companies engaged in similar businesses and owning similar properties in the same general areas in which the Borrower or such Subsidiary operates and to the extent consistent with prudent business practice.

(d) Preservation of Corporate Existence, Etc . Preserve and maintain, and cause each of its Material Subsidiaries to preserve and maintain, its corporate existence, rights (charter and statutory) and franchises (other than "franchises" as described in Arizona Revised Statutes, Section 40-283 or any successor provision) reasonably necessary in the normal conduct of its business, if the failure to maintain such rights or privileges is reasonably likely to have a Material Adverse Effect, and use its commercially reasonable efforts to preserve and maintain such franchises reasonably necessary in the normal conduct of its business, except that (i) the Borrower from time to time may make minor extensions of its lines, plants, services or systems prior to the time a related franchise, certificate of convenience and necessity, license or permit is procured, (ii) from time to time communities served by the Borrower may become incorporated and considerable time may elapse before such a franchise is procured, (iii) certain such

franchises may have expired prior to the renegotiation thereof, (iv) certain minor defects and exceptions may exist which, individually and in the aggregate, are not material and (v) certain franchises, certificates, licenses and permits may not be specific as to their geographical scope; provided , however , that the Borrower and its Subsidiaries may consummate any merger or consolidation permitted under Section 5.02(b).

(e) Visitation Rights . At any reasonable time and from time to time, permit and cause each of its Subsidiaries to permit the Agent or any of the Lenders or any agents or representatives thereof, to examine and make copies of and abstracts from the records and books of account of, and visit the properties of, the Borrower and any of its Subsidiaries, and to discuss the affairs, finances and accounts of the Borrower and any of its Subsidiaries with any of their officers or directors; provided , however , that the Borrower and its Subsidiaries reserve the right to restrict access to any of its properties in accordance with reasonably adopted procedures relating to safety and security; and provided further that the costs and expenses incurred by such Lender or agents or representatives in connection with any such examinations, copies, abstracts, visits or discussions shall be, upon the occurrence and during the continuation of a Default, for the account of the Borrower and, in all other circumstances, for the account of such Lender.

(f) Keeping of Books . Keep, and cause each of its Material Subsidiaries to keep, proper books of record and account, in which full and correct entries shall be made of all financial transactions and the assets and business of the Borrower and each such Subsidiary in a manner that permits the preparation of financial statements in accordance with GAAP.

(g) Maintenance of Properties, Etc . Keep, and cause each Material Subsidiary to keep, all property useful and necessary in its business in good working order and condition (ordinary wear and tear excepted), if the failure to do so is reasonably likely to have a Material Adverse Effect, it being understood that this covenant relates only to the working order and condition of such properties and shall not be construed as a covenant not to dispose of properties.

(h) Reporting Requirements . Furnish to the Agent:

(i) as soon as available and in any event within 50 days after the end of each of the first three fiscal quarters of each fiscal year of the Borrower, (A) for each such fiscal quarter of the Borrower, Consolidated statements of income and cash flows of the Borrower for such fiscal quarter setting forth in each case in comparative form the corresponding figures for the corresponding fiscal quarter in the preceding fiscal year and (B) for the period commencing at the end of the previous fiscal year and ending with the end of each fiscal quarter, Consolidated statements of income and cash flows of the Borrower for such period setting forth in each case in comparative form the corresponding figures for the corresponding period in the preceding fiscal year; provided that so long as the Borrower remains subject to the reporting requirements of the Securities Exchange Act of 1934, as amended, the Borrower may provide, in satisfaction of the requirements of this first sentence of this Section 5.01(h)(i), its report on Form 10-Q for such fiscal quarter. Each set of financial statements provided under this Section 5.01(h)(i) shall be accompanied by a certificate of an Authorized Officer, which certificate shall state that said Consolidated financial statements fairly present in all material respects the Consolidated financial condition and results of operations of the

Borrower in accordance with GAAP (except as disclosed therein) as at the end of, and for, such period (subject to normal year-end audit adjustments) and shall set forth reasonably detailed calculations demonstrating compliance with Section 5.03;

(ii) as soon as available and in any event within 90 days after the end of each fiscal year of the Borrower, Consolidated statements of income and cash flows of the Borrower for such year and the related Consolidated balance sheet of the Borrower as at the end of such year, setting forth in each case in comparative form the corresponding figures for the preceding fiscal year; provided that, so long as the Borrower remains subject to the reporting requirements of the Securities Exchange Act of 1934, as amended, the Borrower may provide, in satisfaction of the requirements of this first sentence of this Section 5.01(h)(ii), its report on Form 10-K for such fiscal year. Each set of financial statements provided pursuant to this Section 5.01(h)(ii) shall be accompanied by (A) an opinion thereon of independent certified public accountants of recognized national standing, which opinion shall state that said Consolidated financial statements fairly present in all material respects the Consolidated financial condition and results of operations of the Borrower as at the end of, and for, such fiscal year, in accordance with GAAP (except as disclosed therein) and (B) a certificate of an Authorized Officer, which certificate shall set forth reasonably detailed calculations demonstrating compliance with Section 5.03;

(iii) as soon as possible and in any event within five days after any Authorized Officer of the Borrower knows of the occurrence of each Default continuing on the date of such statement, a statement of an Authorized Officer of the Borrower setting forth details of such Default and the action that the Borrower has taken and proposes to take with respect thereto;

(iv) promptly after the sending or filing thereof, copies of all reports and registration statements (other than exhibits thereto and registration statements on Form S-8 or its equivalent) that the Borrower or any Subsidiary files with the Securities and Exchange Commission;

(v) promptly after an Authorized Officer becomes aware of the commencement thereof, notice of all actions and proceedings before any court, governmental agency or arbitrator affecting the Borrower or any of its Subsidiaries of the type described in Section 4.01(f), except with respect to any matter referred to in Section 4.01(f)(ii), to the extent disclosed in a report on Form 8-K, Form 10-Q or Form 10-K of the Borrower;

(vi) promptly after (A) any amendment or modification of the 2007 Order, (B) any amendment or modification of Arizona Revised Statutes, Section 40-302, or the promulgation, amendment or modification of any successor or similar statute, or (C) the promulgation, amendment or modification of any Subsequent Order by the Arizona Corporation Commission or any successor thereto, in any case if such amendment, modification or promulgation could affect the validity or enforceability of the indebtedness of the Borrower pursuant to this Agreement, a copy thereof;

(vii) promptly after an Authorized Officer becomes aware of the occurrence thereof, notice of any change by Moody's or S&P of their respective Public Debt Rating or of the cessation (or subsequent commencement) by Moody's or S&P of publication of their respective Public Debt Rating;

(viii) promptly after the occurrence of any ERISA Event, together with (x) a written statement of an Authorized Officer of the Borrower specifying the details of such ERISA Event and the action that the Borrower has taken and proposes to take with respect thereto, (y) a copy of any notice with respect to such ERISA Event that may be required to be filed with the PBGC and (z) a copy of any notice delivered by the PBGC to the Borrower or an ERISA Affiliate with respect to such ERISA Event; and

(ix) such other information respecting the Borrower or any of its Subsidiaries as any Lender through the Agent may from time to time reasonably request.

Information required to be delivered pursuant to Sections 5.01(h)(i), (ii) and (iv) above shall be deemed to have been delivered on the date on which the Borrower provides notice to the Agent that such information has been posted on the Borrower's parent's website on the Internet at www.pinnaclewest.com, at sec.gov/edaux/searches.htm or at another website identified in such notice and accessible by the Lenders without charge; provided that (i) such notice may be included in a certificate delivered pursuant to Section 5.01(h)(i) or (ii) and (ii) the Borrower shall deliver paper copies of the information referred to in Section 5.01(h)(i), (ii), and (iv) to any Lender which requests such delivery.

(i) Change in Nature of Business . Conduct the same general type of business conducted on the date hereof.

Section 5.02 Negative Covenants . So long as any Advance shall remain unpaid, any Letter of Credit shall remain outstanding or any Lender shall have any Commitment hereunder, the Borrower shall not:

(a) Liens, Etc . Create or suffer to exist, or permit any of its Material Subsidiaries to create or suffer to exist, any Lien on or with respect to any of its properties, whether now owned or hereafter acquired, or assign, or permit any of its Material Subsidiaries to assign, any right to receive income, other than:

(i) Permitted Liens;

(ii) Liens upon or in, or conditional sales agreements or other title retention agreements with respect to, any real or personal property acquired or held by the Borrower or any Subsidiary in the ordinary course of business to secure the purchase price of such property, or the construction of or improvements to such property, or to secure Indebtedness incurred solely for the purpose of financing the acquisition, construction or improvement of such property to be subject to such Liens (including any Liens placed on such property within 180 days after the latest of the acquisition, completion of construction or improvement of such property), or Liens existing on such property at the time of its acquisition (other than any such Liens created in contemplation of such acquisition that were not incurred to finance the acquisition of such property) or

extensions, renewals, refundings or replacements of any of the foregoing for the same or a lesser amount, provided , however , that no such Lien shall extend to or cover any properties of any character other than the property being acquired, constructed or improved and proceeds, improvements and replacements thereof and no such extension, renewal, refunding or replacement shall extend to or cover any properties not theretofore subject to the Lien being extended, renewed, refunded or replaced;

(iii) assignments of the right to receive income, and Liens on property, of a Person existing at the time such Person is merged into or consolidated with the Borrower or any Subsidiary of the Borrower or becomes a Subsidiary of the Borrower;

(iv) Liens with respect to the leases and related documents entered into by the Borrower in connection with PVNGS Unit 2 and Liens with respect to the leased interests and related rights if the Borrower reacquires ownership in any of those interests or acquires any of the equity or owner participants' interests in the trusts that hold title to such leased interests, whether or not it also directly assumes the Sale Leaseback Obligation Bonds, and Liens on the Borrower's interests in the trusts that hold title to such leased interests and related rights in the event that the Borrower acquires any of the equity or owner participants' interests in such trusts pursuant to a "special transfer" under the Borrower's existing PVNGS Unit 2 sale and leaseback transactions and any Liens resulting or deemed to have resulted if the PVNGS Unit 2 leases are required to be accounted for as capital leases in accordance with GAAP;

(v) other assignments of the right to receive income and Liens securing Indebtedness or claims in an aggregate principal amount not to exceed 20% of the Borrower's total assets as stated on the most recent balance sheet of the Borrower provided pursuant to Section 4.01(e)(i) or 5.01(h)(ii) hereof at any time outstanding; and

(vi) the replacement, extension or renewal of any Lien permitted by clause (iii) or (iv) above upon or in the same property theretofore subject thereto or the replacement, extension or renewal (without increase in the amount or change in any direct or contingent obligor) of the Indebtedness secured thereby.

(b) Mergers, Etc . Merge or consolidate with or into any Person, or permit any of its Material Subsidiaries to do so, except that (i) any Material Subsidiary of the Borrower may merge or consolidate with or into any other Material Subsidiary of the Borrower, (ii) any Subsidiary of the Borrower may merge into the Borrower or any Material Subsidiary of the Borrower and (iii) the Borrower or any Material Subsidiary may merge with any other Person so long as the Borrower or such Material Subsidiary is the surviving corporation, provided , in each case, that no Default shall have occurred and be continuing at the time of such proposed transaction or would result therefrom.

(c) Sales, Etc. of Assets . Sell, lease, transfer or otherwise dispose of, or permit any of its Material Subsidiaries to sell, lease, transfer or otherwise dispose of, any assets, or grant any option or other right to purchase, lease or otherwise acquire any assets to any Person other than the Borrower or any Subsidiary of the Borrower, except (i) dispositions in the ordinary course of business, including, without limitation, sales or other dispositions of electricity and related and

ancillary services, other commodities, emissions credits and similar mechanisms for reducing pollution, and damaged, obsolete, worn out or surplus property no longer required or useful in the business or operations of the Borrower or any of its Subsidiaries, (ii) sale or other disposition of patents, copyrights, trademarks or other intellectual property that are, in the Borrower's reasonable judgment, no longer economically practicable to maintain or necessary in the conduct of the business of the Borrower or its Subsidiaries and any license or sublicense of intellectual property that does not interfere with the business of the Borrower or any Material Subsidiary, (iii) in a transaction authorized by subsection (b) of this Section, (iv) individual dispositions occurring in the ordinary course of business which involve assets with a book value not exceeding $5,000,000, (v) sales, leases, transfers or dispositions of assets during the term of this Agreement having an aggregate book value not to exceed 30% of the total of all assets properly appearing on the most recent balance sheet of the Borrower provided pursuant to Section 4.01(e)(i) or 5.01(h)(ii) hereof, (vi) at any time following the consummation of the Four Corners Acquisition and the closure by the Borrower of Units 1, 2 and 3 of the Four Corners Power Plant near Farmington, New Mexico, as described in the SEC Reports, disposition of all or any portion of the Borrower's interests in such Units 1, 2 and 3, and (vii) any Lien permitted under Section 5.02(a).

Section 5.03 Financial Covenant . So long as any Advance shall remain unpaid, any Letter of Credit shall remain outstanding or any Lender shall have any Commitment hereunder, the Borrower will maintain a ratio of (a) Consolidated Indebtedness to (b) the sum of Consolidated Indebtedness plus Consolidated Net Worth of not greater than 0.65 to 1.

ARTICLE VI

EVENTS OF DEFAULT

Section 6.01 Events of Default . If any of the following events (" Events of Default ") shall occur and be continuing:

(a) The Borrower shall fail to pay when due (i) any principal of any Advance, (ii) any drawing under any Letter of Credit, or (iii) any interest on any Advance or any other fees or other amounts payable under this Agreement or any other Loan Documents, and (in the case of this clause (iii) only), such failure shall continue for a period of three Business Days; or

(b) Any representation or warranty made by the Borrower herein or by the Borrower (or any of its officers) in any certificate or other document delivered in connection with this Agreement or any other Loan Document shall prove to have been incorrect in any material respect when made or deemed made or furnished; or

(c) (i) The Borrower shall fail to perform or observe any term, covenant or agreement contained in Section 5.01(d) (as to the corporate existence of the Borrower), (h)(iii) or (h)(vi), 5.02 or 5.03, or (ii) the Borrower shall fail to perform or observe any other term, covenant or agreement contained in Section 5.01(e) if such failure shall remain unremedied for 15 days after written notice thereof shall have been given to the Borrower by the Agent or any Lender or (iii) the Borrower shall fail to perform or observe any other term, covenant or agreement contained in this Agreement or any other Loan Document on its part to be performed or observed if such

failure shall remain unremedied for 30 days after written notice thereof shall have been given to the Borrower by the Agent or any Lender; or

(d) (i) The Borrower or any of its Material Subsidiaries shall fail to pay (A) any principal of or premium or interest on an Indebtedness that is outstanding in a principal amount of at least $35,000,000 in the aggregate (but excluding Indebtedness outstanding hereunder), or (B) an amount, or post collateral as contractually required in an amount, of at least $35,000,000 in respect of any Hedge Agreement, of the Borrower or such Material Subsidiary (as the case may be), in each case, when the same becomes due and payable (whether by scheduled maturity, required prepayment, acceleration, demand or otherwise), and such failure shall continue after the applicable grace period, if any, specified in the agreement or instrument relating to such Indebtedness or Hedge Agreement; or (ii) any event of default shall exist under any agreement or instrument relating to any such Indebtedness and shall continue after the applicable grace period, if any, specified in such agreement or instrument, if the effect of such event is to accelerate, or to permit the acceleration of, the maturity of such Indebtedness; or

(e) The Borrower or any of its Material Subsidiaries shall fail to pay any principal of or premium or interest in respect of any operating lease in respect of which the payment obligations of the Borrower have a present value of at least $35,000,000, when the same becomes due and payable (whether by scheduled maturity, required prepayment, acceleration, demand or otherwise), and such failure shall continue after the applicable grace period, if any, specified in such operating lease, if the effect of such failure is to terminate, or to permit the termination of, such operating lease; or

(f) The Borrower or any of its Material Subsidiaries shall generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors; or any proceeding shall be instituted by or against the Borrower or any of its Material Subsidiaries seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, winding up, reorganization, arrangement, adjustment, protection, relief, or composition of it or its debts under any Debtor Relief Law, or seeking the entry of an order for relief or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its property and, in the case of any such proceeding instituted against it (but not instituted by it), either such proceeding shall remain undismissed or unstayed for a period of 60 days, or any of the actions sought in such proceeding (including, without limitation, the entry of an order for relief against, or the appointment of a receiver, trustee, custodian or other similar official for, it or for any substantial part of its property) shall occur; or the Borrower or any of its Material Subsidiaries shall take any corporate action to authorize any of the actions set forth above in this subsection (f); or

(g) Judgments or orders for the payment of money that exceeds any applicable insurance coverage (the insurer of which shall be rated at least "A" by A.M. Best Company) by more than $35,000,000 in the aggregate shall be rendered against the Borrower or any Material Subsidiary and such judgments or orders shall continue unsatisfied or unstayed for a period of 45 days; or

(h) (i) any "person" or "group" (as such terms are used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934, but excluding any employee benefit plan of such person or

its subsidiaries, and any person or entity acting in its capacity as trustee, agent or other fiduciary or administrator of any such plan) becomes the "beneficial owner" (as defined in Rules 13d-3 and 13d-5 under the Securities Exchange Act of 1934), directly or indirectly, of 30% or more of the equity securities of PWCC entitled to vote for members of the board of directors of PWCC; or (ii) during any period of 24 consecutive months, a majority of the members of the board of directors of PWCC cease (other than due to death or disability) to be composed of individuals (A) who were members of that board on the first day of such period, (B) whose election or nomination to that board was approved by individuals referred to in clause (A) above constituting at the time of such election or nomination at least a majority of that board or (C) whose election or nomination to that board was approved by individuals referred to in clauses (A) and (B) above constituting at the time of such election or nomination at least a majority of that board; or (iii) PWCC shall cease for any reason to own, directly or indirectly, 80% of the Voting Stock of the Borrower; or

(i) (i) An ERISA Event occurs with respect to a Pension Plan or Multiemployer Plan which has resulted or could reasonably be expected to result in liability of the Borrower under Title IV of ERISA to the Pension Plan, Multiemployer Plan or the PBGC in an aggregate amount in excess of $35,000,000, or (ii) the Borrower or any ERISA Affiliate fails to pay when due, after the expiration of any applicable grace period, any installment payment with respect to its withdrawal liability under Section 4201 of ERISA under a Multiemployer Plan in an aggregate amount in excess of $35,000,000;

then, and in any such event, the Agent shall at the request, or may with the consent, of the Required Lenders, by notice to the Borrower, (i) declare the obligation of each Lender to make Advances (other than L/C Advances) and of the Issuing Banks to issue Letters of Credit to be terminated, whereupon the same shall forthwith terminate, (ii) declare the Advances, all interest thereon and all other amounts payable under this Agreement to be forthwith due and payable, whereupon the Advances, all such interest and all such amounts shall become and be forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by the Borrower; provided , however , that in the event of an actual or deemed entry of an order for relief with respect to the Borrower under the Bankruptcy Code of the United States of America, (A) the obligation of each Lender to make Advances (other than L/C Advances) and of the Issuing Banks to issue Letters of Credit shall automatically be terminated and (B) the Advances, all such interest and all such amounts shall automatically become and be due and payable, without presentment, demand, protest or any notice of any kind, all of which are hereby expressly waived by the Borrower and (iii) exercise all rights and remedies available to it under this Agreement, the other Loan Documents and applicable Law.

Section 6.02 Actions in Respect of Letters of Credit upon Default . If any Event of Default shall have occurred and be continuing, the Agent may with the consent, or shall at the request, of the Required Lenders, irrespective of whether it is taking any of the actions described in Section 6.01 or otherwise, (a) make demand upon the Borrower to, and forthwith upon such demand the Borrower will Cash Collateralize the aggregate Available Amount of all Letters of Credit then outstanding (whether or not any beneficiary under any Letter of Credit shall have drawn or be entitled at such time to draw thereunder) or (b) make such other arrangements in respect of the outstanding Letters of Credit as shall be acceptable to the Required Lenders, provided , however , that in the event of an actual or deemed entry of an order for relief with

respect to the Borrower under the Bankruptcy Code of the United States of America, the Borrower will Cash Collateralize the aggregate Available Amount of all Letters of Credit then outstanding, without presentment, demand, protest or any notice of any kind, all of which are hereby expressly waived by the Borrower. If at any time the Agent determines that any funds held in the L/C Cash Deposit Account are subject to any right or interest of any Person other than the Agent, the Issuing Banks and the Lenders or that the total amount of such funds is less than the aggregate Available Amount of all Letters of Credit, the Borrower will, forthwith upon demand by the Agent, pay to the Agent, as additional funds to be deposited and held in the L/C Cash Deposit Account, an amount equal to the excess of (a) such aggregate Available Amount over (b) the total amount of funds, if any, then held in the L/C Cash Deposit Account that are free and clear of any such right and interest. Upon the drawing of any Letter of Credit, to the extent funds are on deposit in the L/C Cash Deposit Account, such funds shall be applied to reimburse the Issuing Banks to the extent permitted by applicable Law, or each Lender to the extent such Lender has funded an Advance in respect of such Letter of Credit. The Borrower hereby grants to the Agent, for the benefit of the Issuing Banks and the Lenders, a Lien upon and security interest in the L/C Cash Deposit Account and all amounts held therein from time to time as security for the L/C Obligations, and for application to the Borrower's reimbursement obligations as and when the same shall arise. The Agent shall have exclusive dominion and control, including the exclusive right of withdrawal, over such account. After all such Letters of Credit shall have expired or been fully drawn upon and all other obligations of the Borrower hereunder and under the other Loan Documents shall have been paid in full, the balance, if any, in such L/C Cash Deposit Account shall be promptly returned to the Borrower.

ARTICLE VII

THE AGENT

Section 7.01 Appointment and Authority . Each of the Lenders (for purposes of this Article, references to the Lenders shall also mean the Issuing Banks) hereby irrevocably appoints Barclays Bank to act on its behalf as the Agent hereunder and under the other Loan Documents and authorizes the Agent to take such actions on its behalf and to exercise such powers as are delegated to the Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto. Except as set forth in Section 7.06, the provisions of this Article are solely for the benefit of the Agent and the Lenders, and neither the Borrower nor any of its Affiliates shall have rights as a third party beneficiary of any of such provisions.

Section 7.02 Rights as a Lender . The Person serving as the Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not the Agent and the term "Lender" or "Lenders" shall, unless otherwise expressly indicated or unless the context otherwise requires, include the Person serving as the Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of business with the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not the Agent hereunder and without any duty to account therefor to the Lenders.

Section 7.03 Exculpatory Provisions . The Agent shall not have any duties or obligations except those expressly set forth herein and in the other Loan Documents. Without limiting the generality of the foregoing, the Agent:

(a) shall not be subject to any fiduciary or other implied duties, regardless of whether a Default has occurred and is continuing;

(b) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that the Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein), provided that the Agent shall not be required to take any action that, in its opinion or the opinion of its counsel, may expose the Agent to liability or that is contrary to any Loan Document or applicable Law; and

(c) shall not, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Borrower or any of its Affiliates that is communicated to or obtained by the Person serving as the Agent or any of its Affiliates in any capacity.

The Agent shall not be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as the Agent shall believe in good faith shall be necessary, under the circumstances as provided in Section 6.01 and 8.01) or (ii) in the absence of its own gross negligence or willful misconduct. The Agent shall be deemed not to have knowledge of any Default unless and until notice describing such Default is given to the Agent by the Borrower or a Lender.

The Agent shall not be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Default, (iv) the validity, enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document or (v) the satisfaction of any condition set forth in Article III or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to the Agent.

Section 7.04 Reliance by Agent . The Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. The Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making of any Advance, or the issuance of a Letter of Credit, that by its terms must be fulfilled to the satisfaction of a Lender or an Issuing Bank, the Agent may presume that

such condition is satisfactory to such Lender or such Issuing Bank unless the Agent shall have received notice to the contrary from such Lender or such Issuing Bank prior to the making of such Advance or the issuance of such Letter of Credit. The Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in good faith in accordance with the advice of any such counsel, accountants or experts.

Section 7.05 Delegation of Duties . The Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by the Agent. The Agent and any such sub-agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article shall apply to any such sub-agent and to the Related Parties of the Agent and any such sub-agent, and shall apply to their respective activities in connection with the syndication of the credit facilities provided for herein as well as activities as Agent.

Section 7.06 Resignation of Agent . The Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right, with the consent of the Borrower so long as no Event of Default has occurred and is continuing, to appoint a successor, which shall be a bank with an office in the United States of America, or an Affiliate of any such bank with an office in the United States of America. If no such successor shall have been so appointed by the Required Lenders and shall have accepted such appointment within 45 days after the retiring Agent gives notice of its resignation, then the retiring Agent may, on behalf of the Lenders, appoint a successor Agent meeting the qualifications set forth above; provided that if the Agent shall notify the Borrower and the Lenders that no qualifying Person has accepted such appointment, then such resignation shall nonetheless become effective in accordance with such notice and (1) the retiring Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Agent on behalf of the Lenders under any of the Loan Documents, the retiring Agent shall continue to hold such collateral security until such time as a successor Agent is appointed) and (2) all payments, communications and determinations provided to be made by, to or through the Agent shall instead be made by or to each Lender directly, until such time as the Required Lenders appoint a successor Agent as provided for above in this Section. Upon the acceptance of a successor's appointment as Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring (or retired) Agent, and the retiring Agent shall be discharged from all of its duties and obligations hereunder or under the other Loan Documents (if not already discharged therefrom as provided above in this Section). The fees payable by the Borrower to a successor Agent shall be as agreed between the Borrower and such successor. After the retiring Agent's resignation hereunder and under the other Loan Documents, the provisions of this Article and Section 8.04 shall continue in effect for the benefit of such retiring Agent, its sub-agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring Agent was acting as Agent.

Section 7.07 Non-Reliance on Agent and Other Lenders . Each Lender acknowledges that it has, independently and without reliance upon the Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate,

made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon the Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

Section 7.08 No Other Duties, Etc . Anything herein to the contrary notwithstanding, none of the Arrangers, Syndication Agent, Documentation Agent or other agents listed on the cover page hereof shall have any powers, duties or responsibilities under this Agreement or any of the other Loan Documents, except in its capacity, as applicable, as the Agent or a Lender hereunder.

Section 7.09 Issuing Banks . Each Issuing Bank shall act on behalf of the Lenders with respect to any Letters of Credit issued by it and the documents associated therewith, and each Issuing Bank shall have all of the benefits and immunities provided in this Article VII (other than Section 7.02) to the same extent as such provisions apply to the Agent.

ARTICLE VIII

MISCELLANEOUS

Section 8.01 Amendments, Etc . No amendment or waiver of any provision of this Agreement or any other Loan Document, nor consent to any departure by the Borrower therefrom, shall in any event be effective unless the same shall be in writing and signed by the Required Lenders, and then such waiver or consent shall be effective only in the specific instance and for the specific purpose for which given; provided , however , that no amendment, waiver or consent shall

(a) unless agreed to by each Lender directly affected thereby, (i) reduce or forgive the principal amount of any Advance or the Borrower's obligations to reimburse any drawing on a Letter of Credit, reduce the rate of or forgive any interest thereon (provided that only the consent of the Required Lenders shall be required to waive the applicability of any post-default increase in interest rates), or reduce or forgive any fees hereunder (other than fees payable to the Agent, the Arrangers or any Issuing Bank for their own respective accounts), (ii) extend the final scheduled maturity date or any other scheduled date for the payment of any principal of or interest on any Advance, extend the time of payment of any obligation of the Borrower to reimburse any drawing on any Letter of Credit or any interest thereon, extend the expiry date of any Letter of Credit beyond the Letter of Credit Expiration Date, or extend the time of payment of any fees hereunder (other than fees payable to the Agent, the Arrangers or any Issuing Bank for their own respective accounts), or (iii) increase any Revolving Credit Commitment of any such Lender over the amount thereof in effect or extend the maturity thereof (it being understood that a waiver of any condition precedent set forth in Section 3.02 or of any Default, if agreed to by the Required Lenders or all Lenders (as may be required hereunder with respect to such waiver), shall not constitute such an increase);

(b) unless agreed to by all of the Lenders, (i) reduce the percentage of the aggregate Revolving Credit Commitments or of the aggregate unpaid principal amount of the Advances, or the number or percentage of Lenders, that shall be required for the Lenders or any of them to take or approve, or direct the Agent to take, any action hereunder or under any other Loan Document (including as set forth in the definition of "Required Lenders"), (ii) change any other provision of this Agreement or any of the other Loan Documents requiring, by its terms, the consent or approval of all the Lenders for such amendment, modification, waiver, discharge, termination or consent, or (iii) change or waive any provision of Section 2.15, any other provision of this Agreement or any other Loan Document requiring pro rata treatment of any Lenders, or this Section 8.01 or Section 2.19(b); and

(c) unless agreed to by the Issuing Banks or the Agent in addition to the Lenders required as provided hereinabove to take such action, affect the respective rights or obligations of the Issuing Banks or the Agent, as applicable, hereunder or under any of the other Loan Documents.

Section 8.02 Notices, Etc .

(a) All notices and other communications provided for hereunder shall be either (x) in writing (including facsimile communication) and mailed, faxed or delivered or (y) as and to the extent set forth in Sections 8.02(b) and (c) and in the proviso to this Section 8.02(a), if to the Borrower, at the address specified on Schedule 8.02 ; if to any Lender, at its Domestic Lending Office; if to the Agent, at the address specified on Schedule 8.02 ; and if to any Issuing Bank, at the address specified on Schedule 8.02 or, as to the Borrower or the Agent, at such other address as shall be designated by such party in a written notice to the other parties and, as to each other party, at such other address as shall be designated by such party in a written notice to the Borrower and the Agent. All such notices and communications shall, when mailed or faxed, be effective when deposited in the mails or faxed, respectively, except that notices and communications to the Agent pursuant to Article II, III or VII shall not be effective until received by the Agent. Delivery by facsimile of an executed counterpart of any amendment or waiver of any provision of this Agreement or the Notes or of any Exhibit hereto to be executed and delivered hereunder shall be effective as delivery of a manually executed counterpart thereof. Notices delivered through electronic communications to the extent provided in subsection (b) below, shall be effective as provided in such subsection (b). Upon request of the Borrower, the Agent will provide to the Borrower (i) copies of each Administrative Questionnaire or (ii) the address of each Lender.

(b) Notices and other communications to the Lenders, the Agent and the Issuing Banks hereunder may be delivered or furnished by electronic communication (including e-mail and Internet or intranet websites) pursuant to procedures approved by the Agent and agreed to by the Borrower, provided that the foregoing shall not apply to notices to any Lender or the Issuing Banks pursuant to Article II if such Lender or the Issuing Banks, as applicable, has notified the Agent and the Borrower that it is incapable of receiving notices under such Article by electronic communication. The Agent or the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it, provided that approval of such procedures may be limited to particular notices or communications. Unless the Agent and the Borrower otherwise agree, (i) notices and other

communications sent to an e-mail address shall be deemed received upon the sender's receipt of an acknowledgement from the intended recipient (such as by the "return receipt requested" function, as available, return e-mail or other written acknowledgement), provided that if such notice or other communication is not sent during the normal business hours of the recipient, such notice or communication shall be deemed to have been sent at the opening of business on the next business day for the recipient, and (ii) notices of communications posted to an Internet or intranet website shall be deemed received upon the deemed receipt by the intended recipient at its e-mail address as described in the foregoing clause (i) of notification that such notice or communication is available and identifying the website address therefor.

(c) The Borrower agrees that the Agent may make materials delivered to the Agent pursuant to Sections 5.01(h)(i), (ii) and (iv), as well as any other written information, documents, instruments and other material relating to the Borrower or any of its Subsidiaries and relating to this Agreement, the Notes or the transactions contemplated hereby, or any other materials or matters relating to this Agreement, the Notes or any of the transactions contemplated hereby (collectively, the " Communications ") available to the Lenders by posting such notices on Intralinks or a substantially similar electronic system (the " Platform "). The Borrower acknowledges that (i) the distribution of material through an electronic medium is not necessarily secure and that there are confidentiality and other risks associated with such distribution, (ii) the Platform is provided "as is" and "as available" and (iii) neither the Agent nor any of its Affiliates warrants the accuracy, adequacy or completeness of the Communications or the Platform and each expressly disclaims liability for errors or omissions in the Communications or the Platform. No warranty of any kind, express, implied or statutory, including, without limitation, any warranty of merchantability, fitness for a particular purpose, non-infringement of third party rights or freedom from viruses or other code defects, is made by the Agent or any of its Affiliates in connection with the Platform.

(d) Each Lender agrees that notice to it (as provided in the next sentence) (a " Notice ") specifying that any Communications have been posted to the Platform shall constitute effective delivery of such information, documents or other materials to such Lender for purposes of this Agreement; provided that if requested by any Lender the Agent shall deliver a copy of the Communications to such Lender by e-mail, facsimile or mail. Each Lender agrees (i) to notify the Agent in writing of such Lender's e-mail address to which a Notice may be sent by electronic transmission (including by electronic communication) on or before the date such Lender becomes a party to this Agreement (and from time to time thereafter to ensure that the Agent has on record an effective e-mail address for such Lender) and (ii) that any Notice may be sent to such e-mail address.

(e) The Borrower hereby acknowledges that certain of the Lenders may be "public-side" Lenders (*i.e.,* Lenders that do not wish to receive material non-public information with respect to the Borrower or its securities) (each, a " Public Lender "). The Borrower hereby agrees that (w) all Communications that are to be made available to Public Lenders shall be clearly and conspicuously marked "PUBLIC" which shall mean that the word "PUBLIC" shall appear prominently on the first page thereof; (x) by marking Communications "PUBLIC," the Borrower shall be deemed to have authorized the Agent, the Arranger and the Lenders to treat such Communications as not containing any material non-public information with respect to the Borrower or its securities for purposes of United States of America federal and state securities

laws; (y) all Communications marked "PUBLIC" are permitted to be made available through a portion of the Platform designated as "Public Investor;" and (z) the Agent and the Arranger shall be entitled to treat any Communications that are not marked "PUBLIC" as being suitable only for posting on a portion of the Platform not marked as "Public Investor." Notwithstanding the foregoing, the Borrower shall be under no obligation to mark any Communications "PUBLIC." Notwithstanding anything to the contrary herein, the Borrower and the Agent need not provide to any Public Lender any information, notice, or other document hereunder that is not public information, including without limitation, the Notice of Borrowing and any notice of Default.

Section 8.03 No Waiver; Cumulative Remedies; Enforcement . No failure by any Lender, any Issuing Bank or the Agent to exercise, and no delay by any such Person in exercising, any right, remedy, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise of any right, remedy, power or privilege hereunder preclude any other or further exercise thereof or the exercise of any other right, remedy, power or privilege. The rights, remedies, powers and privileges herein provided are cumulative and not exclusive of any rights, remedies, powers and privileges provided by Law.

Notwithstanding anything to the contrary contained herein or in any other Loan Document, the authority to enforce rights and remedies hereunder and under the other Loan Documents against the Borrower shall be vested exclusively in, and all actions and proceedings at Law in connection with such enforcement shall be instituted and maintained exclusively by, the Agent in accordance with Article VI for the benefit of all the Lenders and the Issuing Banks; provided , however , that the foregoing shall not prohibit (a) the Agent from exercising on its own behalf the rights and remedies that inure to its benefit (solely in its capacity as Agent) hereunder and under the other Loan Documents, (b) any Issuing Bank from exercising the rights and remedies that inure to its benefit (solely in its capacity as an Issuing Bank) hereunder and under the other Loan Documents, (c) any Lender from exercising setoff rights in accordance with Section 8.05 (subject to the terms of Section 2.15), or (d) any Lender from filing proofs of claim or appearing and filing pleadings on its own behalf during the pendency of a proceeding relative to the Borrower under any Debtor Relief Law; and provided , further , that if at any time there is no Person acting as Agent hereunder and under the other Loan Documents, then (i) the Required Lenders shall have the rights otherwise ascribed to the Agent pursuant to Article VI and (ii) in addition to the matters set forth in clauses (b), (c) and (d) of the preceding proviso and subject to Section 2.15, any Lender may, with the consent of the Required Lenders, enforce any rights and remedies available to it and as authorized by the Required Lenders.

Section 8.04 Costs and Expenses; Indemnity; Damage Waiver .

(a) The Borrower agrees to pay on demand all costs and expenses of the Agent in connection with the administration, modification and amendment of this Agreement, the Notes and the other Loan Documents to be delivered hereunder, including, without limitation, the reasonable fees and expenses of counsel for the Agent with respect thereto and with respect to advising the Agent as to its rights and responsibilities under this Agreement. The Borrower further agrees to pay on demand all costs and expenses of the Agent and the Lenders, if any (including, without limitation, reasonable counsel fees and expenses), in connection with the enforcement (whether through negotiations, legal proceedings or otherwise) of this Agreement, the Notes and the other Loan Documents to be delivered hereunder, including, without

limitation, reasonable fees and expenses of counsel for the Agent and each Lender in connection with the enforcement of rights under this Section 8.04(a).

(b) The Borrower agrees to indemnify and hold harmless the Agent (and any sub-agent thereof), each Lender, and each Related Party of any of the foregoing (each, an " Indemnified Party ") from and against any and all claims, damages, losses, liabilities and expenses (including, without limitation, reasonable fees and expenses of counsel) incurred by or asserted or awarded against any Indemnified Party, in each case arising out of or in connection with or by reason of (including, without limitation, in connection with any investigation, litigation or proceeding or preparation of a defense in connection therewith, whether based on contract, tort or any other theory,) (i) the Notes, this Agreement, any of the transactions contemplated herein or the actual or proposed use of the proceeds of any Advance or Letter of Credit (including any refusal by any Issuing Bank to honor a demand for payment under a Letter of Credit if the documents presented in connection with such demand do not strictly comply with the terms of such Letter of Credit), or (ii) the actual or alleged presence of Hazardous Materials on any property of the Borrower or any of its Subsidiaries or any Environmental Action relating in any way to the Borrower or any of its Subsidiaries, provided that such indemnity shall not, as to any Indemnified Party, be available to the extent (a) such fees and expenses are expressly stated in this Agreement to be payable by the Indemnified Party, included expenses payable under Section 2.14, Section 5.01(e) and Section 8.07(b) or (b) such claim, damage, loss, liability or expense is found in a final, non-appealable judgment by a court of competent jurisdiction to have resulted from such Indemnified Party's gross negligence, willful misconduct or material breach of its obligations under this Agreement, in which case any fees and expenses previously paid or advanced by the Borrower to such Indemnified Party in respect of such indemnified obligation will be returned by such Indemnified Party. In the case of an investigation, litigation or other proceeding to which the indemnity in this Section 8.04(b) applies, such indemnity shall be effective whether or not such investigation, litigation or proceeding is brought by the Borrower, its directors, equityholders or creditors or an Indemnified Party or any other Person, whether or not any Indemnified Party is otherwise a party thereto, and whether or not the transactions contemplated hereby are consummated, provided that if the Borrower and such Indemnified Party are adverse parties in any such litigation or proceeding, and the Borrower prevails in a final, non-appealable judgment by a court of competent jurisdiction, any fees or expenses previously paid or advanced by the Borrower to such Indemnified Party pursuant to this Section 8.04(b) will be returned by such Indemnified Party.

(c) To the extent that the Borrower for any reason fails to indefeasibly pay any amount required under subsection (a) or (b) of this Section to be paid by it to the Agent (or any sub-agent thereof), any Issuing Bank or any Related Party of any of the foregoing (and without limiting its obligation to do so), each Lender severally agrees to pay to the Agent (or any such sub-agent), such Issuing Bank or such Related Party, as the case may be, such Lender's Ratable Share (determined as of the time that the applicable unreimbursed expense or indemnity payment is sought) of such unpaid amount, provided that the unreimbursed expense or indemnified loss, claim, damage, liability or related expense, as the case may be, was incurred by or asserted against the Agent (or any such sub-agent) or such Issuing Bank in its capacity as such, or against any Related Party of any of the foregoing acting for the Agent (or any such sub-agent) or such Issuing Bank in connection with such capacity.

(d) Without limiting the rights of indemnification set forth in this Agreement with respect to liabilities asserted by third parties, each party hereto also agrees not to assert any claim for special, indirect, consequential or punitive damages against the other parties hereto, or any Related Person any party hereto, on any theory of liability, arising out of or otherwise relating to the Notes, this Agreement, any of the transactions contemplated herein or the actual or proposed use of the proceeds of the Advances or the Letters of Credit. No Indemnified Party shall be liable for any damages arising from the use by unintended recipients of any information or other materials distributed by it through telecommunications, electronic or other information transmission systems (including Intralinks, SyndTrak or similar systems) in connection with this Agreement or the other Loan Documents, provided that such indemnity shall not, as to any Indemnified Party, be available to the extent such damages are found in a final, non-appealable judgment by a court of competent jurisdiction to have resulted from such Indemnified Party's gross negligence or willful misconduct.

(e) If any payment of principal of, or Conversion of, any Eurodollar Rate Advance is made by the Borrower to or for the account of a Lender other than on the last day of the Interest Period for such Advance, as a result of a payment or Conversion pursuant to Section 2.08(d) or (e), 2.10 or 2.12, acceleration of the maturity of the Advances pursuant to Section 6.01 or for any other reason, or by an Eligible Assignee to a Lender other than on the last day of the Interest Period for such Advance upon an assignment of rights and obligations under this Agreement pursuant to Section 8.07 as a result of a demand by the Borrower pursuant to Section 8.07(a), the Borrower shall, upon demand by such Lender (with a copy of such demand to the Agent), pay to the Agent for the account of such Lender any amounts required to compensate such Lender for any additional losses, costs or expenses that it may reasonably incur as a result of such payment or Conversion, including, without limitation, any loss (excluding loss of anticipated profits), cost or expense incurred by reason of the liquidation or reemployment of deposits or other funds acquired by any Lender to fund or maintain such Advance.

(f) Without prejudice to the survival of any other agreement of the Borrower hereunder, the agreements and obligations of the Borrower contained in Sections 2.11, 2.14 and 8.04 shall survive the payment in full of principal, interest and all other amounts payable hereunder and under the Notes.

Section 8.05 Right of Set-off. Upon (i) the occurrence and during the continuance of any Event of Default and (ii) the making of the request or the granting of the consent specified by Section 6.01 to authorize the Agent to declare the Advances due and payable pursuant to the provisions of Section 6.01, each Lender, each Issuing Bank and each of their respective Affiliates is hereby authorized at any time and from time to time, to the fullest extent permitted by Law, to set off and apply any and all deposits (general or special, time or demand, provisional or final) at any time held and other indebtedness at any time owing by such Lender, such Issuing Bank or any such Affiliate to or for the credit or the account of the Borrower against any and all of the obligations of the Borrower now or hereafter existing under this Agreement or any other Loan Document to such Lender or Issuing Bank, whether or not such Lender or Issuing Bank shall have made any demand under this Agreement or such Note and although such obligations may be contingent or unmatured or are owed to a branch or office of such Lender or such Issuing Bank different from the branch or office holding such deposit or obligated on such indebtedness. Each Lender and each Issuing Bank agrees promptly to notify the Borrower after any such set-

off and application, provided that the failure to give such notice shall not affect the validity of such set-off and application. The rights of each Lender and each Issuing Bank under this Section are in addition to other rights and remedies (including, without limitation, other rights of set-off) that such Lender may have.

Section 8.06 Binding Effect. Except as provided in Section 3.01, this Agreement shall become effective when it shall have been executed by the Borrower and the Agent and when the Agent shall have been notified by each Initial Lender that such Initial Lender has executed it and thereafter shall be binding upon and inure to the benefit of the Borrower, the Agent and each Lender and their respective successors and assigns, except that the Borrower shall not have the right to assign its rights hereunder or any interest herein without the prior written consent of the Lenders.

Section 8.07 Successors and Assigns.

(a) The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby, except that the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of the Agent and each Lender (and any purported assignment or transfer without such consent shall be null and void) and no Lender may assign or otherwise transfer any of its rights or obligations hereunder except (i) to an assignee in accordance with the provisions of subsection (b) of this Section, (ii) by way of participation in accordance with the provisions of subsection (d) of this Section, or (iii) by way of pledge or assignment of a security interest subject to the restrictions of subsection (f) of this Section. Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby, Participants to the extent provided in subsection (d) of this Section and, to the extent expressly contemplated hereby, the Related Parties of each of the Agent, the Issuing Banks and the Lenders) any legal or equitable right, remedy or claim under or by reason of this Agreement.

(b) Any Lender may at any time assign to one or more assignees all or a portion of its rights and obligations under this Agreement (including all or a portion of its Revolving Credit Commitment and the Advances (including for purposes of this subsection (b), participations in L/C Obligations) at the time owing to it); provided that any such assignment shall be subject to the following conditions:

(i) Minimum Amounts.

(A) in the case of an assignment of the entire remaining amount of the assigning Lender's Revolving Credit Commitment and the Advances at the time owing to it or in the case of an assignment to a Lender, no minimum amount need be assigned; and

(B) in any case not described in subsection (b)(i)(A) of this Section, the aggregate amount of the Revolving Credit Commitment (which for this purpose includes Advances outstanding thereunder) or, if the Revolving Credit Commitment is not then in effect, the principal outstanding balance of the

Advances of the assigning Lender subject to each such assignment, determined as of the date the Assignment and Assumption with respect to which such assignment is delivered to the Agent or, if "Trade Date" is specified in the Assignment and Assumption, as of the Trade Date, shall not be less than $5,000,000 unless each of the Agent and, so long as no Event of Default has occurred and is continuing, the Borrower otherwise consents (each such consent not to be unreasonably withheld or delayed).

(ii) Proportionate Amounts . Each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations under this Agreement with respect to the Advances, L/C Obligations or the Revolving Credit Commitment assigned, and each such assignment shall be of a constant, and not a varying, percentage of all rights and obligations under this Agreement;

(iii) Required Consents . No consent shall be required for any assignment except to the extent required by subsection (b)(i)(B) of this Section and, in addition:

(A) the consent of the Borrower (such consent not to be unreasonably withheld or delayed; provided that the Borrower shall be deemed to have consented to any such assignment unless it shall object thereto by written notice to the Agent within ten (10) Business Days after having received notice thereof) shall be required unless (1) an Event of Default has occurred and is continuing at the time of such assignment or (2) such assignment is to a Lender, an Affiliate of a Lender or an Approved Fund;

(B) the consent of the Agent (such consent not to be unreasonably withheld or delayed) shall be required if such assignment is to a Person that is not a Lender, an Affiliate of a Lender or an Approved Fund with respect to such Lender; and

(C) the consent of each Issuing Bank (such consent not to be unreasonably withheld or delayed) shall be required for any assignment that increases the obligation of the assignee to participate in exposure under one or more Letters of Credit (whether or not then outstanding).

(iv) Assignment and Assumption . The parties to each assignment shall execute and deliver to the Agent an Assignment and Assumption, together with a processing and recordation fee in the amount of $3,500; provided , however , that no such fee shall be payable in the case of an assignment made at the request of the Borrower to an existing Lender. The assignee, if it is not a Lender, shall deliver to the Agent an Administrative Questionnaire.

(v) No Assignment to Borrower . No such assignment shall be made to the Borrower or any of the Borrower's Affiliates or Subsidiaries.

(vi) No Assignment to Natural Persons . No such assignment shall be made to a natural person.

Subject to acceptance and recording thereof by the Agent pursuant to subsection (c) of this Section and notice thereof to the Borrower, from and after the effective date specified in each Assignment and Assumption, the assignee thereunder shall be a party to this Agreement and, to the extent of the interest assigned by such Assignment and Assumption, have the rights and obligations of a Lender under this Agreement, and the assigning Lender thereunder shall, to the extent of the interest assigned by such Assignment and Assumption, be released from its obligations under this Agreement (and, in the case of an Assignment and Assumption covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto) but shall continue to be entitled to the benefits of Sections 2.11, 2.14 and 8.04 with respect to facts and circumstances occurring prior to the effective date of such assignment. Upon request, the Borrower (at its expense) shall execute and deliver a Note to the assignee Lender. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this subsection shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with subsection (d) of this Section.

(c) Register. The Agent shall maintain at the Agent's Office a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Revolving Credit Commitments of, and principal amounts of the Advances and L/C Obligations owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive, absent manifest error, and the Borrower, the Agent and the Lenders may treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register shall be available for inspection by the Borrower and any Lender, at any reasonable time and from time to time upon reasonable prior notice.

(d) Participations. Any Lender may at any time, without the consent of, or notice to, the Borrower or the Agent, sell participations to any Person (other than a natural person or the Borrower or any of the Borrower's Affiliates or Subsidiaries) (each, a "Participant") in all or a portion of such Lender's rights and/or obligations under this Agreement (including all or a portion of its Revolving Credit Commitment and/or the Advances (including such Lender's participations in L/C Obligations) owing to it); provided that (i) such Lender's obligations under this Agreement shall remain unchanged, (ii) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, (iii) the Borrower, the Agent, the Lenders and the Issuing Banks shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement and (iv) no participant under any such participation shall have any right to approve any amendment or waiver of any provision of this Agreement or any Note, or any consent to any departure by the Borrower therefrom, except to the extent that such amendment, waiver or consent would reduce the principal of, or interest on, any Obligations or any fees or other amounts payable hereunder, in each case to the extent subject to such participation, or postpone any date fixed for any payment of principal of, or interest on, any Obligations or any fees or other amounts payable hereunder, in each case to the extent subject to such participation.

Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to enforce this Agreement and to approve any

amendment, modification or waiver of any provision of this Agreement; provided that such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, waiver or other modification addressing the matters set forth in clause (iv) above to the extent subject to such participation. Subject to subsection (e) of this Section, the Borrower agrees that each Participant shall be entitled to the benefits of Sections 2.11, 2.14 and 8.04(e) to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to subsection (b) of this Section. To the extent permitted by Law, each Participant also shall be entitled to the benefits of Section 8.05 as though it were a Lender, provided such Participant agrees to be subject to Section 2.15 as though it were a Lender.

(e) Limitations upon Participant Rights. A Participant shall not be entitled to receive any greater payment under Section 2.11 or 2.14 than the applicable Lender would have been entitled to receive with respect to the participation sold to such Participant, unless the sale of the participation to such Participant is made with the Borrower's prior written consent. A Participant that would be a Foreign Lender if it were a Lender shall not be entitled to the benefits of Section 2.14 unless the Borrower is notified of the participation sold to such Participant and such Participant agrees, for the benefit of the Borrower, to comply with Section 2.14(e) as though it were a Lender.

(f) Certain Pledges. Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement (including under its Note, if any) to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank; provided that no such pledge or assignment shall release such Lender from any of its obligations hereunder or substitute any such pledgee or assignee for such Lender as a party hereto.

(g) Resignation as an Issuing Bank after Assignment. Notwithstanding anything to the contrary contained herein, if at any time any Issuing Bank assigns all of its Revolving Credit Commitment and Advances pursuant to subsection (b) above, such Issuing Bank may, upon 30 days' notice to the Borrower and the Lenders, resign as an Issuing Bank. If any Issuing Bank resigns, it shall retain all the rights, powers, privileges and duties of an Issuing Bank hereunder with respect to all Letters of Credit outstanding as of the effective date of its resignation as an Issuing Bank and all L/C Obligations with respect thereto (including the right to require the Lenders to make Base Rate Advances or fund risk participations in Unreimbursed Amounts pursuant to Section 2.03(c)).

(h) The words "execution," "signed," "signature," and words of like import in any Assignment and Assumption shall be deemed to include electronic signatures or the keeping of records in electronic form, each of which shall be of the same legal effect, validity or enforceability as a manually executed signature or the use of a paper-based recordkeeping system, as the case may be, to the extent and as provided for in any applicable Law, including the Federal Electronic Signatures in Global and National Commerce Act, the New York State Electronic Signatures and Records Act, or any other similar state Laws based on the Uniform Electronic Transactions Act.

Section 8.08 Confidentiality. Neither the Agent nor any Lender may disclose to any Person any confidential, proprietary or non-public information of the Borrower furnished to the

Agent or the Lenders by the Borrower (such information being referred to collectively herein as the " Borrower Information "), except that each of the Agent and each of the Lenders may disclose Borrower Information (i) to its and its affiliates' employees, officers, directors, agents and advisors having a need to know in connection with this Agreement (it being understood that the Persons to whom such disclosure is made will be informed of the confidential nature of such Borrower Information and instructed to keep such Borrower Information confidential on substantially the same terms as provided herein), (ii) to the extent requested by any regulatory authority, (iii) to the extent required by applicable Laws or regulations or by any subpoena or similar legal process, (iv) to any other party to this Agreement, (v) in connection with the exercise of any remedies hereunder or any suit, action or proceeding relating to this Agreement or the enforcement of rights hereunder, (vi) subject to an agreement containing provisions substantially the same as those of this Section 8.08, (A) to any assignee or participant or prospective assignee or participant, (B) any direct, indirect, actual or prospective counterparty (and its advisor) to any swap, derivative or securitization transaction related to the obligations under this Agreement and (C) to any credit insurance provider relating to the Borrower and its Obligations, (vii) to the extent such Borrower Information (A) is or becomes generally available to the public on a non-confidential basis other than as a result of a breach of this Section 8.08 by the Agent or such Lender or their Related Parties, or (B) is or becomes available to the Agent or such Lender on a nonconfidential basis from a source other than the Borrower (provided that the source of such information was not known by the recipient after inquiry to be bound by a confidentiality agreement with or other contractual, legal or fiduciary obligation of confidentiality to the Borrower or any other Person with respect to such information) and (viii) with the consent of the Borrower. The obligations under this Section 8.08 shall survive for two calendar years after the date of the termination of this Agreement.

Section 8.09 Governing Law . This Agreement and the Notes shall be governed by, and construed in accordance with, the Laws of the State of New York (including Sections 5-1401 and 5-1402 of the General Obligations Law but otherwise without regard to conflict of law principles).

Section 8.10 Counterparts; Integration; Effectiveness . This Agreement may be executed in counterparts (and by different parties hereto in different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. This Agreement and the other Loan Documents constitute the entire contract among the parties relating to the subject matter hereof and supersede any and all previous agreements and understandings, oral or written, relating to the subject matter hereof. Except as provided in Section 3.01, this Agreement shall become effective when it shall have been executed by the Agent and when the Agent shall have received counterparts hereof that, when taken together, bear the signatures of each of the other parties hereto. Delivery of an executed counterpart of a signature page of this Agreement by telecopy or other electronic imaging means shall be effective as delivery of a manually executed counterpart of this Agreement.

Section 8.11 Jurisdiction, Etc .

(a) Each of the parties hereto hereby submits to the exclusive jurisdiction of any New York State court or federal court of the United States of America sitting in the Borough of Manhattan in New York City, and any appellate court from any thereof, in any action or

proceeding arising out of or relating to this Agreement or the other Loan Documents, or for recognition or enforcement of any judgment, and each of the parties hereto hereby agrees that all claims in respect of any such action or proceeding may be heard and determined in any such New York State court or, to the extent permitted by Law, in such federal court. Nothing in this Agreement shall affect any right that any party may otherwise have to bring any action or proceeding relating to this Agreement or the Notes in the courts of any jurisdiction.

(b) Each of the parties hereto irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection that it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement or the Notes in any New York State or federal court. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by Law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

Section 8.12 Payments Set Aside . To the extent that any payment by or on behalf of the Borrower is made to the Agent, any Issuing Bank or any Lender, or the Agent, any Issuing Bank or any Lender exercises its right of setoff, and such payment or the proceeds of such setoff or any part thereof is subsequently invalidated, declared to be fraudulent or preferential, set aside or required (including pursuant to any settlement entered into by the Agent, such Issuing Bank or such Lender in its discretion) to be repaid to a trustee, receiver or any other party, in connection with any proceeding under any Debtor Relief Law or otherwise, then (a) to the extent of such recovery, the obligation or part thereof originally intended to be satisfied shall be revived and continued in full force and effect as if such payment had not been made or such setoff had not occurred, and (b) each Lender and each Issuing Bank severally agrees to pay to the Agent upon demand its applicable share (without duplication) of any amount so recovered from or repaid by the Agent, plus interest thereon from the date of such demand to the date such payment is made at a rate per annum equal to the Federal Funds Rate from time to time in effect. The obligations of the Lenders and the Issuing Banks under clause (b) of the preceding sentence shall survive the payment in full of the Obligations and the termination of this Agreement.

Section 8.13 Patriot Act . Each Lender hereby notifies the Borrower that pursuant to the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the " Act "), it is required to obtain, verify and record information that identifies each borrower, guarantor or grantor (the " Loan Parties "), which information includes the name and address of each Loan Party and other information that will allow such Lender to identify such Loan Party in accordance with the Act. The Borrower shall provide, to the extent commercially reasonable, such information and take such actions as are reasonably requested by the Agent or any Lender in order to assist the Agent and such Lender in maintaining compliance with the Act.

Section 8.14 Waiver of Jury Trial . EACH OF THE BORROWER, THE AGENT AND THE LENDERS HEREBY IRREVOCABLY WAIVES ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM (WHETHER BASED ON CONTRACT, TORT OR OTHERWISE) ARISING OUT OF OR RELATING TO THIS AGREEMENT, THE NOTES OR ANY OTHER LOAN DOCUMENT OR THE ACTIONS OF THE BORROWER, THE AGENT OR ANY LENDER IN THE NEGOTIATION, ADMINISTRATION, PERFORMANCE OR ENFORCEMENT THEREOF.

Section 8.15 No Advisory or Fiduciary Responsibility. In connection with all aspects of each transaction contemplated hereby, the Borrower acknowledges and agrees that: (i) the credit facilities provided for hereunder and any related arranging or other services in connection therewith (including in connection with any amendment, waiver or other modification hereof or of any other Loan Document) are an arm's-length commercial transaction between the Borrower, on the one hand, and the Agent, each of the Lenders and each of the Arrangers, on the other hand, and the Borrower is capable of evaluating and understanding and understands and accepts the terms, risks and conditions of the transactions contemplated hereby and by the other Loan Documents (including any amendment, waiver or other modification hereof or thereof); (ii) in connection with the process leading to such transaction, each of the Agent, the Lenders and the Arrangers is and has been acting solely as a principal and is not the financial advisor, agent or fiduciary, for the Borrower or any of its Affiliates, stockholders, creditors or employees or any other Person; (iii) neither the Agent nor any Lender or Arranger has assumed or will assume an advisory, agency or fiduciary responsibility in favor of the Borrower with respect to any of the transactions contemplated hereby or the process leading thereto, including with respect to any amendment, waiver or other modification hereof or of any other Loan Document (irrespective of whether the Agent or any Lender or Arranger has advised or is currently advising the Borrower or any of its Affiliates on other matters) and neither the Agent nor any Lender or Arranger has any obligation to the Borrower with respect to the transactions contemplated hereby except those obligations expressly set forth herein and in the other Loan Documents; (iv) the Agent, each of the Lenders and the Arrangers and their respective Affiliates may be engaged in a broad range of transactions that involve interests that differ from those of the Borrower and its Affiliates, and neither the Agent nor any Lender or Arranger has any obligation to disclose any of such interests by virtue of any advisory, agency or fiduciary relationship; and (v) the Agent and each Lender and Arranger have not provided and will not provide any legal, accounting, regulatory or tax advice with respect to any of the transactions contemplated hereby (including any amendment, waiver or other modification hereof or of any other Loan Document) and the Borrower has consulted its own legal, accounting, regulatory and tax advisors to the extent it has deemed appropriate. The Borrower hereby waives and releases, to the fullest extent permitted by Law, any claims that it may have against the Agent and each Lender and Arranger with respect to any breach or alleged breach of agency or fiduciary duty in connection with the Loan Documents.

Section 8.16 Survival of Representations and Warranties. All representations and warranties made hereunder and in any other Loan Document or other document delivered pursuant hereto or thereto or in connection herewith or therewith shall survive the execution and delivery hereof and thereof. Such representations and warranties have been or will be relied upon by the Agent and each Lender, regardless of any investigation made by the Agent or any Lender or on their behalf, and shall continue in full force and effect as long as any Advance or any other Obligation hereunder shall remain unpaid or unsatisfied or any Letter of Credit shall remain outstanding.

Section 8.17 Severability. If any provision of this Agreement or the other Loan Documents is held to be illegal, invalid or unenforceable, (a) the legality, validity and enforceability of the remaining provisions of this Agreement and the other Loan Documents shall not be affected or impaired thereby and (b) the parties shall endeavor in good faith negotiations to replace the illegal, invalid or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the illegal, invalid or

unenforceable provisions. The invalidity of a provision in a particular jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, as of the date first above written.

ARIZONA PUBLIC SERVICE COMPANY

By: /s/ Lee R. Nickloy
Name: Lee R. Nickloy
Title: Vice President and Treasurer

Signature Page to Credit Agreement

ADMINISTRATIVE AGENT:

BARCLAYS BANK, PLC ,
as Administrative Agent, as a Lender and as an Issuing Bank

By: /s/ Alicia Borys
Name: Alicia Borys
Title: Assistant Vice President

Signature Page to Credit Agreement

LENDERS:

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
as a Lender and as an Issuing Bank

By: /s/ Shaheen Malik
Name: Shaheen Malik
Title: Vice President

By: /s/ Rahul Parmar
Name: Rahul Parmar
Title: Associate

Signature Page to Credit Agreement

BANK OF AMERICA, N.A.,
as a Lender

By: /s/ Justin Martin
Name: Justin Martin
Title: Vice President

Signature Page to Credit Agreement

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as a Lender

By: /s/ Yann Blindert
Name: Yann Blindert
Title: Vice President

Signature Page to Credit Agreement

THE BANK OF NEW YORK MELLON,
as a Lender

By: /s/ Mark W. Rogers
Name: Mark W. Rogers
Title: Vice President

Signature Page to Credit Agreement

THE BANK OF NOVA SCOTIA,
as a Lender

By: /s/ Thane Rattew
Name: Thane Rattew
Title: Managing Director

Signature Page to Credit Agreement

BNP PARIBAS,
as a Lender

By: /s/ Francis J. Delaney
Name: Francis J. Delaney
Title: Managing Director

By: /s/ Pasquale A. Perraglia IV
Name: Pasquale A. Perraglia IV
Title: Vice President

Signature Page to Credit Agreement

DEUTSCHE BANK AG NEW YORK BRANCH,
as a Lender

By: /s/ Philippe Sandmeier
Name: Philippe Sandmeier
Title: Managing Director

By: /s/ Ming K. Chu
Name: Ming K. Chu
Title: Vice President

Signature Page to Credit Agreement

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: /s/ Nancy R. Barwig
Name: Nancy R. Barwig
Title: Credit Executive

Signature Page to Credit Agreement

THE ROYAL BANK OF SCOTLAND plc,
as a Lender

By: /s/ Tyler J. McCarthy
Name: Tyler J. McCarthy
Title: Director

Signature Page to Credit Agreement

UBS LOAN FINANCE LLC,
as a Lender

By: /s/ Irja R. Otsa
Name: Irja R. Otsa
Title: Associate Director

By: /s/ Mary E. Evans
Name: Mary E. Evans
Title: Associate Director

Signature Page to Credit Agreement

U.S. BANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ Holland H. Williams
Name: Holland H. Williams
Title: AVP & Portfolio Mgr.

Signature Page to Credit Agreement

GOLDMAN SACHS BANK USA,
as a Lender

By: /s/ Mark Walton
Name: Mark Walton
Title: Authorized Signatory

Signature Page to Credit Agreement

KEYBANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ Keven D. Smith
Name: Keven D. Smith
Title: Senior Vice President

Signature Page to Credit Agreement

MORGAN STANLEY BANK, N.A.,
as a Lender

By: /s/ Sherrese Clarke
Name: Sherrese Clarke
Title: Authorized Signatory

Signature Page to Credit Agreement

UNION BANK, N.A.,
as a Lender

By: /s/ Efrain Soto
Name: Efrain Soto
Title: Vice President

Signature Page to Credit Agreement

SUNTRUST BANK,
as a Lender

By: /s/ Andrew Johnson
Name: Andrew Johnson
Title: Director

Signature Page to Credit Agreement

THE NORTHERN TRUST COMPANY,
as a Lender

By: /s/ John Lascody
Name: John Lascody
Title: Second Vice President

Signature Page to Credit Agreement

COMERICA BANK,
as a Lender

By: /s/ Mark C. Skrzynski
Name: Mark C. Skrzynski
Title: Assistant Vice President

Signature Page to Credit Agreement

SCHEDULE 1.01
COMMITMENTS AND RATABLE SHARES

Bank	Revolving Credit Commitment	Ratable Share
Barclays Bank PLC	$ 35,500,000.00	7.10%
Credit Suisse AG, Cayman Islands Branch	$ 35,500,000.00	7.10%
Bank of America, N.A.	$ 35,500,000.00	7.10%
Wells Fargo Bank, National Association	$ 35,500,000.00	7.10%
The Bank of New York Mellon	$ 28,500,000.00	5.70%
The Bank of Nova Scotia	$ 28,500,000.00	5.70%
BNP Paribas	$ 28,500,000.00	5.70%
Deutsche Bank AG New York Branch	$ 28,500,000.00	5.70%
JPMorgan Chase Bank, N.A.	$ 28,500,000.00	5.70%
The Royal Bank of Scotland plc	$ 28,500,000.00	5.70%
UBS Loan Finance LLC	$ 28,500,000.00	5.70%
U.S. Bank National Association	$ 28,500,000.00	5.70%
Goldman Sachs Bank USA	$ 20,000,000.00	4.00%
KeyBank National Association	$ 20,000,000.00	4.00%
Morgan Stanley Bank, N.A.	$ 20,000,000.00	4.00%
Union Bank, N.A.	$ 20,000,000.00	4.00%
SunTrust Bank	$ 20,000,000.00	4.00%
The Northern Trust Company	$ 15,000,000.00	3.00%
Comerica Bank	$ 15,000,000.00	3.00%
TOTAL	$ 500,000,000.00	100.00%

SCHEDULE 4.01(j)
SUBSIDIARIES [1]

Bixco, Inc.
Axiom Power Solutions, Inc.
PWE Newco, Inc.

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1 The Borrrower's three nuclear decommissioning trusts relating to PVNGS may also be deemed to be subsidiaries under a literal reading of the definition.

SCHEDULE 4.01(k)
EXISTING INDEBTEDNESS

ne.

SCHEDULE 8.02
CERTAIN ADDRESSES FOR NOTICES

BORROWER:

Arizona Public Service Company
400 North 5th Street
Mail Station 9040
Phoenix, AZ 85004
Attention: Treasurer
Telephone: (602) 250-3300
Telecopier: (602) 250-3902
Electronic lee.nickloy@pinnaclewest.com

AGENT :

Agent's Office
(for payments and Requests for Credit Extensions):

Barclays Bank PLC
Aurora Bldg 120 Bothwell St
G27JS, Glasgow
United Kingdom
Attention: Steven Smitherman / Barrie Cairns
Telephone: 212.526.0261 / 212.526.0209
Email: steven.smitherman@barcap.com / barrie.cairns@barcap.com

with copies to:

Barclays Bank PLC
745 Seventh Avenue
New York, NY 10019
Attention: Alicia Borys
Facsimile: 212.526.5115
Telephone: 212.526.4291
Email: Alicia.borys@barcap.com

Barclays Bank PLC
745 Seventh Avenue
New York, NY 10019
Attention: Vanessa A. Kurbatskiy
Facsimile: 212.526.5115
Telephone: 212.526.2799
Email: Vanessa.kurbatskiy@barcap.com

Agent's Account/Barclays Bank Agency Service Wiring Information

Barclays Bank PLC
[redacted]w York, New York
[redacted]BA: 026002574
Account Number: 050-01910-4
Account Name: Clad Control Account
Ref: Arizona Public Service

Other Notices as Agent :

Barclays Bank PLC
745 Seventh Avenue
New York, NY 10019
Attention: Alicia Borys
Facsimile: 212.526.5115
Telephone: 212.526.4291
Email: Alicia.borys@barcap.com

Barclays Bank PLC
745 Seventh Avenue
New York, NY 10019
Attention: Vanessa A. Kurbatskiy
Facsimile: 212.526.5115
Telephone: 212.526.2799
Email: Vanessa.kurbatskiy@barcap.com

ISSUING BANKS:

Barclays Bank PLC

[redacted]rclays Bank PLC
[redacted]0 Park Avenue
New York, NY 10166
Attn. Letters of Credit / Dawn Townsend
Fax (212) 412 5011
Phone (201) 499-2081
Email xraletterofcredit@baclayscapital.com

Credit Suisse AG, Cayman Islands Branch

Credit Suisse AG, Cayman Islands Branch
7033 Louis Stephens Drive
P.O. Box 110047
Research Triangle Park, NC 27709
Attention: Brendan Hagan
Facsimile: (866) 469-3871
Telephone: (919) 994-5733
Email: Brendan.Hagan@credit-suisse.com

EXHIBIT A — FORM OF PROMISSORY NOTE

_____, 20__

FOR VALUE RECEIVED, the undersigned, ARIZONA PUBLIC SERVICE COMPANY, an Arizona corporation (the " Borrower "), hereby promises to pay to the order of _____ or its registered assigns (the " Lender "), in accordance with the provisions of the Credit Agreement (as hereinafter defined), the principal amount of each Advance from time to time made by the Lender to the Borrower pursuant to the Four-Year Credit Agreement dated as of February 14, 2011 among the Borrower, the Lender and certain other lenders parties thereto, Barclays Bank PLC, as Agent for the Lender and such other lenders, and the issuing banks and other agents party thereto (as amended or modified from time to time, the " Credit Agreement "; the terms defined therein being used herein as therein defined) outstanding on such date.

The Borrower promises to pay interest on the unpaid principal amount of each Advance from the date of such Advance until such principal amount is paid in full, at such interest rates, and payable at such times, as are specified in the Credit Agreement.

Both principal and interest are payable in lawful money of the United States of America to the Agent for the account of the Lender in same day funds at the address and account specified on Schedule 8.02 . Each Advance owing to the Lender by the Borrower pursuant to the Credit Agreement, and all payments made on account of principal thereof, shall be recorded by the Lender and, prior to any transfer hereof, endorsed on the grid attached hereto which is part of this Promissory Note.

This Promissory Note is one of the Notes referred to in, and is entitled to the benefits of, the Credit Agreement. The Credit Agreement, among other things, (i) provides for the making of Advances by the Lender to the Borrower from time to time in an aggregate amount not to exceed at any time the Lender's Unused Commitment, the indebtedness of the Borrower resulting from each such Advance being evidenced by this Promissory Note and (ii) contains provisions for acceleration of the maturity hereof upon the happening of certain stated events and also for prepayments on account of principal hereof prior to the maturity hereof upon the terms and conditions therein specified.

THIS PROMISSORY NOTE SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

ARIZONA PUBLIC SERVICE COMPANY

By: _____
Name: _____
Title: _____

ADVANCES AND PAYMENTS OF PRINCIPAL

Date	Amount of Advance	Amount of Principal Paid or Prepaid	Unpaid Principal Balance	Notation Made By

A-2

EXHIBIT B — FORM OF NOTICE OF BORROWING

Barclays Bank PLC, as Agent
for the Lenders parties
to the Credit Agreement
referred to below

Attention: Bank Loan Syndications Department

[Date]

Ladies and Gentlemen:

The undersigned, Arizona Public Service Company, refers to the Four-Year Credit Agreement, dated as of February 14, 2011 (as amended or modified from time to time, the " Credit Agreement ", the terms defined therein being used herein as therein defined), among the undersigned, certain Lenders parties thereto, Barclays Bank PLC, as Agent for said Lenders and the Issuing Banks and other agents party thereto, and hereby gives you notice, irrevocably, pursuant to Section 2.02 of the Credit Agreement that the undersigned hereby requests a Borrowing under the Credit Agreement, and in that connection sets forth below the information relating to such Borrowing (the " Proposed Borrowing ") as required by Section 2.02(a) of the Credit Agreement:

(i) The Business Day of the Proposed Borrowing is _____, 20_____.

(ii) The Type of Advances comprising the Proposed Borrowing is [Base Rate Advances] [Eurodollar Rate Advances].

(iii) The aggregate amount of the Proposed Borrowing is $_____.

[(iv) The initial Interest Period for each Eurodollar Rate Advance made as part of the Proposed Borrowing is _____ month[s].]

The undersigned hereby certifies that the following statements are true on the date hereof, and will be true on the date of the Proposed Borrowing:

(A) the representations and warranties contained in Section 4.01 (other than Sections 4.01(k), 4.01(e)(ii) and 4.01(f)(ii)) of the Credit Agreement are correct, before and after giving effect to the Proposed Borrowing and to the application of the proceeds therefrom, as though made on and as of such date;

(B) no event has occurred and is continuing, or would result from such Proposed Borrowing or from the application of the proceeds therefrom, that constitutes a Default;

(C) all required regulatory authorizations including the 2007 Order and/or any Subsequent Order in respect of the Proposed Borrowing have been obtained and are in full force and effect and, before and after giving effect to the Proposed Borrowing and to the application of

the proceeds therefrom, the Borrower is in compliance with the provisions of the applicable order; and

(D) before and after giving effect to the Proposed Borrowing and to the application of the proceeds therefrom, as though made on and as of such date, the Indebtedness of the Borrower does not exceed that permitted by (i) applicable resolutions of the Board of Directors of the Borrower, (ii) applicable Arizona Laws, or (iii) the 2007 Order or any Subsequent Order, whichever is in force and effect at such time.

Very truly yours,

ARIZONA PUBLIC SERVICE COMPANY

By: _____
Name: _____
Title: _____

EXHIBIT C — FORM OF
ASSIGNMENT AND ASSUMPTION

This Assignment and Assumption (the " Assignment and Assumption ") is dated as of the Effective Date set forth below and entered into by and between **[Insert name of Assignor]** (the " Assignor ") and **[Insert name of Assignee]** (the " Assignee "). Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as amended, the " Credit Agreement "), receipt of a copy of which is hereby acknowledged by the Assignee. Annex 1 attached hereto (the " Standard Terms and Conditions ") is hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

For an agreed consideration, the Assignor hereby irrevocably sells and assigns to the Assignee, and the Assignee hereby irrevocably purchases and assumes from the Assignor, subject to and in accordance with the Standard Terms and Conditions and the Credit Agreement, as of the Effective Date referred to below (i) all of the Assignor's rights and obligations in its capacity as a Lender under the Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of the Assignor under the respective facilities identified below (including without limitation any letters of credit, guarantees, and swingline loans included in such facilities) and (ii) to the extent permitted to be assigned under applicable Law, all claims, suits, causes of action and any other right of the Assignor (in its capacity as a Lender) against any Person, whether known or unknown, arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including, but not limited to, contract claims, tort claims, malpractice claims, statutory claims and all other claims at Law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned pursuant to clauses (i) and (ii) above being referred to herein collectively as, the " Assigned Interest "). Each such sale and assignment is without recourse to the Assignor and, except as expressly provided in this Assignment and Assumption, without representation or warranty by the Assignor. Assignee shall deliver (if it is not already a Lender) to the Agent an Administrative Questionnaire.

1. Assignor: _____

2. Assignee: _____
   [and is an Affiliate of [identify Bank] [1]]

3. Borrower: Arizona Public Service Company

4. Agent: Barclays Bank PLC, as the administrative agent under the Credit Agreement

5. Credit Agreement: The Four-Year Credit Agreement dated as of February 14, 2011, by and among the Borrower, the Lenders party thereto, the Agent and the Issuing Banks and other agents party thereto.

6. Assigned Interest:

---

[1] Select as applicable.

Aggregate Amount of Commitment for all Lenders	Amount of Commitment Assigned	Percentage Assigned of Commitment [2]	CUSIP Number
	$	%	

[7. Trade Date:] [3]
Effective Date: _____, 20_____ **[TO BE INSERTED BY AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR.]**

The terms set forth in this Assignment and Assumption are hereby agreed to:

ASSIGNOR
[NAME OF ASSIGNOR]

By: _____
Name: _____
Title: _____

ASSIGNEE
[NAME OF ASSIGNEE]

By: _____
Name: _____
Title: _____

[Consented to and] [4] Accepted:
BARCLAYS BANK PLC, as Agent

_____
Name: _____
Title: _____

[Consented to:] [5]
[BARCLAYS BANK PLC, as Issuing Bank]

By: _____
Name: _____
Title: _____

[CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH, as Issuing Bank]

---

2 Set forth, to at least 9 decimals, as a percentage of the Commitment of all Banks thereunder.

3 To be completed if the Assignor and the Assignee intend that the minimum assignment amount is to be determined as of the Trade Date.

4 To be added only if the consent of the Agent is required by the terms of the Credit Agreement.

5 To be added only if the consent of the Borrowers and/or other parties (e.g. Issuing Bank) is required by the terms of the Credit Agreement.

By: _____
Name: _____
Title: _____

ARIZONA PUBLIC SERVICE COMPANY

By: _____
Name: _____
Title: _____

ANNEX 1 TO ASSIGNMENT AND ASSUMPTION
STANDARD TERMS AND CONDITIONS FOR
ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties .

1.1 Assignor . The Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of the Assigned Interest, (ii) the Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents, (iii) the financial condition of the Borrower, any of its Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document or (iv) the performance or observance by the Borrower of any of its obligations under any Loan Document.

1.2 Assignee . The Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) it meets all the requirements to be an Eligible Assignee under Section 8.07 of the Credit Agreement (subject to such consents, if any, as may be required under Section 8.07 of the Credit Agreement), (iii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by the Assigned Interest and either it, or the Person exercising discretion in making its decision to acquire the Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the Credit Agreement, and has received or has been accorded the opportunity to receive copies of the most recent financial statements referred to in Section 4.01(e) or delivered pursuant to Section 5.01(h), as applicable, thereof, as applicable, and such other documents and information as it deems appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase the Assigned Interest, (vi) it has, independently and without reliance upon the Agent, the Assignor or any other Lender and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Assignment and Assumption and to purchase the Assigned Interest, and (vi) if it is a foreign lender, attached to the Assignment and Assumption is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by the Assignee; and (b) agrees that (i) it will, independently and without reliance on the Agent, the Assignor or any other Lender, and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments . From and after the Effective Date, the Agent shall make all payments in respect of the Assigned Interest (including payments of principal, interest, fees and other

amounts) to the Assignor for amounts which have accrued to but excluding the Effective Date and to the Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions . This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties here and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by facsimile shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the Law of the State of New York.

Exhibit 12.1

PINNACLE WEST CAPITAL CORPORATION
COMPUTATION OF EARNINGS TO FIXED CHARGES
(dollars in thousands)

	Twelve Months Ended December 31,				
	2010	2009	2008	2007	2006
Earnings:					
Income from continuing operations attributable to common shareholders	$ 330,435	$ 233,349	$ 260,840	$ 283,370	$ 265,320
Income taxes	164,321	136,506	95,544	142,330	123,915
Fixed charges	248,664	241,568	224,453	213,531	203,899
Total earnings	$ 743,420	$ 611,423	$ 580,837	$ 639,231	$ 593,134
Fixed Charges:					
Interest expense	$ 244,174	$ 237,527	$ 219,916	$ 209,354	$ 200,411
Estimated interest portion of annual rents	4,490	4,041	4,537	4,177	3,488
Total fixed charges	$ 248,664	$ 241,568	$ 224,453	$ 213,531	$ 203,899
Ratio of Earnings to Fixed Charges (rounded down)	2.98	2.53	2.58	2.99	2.90

Exhibit 12.2

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF EARNINGS TO FIXED CHARGES
(dollars in thousands)

	Twelve Months Ended December 31,				
	2010	2009	2008	2007	2006
Earnings:					
Income from continuing operations attributable to common shareholder	$ 335,663	$ 251,225	$ 262,344	$ 283,940	$ 269,730
Income taxes	170,465	152,574	107,261	151,157	138,927
Fixed charges	234,184	227,274	206,896	195,144	184,059
Total earnings	$ 740,312	$ 631,073	$ 576,501	$ 630,241	$ 592,716
Fixed Charges:					
Interest charges	$ 225,269	$ 218,969	$ 197,964	$ 186,702	$ 176,459
Amortization of debt discount	4,559	4,675	4,702	4,639	4,363
Estimated interest portion of annual rents	4,356	3,630	4,230	3,803	3,237
Total fixed charges	$ 234,184	$ 227,274	$ 206,896	$ 195,144	$ 184,059
Ratio of Earnings to Fixed Charges (rounded down)	3.16	2.77	2.78	3.22	3.22

Exhibit 12.3

PINNACLE WEST CAPITAL CORPORATION
COMPUTATION OF EARNINGS TO FIXED CHARGES
(dollars in thousands)

	Twelve Months Ended December 31,				
	2010	2009	2008	2007	2006
Earnings:					
Income from continuing operations attributable to common shareholders	$ 330,435	$ 233,349	$ 260,840	$ 283,370	$ 265,320
Income taxes	164,321	136,506	95,544	142,330	123,915
Fixed charges	248,664	241,568	224,453	213,531	203,899
Total earnings	$ 743,420	$ 611,423	$ 580,837	$ 639,231	$ 593,134
Fixed Charges:					
Interest expense	$ 244,174	$ 237,527	$ 219,916	$ 209,354	$ 200,411
Estimated interest portion of annual rents	4,490	4,041	4,537	4,177	3,488
Total fixed charges	$ 248,664	$ 241,568	$ 224,453	$ 213,531	$ 203,899
Preferred Stock Dividend Requirements:					
Income before income taxes attributable to common shareholders	$ 494,756	$ 369,855	$ 356,384	$ 425,700	$ 389,235
Net income from continuing operations attributable to common shareholders	330,435	233,349	260,840	283,370	265,320
Ratio of income before income taxes to net income	1.50	1.58	1.37	1.50	1.47
Preferred stock dividends	—	—	—	—	—
Preferred stock dividend requirements — ratio (above) times preferred stock dividends	$ —	$ —	$ —	$ —	$ —
Fixed Charges and Preferred Stock Dividend Requirements:					
Fixed charges	$ 248,664	$ 241,568	$ 224,453	$ 213,531	$ 203,899
Preferred stock dividend requirements	—	—	—	—	—
Total	$ 248,664	$ 241,568	$ 224,453	$ 213,531	$ 203,899
Ratio of Earnings to Fixed Charges (rounded down)	2.98	2.53	2.58	2.99	2.90

PNW has the following subsidiaries:

1) Arizona Public Service Company
2) APS Energy Services Company, Inc.
3) El Dorado Investment Company
4) Pinnacle West Energy Corporation (merged into PWCC 8/1/06)
5) SunCor Development Company
6) APSES Holdings, Inc.
   APS Energy L.P. (dissolved 9/29/06)
7) Pinnacle West Marketing & Trading Co., LLC

Pinnacle West Energy affiliates:

1) GenWest, LLC } now under PWCC
2) APACS Holdings, LLC } now under PWCC

Arizona Public Service Company has the following subsidiaries/affiliates:

1) APS Foundation, Inc.
2) Axiom Power Solutions, Inc.
3) BIXCO, Inc.
4) PWE NEWCO, Inc.
5) Powertree Carbon Co., LLC

APS Energy Services Company has or has had the following affiliates:

1) Apex Power LLC
2) Northwind Phoenix LLC (a Delaware LLC/subsidiary of APSES) (sold 6/22/10)
3) Tucson District Energy, LLC (an Arizona LLC/subsidiary of Northwind Phx LLC) (sold 6/22/10)
4) Crest Power, LLC (dormant)

El Dorado has or has had the following investments / affiliates:

1) Acoustic Locating Services, LLC
2) Aegis Technologies, Inc. (dissolved in 2009)
3) Arizona Business Accelerator (dissolved in 2008)
4) Arizona Professional Baseball Ltd Partnership
5) Dominion Fund II (dissolved as of 12/31/02)
6) El Dorado Ventures / El Dorado Ventures II (dissolved as of 12/31/02)
7) El Dorado Ventures III (dissolving)
8) Gateway Data Sciences Corp. (dissolved as of 12/31/02)
9) NAC Holding Inc./ NAC International Inc. (all stock sold on 11/18/04 to USEC, Inc)
10) NxtPhase Corporation (sold in 2009)
11) Phoenix Downtown Theater LLC
12) Phoenix Suns Ltd Partnership (sold on 6/30/04)
13) PowerOneData, Inc. (sold in 2008)
14) Serveron Corporation (sold in 2007)
15) Underground Imaging Technologies (Vermeer Manufacturing Company)
16) SoftSwitching Technologies
17) Zolo Technologies

SunCor has the following subsidiaries and other related entities:

1. Centrepoint Associates, LLC (Kimco)
2. Club West Golf Course, LLC
3. Coral Canyon HD, LLC (SITLA)
4. Golf de Mexico, S.A. de C.V.
5. Hayden Ferry Lakeside, LLC
   - Lakeside Residential Communities, LLC
     - BV at Hayden Ferry Lakeside, LLC
     - Edgewater at Hayden Ferry Lakeside, LLC
     - Waterford at Hayden Ferry Lakeside, LLC
   - Hayden Ferry Lakeside II, LLC
   - Hayden Ferry Lakeside III, LLC
6. Hidden Hills of Scottsdale, LLC

7. Highland Water Company, Inc.
8. Kabuto SunCor JV (Kabuto Int'l Corp.)
9. Marina Heights, LLC
10. Palm Valley 303 Building 1, LLC
11. Palm Valley Golf Club, Inc.
12. Palm Valley Professional Plaza, LLC
13. Rancho Viejo de Santa Fe, Inc.
14. Riverside Distribution Center, LLC (Ryan Buckeye, LLC)
15. Scottsdale Mountain Limited Partnership
16. SDC Prescott, LLC
17. SDC Prescott Valley, LLC
18. SDC Yavapai, LLC
19. Sedona Golf Resort LC (Sedona Assoc. LP)
20. StoneRidge Commercial, LLC
21. StoneRidge — Prescott Valley LLC
    StoneRidge Golf Course, LLC
22. SunCor Homes, Inc. (fka Golden Heritage Homes, Inc.)
    SunCor Construction AZ, Inc
    Golden Heritage Construction Nevada, LLC
    SunCor Financial, LLC
23. SunCor Construction, Inc.
24. SunCor Golf, Inc.
    Westworld Golf Course, LLC
25. SunCor Idaho, Inc.
    Avimor, LLC
    SunCor Realty & Management Idaho, LLC
26. SunCor New Mexico, Inc.
    SunCor Albuquerque, LLC
    SunCor Construction NM, LLC
27. SunCor Realty & Management Company
28. SunCor Utah, Inc.
29. SunRidge Canyon, LLC
30. Talavi Associates, LLC (WLD Partners)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-158779 and 333-155641 on Form S-3; and in Registration Statement Nos. 33-54307, 333-143432, 333-91786, and 333-157151 on Form S-8 of our report dated February 18, 2011 relating to the consolidated financial statements and financial statement schedules of Pinnacle West Capital Corporation and the effectiveness of Pinnacle West Capital Corporation's internal control over financial reporting (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of amended accounting guidance related to the consolidation of variable interest entities on January 1, 2010) appearing in this Annual Report on Form 10-K of Pinnacle West Capital Corporation for the year ended December 31, 2010.

/s/ Deloitte & Touche LLP
Phoenix, Arizona
February 18, 2011

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-158779-01 on Form S-3; and in Registration Statement Nos. 333-46161 and 333-158774 on Form S-8 of our report dated February 18, 2011 relating to the consolidated financial statements and financial statement schedule of Arizona Public Service Company, and the effectiveness of Arizona Public Company's internal control over financial reporting (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of amended accounting guidance related to the consolidation of variable interest entities on January 1, 2010), appearing in this Annual Report on Form 10-K of Arizona Public Service Company for the year ended December 31, 2010.

/s/ Deloitte & Touche LLP
Phoenix, Arizona
February 18, 2011

Exhibit 31.1

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2011.

/s/ Donald E. Brandt
Donald E. Brandt
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James R. Hatfield, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2011.

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President & Chief Financial Officer

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Annual Report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2011.

/s/ Donald E. Brandt
Donald E. Brandt
Chairman and Chief Executive Officer

CERTIFICATION

I, James R. Hatfield, certify that:

1. I have reviewed this Annual Report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2011.

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President & Chief Financial Officer

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Pinnacle West Capital Corporation for the fiscal year ended December 31, 2010 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: February 18, 2011.

/s/ Donald E. Brandt
Donald E. Brandt
Chairman, President and Chief Executive Officer

I, James R. Hatfield, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Pinnacle West Capital Corporation for the fiscal year ended December 31, 2010 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: February 18, 2011.

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President and Chief Financial Officer

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Arizona Public Service Company for the fiscal year ended December 31, 2010 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: February 18, 2011.

/s/ Donald E. Brandt
Donald E. Brandt
Chairman and Chief Executive Officer

I, James R. Hatfield, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of Arizona Public Service Company for the fiscal year ended December 31, 2010 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: February 18, 2011.

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President and Chief Financial Officer

F-1

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED INCOME STATEMENTS
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED 12/31/2010 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Test Year (a) Actual Year Ended 12/31/2010 (A)	Projected Years (b) Present Rates Year Ended 12/31/2011 (B)	Present Rates Year Ended 12/31/2012 (C)	Present Rates Year Ended 12/31/2013 (D)	Proposed Rates Year Ended 12/31/2012 (E)	Proposed Rates Year Ended 12/31/2013 (F)	Line No.
1.	Electric operating revenues	$ 3,180,807	$ 3,242,469	$ 3,393,545	$ 3,447,159	$ 3,478,076	$ 3,693,927	1.
2.	Fuel and purchased power	1,046,815	985,439	1,028,986	1,057,135	1,042,104	1,066,762	2.
3.	Operating revenues less fuel and purchased power	2,133,992	2,257,030	2,364,559	2,390,024	2,435,972	2,627,165	3.
	Other Operating Expenses:							
4.	Operations and maintenance excluding fuel and purchased power *	900,372	963,110	999,277	1,079,398	1,017,251	1,088,409	4.
5.	Depreciations and Amortization	406,632	421,726	403,998	400,376	404,136	440,345	5.
6.	Income taxes	175,440	192,641	230,798	193,377	253,878	273,496	6.
7.	Other taxes	134,467	153,869	174,918	194,124	174,953	194,124	7.
8.	Operating income	517,081	525,684	555,568	522,749	585,754	630,791	8.
	Other Income (Deductions):							
9.	Income taxes	4,975	4,410	8,245	11,237	8,272	11,385	9.
10.	Allowance for equity funds used during construction	22,066	26,691	24,505	23,277	24,490	23,276	10.
11.	Other income	8,956	5,036	2,163	1,740	2,094	1,367	11.
12.	Other expenses	(15,859)	(15,664)	(16,973)	(19,692)	(16,973)	(19,693)	12.
13.	Total	20,138	20,473	17,940	16,562	17,883	16,335	13.
14.	Income Before Interest Deductions	537,219	546,157	573,508	539,311	603,637	647,126	14.
	Interest Deductions							
15.	Interest on long-term debt	205,209	214,337	215,357	240,818	209,732	226,870	15.
16.	Interest on short-term borrowings	8,267	6,007	8,120	8,474	8,593	7,815	16.
17.	Debt discount, premium and expense	4,559	4,584	3,683	3,854	3,655	3,788	17.
18.	Allowance for borrowed funds used during construction	(16,479)	(17,437)	(22,760)	(23,322)	(22,746)	(23,322)	18.
19.	Total	201,556	207,491	204,400	229,824	199,234	215,151	19.
20.	Net Income	$ 335,663	$ 338,666	$ 369,108	$ 309,487	$ 404,403	$ 431,975	20.
21.	Earnings per Share of Average Common Stock Outstanding **	$ 4.71	N/A	N/A	N/A	N/A	N/A	21.
22.	% Return on Average Common Equity	9.3%	8.8%	9.1%	7.1%	10.0%	9.7%	22.
23.	Average Common Equity	3,627,930	3,870,226	4,047,880	4,344,738	4,057,279	4,438,602	23.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs..
** Optional for projected years. Line 22 is calculated using the common stock shares of Arizona Public Service Company. APS's common stock shares have remained constant at 71.3 million, even though Pinnacle West has increased its equity investment in APS, and are wholly owned by Pinnacle West Capital Corporation. Pinnacle West's common stock is publicly held and the PNW share count is more indicative of the increasing equity investment needed to support APS's investment to serve its customers. APS's earnings per share of Pinnacle West diluted common stock outstanding was $3.13 for the Test Year ended 12/31/10.

Supporting Schedules:
(a) E-2

Recap Schedules:
(b) A-2

F-2

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED CHANGES IN FINANCIAL POSITION
PRESENT RATES AND WITH PROPOSED RATE INCREASE
TEST YEAR ENDED 12/31/2010 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Test Year (a) Actual Year Ended 12/31/2010 (A)	Projected Years (b) Present Rates Year Ended 12/31/2011 (B)	Present Rates Year Ended 12/31/2012 (C)	Present Rates Year Ended 12/31/2013 (D)	Proposed Rates Year Ended 12/31/2012 (E)	Proposed Rates Year Ended 12/31/2013 (F)	Line No.
	Cash Flows from Operations							
1.	Net Income	$ 335,663	$ 338,666	$ 369,108	$ 309,487	$ 404,403	$ 431,975	1.
	Items Not Requiring Cash:							
2.	Depreciation and amortization including nuclear fuel	463,522	490,261	478,637	473,559	478,775	513,527	2.
3.	Allowance for equity funds used during construction	(22,066)	(26,691)	(24,505)	(23,277)	(24,505)	(23,277)	3.
4.	Deferred income taxes	224,095	202,746	186,282	170,639	209,335	250,610	4.
5.	Changes in mark-to-market valuations	2,688	-	-	-	-	-	5.
6.	Deferred fuel and purchased power	93,631	96,208	141,728	131,667	70,343	7,637	6.
7.	Deferred fuel and purchased power amortization	(122,481)	(164,878)	(147,350)	(138,683)	(63,644)	(6,458)	7.
8.	Other	(316,903)	249,287	113,845	(58,859)	130,830	(47,159)	8.
9.	Net cash provided	658,149	1,185,600	1,117,745	864,531	1,205,538	1,126,856	9.
	Cash Flow from Investing Activities:							
10.	Capital expenditures (c) *	(747,967)	(952,102)	(1,348,730)	(961,416)	(1,339,430)	(961,416)	10.
11.	Contributions in aid of construction	32,754	-	-	-	-	-	11.
12.	Allowance for borrowed funds used during construction	(16,479)	(17,437)	(22,760)	(23,322)	(22,746)	(23,322)	12.
13.	Proceeds from nuclear decommissioning trust sales	560,469	-	-	-	-	-	13.
14.	Investment in nuclear decommissioning trust	(584,885)	(24,304)	(21,372)	(21,372)	(21,457)	(21,457)	14.
15.	Other	8,576	53,400	(110,000)	-	(110,000)	-	15.
16.	Net cash used	(747,532)	(940,444)	(1,502,862)	(1,006,111)	(1,493,633)	(1,006,194)	16.
	Cash Flows from Financing:							
17.	Issuance of long-term debt	-	400,000	600,000	375,000	550,000	125,000	17.
18.	Short-term borrowings and payments-net	-	-	31,833	13,875	-	1,920	18.
19.	Equity infusion	252,833	-	250,000	-	250,000	-	19.
20.	Dividends paid on common stock	(182,400)	(230,598)	(236,189)	(247,286)	(235,972)	(246,360)	20.
21.	Repayment and reacquisition of long-term debt	(1,911)	(400,000)	(375,000)	-	(375,000)	-	21.
22.	Net cash provided	68,522	(230,598)	270,645	141,590	189,028	(119,440)	22.
23.	Net increase (decrease) in cash and cash equivalents	(20,861)	14,558	(114,473)	10	(99,067)	1,221	23.
24.	Cash and cash equivalents at beginning of period	120,798	99,937	114,495	22	114,495	15,428	24.
25.	Cash and cash equivalents at end of period	$ 99,937	$ 114,495	$ 22	$ 33	$ 15,428	$ 16,649	25.

Notes:
* Years 2011, 2012, and 2013 capital expenditures and CIAC are combined on the Capital expenditures line

Supporting Schedules:
(a) E-3
(c) F-3

Recap Schedules:
(b) A-5

F-3

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED CAPITAL EXPENDITURES
TEST YEAR ENDED 12/31/2010 AND PROJECTED YEARS
(Thousands of Dollars)

Line No.	Description	Year to Date Year Ended 12/31/2010 (A)	Projected Years * Year Ended 12/31/2011 (B)	Year Ended 12/31/2012 (C)	Year Ended 12/31/2013 (D)	Line No.
	Electric:					
1.	Production Plant:	$ 251,517	$ 439,806	$ 708,085	$ 376,221	1.
2.	Transmission:	119,611	135,358	206,744	233,398	2.
3.	Distribution:	230,647	241,650	273,226 **	237,612	3.
4.	General:	62,483	132,753	148,611	111,284	4.
5.	Total Construction Expenditures (a)	664,258	949,567	1,336,666 ***	958,515	5.
6.	Property Taxes Capitalized	2,186	2,536	2,764	2,902	6.
7.	Capital Expenditures (b)	666,444	952,103	1,339,430	961,417	7.
8.	Allowance for Equity Funds Used During Construction	22,066	26,691	24,490	23,276	8.
9.	Allowance for Borrowed Funds Used During Construction	16,479	17,437	22,746	23,322	9.
10.	Total Capital Expenditures with AFUDC	$ 704,989	$ 996,231	$ 1,386,666	$ 1,008,015	10.

Notes:
* Years 2012 and 2013 have been reduced for Schedule 3 fees recorded as CIAC.
** 2012 construction expenditures are higher for present rates due to the current treatment of Schedule 3 proceeds through 12/31/12.
*** Includes $294M purchase of SCE share of Four Corners Units 4 and 5.

Supporting Schedules:
N/A

Recap Schedules:
(a) A-4
(b) F-2

F-4

ARIZONA PUBLIC SERVICE COMPANY
ASSUMPTIONS USED IN DEVELOPING PROJECTIONS
TEST YEAR ENDED 12/31/2010

Line No.	Item		Line No.
	A.	Customer Growth:	
1.		Retail customer growth for the period 2011-2013 is forecast to grow at an annual average rate of 1.7%.	1.
	B.	Growth in Retail Energy and Retail Peak Demand	
2.		Retail energy sales, assuming normal weather, for the period 2011 to 2013 are forecast to grow at an annual average rate	2.
3.		of 0.4%. Retail Own Load summer peak demand for the same period is projected to grow at an annual average rate of 0.8%,	3.
4.		assuming normal weather. Sales growth also reflects the impact of the company's EE and DE programs.	4.
	C.	Wholesale and Economy Interchange Sales	
5.		Firm wholesale sales and peak demand for requirement-to-serve customers are forecast per existing contracts. The	5.
6.		Company sells energy on an economy interchange basis on a short-term basis from time to time. Such sales are made	6.
7.		at prices above the Company's variable costs to generate energy.	7.
	D.	Base Fuel Charge and PSA Revenues	
8.		Base Fuel Charge reflects 3.7571 cents/kWh in 2011 to 2013 consistent with Decision No. 71448. Forecast further assumes	8.
9.		PSA Annual Adjustor mechanisms are in effect and a new Forward Adjustor is set each year reflecting that year's anticipated	9.
10.		fuel and purchased power costs in excess of the Base Fuel Rate. The Forward Adjustor is reset annually with the first billing	10.
11.		cycle in February. Starting July 1, 2012 consistent with a 5.2% base rate decrease the Base Fuel Rate decreases	11.
12.		to 3.2514 cents/kWh in the Proposed Rates forecast.	12.
	E.	Fuel	
13.		Fuel costs are based on projected sales, forward contract and market fuel prices and projected operating availability factors	13.
14.		of power plants. Fuel costs reflect use of the PSA cost deferral and annual adjustor recovery mechanism approved in	14.
15.		Decision No. 71448 in present rates case.	15.
	F.	Operations & Maintenance Expenses	
16.		Growth in Operational O&M expenses managed to the rate of retail sales growth, before the impacts of EE and DE.	16.
	G.	Construction Expenditures	
17.		The level of expenditures is primarily driven by customer, sales, and load growth, maintaining reliability, legal and regulatory	17.
18.		requirements, including environmental requirements and Arizona Sun program. Contributions in aid of construction (CIAC)	18.
19.		are normally used to reduce capital expenditures. Consistent with Decision No. 71448 proceeds collected under Schedule 3 related	19.
20.		to line extension policy are treated as revenues beginning in January 1, 2010 thru June 30, 2012 in proposed rates forecast	20.
22.		and separately thru December 31, 2012 in present rates forecast. See SFR Schedule F-3 for expenditure table.	22.
	H.	Capital Structure Changes	
23.		Capital Structure and Financing are shown on Schedules A-3, D-1, D-2, D-3 and F-2.	23.
	I.	Financing and Regulatory	
24.		Forecast Interest Rates:	24.
25.		Variable Rate Pollution Control Bonds - 0.85% in 2011, 1.20% in 2012, 1.73% in 2013	25.
26.		Commercial Paper - 1.0% in 2011, 1.5% in 2012, 2.25% in 2013	26.
27.		New Long-Term Unsecured Debt - 5.75% in 2011, 6.75% in 2012, 7.25% in 2013	27.
28.		Pinnacle West decides and is able to issue $250 million of common stock in 2012 and infuse the net proceeds into APS.	28.
29.		The proposed rates case assumes rates are effective on July 1, 2012.	29.
30.		The Commission allows APS to adopt increases to the TCA rate charged to retail customers once approved by the FERC.	30.

G-1

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE SUMMARY - *PRESENT RATES*
RATES OF RETURN BY CUSTOMER CLASSIFICATION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Base Rates	$ 2,952,323	$ 2,868,858 (a)	$ 83,465	$ 1,470,134 (a)	$ 1,342,599 (a)	$ 26,669 (a)	$ 20,999 (a)	$ 8,457 (a)
1.b.	Revenues from Surcharges	-	-	-	-	-	-	-	-
1.c.	Other Electric Revenues	136,850	121,013	15,837	61,675	56,526	1,216	1,167	429
2.	Expenses	2,315,888	2,315,059 (b)	829	1,253,698 (b)	1,016,830 (b)	24,199 (b)	15,449 (b)	4,883 (b)
3.	Operating Income Before Income Taxes	773,285	674,812	98,473	278,111	382,295	3,686	6,717	4,003
4.	Income Taxes	226,357	200,456	25,901	70,246	126,158	920	1,875	1,257
5.	Net Operating Income	$ 546,928	$ 474,356	$ 72,572	$ 207,865	$ 256,137	$ 2,766	$ 4,842	$ 2,746
6.	Rate Base	$ 6,843,849	$ 5,720,277 (c)	$ 1,123,572	$ 3,419,731 (c)	$ 2,159,417 (c)	$ 45,658 (c)	$ 67,341 (c)	$ 28,130 (c)
7.	Rate of Return	7.99%	8.29%	6.46%	6.08%	11.86%	6.06%	7.19%	9.76%

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

G-2

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE SUMMARY - *PROPOSED RATES*
RATES OF RETURN BY CUSTOMER CLASSIFICATION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Base Rates	$ 3,006,933	$ 2,923,468	$ 83,465	$ 1,503,364	$ 1,362,848	$ 27,221	$ 21,436	$ 8,599
1.b.	Revenues from Surcharges	-	-	-	-	-	-	-	-
1.c.	Other Electric Revenues	136,850	121,013	15,837	61,675	56,526	1,216	1,167	429
2.	Expenses	2,315,888	2,315,059 (b)	829	1,253,698 (b)	1,016,830 (b)	24,199 (b)	15,449 (b)	4,883 (b)
3.	Operating Income Before Income Taxes	827,895	729,422	98,473	311,341	402,544	4,238	7,154	4,145
4.	Income Taxes	247,933	222,032	25,901	83,375	134,158	1,138	2,048	1,313
5.	Net Operating Income	$ 579,962	$ 507,390	$ 72,572	$ 227,966	$ 268,386	$ 3,100	$ 5,106	$ 2,832
6.	Rate Base	$ 6,843,849	$ 5,720,277 (c)	$ 1,123,572	$ 3,419,731 (c)	$ 2,159,417 (c)	$ 45,658 (c)	$ 67,341 (c)	$ 28,130 (c)
7.	Rate of Return	8.47%	8.87%	6.46%	6.67%	12.43%	6.79%	7.58%	10.07%

Schedule H-1 Base Revenue Reconciliation

		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
8.	Revenues from Present Rates	$ 2,952,323	$ 2,868,858	$ 83,465	$ 1,470,134	$ 1,342,599	$ 26,669	$ 20,999	$ 8,457
9.	Revenue Increase from Proposed Rates (excluding Fair Value)*	54,610	54,610	-	33,230	20,249	552	437	142
10.	Revenue Increase from Fair Value	40,883	40,883	-	24,874	15,164	414	324	107
11.	Subtotal of Revenue Increase	95,493	95,493	-	58,104	35,413	966	761	249
12.	Total Proposed Base Revenues	$ 3,047,816	$ 2,964,351 (a)	$ 83,465	$ 1,528,238 (a)	$ 1,378,012 (a)	$ 27,635 (a)	$ 21,760 (a)	$ 8,706

Notes:
* Proposed Rates allocated based on Total Proposed Increase - Column (c) Schedule H-1.

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

Recap Schedules:
N/A

G-3

ARIZONA PUBLIC SERVICE COMPANY
RATE BASE ALLOCATIONS TO CLASSES OF SERVICE
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	$ 1,397,049	$ -	$ -	$ 170,518	$ 191,949	$ 108,260	$ 733,772	$ 285,304	$ 2,886,852	58.77%	$ 16,693	48.21%
2.	General Service	1,125,777	-	-	125,477	141,248	0	441,782	123,330	1,957,614	39.85%	17,333	50.07%
3.	Water Pumping	32,712	-	-	4,008	4,512	0	0	1,378	42,610	0.87%	391	1.13%
4.	Street Lighting	11,436	-	-	1,277	1,437	477	5,083	1,258	20,968	0.43%	172	0.50%
5.	Dusk to Dawn	2,128	-	-	235	265	88	937	231	3,884	0.08%	31	0.09%
6.	Total	$ 2,569,102 (b)(c)	$ -	$ -	$ 301,515 (b)(c)	$ 339,411 (b)(c)	$ 108,825 (b)(c)	$ 1,181,574 (b)(c)	$ 411,501 (b)(c)	$ 4,911,928	100.00%	$ 34,620 (b)(c)	100.00%

	Class of Service	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
7.	Residential	$ (101,918)	$ 35,868	$ 130,563	$ 96,157	$ 9,284	$ -	$ -	$ (1,946)	$ 1,563	$ 169,571	86.80%
8.	General Service	(82,753)	4,950	14,368	26,524	1,145	-	-	(240)	193	(35,813)	-18.33%
9.	Water Pumping	(4,242)	310	-	759	14	-	-	(3)	2	(3,160)	-1.62%
10.	Street Lighting	(631)	-	-	-	9	-	42,570	(2)	2	41,948	21.47%
11.	Dusk to Dawn	(186)	-	-	-	78	22,920	-	(16)	13	22,809	11.68%
12.	Total	$ (189,730) (b)(c)	$ 41,128 (b)(c)	$ 144,931 (b)(c)	$ 123,440 (b)(c)	$ 10,530 (b)(c)	$ 22,920 (b)(c)	$ 42,570 (b)(c)	$ (2,207) (b)(c)	$ 1,773 (b)(c)	$ 195,355	100.00%

	Class of Service	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)	TOTAL ACC JURIS. %
		(A)	(B)	(C)	(D)	(E)	(F)
13.	Residential	$ 346,615	59.92%	$ -	0.00%	$ 3,419,731	59.78%
14.	General Service	220,283	38.09%	-	0.00%	2,159,417	37.75%
15.	Water Pumping	5,817	1.01%	-	0.00%	45,658	0.80%
16.	Street Lighting	4,253	0.74%	-	0.00%	67,341	1.18%
17.	Dusk to Dawn	1,406	0.24%	-	0.00%	28,130	0.49%
18.		$ 578,374 (b)(c)	100.00%	$ -	0.00%	$ 5,720,277	100.00%

Supporting Schedules:
(b) G-5
(c) G-7

Recap Schedules:
(a) G-1 & G-2

G-4

ARIZONA PUBLIC SERVICE COMPANY
EXPENSE ALLOCATION TO CLASSES OF SERVICE
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	$ 309,906	$ -	$ 67,694	$ 7,091	$ 31,190	$ 17,978	$ 74,627	$ 23,668	$ 532,154	56.17%	$ 545,638	48.08%
2.	General Service	249,730	-	58,844	13,073	22,952	-	44,930	10,260	399,789	42.19%	570,534	50.27%
3.	Water Pumping	7,256	-	2,069	418	733	-	-	111	10,587	1.12%	12,635	1.11%
4.	Street Lighting	2,537	-	590	133	234	79	519	104	4,196	0.44%	5,267	0.46%
5.	Dusk to Dawn	472	-	104	24	43	15	94	20	772	0.08%	923	0.08%
6.	Total	$ 569,901 (a)(b)	$ - (a)(b)	$ 129,301 (a)(b)	$ 20,739 (a)(b)	$ 55,152 (a)(b)	$ 18,072 (a)(b)	$ 120,170 (a)(b)	$ 34,163 (a)(b)	$ 947,498	100.00%	$ 1,134,997 (a)(b)	100.00%

	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
7.	Residential	$ 5,974	$ 13,328	$ 37,547	$ 80,586	$ -	$ -	$ 5,471	$ 12,341	$ 155,247	81.95%
8.	General Service	825	1,467	10,357	9,940	-	-	675	1,522	24,786	13.08%
9.	Water Pumping	52	-	296	120	-	-	8	18	494	0.26%
10.	Street Lighting	-	-	-	78	-	5,676	5	12	5,771	3.05%
11.	Dusk to Dawn	-	-	-	677	2,322	-	46	104	3,149	1.66%
12.	Total	$ 6,851 (a)(b)	$ 14,795 (a)(b)	$ 48,200 (a)(b)	$ 91,401 (a)(b)	$ 2,322 (a)(b)	$ 5,676 (a)(b)	$ 6,205 (a)(b)	$ 13,997 (a)(b)	$ 189,447	100.00%

	Class of Service	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (c)	TOTAL ACC JURIS. %
		(A)	(B)	(C)	(D)	(E)	(F)
13.	Residential	$ (1,159)	54.39%	$ 21,818	48.22%	$ 1,253,698	54.15%
14.	General Service	(934)	43.83%	22,655	50.06%	1,016,830	43.92%
15.	Water Pumping	(27)	1.27%	510	1.13%	24,199	1.05%
16.	Street Lighting	(9)	0.42%	224	0.50%	15,449	0.67%
17.	Dusk to Dawn	(2)	0.09%	41	0.09%	4,883	0.21%
18.	Total	$ (2,131) (a)(b)	100.00%	$ 45,248 (a)(b)	100.00%	$ 2,315,059	100.00%

Supporting Schedules:
(a) G-6
(b) G-7

Recap Schedules:
(c) G-1 & G-2

G-5

ARIZONA PUBLIC SERVICE COMPANY
DISTRIBUTION OF RATE BASE BY FUNCTION
TOTAL RATE BASE
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	$ 2,569,102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,569,102	52.29%
2.	Transmission Substation	-	-	-	-	-	-	-	-	-	0.00%
3.	Transmission Lines	-	-	-	-	-	-	-	-	-	0.00%
4.	Distribution Substation	-	-	-	301,515	-	-	-	-	301,515	6.14%
5.	Distribution OH Primary	-	-	-	-	339,411	-	-	-	339,411	6.91%
6.	Distribution OH Secondary	-	-	-	-	-	108,825	-	-	108,825	2.22%
7.	Distribution UG Lines	-	-	-	-	-	-	1,181,574	-	1,181,574	24.06%
8.	Distribution Line TXFs	-	-	-	-	-	-	-	411,501	411,501	8.38%
9.	Total	$ 2,569,102	$ -	$ -	$ 301,515	$ 339,411	$ 108,825	$ 1,181,574	$ 411,501	$ 4,911,928	100.00%

	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
10.	Cust. Advances & Deposit	$ (189,730)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (189,730)	-97.12%
11.	Distribution OH Services	-	41,128	-	-	-	-	-	-	-	41,128	21.05%
12.	Distribution UG Services	-	-	144,931	-	-	-	-	-	-	144,931	74.19%
13.	Distribution Meters	-	-	-	123,440	-	-	-	-	-	123,440	63.19%
14.	Customer Accounts	-	-	-	-	10,530	-	-	-	-	10,530	5.39%
15.	Dusk to Dawn	-	-	-	-	-	22,920	-	-	-	22,920	11.73%
16.	Street Lighting	-	-	-	-	-	-	42,570	-	-	42,570	21.79%
17.	Customer Service & Info	-	-	-	-	-	-	-	(2,207)	-	(2,207)	-1.13%
18.	Sales	-	-	-	-	-	-	-	-	1,773	1,773	0.91%
19.	Total	$ (189,730)	$ 41,128	$ 144,931	$ 123,440	$ 10,530	$ 22,920	$ 42,570	$ (2,207)	$ 1,773	$ 195,355	100.00%

	Plant Classification	Total Energy	Total Energy %	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
20.	Production - Energy	$ 34,620	100.00%	$ -	-	$ -	-	$ -
21.	Regulatory Assets	-	-	578,374	100.00%	-	-	-
22.	System Benefits	-	-	-	-	-	100.00%	-
23.	TOTAL ACC							$ 5,720,277

Supporting Schedules:
N/A

Recap Schedules:
(a) G-3

G-6

ARIZONA PUBLIC SERVICE COMPANY
DISTRIBUTION OF EXPENSES BY FUNCTION
OPERATING EXPENSES EXCLUDING INCOME TAXES
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	$ 569,901	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 569,901	60.14%
2.	Transmission Substation	-	-	-	-	-	-	-	-	-	0.00%
3.	Transmission Lines	-	-	129,301	-	-	-	-	-	129,301	13.65%
4.	Distribution Substation	-	-	-	20,739	-	-	-	-	20,739	2.19%
5.	Distribution OH Primary	-	-	-	-	55,152	-	-	-	55,152	5.82%
6.	Distribution OH Secondary	-	-	-	-	-	18,072	-	-	18,072	1.91%
7.	Distribution UG Lines	-	-	-	-	-	-	120,170	-	120,170	12.68%
8.	Distribution Line TXFs	-	-	-	-	-	-	-	34,163	34,163	3.61%
9.	Total	$ 569,901	$ -	$ 129,301	$ 20,739	$ 55,152	$ 18,072	$ 120,170	$ 34,163	$ 947,498	100.00%

	Plant Classification	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
10.	Distribution OH Services	$ 6,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,851	3.62%
11.	Distribution UG Services	-	14,795	-	-	-	-	-	-	14,795	7.81%
12.	Distribution Meters	-	-	48,200	-	-	-	-	-	48,200	25.43%
13.	Customer Accounts	-	-	-	91,401	-	-	-	-	91,401	48.24%
14.	Dusk to Dawn	-	-	-	-	2,322	-	-	-	2,322	1.23%
15.	Street Lighting	-	-	-	-	-	5,676	-	-	5,676	3.00%
16.	Customer Service & Info	-	-	-	-	-	-	6,205	-	6,205	3.28%
17.	Sales	-	-	-	-	-	-	-	13,997	13,997	7.39%
18.	Total	$ 6,851	$ 14,795	$ 48,200	$ 91,401	$ 2,322	$ 5,676	$ 6,205	$ 13,997	$ 189,447	100.00%

	Plant Classification	Total Production - Energy	Total Energy %	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
19.	Production - Energy	$ 1,134,997	100.00%	$ -	-	$ -	-	$ -
20.	Regulatory Assets	-	-	(2,131)	100.00%	-	-	-
21.	System Benefits	-	-	-	-	45,248	100.00%	-
22.	TOTAL ACC							$ 2,315,059

Supporting Schedules:
N/A

Recap Schedules:
(a) G-4

G-7

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Total Retail (D)	Residential (E)	General Service (F)	E-221 (Water Pumping) (G)	Street Lighting (H)	Dusk to Dawn (I)
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	1.0000	0.9660	0.0340	0.9660	0.5253	0.4233	0.0123	0.0043	0.0008
	Production Demand	100.00%	96.60%	3.40%	96.60%	52.53%	42.33%	1.23%	0.43%	0.08%
2. DEMPROD6	Specific Assignment	100	0	100	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Substation	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Lines	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMTRAN4	Specific Assignment	100	0	100	0	0	0	0	0	0
	SCE Specific	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	8,276,369	8,276,369	0	8,276,369	4,680,596	3,444,261	110,011	35,051	6,450
	Distribution Substation	100.00%	100.00%	0.00%	100.00%	56.55%	41.62%	1.33%	0.42%	0.08%
7. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	8,113,051	8,113,051	0	8,113,051	4,588,234	3,376,295	107,840	34,359	6,323
	Distribution OH Primary Lines	100.00%	100.00%	0.00%	100.00%	56.55%	41.62%	1.33%	0.42%	0.08%
8. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,433,779	7,433,779	0	7,433,779	7,395,179	0	0	32,600	6,000
	Distribution OH Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.48%	0.00%	0.00%	0.44%	0.08%
9. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	8,005,211	8,005,211	0	8,005,211	4,588,234	3,376,295	0	34,359	6,323
	Distribution UG Primary Lines	100.00%	100.00%	0.00%	100.00%	57.32%	42.17%	0.00%	0.43%	0.08%
10. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,433,779	7,433,779	0	7,433,779	7,395,179	0	0	32,600	6,000
	Distribution UG Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.48%	0.00%	0.00%	0.44%	0.08%
11. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	10,518,587	10,518,587	0	10,518,587	7,765,086	2,541,612	171,358	34,231	6,300
	Distribution OH Line Transformers	100.00%	100.00%	0.00%	100.00%	73.82%	24.16%	1.63%	0.33%	0.06%
12. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	11,390,711	11,390,711	0	11,390,711	7,765,086	3,585,094	0	34,231	6,300
	Distribution UG Line Transformers	100.00%	100.00%	0.00%	100.00%	68.17%	31.47%	0.00%	0.30%	0.06%
13. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	452,792	452,792	0	452,792	394,882	54,498	3,412	0	0
	Distribution OH Services	100.00%	100.00%	0.00%	100.00%	87.22%	12.03%	0.75%	0.00%	0.00%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Total Retail (D)	Residential (E)	General Service (F)	E-221 (Water Pumping) (G)	Street Lighting (H)	Dusk to Dawn (I)
14. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	667,738	667,738	0	667,738	601,540	66,198	0	0	0
	Distribution UG Services	100.00%	100.00%	0.00%	100.00%	90.10%	9.90%	0.00%	0.00%	0.00%
15. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	8,113,051	8,113,051	0	8,113,051	4,588,234	3,376,295	107,840	34,359	6,323
	Distribution Rents	100.00%	100.00%	0.00%	100.00%	56.55%	41.62%	1.33%	0.42%	0.08%
16. ENERGY1	Customer Class Energy @ Generation (MWH)	30,040,123	29,310,983	729,140	29,310,983	14,132,767	14,675,166	331,078	145,323	26,649
	Production - Energy	100.00%	97.57%	2.43%	97.57%	47.04%	48.86%	1.10%	0.48%	0.09%
17. ENERGY2	Weighted Hourly Energy Allocator @ Generation	100.00	97.57	2.43	97.57	47.21	48.74	1.09	0.45	0.08
	Production - Energy (Fuel and Purchased Power)	100.00%	97.57%	2.43%	97.57%	47.21%	48.74%	1.09%	0.45%	0.08%
18. CUST370	Weighted Costs for Distribution Meters ($)	1,287,002	1,279,139	7,863	1,279,139	996,422	274,853	7,864	0	0
	Distribution Meters	100.00%	99.39%	0.61%	99.39%	77.41%	21.37%	0.61%	0.00%	0.00%
19. CUST371	Dusk to Dawn Customer Class Specific	1	1	0	1	0	0	0	0	1
	Dusk to Dawn	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
20. CUST373	Street Lighting Customer Class Specific	1	1	0	1	0	0	0	1	0
	Street Lighting	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%
21. CUSTNUM	Number of Customer Accounts	1,131,675	1,130,151	1,524	1,130,151	996,422	122,909	1,481	963	8,376
	Customer Accounts	100.00%	99.87%	0.13%	99.87%	88.06%	10.85%	0.13%	0.09%	0.74%
22. CUST910	Number of Customer Accounts	1,130,151	1,130,151	0	1,130,151	996,422	122,909	1,481	963	8,376
	Customer Service and Information	100.00%	100.00%	0.00%	100.00%	88.17%	10.87%	0.13%	0.09%	0.74%
23. CUST916	Number of Customer Accounts	1,131,675	1,130,151	1,524	1,130,151	996,422	122,909	1,481	963	8,376
	Sales Expense	100.00%	99.87%	0.13%	99.87%	88.06%	10.85%	0.13%	0.09%	0.74%
24. DEMREGAST	Average & Excess @ Generation - Retail [4CP Juris.]	1.0000	0.9660	0.0340	0.9660	0.5253	0.4233	0.0123	0.0043	0.0008
	Regulatory Asset - Demand Related	100.00%	96.60%	3.40%	96.60%	52.53%	42.33%	1.23%	0.43%	0.08%
25. ERGREGAST	Customer Class Energy @ Generation (MWH)	30,040,123	29,310,983	729,140	29,310,983	14,132,767	14,675,166	331,078	145,323	26,649
	Regulatory Asset - Energy Related	100.00%	97.57%	2.43%	97.57%	47.04%	48.86%	1.10%	0.48%	0.09%
26. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	30,040,123	29,310,983	729,140	29,310,983	14,132,767	14,675,166	331,078	145,323	26,649
	System Benefits - Energy Related	100.00%	97.57%	2.43%	97.57%	47.04%	48.86%	1.10%	0.48%	0.09%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	General Service (J)	E-20 (Church Rate) General Service (K)	Time-of-Use (0 - 100 kW) General Service (L)	Time-of-Use (101 - 400 kW) General Service (M)	Time-of-Use (401+ kW) General Service (N)	E-30, E-32 (0 - 100 kW) General Service (O)	E-32 (101 - 400 kW) General Service (P)	E-32 (401+ kW) General Service (Q)	E-34 General Service (R)	E-35 General Service (S)
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	0.4233	.0019	.0011	.0016	.0067	.1520	.1043	.0960	.0255	.0342
	Production Demand	42.33%	0.19%	0.11%	0.16%	0.67%	15.20%	10.43%	9.60%	2.55%	3.42%
2. DEMPROD6	Specific Assignment	0	0	0	0	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0	0	0	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0	0	0	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMTRAN4	Specific Assignment	0	0	0	0	0	0	0	0	0	0
	SCE Specific	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	3,444,261	18,693	7,884	12,417	48,609	1,358,447	880,493	764,538	187,237	165,943
	Distribution Substation	41.62%	0.23%	0.10%	0.15%	0.59%	16.40%	10.64%	9.24%	2.26%	2.01%
7. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	3,376,295	18,324	7,728	12,172	47,649	1,331,641	863,119	749,452	183,542	162,668
	Distribution OH Primary Lines	41.62%	0.23%	0.10%	0.15%	0.59%	16.40%	10.64%	9.24%	2.26%	2.01%
8. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0
	Distribution OH Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	3,376,295	18,324	7,728	12,172	47,649	1,331,641	863,119	749,452	183,542	162,668
	Distribution UG Primary Lines	42.17%	0.23%	0.10%	0.15%	0.60%	16.63%	10.78%	9.36%	2.29%	2.03%
10. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0
	Distribution UG Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
11. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,541,612	23,493	10,431	14,785	0	1,875,664	617,239	0	0	0
	Distribution OH Line Transformers	24.16%	0.22%	0.10%	0.14%	0.00%	17.83%	5.87%	0.00%	0.00%	0.00%
12. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,585,094	23,493	10,431	14,785	47,882	1,875,664	617,239	818,242	64,084	113,274
	Distribution UG Line Transformers	31.47%	0.21%	0.09%	0.13%	0.42%	16.47%	5.42%	7.18%	0.56%	0.99%
13. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	54,498	157	147	72	0	53,220	902	0	0	0
	Distribution OH Services	12.03%	0.03%	0.03%	0.02%	0.00%	11.75%	0.20%	0.00%	0.00%	0.00%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	General Service (J)	E-20 (Church Rate) General Service (K)	Time-of-Use (0 - 100 kW) General Service (L)	Time-of-Use (101 - 400 kW) General Service (M)	Time-of-Use (401+ kW) General Service (N)	E-30, E-32 (0 - 100 kW) General Service (O)	E-32 (101 - 400 kW) General Service (P)	E-32 (401+ kW) General Service (Q)	E-34 General Service (R)	E-35 General Service (S)
14. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	66,198	162	152	80	136	54,988	4,533	2,997	1,266	1,884
	Distribution UG Services	9.90%	0.02%	0.02%	0.01%	0.02%	8.23%	0.68%	0.45%	0.19%	0.28%
15. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	3,376,295	18,324	7,728	12,172	47,649	1,331,641	863,119	749,452	183,542	162,668
	Distribution Rents	41.62%	0.23%	0.10%	0.15%	0.59%	16.40%	10.64%	9.24%	2.26%	2.01%
16. ENERGY1	Customer Class Energy @ Generation (MWH)	14,675,166	36,862	47,810	73,603	311,326	4,129,250	3,449,673	3,732,824	1,140,125	1,753,693
	Production - Energy	48.86%	0.12%	0.16%	0.25%	1.04%	13.75%	11.47%	12.43%	3.80%	5.84%
17. ENERGY2	Weighted Hourly Energy Allocator @ Generation	48.74	0.12	0.16	0.24	1.02	13.82	11.52	12.38	3.76	5.72
	Production - Energy (Fuel and Purchased Power)	48.74%	0.12%	0.16%	0.24%	1.02%	13.82%	11.52%	12.38%	3.76%	5.72%
18. CUST370	Weighted Costs for Distribution Meters ($)	274,853	2,055	1,231	480	783	227,493	28,562	10,109	2,263	1,877
	Distribution Meters	21.37%	0.16%	0.10%	0.04%	0.06%	17.67%	2.22%	0.79%	0.18%	0.15%
19. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21. CUSTNUM	Number of Customer Accounts	122,909	344	323	79	50	116,484	4,515	1,042	35	37
	Customer Accounts	10.85%	0.03%	0.03%	0.01%	0.00%	10.29%	0.40%	0.09%	0.00%	0.00%
22. CUST910	Number of Customer Accounts	122,909	344	323	79	50	116,484	4,515	1,042	35	37
	Customer Service and Information	10.87%	0.03%	0.03%	0.01%	0.00%	10.31%	0.40%	0.09%	0.00%	0.00%
23. CUST916	Number of Customer Accounts	122,909	344	323	79	50	116,484	4,515	1,042	35	37
	Sales Expense	10.85%	0.03%	0.03%	0.01%	0.00%	10.29%	0.40%	0.09%	0.00%	0.00%
24. DEMREGAST	Average & Excess @ Generation - Retail [4CP Juris.]	0.4233	.0019	.0011	.0016	.0067	.1520	.1043	.0960	.0255	.0342
	Regulatory Asset - Demand Related	42.33%	0.19%	0.11%	0.16%	0.67%	15.20%	10.43%	9.60%	2.55%	3.42%
25. ERGREGAST	Customer Class Energy @ Generation (MWH)	14,675,166	36,862	47,810	73,603	311,326	4,129,250	3,449,673	3,732,824	1,140,125	1,753,693
	Regulatory Asset - Energy Related	48.86%	0.12%	0.16%	0.25%	1.04%	13.75%	11.47%	12.43%	3.80%	5.84%
26. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	14,675,166	36,862	47,810	73,603	311,326	4,129,250	3,449,673	3,732,824	1,140,125	1,753,693
	System Benefits - Energy Related	48.86%	0.12%	0.16%	0.25%	1.04%	13.75%	11.47%	12.43%	3.80%	5.84%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	Residential (T)	Residential E-12 (U)	Residential ET-1 & ET-2 (V)	Residential ECT-1 & ECT-2 (W)
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	0.5253	.1491	.2867	.0895
	Production Demand	52.53%	14.91%	28.67%	8.95%
2. DEMPROD6	Specific Assignment	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%
5. DEMTRAN4	Specific Assignment	0	0	0	0
	SCE Specific	0.00%	0.00%	0.00%	0.00%
6. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	4,680,596	1,303,191	2,585,218	792,187
	Distribution Substation	56.55%	15.75%	31.23%	9.57%
7. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	4,588,234	1,277,475	2,534,204	776,555
	Distribution OH Primary Lines	56.55%	15.75%	31.23%	9.57%
8. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,395,179	2,393,931	3,907,050	1,094,198
	Distribution OH Secondary Lines	99.48%	32.20%	52.56%	14.72%
9. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	4,588,234	1,277,475	2,534,204	776,555
	Distribution UG Primary Lines	57.32%	15.96%	31.66%	9.70%
10. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	7,395,179	2,393,931	3,907,050	1,094,198
	Distribution UG Secondary Lines	99.48%	32.20%	52.56%	14.72%
11. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,765,086	2,513,675	4,102,481	1,148,930
	Distribution OH Line Transformers	73.82%	23.90%	39.00%	10.92%
12. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,765,086	2,513,675	4,102,481	1,148,930
	Distribution UG Line Transformers	68.17%	22.07%	36.01%	10.09%
13. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	394,882	189,249	169,643	35,990
	Distribution OH Services	87.22%	41.80%	37.47%	7.95%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

ARIZONA PUBLIC SERVICE COMPANY
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED 12/31/2010

Factor	Definition and Application of Allocation Factor	Residential (T)	Residential E-12 (U)	Residential ET-1 & ET-2 (V)	Residential ECT-1 & ECT-2 (W)
14. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	601,540	288,290	258,424	54,826
	Distribution UG Services	90.10%	43.18%	38.71%	8.21%
15. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	4,588,234	1,277,475	2,534,204	776,555
	Distribution Rents	56.55%	15.75%	31.23%	9.57%
16. ENERGY1	Customer Class Energy @ Generation (MWH)	14,132,767	4,310,449	7,352,176	2,470,142
	Production - Energy	47.04%	14.35%	24.47%	8.22%
17. ENERGY2	Weighted Hourly Energy Allocator @ Generation	47.21	14.45	24.53	8.23
	Production - Energy (Fuel and Purchased Power)	47.21%	14.45%	24.53%	8.23%
18. CUST370	Weighted Costs for Distribution Meters ($)	996,422	400,352	492,908	103,162
	Distribution Meters	77.41%	31.10%	38.29%	8.02%
19. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%
20. CUST373	Street Lighting Customer Class Specific	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%
21. CUSTNUM	Number of Customer Accounts	996,422	477,539	428,067	90,816
	Customer Accounts	88.06%	42.21%	37.83%	8.02%
22. CUST910	Number of Customer Accounts	996,422	477,539	428,067	90,816
	Customer Service and Information	88.17%	42.25%	37.88%	8.04%
23. CUST916	Number of Customer Accounts	996,422	477,539	428,067	90,816
	Sales Expense	88.06%	42.21%	37.83%	8.02%
24. DEMREGAST	Average & Excess @ Generation - Retail [4CP Juris.]	0.5253	.1491	.2867	.0895
	Regulatory Asset - Demand Related	52.53%	14.91%	28.67%	8.95%
25. ERGREGAST	Customer Class Energy @ Generation (MWH)	14,132,767	4,310,449	7,352,176	2,470,142
	Regulatory Asset - Energy Related	47.04%	14.35%	24.47%	8.22%
26. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	14,132,767	4,310,449	7,352,176	2,470,142
	System Benefits - Energy Related	47.04%	14.35%	24.47%	8.22%

Supporting Schedule:
N/A

Recap Schedule:
G-3
G-4

H-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING DECEMBER 31, 2010 ADJUSTED

Line No.	Customer Classification	Base Revenues in the Test Year (a) (A) Present Rates [1, 2] ($000)	(B) Proposed Rates [2] ($000)	Proposed Increase (b) (C) Amount ($000) (B) - (A)	(D) % (C) / (A)	Line No.
1.	Residential	$ 1,470,134	$ 1,528,238	$ 58,104	3.95%	1.
2.	General Service	1,342,599	1,378,012	35,413	2.64%	2.
3.	Irrigation/Water Pumping	26,669	27,635	966	3.62%	3.
4.	Outdoor Lighting	20,999	21,760	761	3.62%	4.
5.	Dusk to Dawn Lighting Service	8,457	8,706	249	2.94%	5.
6.	Total Sales to Ultimate Retail Customers	$ 2,868,858	$ 2,964,351	$ 95,493	3.33%	6.

Notes:
1) Base Revenues under Present Rates reflect adjusted Test Year revenues including applicable pro forma adjustments.
2) Present and Proposed Rates base revenues include transmission. Costs based on OATT rates effective during Test Year.

Supporting Schedules:
(a) H-2

Recap Schedules:
(b) A-1

H-2

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh Sales	(D) Average Annual kWh Usage per Customer [(C) x 1000] / (B)	(E) Base Revenues under Present Rates[1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Proposed Revenue Transmission Revenue[7] ($000)	(I) Proposed Revenue Total Revenue ($000)	(J) Increase -Base Rates Amount ($000) (I) - (E)	(K) Increase -Base Rates % (J) / (E)	Line No.
1.	Residential											1.
2.	E-12	449,101	3,698,573	8,236	464,358	E-12	460,759	19,267	480,026	15,668	3.37%	2.
3.	ET-1	278,353	4,136,790	14,862	462,337	ET-1	459,350	21,553	480,903	18,566	4.02%	3.
4.	ET-2	114,450	1,739,717	15,201	250,031	ET-2	248,466	11,604	260,070	10,039	4.02%	4.
5.	ECT-2	38,017	1,364,662	35,896	104,438	ECT-2	103,099	5,533	108,632	4,194	4.02%	5.
6.	ECT-1R	47,380	1,385,780	29,248	120,460	ECT-1R	119,047	6,250	125,297	4,837	4.02%	6.
7.	ET-SP	108	2,301	21,306	221	ET-SP	219	10	229	8	3.62%	7.
8.	E-12 Low income	36,296	328,089	9,039	29,008	E-12 Low income	29,609	1,434	31,043	2,035	7.02%	8.
9.	ET-1 low income	15,267	207,243	13,575	18,649	ET-1 low income	18,961	997	19,958	1,309	7.02%	9.
10.	ET-2 low income	8,588	179,769	20,933	16,008	ET-2 low income	16,379	753	17,132	1,124	7.02%	10.
11.	ECT-2 low income	1,431	36,200	25,297	2,988	ECT-2 low income	3,016	182	3,198	210	7.03%	11.
12.	ECT-1R Low income	998	19,159	19,197	1,636	ECT-1R Low income	1,641	109	1,750	114	6.97%	12.
13.	Total Residential	989,989	13,098,283	13,231	1,470,134	Total Residential	1,460,546	67,692	1,528,238	58,104	3.95%	13.
14.												14.
15.	General Service											15.
16.	E-20	328	36,664	111,780	3,886	E-20	3,741	296	4,037	151	3.89%	16.
17.	E-30	4,644	6,349	1,367	1,406	E-30	1,414	27	1,441	35	2.49%	17.
18.	E-40	1	-	-	1	See note 9						18.
19.	E-32 XS	82,396	1,418,941	17,221	199,177	E-32 XS	197,575	6,037	203,612	4,435	2.23%	19.
20.	E-32 S	29,411	2,551,983	86,770	290,021	E-32 S	282,470	13,992	296,462	6,441	2.22%	20.
21.	E-32 M	4,425	3,279,542	741,139	317,315	E-32 M	311,476	14,631	326,107	8,791	2.77%	21.
22.	E-32 L	1,035	3,647,139	3,523,806	303,798	E-32 L	298,567	13,649	312,216	8,418	2.77%	22.
23.	E-32 TOU XS	78	4,609	59,090	633	E-32 TOU XS	626	20	646	13	2.05%	23.
24.	E-32 TOU S	219	41,567	189,804	4,454	E-32 TOU S	4,371	171	4,542	88	1.98%	24.
25.	E-32 TOU M	73	69,937	958,041	6,385	E-32 TOU M	6,301	242	6,543	158	2.47%	25.
26.	E-32 TOU L	47	295,614	6,289,660	22,917	E-32 TOU L	22,672	880	23,552	635	2.77%	26.
27.	E-34	36	1,086,047	30,167,972	80,597	E-34	79,241	3,832	83,073	2,476	3.07%	27.
28.	E-35	29	1,673,369	57,702,379	112,009	E-35	110,711	5,070	115,781	3,772	3.37%	28.
29.	Total General Service	122,722	14,111,761	114,990	1,342,599	Total General Service	1,319,165	58,847	1,378,012	35,413	2.64%	29.
30.												30.
31.	Irrigation and Water Pumping	1,450	313,308	216,074	26,669	Irrigation and Water Pumping	25,566	2,069	27,635	966	3.62%	31.
32.												32.
33.	Outdoor Lighting											33.
34.	E-58	624	33,212	53,224	10,107	E-58	10,340	138	10,478	371	3.67%	34.
35.	E-59	293	93,502	319,119	9,701	E-59	9,651	396	10,047	346	3.57%	35.
36.	Contract 12	41	11,496	280,390	1,013	Contract 12	1,006	42	1,048	35	3.46%	36.
37.	E-67	181	3,432	18,961	178	E-67	174	13	187	9	5.06%	37.
38.	Total Outdoor Lighting	1,139	141,642	124,356	20,999	Total Outdoor Lighting	21,171	589	21,760	761	3.62%	38.
39.												39.
40.	Dusk to Dawn Lighting	See Note 5	24,613	See Note 5	8,457	Dusk to Dawn Lighting	8,602	104	8,706	249	2.94%	40.
41.												41.
42.	Total Sales to Ultimate Retail Customers	1,115,300	27,689,607 See Note 10	24,827	2,868,858		2,835,050	129,301	2,964,351	95,493	3.33%	42.

Notes:
1) Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 71448.
2) Share the Light Rate Schedules are included in Rate Schedule E-58.
3) Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, CMPW-01, E-53, E-54, RSSP, PPR, CPP-GS, Solar-2, Solar-3, GPS-1, GPS-2, GPS-3, EPR-2, EPR-6, E-56, and SC-S.
4) Rate Schedule E-36 is not included as prices are market-related.
5) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
7) Transmission revenues based on OATT charges effective during test year.
8) Rate Schedules GS Schools M, GS-Schools L have no revenue or customers.
9) Rate E-40 proposed revenue is reflected in E-32 M
10) Excludes 144,149 MWh of revenue credit customers, total sales with revenue credit customers = 27,833,756 MWh

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

H-3

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
1.	E-3	Residential Energy	Rate	Sum & Win	For Bills 0-400 kWh	40% disc.	For Bills 0-400 kWh	25% disc.	-15% disc.	1.
2.		Support Program			For Bills 401-800 kWh	26% disc.	For Bills 401-800 kWh	25% disc.	-1% disc.	2.
3.					For Bills 801-1200 kWh	14% disc.	For Bills 801-1200 kWh	$ 18.00 disc.	depends on usage disc.	3.
4.					For Bills 1201 kWh and above	$ 13.00 disc.	For Bills 1201 kWh and above	$ 18.00 disc.	$ 5.00 disc.	4.
5.										5.
6.	E-4	Medical Care	Rate	Sum & Win	For Bills 0-800 kWh	40% disc.	For Bills 0-800 kWh	25% disc.	-15% disc.	6.
7.		Equipment			For Bills 801-1400 kWh	26% disc.	For Bills 801-1400 kWh	$ 36.00 disc.	depends on usage disc.	7.
8.		Support Program			For Bills 1401-2000 kWh	14% disc.	For Bills 1401-2000 kWh	$ 36.00 disc.	depends on usage disc.	8.
9.					For Bills 2001 kWh and above	$ 26.00 disc.	For Bills 2001 kWh and above	$ 36.00 disc.	$ 10.00 disc.	9.
10.										10.
11.	E-12	Residential Service	Rate	Summer	Basic Service Charge	$ 0.285 /day	Basic Service Charge	$ 0.390 /day	$ 0.105 /day	11.
12.					First 400 kWh	0.09671 /kWh	First 400 kWh	0.09110 /kWh	(0.00561) /kWh	12.
13.					Next 400 kWh	0.13739 /kWh	Next 400 kWh	0.13180 /kWh	(0.00559) /kWh	13.
14.					Next 2200 kWh	0.16281 /kWh	Next 2200 kWh	0.15723 /kWh	(0.00558) /kWh	14.
15.					All additional kWh	0.17358	All additional kWh	0.16800 /kWh	(0.00558) /kWh	15.
16.										16.
17.				Winter	Basic Service Charge	$ 0.285 /day	Basic Service Charge	$ 0.390 /day	$ 0.105 /day	17.
18.					All kWh	0.09397 /kWh	All kWh	0.08836 /kWh	(0.00561) /kWh	18.
19.										19.
20.			Minimum	Sum & Win	Basic Service Charge	$ 0.285 /day	N/A	N/A /day	N/A /day	20.
21.										21.
22.	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	22.
23.		Time of Use			All On-Peak kWh	0.17866 /kWh	All On-Peak kWh	0.16488 /kWh	(0.01378) /kWh	23.
24.					All Off-Peak kWh	0.05774 /kWh	All Off-Peak kWh	0.06601 /kWh	0.00827 /kWh	24.
25.										25.
26.				Winter	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	26.
27.					All On-Peak kWh	0.14515 /kWh	All On-Peak kWh	0.12508 /kWh	(0.02007) /kWh	27.
28.					All Off-Peak kWh	0.05565 /kWh	All Off-Peak kWh	0.06258 /kWh	0.00693 /kWh	28.
29.										29.
30.			Minimum	Sum & Win	Basic Service Charge	$ 0.556 /day	N/A	N/A /day	N/A /day	30.
31.										31.
32.	ET-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	32.
33.		Time of Use			All On-Peak kWh	0.24445 /kWh	All On-Peak kWh	0.21275 /kWh	(0.03170) /kWh	33.
34.					All Off-Peak kWh	0.06126 /kWh	All Off-Peak kWh	0.06848 /kWh	0.00722 /kWh	34.
35.										35.
36.				Winter	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.02300 /day	36.
37.					All On-Peak kWh	0.19825 /kWh	All On-Peak kWh	0.17260 /kWh	(0.02565) /kWh	37.
38.					All Off-Peak kWh	0.06124 /kWh	All Off-Peak kWh	0.06846 /kWh	0.00722 /kWh	38.
39.										39.
40.			Minimum	Sum & Win	Basic Service Charge	$ 0.556 /day	N/A	N/A /day	N/A /day	40.
41.										41.
42.	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	42.
43.		Time of Use with			All On-Peak kW	13.372 /kW	All On-Peak kW	14.039 /kW	0.66700 /kW	43.
44.		Demand Charge			All On-Peak kWh	0.07434 /kWh	All On-Peak kWh	0.07191 /kWh	(0.00243) /kWh	44.
45.					All Off-Peak kWh	0.04159 /kWh	All Off-Peak kWh	0.03753 /kWh	(0.00406) /kWh	45.
46.										46.
47.				Winter	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	47.
48.					All On-Peak kW	9.189 /kW	All On-Peak kW	9.648 /kW	0.45896 /kW	48.
49.					All On-Peak kWh	0.05609 /kWh	All On-Peak kWh	0.05288 /kWh	(0.00321) /kWh	49.
50.					All Off-Peak kWh	0.03976 /kWh	All Off-Peak kWh	0.03573 /kWh	(0.00403) /kWh	50.
51.										51.
52.			Minimum	Sum & Win	Minimum	$ 0.556 /day	N/A	N/A /day	N/A /day	52.
53.										53.
54.	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	54.
55.		Time of Use with			All On-Peak kW	13.404 /kW	All On-Peak kW	14.060 /kW	0.656 /kW	55.
56.		Demand Charge			All On-Peak kWh	0.08845 /kWh	All On-Peak kWh	0.08676 /kWh	(0.00169) /kWh	56.
57.					All Off-Peak kWh	0.04363 /kWh	All Off-Peak kWh	0.03975 /kWh	(0.00388) /kWh	57.
58.										58.
59.				Winter	Basic Service Charge	$ 0.556 /day	Basic Service Charge	$ 0.579 /day	0.023 /day	59.
60.					All On-Peak kW	9.203 /kW	All On-Peak kW	9.653 /kW	0.450 /kW	60.
61.					All On-Peak kWh	0.05815 /kWh	All On-Peak kWh	0.05498 /kWh	(0.00317) /kWh	61.
62.					All Off-Peak kWh	0.04273 /kWh	All Off-Peak kWh	0.03881 /kWh	(0.00392) /kWh	62.
63.										63.
64.			Minimum	Sum & Win	Minimum	$ 0.556 /day	N/A	N/A /day	N/A /day	64.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
65.										65.
66.	ET-SP	Residential Service	Rate	Super Peak	Basic Service Charge	$ 0.556	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	66.
67.				Summer	All Super-Peak kWh	0.49445	All Super-Peak kWh	0.46282 /kWh	(0.03163) /kWh	67.
68.		Time of Use			All On-Peak kWh	0.24445	All On-Peak kWh	0.21282 /kWh	(0.03163) /kWh	68.
69.					All Off-Peak kWh	0.05254	All Off-Peak kWh	0.05911 /kWh	0.00657 /kWh	69.
70.										70.
71.				Summer	Basic Service Charge	$ 0.556	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	71.
72.					All On-Peak kWh	0.24445	All On-Peak kWh	0.21282 /kWh	(0.03163) /kWh	72.
73.					All Off-Peak kWh	0.05254	All Off-Peak kWh	0.05911 /kWh	0.00657 /kWh	73.
74.										74.
75.				Winter	Basic Service Charge	$ 0.556	Basic Service Charge	$ 0.579 /day	$ 0.023 /day	75.
76.					All On-Peak kWh	0.19825	All On-Peak kWh	0.17265 /kWh	(0.02560) /kWh	76.
77.					All Off-Peak kWh	0.05253	All Off-Peak kWh	0.05908 /kWh	0.00655 /kWh	77.
78.				Sup. Pk. Sum,						78.
79.			Minimum	Sum & Win	Basic Service Charge	$ 0.556	N/A	N/A /day	N/A /day	79.
80.										80.
81.	E-12 L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.253 /day	Basic Service Charge	$ 0.345 /day	$ 0.092 /day	81.
82.					First 400 kWh	0.08570 /kWh	First 400 kWh	0.08322 /kWh	(0.00248) /kWh	82.
83.					Next 400 kWh	0.12175 /kWh	Next 400 kWh	0.12061 /kWh	(0.00114) /kWh	83.
84.					All additional kWh	0.14427 /kWh	All additional kWh	0.14396 /kWh	(0.00031) /kWh	84.
85.										85.
86.				Winter	Basic Service Charge	$ 0.253 /day	Basic Service Charge	$ 0.345 /day	$ 0.092 /day	86.
87.					All kWh	0.08327 /kWh	All kWh	0.08070 /kWh	(0.00257) /kWh	87.
88.										88.
89.			Minimum	Sum & Win	Basic Service Charge	$ 0.253 /day	N/A	N/A /day	N/A /day	89.
90.										90.
91.	ET-1 L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	91.
92.		Time of Use			All On-Peak kWh	0.15810 /kWh	All On-Peak kWh	0.15045 /kWh	(0.00765) /kWh	92.
93.					All Off-Peak kWh	0.05110 /kWh	All Off-Peak kWh	0.06020 /kWh	0.00910 /kWh	93.
94.										94.
95.				Winter	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	95.
96.					All On-Peak kWh	0.12845 /kWh	All On-Peak kWh	0.11439 /kWh	(0.01406) /kWh	96.
97.					All Off-Peak kWh	0.04925 /kWh	All Off-Peak kWh	0.05721 /kWh	0.00796 /kWh	97.
98.										98.
99.			Minimum	Sum & Win	Basic Service Charge	$ 0.493 /day	N/A	N/A /day	N/A /day	99.
100.										100.
101.	ET-2 L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	101.
102.		Time of Use			All On-Peak kWh	0.21601 /kWh	All On-Peak kWh	0.19301 /kWh	(0.02300) /kWh	102.
103.					All Off-Peak kWh	0.05413 /kWh	All Off-Peak kWh	0.06384 /kWh	0.00971 /kWh	103.
104.										104.
105.				Winter	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	105.
106.					All On-Peak kWh	0.17519 /kWh	All On-Peak kWh	0.15657 /kWh	(0.01862) /kWh	106.
107.					All Off-Peak kWh	0.05412 /kWh	All Off-Peak kWh	0.06382 /kWh	0.00970 /kWh	107.
108.										108.
109.			Minimum	Sum & Win	Basic Service Charge	$ 0.493 /day	N/A	N/A /day	N/A /day	109.
110.										110.
111.	ECT-1R L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	111.
112.		Time of Use with			All On-Peak kW	11.860 /kW	All On-Peak kW	14.596 /kW	2.736 /kW	112.
113.		Demand Charge			All On-Peak kWh	0.06593 /kWh	All On-Peak kWh	0.07453 /kWh	0.00860 /kWh	113.
114.					All Off-Peak kWh	0.03689 /kWh	All Off-Peak kWh	0.03880 /kWh	0.00191 /kWh	114.
115.										115.
116.				Winter	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	116.
117.					All On-Peak kW	8.150 /kW	All On-Peak kW	10.030 /kW	1.880 /kW	117.
118.					All On-Peak kWh	0.04975 /kWh	All On-Peak kWh	0.05488 /kWh	0.00513 /kWh	118.
119.					All Off-Peak kWh	0.03526 /kWh	All Off-Peak kWh	0.03707 /kWh	0.00181 /kWh	119.
120.										120.
121.			Minimum	Sum & Win	Minimum	$ 0.493 /day	N/A	N/A /day	N/A /day	121.
122.										122.
123.	ECT-2 L	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	123.
124.		Time of Use with			All On-Peak kW	11.870 /kW	All On-Peak kW	12.930 /kW	1.060 /kW	124.
125.		Demand Charge			All On-Peak kWh	0.07833 /kWh	All On-Peak kWh	0.07906 /kWh	0.00073 /kWh	125.
126.					All Off-Peak kWh	0.03864 /kWh	All Off-Peak kWh	0.03596 /kWh	(0.00268) /kWh	126.
127.										127.
128.				Winter	Basic Service Charge	$ 0.493 /day	Basic Service Charge	$ 0.579 /day	$ 0.086 /day	128.
129.					All On-Peak kW	8.150 /kW	All On-Peak kW	8.878 /kW	0.728 /kW	129.
130.					All On-Peak kWh	0.05150 /kWh	All On-Peak kWh	0.04993 /kWh	(0.00157) /kWh	130.
131.					All Off-Peak kWh	0.03784 /kWh	All Off-Peak kWh	0.03509 /kWh	(0.00275) /kWh	131.
132.										132.
133.			Minimum	Sum & Win	Minimum	$ 0.493 /day	N/A	N/A /day	N/A /day	133.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
134.													134.
135.	CPP-RES	Residential Service	Rate	Summer	Critical Peak Price	$ 0.40000	/kWh	Critical Peak Price	$ 0.250000	/kWh	$ (0.150000)	/kWh	135.
136.		Critical Peak Pricing			Energy Discount	$ (0.018910)	/kWh	Energy Discount	$ (0.012143)	/kWh	$ 0.006767	/kWh	136.
137.													137.
138.	PTR-RES	Residential Service	Rate	Summer	PROPOSE NEW SCHEDULE			Energy Discount	$ 0.250000	/kWh	$ 0.250000	/kWh	138.
139.		Peak Time Rebate											139.
140.													140.
141.	E-20	General Service	Rate	Summer	Basic Service Charge	$ 1.065	/day	Basic Service Charge	$ 1.147	/day	$ 0.082	/day	141.
142.		Time of Use for			All On-Peak kW	2.391	/kW	All On-Peak kW	1.290	/kW	(1.101)	/kW	142.
143.		Religious Houses of			Excess Off-Peak kW	1.196	/kW	Excess Off-Peak kW	0.645	/kW	(0.55100)	/kWh	143.
144.		Worship			All On-Peak kWh	0.14380	/kWh	All On-Peak kWh	0.14534	/kWh	0.00154	/kWh	144.
145.					All Off-Peak kWh	0.06945	/kWh	All Off-Peak kWh	0.07019	/kWh	0.00074	/kWh	145.
146.													146.
147.				Winter	Basic Service Charge	$ 1.065	/day	Basic Service Charge	$ 1.147	/day	$ 0.0820	/day	147.
148.					All On-Peak kW	2.156	/kW	All On-Peak kW	1.290	/kW	(0.866)	/kW	148.
149.					Excess Off-Peak kW	1.078	/kW	Excess Off-Peak kW	0.645	/kW	(0.43300)	/kWh	149.
150.					All On-Peak kWh	0.12644	/kWh	All On-Peak kWh	0.12779	/kWh	0.00135	/kWh	150.
151.					All Off-Peak kWh	0.06226	/kWh	All Off-Peak kWh	0.06292	/kWh	0.00066	/kWh	151.
152.													152.
153.			Minimum	Sum & Win	Basic Service Charge	$ 1.065	/day	N/A	N/A	/day	N/A	/day	153.
154.					Demand Charge	1.951	/kW	N/A	N/A	/kW	N/A	/kW	154.
155.													155.
156.	E-30	Extra Small General	Rate	Summer	Basic Service Charge	$ 0.311	/day	Basic Service Charge	$ 0.305	/day	$ (0.006)	/day	156.
157.		Service Unmetered			All kWh	0.14447	/kWh	All kWh	0.14777	/kWh	0.00330	/kWh	157.
158.													158.
159.				Winter	Basic Service Charge	$ 0.311	/day	Basic Service Charge	$ 0.305	/day	$ (0.006)	/day	159.
160.					All kWh	0.12967	/kWh	All kWh	0.13212	/kWh	0.00245	/kWh	160.
161.													161.
162.	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	162.
163.		20 kW or Less			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	163.
164.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	164.
165.					First 5,000 kWh: Secondary	0.13261	/kWh	First 5,000 kWh: Secondary	0.13209	/kWh	(0.0005)	/kWh	165.
166.					All remaining kWh: Secondary	0.07251	/kWh	All remaining kWh: Secondary	0.07001	/kWh	(0.0025)	/kWh	166.
167.					First 5,000 kWh: Primary	0.12939	/kWh	First 5,000 kWh: Primary	0.12877	/kWh	(0.0006)	/kWh	167.
168.					All remaining kWh: Primary	0.06929	/kWh	All remaining kWh: Primary	0.06668	/kWh	(0.0026)	/kWh	168.
169.													169.
170.				Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	170.
171.					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	171.
172.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	172.
173.					First 5,000 kWh: Secondary	0.11512	/kWh	First 5,000 kWh: Secondary	0.11402	/kWh	(0.00110)	/kWh	173.
174.					All remaining kWh: Secondary	0.05501	/kWh	All remaining kWh: Secondary	0.05193	/kWh	(0.00308)	/kWh	174.
175.					First 5,000 kWh: Primary	0.11189	/kWh	First 5,000 kWh: Primary	0.11069	/kWh	(0.00120)	/kWh	175.
176.					All remaining kWh: Primary	0.05179	/kWh	All remaining kWh: Primary	0.04861	/kWh	(0.00318)	/kWh	176.
177.													177.
178.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.672	/day	N/A	N/A	/day	N/A	/day	178.
179.					BSC: Instrument-rated Meters	1.324	/day	N/A	N/A	/day	N/A	/day	179.
180.					BSC: Primary Meters	3.415	/day	N/A	N/A	/day	N/A	/day	180.
181.													181.
182.	E-32 S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	182.
183.		21-100 kW			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	183.
184.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	184.
185.					First 100 kW: Secondary	9.675	/kW	First 100 kW: Secondary	8.327	/kW	(1.348)	/kW	185.
186.					All remaining kW: Secondary	5.146	/kW	All remaining kW: Secondary	3.665	/kW	(1.481)	/kW	186.
187.					First 100 kW: Primary	8.976	/kW	First 100 kW: Primary	7.607	/kW	(1.369)	/kW	187.
188.					All remaining kW: Primary	4.448	/kW	All remaining kW: Primary	2.947	/kW	(1.501)	/kW	188.
189.					First 200 kWh per kW	0.10403	/kWh	First 200 kWh per kW	0.10655	/kWh	0.00252	/kWh	189.
190.					All remaining kWh	0.06083	/kWh	All remaining kWh	0.06209	/kWh	0.00126	/kWh	190.
191.													191.
192.			Rate	Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	192.
193.					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	193.
194.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	194.
195.					First 100 kW: Secondary	9.675	/kW	First 100 kW: Secondary	8.327	/kW	(1.348)	/kW	195.
196.					All remaining kW: Secondary	5.146	/kW	All remaining kW: Secondary	3.665	/kW	(1.481)	/kW	196.
197.					First 100 kW: Primary	8.976	/kW	First 100 kW: Primary	7.607	/kW	(1.369)	/kW	197.
198.					All remaining kW: Primary	4.448	/kW	All remaining kW: Primary	2.947	/kW	(1.501)	/kW	198.
199.					First 200 kWh per kW	0.08689	/kWh	First 200 kWh per kW	0.08891	/kWh	0.00202	/kWh	199.
200.					All remaining kWh	0.04369	/kWh	All remaining kWh	0.04445	/kWh	0.00076	/kWh	200.
201.													201.
202.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.672	/day	N/A	N/A	/day	N/A	/day	202.
203.					BSC: Instrument-rated Meters	1.324	/day	N/A	N/A	/day	N/A	/day	203.
204.					BSC: Primary Meters	3.415	/day	N/A	N/A	/day	N/A	/day	204.
205.					Minimum Demand Charge:	2.180	/kW	N/A	N/A	/kW	N/A	/kW	205.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
206.													206.
207.	E-32 M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	207.
208.		101- 400 kW			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	208.
209.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	209.
210.					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	26.855	/day	0.692	/day	210.
211.					First 100 kW: Secondary	9.597	/kW	First 100 kW: Secondary	8.294	/kW	(1.303)	/kW	211.
212.					All remaining kW: Secondary	5.105	/kW	All remaining kW: Secondary	3.644	/kW	(1.461)	/kW	212.
213.					First 100 kW: Primary	8.905	/kW	First 100 kW: Primary	7.578	/kW	(1.327)	/kW	213.
214.					All remaining kW: Primary	4.412	/kW	All remaining kW: Primary	2.927	/kW	(1.485)	/kW	214.
215.					First 100 kW: Transmission	6.942	/kW	First 100 kW: Transmission	5.546	/kW	(1.396)	/kW	215.
216.					All remaining kW: Transmission	2.450	/kW	All remaining kW: Transmission	0.895	/kW	(1.555)	/kW	216.
217.					First 200 kWh per kW	0.10320	/kWh	First 200 kWh per kW	0.10628	/kWh	0.00308	/kWh	217.
218.					All remaining kWh	0.06034	/kWh	All remaining kWh	0.06192	/kWh	0.00158	/kWh	218.
219.													219.
220.			Rate	Winter	BSC: Self-Contained Meters	$ 0.672	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.014)	/day	220.
221.					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	221.
222.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	222.
223.					BSC: Transmission Meters	26.163	/day	BSC: Transmission Meters	26.855	/day	0.692	/day	223.
224.					First 100 kW: Secondary	9.597	/kW	First 100 kW: Secondary	8.294	/kW	(1.303)	/kW	224.
225.					All remaining kW: Secondary	5.105	/kW	All remaining kW: Secondary	3.644	/kW	(1.461)	/kW	225.
226.					First 100 kW: Primary	8.905	/kW	First 100 kW: Primary	7.578	/kW	(1.327)	/kW	226.
227.					All remaining kW: Primary	4.412	/kW	All remaining kW: Primary	2.927	/kW	(1.485)	/kW	227.
228.					First 100 kW: Transmission	6.942	/kW	First 100 kW: Transmission	5.546	/kW	(1.396)	/kW	228.
229.					All remaining kW: Transmission	2.450	/kW	All remaining kW: Transmission	0.895	/kW	(1.555)	/kW	229.
230.					First 200 kWh per kW	0.08619	/kWh	First 200 kWh per kW	0.08867	/kWh	0.00248	/kWh	230.
231.					All remaining kWh	0.04334	/kWh	All remaining kWh	0.04433	/kWh	0.00099	/kWh	231.
232.													232.
233.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.672	/day						233.
234.					BSC: Instrument-rated Meters	1.324	/day	N/A	N/A	/day	N/A	/day	234.
235.					BSC: Primary Meters	3.415	/day	N/A	N/A	/day	N/A	/day	235.
236.					BSC: Transmission Meters	26.163	/day	N/A	N/A	/day	N/A	/day	236.
237.					Minimum Demand Charge:	2.162	/kW	N/A	N/A	/kW	N/A	/kW	237.
238.													238.
239.	E-32 L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.410)	/day	239.
240.		401 kW and above			BSC: Instrument-rated Meters	1.627	/day	BSC: Instrument-rated Meters	1.328	/day	(0.299)	/day	240.
241.					BSC: Primary Meters	3.419	/day	BSC: Primary Meters	3.477	/day	0.058	/day	241.
242.					BSC: Transmission Meters	22.915	/day	BSC: Transmission Meters	26.855	/day	3.940	/day	242.
243.					First 100 kW: Secondary	9.384	/kW	First 100 kW: Secondary	16.899	/kW	7.515	/kW	243.
244.					All remaining kW: Secondary	4.993	/kW	All remaining kW: Secondary	12.313	/kW	7.320	/kW	244.
245.					First 100 kW: Primary	8.703	/kW	First 100 kW: Primary	16.188	/kW	7.485	/kW	245.
246.					All remaining kW: Primary	4.315	/kW	All remaining kW: Primary	11.605	/kW	7.290	/kW	246.
247.					First 100 kW: Transmission	6.788	/kW	First 100 kW: Transmission	13.188	/kW	6.400	/kW	247.
248.					All remaining kW: Transmission	2.396	/kW	All remaining kW: Transmission	9.601	/kW	7.205	/kW	248.
249.					First 200 kWh per kW	0.10093	/kWh	First 200 kWh per kW	0.05935	/kWh	(0.04158)	/kWh	249.
250.					All remaining kWh	0.05902	/kWh	All remaining kWh	0.05935	/kWh	0.00033	/kWh	250.
251.													251.
252.			Rate	Winter	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.410)	/day	252.
253.					BSC: Instrument-rated Meters	1.627	/day	BSC: Instrument-rated Meters	1.328	/day	(0.299)	/day	253.
254.					BSC: Primary Meters	3.419	/day	BSC: Primary Meters	3.477	/day	0.058	/day	254.
255.					BSC: Transmission Meters	22.915	/day	BSC: Transmission Meters	26.855	/day	3.940	/day	255.
256.					First 100 kW: Secondary	9.384	/kW	First 100 kW: Secondary	16.899	/kW	7.515	/kW	256.
257.					All remaining kW: Secondary	4.993	/kW	All remaining kW: Secondary	12.313	/kW	7.320	/kW	257.
258.					First 100 kW: Primary	8.703	/kW	First 100 kW: Primary	16.188	/kW	7.485	/kW	258.
259.					All remaining kW: Primary	4.315	/kW	All remaining kW: Primary	11.605	/kW	7.290	/kW	259.
260.					First 100 kW: Transmission	6.788	/kW	First 100 kW: Transmission	13.188	/kW	6.400	/kW	260.
261.					All remaining kW: Transmission	2.396	/kW	All remaining kW: Transmission	9.601	/kW	7.205	/kW	261.
262.					First 200 kWh per kW	0.08430	/kWh	First 200 kWh per kW	0.04249	/kWh	(0.04181)	/kWh	262.
263.					All remaining kWh	0.04239	/kWh	All remaining kWh	0.04249	/kWh	0.00010	/kWh	263.
264.													264.
265.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 1.068	/day						265.
266.					BSC: Instrument-rated Meters	1.627	/day	BSC: Self-Contained Meters	0.658	/day	$ (0.410)	/day	266.
267.					BSC: Primary Meters	3.419	/day	BSC: Instrument-rated Meters	1.328	/day	(0.299)	/day	267.
268.					BSC: Transmission Meters	22.915	/day	BSC: Primary Meters	3.477	/day	0.058	/day	268.
269.					Minimum Demand Charge:	2.115	/kW	BSC: Transmission Meters	26.855	/day	3.940	/day	269.
270.								First 100 kW: Secondary	16.899	/kW	16.899	/kW	270.
271.								All remaining kW: Secondary	12.313	/kW	12.313	/kW	271.
272.								First 100 kW: Primary	16.188	/kW	16.188	/kW	272.
273.								All remaining kW: Primary	11.605	/kW	11.605	/kW	273.
274.								First 100 kW: Transmission	13.188	/kW	13.188	/kW	274.
								All remaining kW: Transmission	9.601	/kW	9.601	/kW	

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
275.													275.
276.	E-32TOU XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.052)	/day	276.
277.		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	277.
278.		20 kW or Less			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	278.
279.					First 5,000 On-Peak kWh: Secondary	0.16831	/kWh	First 5,000 On-Peak kWh: Secondary	0.16793	/kWh	(0.00038)	/kWh	279.
280.					All remaining On-Peak kWh: Secondary	0.08318	/kWh	All remaining On-Peak kWh: Secondary	0.08008	/kWh	(0.00310)	/kWh	280.
281.					First 5,000 Off-Peak kWh: Secondary	0.12438	/kWh	First 5,000 Off-Peak kWh: Secondary	0.12303	/kWh	(0.00135)	/kWh	281.
282.					All remaining Off-Peak kWh: Secondary	0.04459	/kWh	All remaining Off-Peak kWh: Secondary	0.04082	/kWh	(0.00377)	/kWh	282.
283.					First 5,000 On-Peak kWh: Primary	0.16498	/kWh	First 5,000 On-Peak kWh: Primary	0.16442	/kWh	(0.00056)	/kWh	283.
284.					All remaining On-Peak kWh: Primary	0.07907	/kWh	All remaining On-Peak kWh: Primary	0.07574	/kWh	(0.00333)	/kWh	284.
285.					First 5,000 Off-Peak kWh: Primary	0.12105	/kWh	First 5,000 Off-Peak kWh: Primary	0.11951	/kWh	(0.00154)	/kWh	285.
286.					All remaining Off-Peak kWh: Primary	0.04126	/kWh	All remaining Off-Peak kWh: Primary	0.03731	/kWh	(0.00395)	/kWh	286.
287.													287.
288.				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.052)	/day	288.
289.					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	289.
290.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	290.
291.					First 5,000 On-Peak kWh: Secondary	0.15082	/kWh	First 5,000 On-Peak kWh: Secondary	0.15020	/kWh	(0.00062)	/kWh	291.
292.					All remaining On-Peak kWh: Secondary	0.06565	/kWh	All remaining On-Peak kWh: Secondary	0.06231	/kWh	(0.00334)	/kWh	292.
293.					First 5,000 Off-Peak kWh: Secondary	0.10688	/kWh	First 5,000 Off-Peak kWh: Secondary	0.10527	/kWh	(0.00159)	/kWh	293.
294.					All remaining Off-Peak kWh: Secondary	0.03181	/kWh	All remaining Off-Peak kWh: Secondary	0.02787	/kWh	(0.00394)	/kWh	294.
295.					First 5,000 On-Peak kWh: Primary	0.14749	/kWh	First 5,000 On-Peak kWh: Primary	0.14668	/kWh	(0.00081)	/kWh	295.
296.					All remaining On-Peak kWh: Primary	0.06154	/kWh	All remaining On-Peak kWh: Primary	0.05797	/kWh	(0.00357)	/kWh	296.
297.					First 5,000 Off-Peak kWh: Primary	0.10353	/kWh	First 5,000 Off-Peak kWh: Primary	0.10176	/kWh	(0.00177)	/kWh	297.
298.					All remaining Off-Peak kWh: Primary	0.02848	/kWh	All remaining Off-Peak kWh: Primary	0.02435	/kWh	(0.00413)	/kWh	298.
299.													299.
300.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.710	/day						300.
301.					BSC: Instrument-rated Meters	1.324	/day	N/A	N/A	/day	N/A	/day	301.
302.					BSC: Primary Meters	3.415	/day	N/A	N/A	/day	N/A	/day	302.
303.								N/A	N/A	/day	N/A	/day	303.
304.	E-32TOU S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.052)	/day	304.
305.		Time of Use			BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	305.
306.		21-100 kW			BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	306.
307.					First 100 On-Peak kW: Secondary	14.322	/kW	First 100 On-Peak kW: Secondary	13.230	/kW	(1.092)	/kW	307.
308.					All remaining On-Peak kW: Secondary	9.725	/kW	All remaining On-Peak kW: Secondary	8.455	/kW	(1.270)	/kW	308.
309.					First 100 Off-Peak kW: Secondary	5.492	/kW	First 100 Off-Peak kW: Secondary	5.705	/kW	0.213	/kW	309.
310.					All remaining Off-Peak kW: Secondary	3.059	/kW	All remaining Off-Peak kW: Secondary	3.178	/kW	0.119	/kW	310.
311.					First 100 On-Peak kW: Primary	13.863	/kW	First 100 On-Peak kW: Primary	12.753	/kW	(1.110)	/kW	311.
312.					All remaining On-Peak kW: Primary	9.657	/kW	All remaining On-Peak kW: Primary	8.384	/kW	(1.273)	/kW	312.
313.					First 100 Off-Peak kW: Primary	4.916	/kW	First 100 Off-Peak kW: Primary	5.107	/kW	0.191	/kW	313.
314.					All remaining Off-Peak kW: Primary	2.979	/kW	All remaining Off-Peak kW: Primary	3.095	/kW	0.116	/kW	314.
315.					All On-Peak kWh:	0.07291	/kWh	All On-Peak kWh:	0.07352	/kWh	0.00061	/kWh	315.
316.					All Off-Peak kWh:	0.05794	/kWh	All Off-Peak kWh:	0.05833	/kWh	0.00039	/kWh	316.
317.													317.
318.				Winter	BSC: Self-Contained Meters	$ 0.710	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.052)	/day	318.
319.					BSC: Instrument-rated Meters	1.324	/day	BSC: Instrument-rated Meters	1.328	/day	0.004	/day	319.
320.					BSC: Primary Meters	3.415	/day	BSC: Primary Meters	3.477	/day	0.062	/day	320.
321.					First 100 On-Peak kW: Secondary	14.322	/kW	First 100 On-Peak kW: Secondary	13.230	/kW	(1.092)	/kW	321.
322.					All remaining On-Peak kW: Secondary	9.725	/kW	All remaining On-Peak kW: Secondary	8.455	/kW	(1.270)	/kW	322.
323.					First 100 Off-Peak kW: Secondary	5.492	/kW	First 100 Off-Peak kW: Secondary	5.705	/kW	0.213	/kW	323.
324.					All remaining Off-Peak kW: Secondary	3.059	/kW	All remaining Off-Peak kW: Secondary	3.178	/kW	0.119	/kW	324.
325.					First 100 On-Peak kW: Primary	13.863	/kW	First 100 On-Peak kW: Primary	12.753	/kW	(1.110)	/kW	325.
326.					All remaining On-Peak kW: Primary	9.657	/kW	All remaining On-Peak kW: Primary	8.384	/kW	(1.273)	/kW	326.
327.					First 100 Off-Peak kW: Primary	4.916	/kW	First 100 Off-Peak kW: Primary	5.107	/kW	0.191	/kW	327.
328.					All remaining Off-Peak kW: Primary	2.979	/kW	All remaining Off-Peak kW: Primary	3.095	/kW	0.116	/kW	328.
329.					All On-Peak kWh:	0.05586	/kWh	All On-Peak kWh:	0.05622	/kWh	0.00036	/kWh	329.
330.					All Off-Peak kWh:	0.04089	/kWh	All Off-Peak kWh:	0.04102	/kWh	0.00013	/kWh	330.
331.													331.
332.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.710	/day						332.
333.					BSC: Instrument-rated Meters	1.324	/day	N/A	N/A	/day	N/A	/day	333.
334.					BSC: Primary Meters	3.415	/day	N/A	N/A	/day	N/A	/day	334.
335.					Minimum Demand Charge:	2.206	/kW	N/A	N/A	/kW	N/A	/kW	335.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
336.										336.
337.	E-32TOU M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.052) /day	337.
338.		Time of Use			BSC: Instrument-rated Meters	1.324 /day	BSC: Instrument-rated Meters	1.328 /day	0.004 /day	338.
339.		101- 400 kW			BSC: Primary Meters	3.415 /day	BSC: Primary Meters	3.477 /day	0.062 /day	339.
340.					BSC: Transmission Meters	26.163 /day	BSC: Transmission Meters	26.855 /day	0.692 /day	340.
341.					First 100 On-Peak kW: Secondary	14.209 /kW	First 100 On-Peak kW: Secondary	13.343 /kW	(0.866) /kW	341.
342.					All remaining On-Peak kW: Secondary	9.649 /kW	All remaining On-Peak kW: Secondary	8.523 /kW	(1.126) /kW	342.
343.					First 100 Residual kW: Secondary	5.449 /kW	First 100 Off-Peak kW: Secondary	5.759 /kW	0.310 /kW	343.
344.					All remaining Residual kW: Secondary	3.034 /kW	All remaining Off-Peak kW: Secondary	3.206 /kW	0.172 /kW	344.
345.					First 100 On-Peak kW: Primary	13.753 /kW	First 100 On-Peak kW: Primary	12.861 /kW	(0.892) /kW	345.
346.					All remaining On-Peak kW: Primary	9.581 /kW	All remaining On-Peak kW: Primary	8.451 /kW	(1.130) /kW	346.
347.					First 100 Residual kW: Primary	4.877 /kW	First 100 Off-Peak kW: Primary	5.154 /kW	0.277 /kW	347.
348.					All remaining Residual kW: Primary	2.955 /kW	All remaining Off-Peak kW: Primary	3.123 /kW	0.168 /kW	348.
349.					First 100 On-Peak kW: Transmission	12.938 /kW	First 100 On-Peak kW: Transmission	12.000 /kW	(0.938) /kW	349.
350.					All remaining On-Peak kW: Transmission	9.300 /kW	All remaining On-Peak kW: Transmission	8.154 /kW	(1.146) /kW	350.
351.					First 100 Residual kW: Transmission	4.232 /kW	First 100 Off-Peak kW: Transmission	4.472 /kW	0.240 /kW	351.
352.					All remaining Residual kW: Transmission	2.849 /kW	All remaining Off-Peak kW: Transmission	3.011 /kW	0.162 /kW	352.
353.					All On-Peak kWh:	0.07233 /kWh	All On-Peak kWh:	0.07299 /kWh	0.00066 /kWh	353.
354.					All Off-Peak kWh:	0.05748 /kWh	All Off-Peak kWh:	0.05790 /kWh	0.00042 /kWh	354.
355.										355.
356.				Winter	BSC: Self-Contained Meters	$ 0.710 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.052) /day	356.
357.					BSC: Instrument-rated Meters	1.324 /day	BSC: Instrument-rated Meters	1.328 /day	0.004 /day	357.
358.					BSC: Primary Meters	3.415 /day	BSC: Primary Meters	3.477 /day	0.062 /day	358.
359.					BSC: Transmission Meters	26.163 /day	BSC: Transmission Meters	26.855 /day	0.692 /day	359.
360.					First 100 On-Peak kW: Secondary	14.209 /kW	First 100 On-Peak kW: Secondary	13.343 /kW	(0.866) /kW	360.
361.					All remaining On-Peak kW: Secondary	9.649 /kW	All remaining On-Peak kW: Secondary	8.523 /kW	(1.126) /kW	361.
362.					First 100 Residual kW: Secondary	5.449 /kW	First 100 Off-Peak kW: Secondary	5.759 /kW	0.310 /kW	362.
363.					All remaining Residual kW: Secondary	3.034 /kW	All remaining Off-Peak kW: Secondary	3.206 /kW	0.172 /kW	363.
364.					First 100 On-Peak kW: Primary	13.753 /kW	First 100 On-Peak kW: Primary	12.861 /kW	(0.892) /kW	364.
365.					All remaining On-Peak kW: Primary	9.581 /kW	All remaining On-Peak kW: Primary	8.451 /kW	(1.130) /kW	365.
366.					First 100 Residual kW: Primary	4.877 /kW	First 100 Off-Peak kW: Primary	5.154 /kW	0.277 /kW	366.
367.					All remaining Residual kW: Primary	2.955 /kW	All remaining Off-Peak kW: Primary	3.123 /kW	0.168 /kW	367.
368.					First 100 On-Peak kW: Transmission	12.938 /kW	First 100 On-Peak kW: Transmission	12.000 /kW	(0.938) /kW	368.
369.					All remaining On-Peak kW: Transmission	9.300 /kW	All remaining On-Peak kW: Transmission	8.154 /kW	(1.146) /kW	369.
370.					First 100 Residual kW: Transmission	4.232 /kW	First 100 Off-Peak kW: Transmission	4.472 /kW	0.240 /kW	370.
371.					All remaining Residual kW: Transmission	2.849 /kW	All remaining Off-Peak kW: Transmission	3.011 /kW	0.162 /kW	371.
372.					All On-Peak kWh:	0.05542 /kWh	All On-Peak kWh:	0.05581 /kWh	0.00039 /kWh	372.
373.					All Off-Peak kWh:	0.04057 /kWh	All Off-Peak kWh:	0.04073 /kWh	0.00016 /kWh	373.
374.										374.
375.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.710 /day	N/A	N/A /day	N/A /day	375.
376.					BSC: Instrument-rated Meters	1.324 /day	N/A	N/A /day	N/A /day	376.
377.					BSC: Primary Meters	3.415 /day	N/A	N/A /day	N/A /day	377.
378.					BSC: Transmission Meters	26.163 /day	N/A	N/A /day	N/A /day	378.
379.					Minimum Demand Charge:	2.189 /kW	N/A	N/A /kW	N/A /kW	379.

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
380.										380.
381.	E-32TOU L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.710 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.052) /day	381.
382.		Time of Use			BSC: Instrument-rated Meters	1.324 /day	BSC: Instrument-rated Meters	1.328 /day	0.004 /day	382.
383.		401 kW and above			BSC: Primary Meters	3.415 /day	BSC: Primary Meters	3.477 /day	0.062 /day	383.
384.					BSC: Transmission Meters	26.163 /day	BSC: Transmission Meters	26.855 /day	0.692 /day	384.
385.					First 100 On-Peak kW: Secondary	13.901 /kW	First 100 On-Peak kW: Secondary	13.139 /kW	(0.762) /kW	385.
386.					All remaining On-Peak kW: Secondary	9.439 /kW	All remaining On-Peak kW: Secondary	8.379 /kW	(1.060) /kW	386.
387.					First 100 Residual kW: Secondary	5.331 /kW	First 100 Off-Peak kW: Secondary	5.688 /kW	0.357 /kW	387.
388.					All remaining Residual kW: Secondary	2.969 /kW	All remaining Off-Peak kW: Secondary	3.168 /kW	0.199 /kW	388.
389.					First 100 On-Peak kW: Primary	13.455 /kW	First 100 On-Peak kW: Primary	12.663 /kW	(0.792) /kW	389.
390.					All remaining On-Peak kW: Primary	9.373 /kW	All remaining On-Peak kW: Primary	8.308 /kW	(1.065) /kW	390.
391.					First 100 Residual kW: Primary	4.771 /kW	First 100 Off-Peak kW: Primary	5.090 /kW	0.319 /kW	391.
392.					All remaining Residual kW: Primary	2.891 /kW	All remaining Off-Peak kW: Primary	3.085 /kW	0.194 /kW	392.
393.					First 100 On-Peak kW: Transmission	12.658 /kW	First 100 On-Peak kW: Transmission	11.813 /kW	(0.845) /kW	393.
394.					All remaining On-Peak kW: Transmission	9.098 /kW	All remaining On-Peak kW: Transmission	7.282 /kW	(1.816) /kW	394.
395.					First 100 Residual kW: Transmission	4.140 /kW	First 100 Off-Peak kW: Transmission	4.417 /kW	0.277 /kW	395.
396.					All remaining Residual kW: Transmission	2.787 /kW	All remaining Off-Peak kW: Transmission	2.974 /kW	0.187 /kW	396.
397.					All On-Peak kWh:	0.07076 /kWh	All On-Peak kWh:	0.07184 /kWh	0.00108 /kWh	397.
398.					All Off-Peak kWh:	0.05623 /kWh	All Off-Peak kWh:	0.05699 /kWh	0.00076 /kWh	398.
399.										399.
400.				Winter	BSC: Self-Contained Meters	$ 0.710 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.052) /day	400.
401.					BSC: Instrument-rated Meters	1.324 /day	BSC: Instrument-rated Meters	1.328 /day	0.004 /day	401.
402.					BSC: Primary Meters	3.415 /day	BSC: Primary Meters	3.477 /day	0.062 /day	402.
403.					BSC: Transmission Meters	26.163 /day	BSC: Transmission Meters	26.855 /day	0.692 /day	403.
404.					First 100 On-Peak kW: Secondary	13.901 /kW	First 100 On-Peak kW: Secondary	13.139 /kW	(0.762) /kW	404.
405.					All remaining On-Peak kW: Secondary	9.439 /kW	All remaining On-Peak kW: Secondary	8.379 /kW	(1.060) /kW	405.
406.					First 100 Residual kW: Secondary	5.331 /kW	First 100 Off-Peak kW: Secondary	5.688 /kW	0.357 /kW	406.
407.					All remaining Residual kW: Secondary	2.969 /kW	All remaining Off-Peak kW: Secondary	3.168 /kW	0.199 /kW	407.
408.					First 100 On-Peak kW: Primary	13.455 /kW	First 100 On-Peak kW: Primary	12.663 /kW	(0.792) /kW	408.
409.					All remaining On-Peak kW: Primary	9.373 /kW	All remaining On-Peak kW: Primary	8.308 /kW	(1.065) /kW	409.
410.					First 100 Residual kW: Primary	4.771 /kW	First 100 Off-Peak kW: Primary	5.090 /kW	0.319 /kW	410.
411.					All remaining Residual kW: Primary	2.891 /kW	All remaining Off-Peak kW: Primary	3.085 /kW	0.194 /kW	411.
412.					First 100 On-Peak kW: Transmission	12.658 /kW	First 100 On-Peak kW: Transmission	11.813 /kW	(0.845) /kW	412.
413.					All remaining On-Peak kW: Transmission	9.098 /kW	All remaining On-Peak kW: Transmission	7.282 /kW	(1.816) /kW	413.
414.					First 100 Residual kW: Transmission	4.140 /kW	First 100 Off-Peak kW: Transmission	4.417 /kW	0.277 /kW	414.
415.					All remaining Residual kW: Transmission	2.787 /kW	All remaining Off-Peak kW: Transmission	2.974 /kW	0.187 /kW	415.
416.					All On-Peak kWh:	0.05421 /kWh	All On-Peak kWh:	0.05492 /kWh	0.001 /kWh	416.
417.					All Off-Peak kWh:	0.03968 /kWh	All Off-Peak kWh:	0.04007 /kWh	0.000 /kWh	417.
418.										418.
419.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.710 /day	N/A	N/A /day	N/A /day	419.
420.					BSC: Instrument-rated Meters	1.324 /day	N/A	N/A /day	N/A /day	420.
421.					BSC: Primary Meters	3.415 /day	N/A	N/A /day	N/A /day	421.
422.					BSC: Transmission Meters	26.163 /day	N/A	N/A /day	N/A /day	422.
423.					Minimum Demand Charge:	2.141 /kW	N/A	N/A /kW	N/A /kW	423.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
424.										424.
425.	E-34	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 1.135 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.477) /day	425.
426.		General Service			BSC: Instrument-rated Meters	1.776 /day	BSC: Instrument-rated Meters	1.328 /day	(0.448) /day	426.
427.					BSC: Primary Meters	3.828 /day	BSC: Primary Meters	3.477 /day	(0.351) /day	427.
428.					BSC: Transmission Meters	26.161 /day	BSC: Transmission Meters	26.855 /day	0.694 /day	428.
429.					All kW: Secondary	17.377 /kW	All kW: Secondary	16.646 /kW	(0.731) /kW	429.
430.					All kW: Primary	16.478 /kW	All kW: Primary	15.687 /kW	(0.791) /kW	430.
431.					All kW: Primary on Military Bases	12.787 /kW	All kW: Primary on Military Bases	11.749 /kW	(1.038) /kW	431.
432.					All kW: Transmission	12.005 /kW	All kW: Transmission	10.914 /kW	(1.091) /kW	432.
433.					All kWh	0.04220 /kWh	All kWh	0.04258 /kWh	0.000 /kWh	433.
434.										434.
435.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 1.135 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.477) /day	435.
436.					BSC: Instrument-rated Meters	1.776 /day	BSC: Instrument-rated Meters	1.328 /day	(0.448) /day	436.
437.					BSC: Primary Meters	3.828 /day	BSC: Primary Meters	3.477 /day	(0.351) /day	437.
438.					BSC: Transmission Meters	26.161 /day	BSC: Transmission Meters	26.855 /day	0.694 /day	438.
439.					Demand Charge: Secondary	17.377 /kW	Demand Charge: Secondary	16.646 /kW	(0.731) /kW	439.
440.					Demand Charge: Primary	16.478 /kW	Demand Charge: Primary	15.687 /kW	(0.791) /kW	440.
441.					Demand Charge: Primary on Military Bases	12.787 /kW	Demand Charge: Primary on Military Bases	11.749 /kW	(1.038) /kW	441.
442.					Demand Charge: Transmission	12.005 /kW	Demand Charge: Transmission	10.914 /kW	(1.091) /kW	442.
443.										443.
444.	E-35	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 1.183 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.525) /day	444.
445.		General Service			BSC: Instrument-rated Meters	1.795 /day	BSC: Instrument-rated Meters	1.328 /day	(0.467) /day	445.
446.		Time Of Use			BSC: Primary Meters	3.881 /day	BSC: Primary Meters	3.477 /day	(0.404) /day	446.
447.					BSC: Transmission Meters	26.574 /day	BSC: Transmission Meters	26.855 /day	0.281 /day	447.
448.					All On-Peak kW: Secondary	15.091 /kW	All On-Peak kW: Secondary	14.351 /kW	(0.740) /kW	448.
449.					All Excess Off-Peak kW: Secondary	2.734 /kW	All Off-Peak kW: Secondary	2.945 /kW	0.211 /kW	449.
450.					All On-Peak kW: Primary	14.343 /kW	All On-Peak kW: Primary	13.545 /kW	(0.798) /kW	450.
451.					All Excess Off-Peak kW: Primary	2.659 /kW	All Off-Peak kW: Primary	2.864 /kW	0.205 /kW	451.
452.					All On-Peak kW: Primary on Military Bases	11.520 /kW	All On-Peak kW: Primary on Military Bases	10.502 /kW	(1.018) /kW	452.
453.					All Excess Off-Peak kW; Primary on Military	2.376 /kW	All Off-Peak kW: Primary on Military Bases	2.559 /kW	0.183 /kW	453.
454.					All On-Peak kW: Trans.	10.483 /kW	All On-Peak kW: Transmission	9.385 /kW	(1.098) /kW	454.
455.					All Excess Off-Peak kW: Trans.	2.273 /kW	All Off-Peak kW: Transmission	2.448 /kW	0.175 /kW	455.
456.					All On-Peak kWh	0.04694 /kWh	All On-Peak kWh	0.04749 /kWh	0.00055 /kWh	456.
457.					All Off-Peak kWh	0.03530 /kWh	All Off-Peak kWh	0.03559 /kWh	0.00029 /kWh	457.
458.										458.
459.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 1.183 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.525) /day	459.
460.					BSC: Instrument-rated Meters	1.795 /day	BSC: Instrument-rated Meters	1.328 /day	(0.467) /day	460.
461.					BSC: Primary Meters	3.881 /day	BSC: Primary Meters	3.477 /day	(0.404) /day	461.
462.					BSC: Transmission Meters	26.574 /day	BSC: Transmission Meters	26.855 /day	0.281 /day	462.
463.					Demand Charge: Secondary	15.091 /kW	Demand Charge: Secondary	14.351 /kW	(0.740) /kW	463.
464.					Demand Charge: Primary	14.343 /kW	Demand Charge: Primary	13.545 /kW	(0.798) /kW	464.
465.					Demand Charge: Primary on Military Bases	11.520 /kW	Demand Charge: Primary on Military Bases	10.502 /kW	(1.018) /kW	465.
466.					Demand Charge: Transmission	10.483 /kW	Demand Charge: Transmission	9.385 /kW	(1.098) /kW	466.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
467.										467.
468.	E-36 XL	Station Use Service	Rate	Sum & Win	Basic Service Charge	$ 6,912.00 /mo	Basic Service Charge	$ 6,912.00 /mo	$ - /mo	468.
469.					Metering Charge Company Owned	1.29%	Metering Charge Company Owned	1.29%	-	469.
470.					Metering Charge Customer Owned	0.35%	Metering Charge Customer Owned	0.35%	-	470.
471.					All kW: Secondary	5.190 /kW	All kW: Secondary	3.605 /kW	(1.585) /kW	471.
472.					All kW: Primary	5.008 /kW	All kW: Primary	3.423 /kW	(1.585) /kW	472.
473.					All kW: Transmission	1.620 /kW	All kW: Transmission	0.035 /kW	(1.585) /kW	473.
474.					All kWh: Hourly Pricing Proxy plus	0.00057 /kWh	All kWh: Hourly Pricing Proxy plus	0.00057 /kWh	- /kWh	474.
475.										475.
476.	E-36 M	Station Use Service Medium	Rate	Sum & win	PROPOSE NEW SCHEDULE		Billed on applicable E-32 rate except for BSC Charge			476.
477.							BSC: Self-Contained Meters	$ 1.344 /day	$ 1.344 /day	477.
478.							BSC: Instrument-rated Meters	1.322 /day	1.322 /day	478.
479.							BSC: Primary Meters	6.830 /day	6.830 /day	479.
480.										480.
481.										481.
482.	E-40	Agricultural Wind		Sum & Win	Service Charge $/HP	$ 0.049 /HP-day	RATE E-40 PROPOSE TO CANCEL; CUSTOMER TO MOVE TO E-32 XS			482.
483.		Machine Service			All kWh	0.09106 /kWh				483.
484.										484.
485.	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES** (Company Owned)		**FIXTURES** (Company Owned)			485.
486.		Service			A. Acorn 9,500 HPS	$ 27.06 /mo	A. Acorn 9,500 HPS	$ 27.88 /mo	$ 0.82 /mo	486.
487.					Acorn 16,000 HPS	30.04 /mo	Acorn 16,000 HPS	30.85 /mo	0.81 /mo	487.
488.					B. Architectural 9,500 HPS	15.38 /mo	B. Architectural 9,500 HPS	15.77 /mo	0.39 /mo	488.
489.					Architectural 16,000 HPS	17.96 /mo	Architectural 16,000 HPS	18.33 /mo	0.37 /mo	489.
490.					Architectural 30,000 HPS	21.31 /mo	Architectural 30,000 HPS	21.67 /mo	0.36 /mo	490.
491.					Architectural 50,000 HPS	26.29 /mo	Architectural 50,000 HPS	26.60 /mo	0.31 /mo	491.
492.					Architectural 14,000 MH	21.51 /mo	Architectural 14,000 MH	21.99 /mo	0.48 /mo	492.
493.					Architectural 21,000 MH	24.42 /mo	Architectural 21,000 MH	24.88 /mo	0.46 /mo	493.
494.					Architectural 36,000 MH	30.54 /mo	Architectural 36,000 MH	30.98 /mo	0.44 /mo	494.
495.					Architectural 8,000 LPS	22.35 /mo	Architectural 8,000 LPS	23.04 /mo	0.69 /mo	495.
496.					Architectural 13,500 LPS	26.36 /mo	Architectural 13,500 LPS	27.11 /mo	0.75 /mo	496.
497.					Architectural 22,500 LPS	30.11 /mo	Architectural 22,500 LPS	30.90 /mo	0.79 /mo	497.
498.					Architectural 33,000 LPS	36.22 /mo	Architectural 33,000 LPS	37.16 /mo	0.94 /mo	498.
499.					C. Cobra/Roadway 5,800 HPS	8.73 /mo	C. Cobra/Roadway 5,800 HPS	8.93 /mo	0.20 /mo	499.
500.					Cobra/Roadway 9,500 HPS	10.28 /mo	Cobra/Roadway 9,500 HPS	10.49 /mo	0.21 /mo	500.
501.					Cobra/Roadway 16,000 HPS	12.87 /mo	Cobra/Roadway 16,000 HPS	13.05 /mo	0.18 /mo	501.
502.					Cobra/Roadway 30,000 HPS	15.52 /mo	Cobra/Roadway 30,000 HPS	15.67 /mo	0.15 /mo	502.
503.					Cobra/Roadway 50,000 HPS	21.06 /mo	Cobra/Roadway 50,000 HPS	21.18 /mo	0.12 /mo	503.
504.					Cobra/Roadway 14,000 MH	14.97 /mo	Cobra/Roadway 14,000 MH	15.21 /mo	0.24 /mo	504.
505.					Cobra/Roadway 21,000 MH	17.49 /mo	Cobra/Roadway 21,000 MH	17.70 /mo	0.21 /mo	505.
506.					Cobra/Roadway 36,000 MH	23.03 /mo	Cobra/Roadway 36,000 MH	23.20 /mo	0.17 /mo	506.
507.					Cobra/Roadway 8,000 FL	17.20 /mo	Cobra/Roadway 8,000 FL	17.67 /mo	0.47 /mo	507.
508.					D. Decorative Transit 9,500 HPS	37.09 /mo	D. Decorative Transit 9,500 HPS	38.27 /mo	1.18 /mo	508.
509.					Decorative Transit 16,000 HPS	36.88 /mo	Decorative Transit 16,000 HPS	37.94 /mo	1.06 /mo	509.
510.					Decorative Transit 30,000 HPS	42.46 /mo	Decorative Transit 30,000 HPS	43.59 /mo	1.13 /mo	510.
511.					E. Flood 30,000 HPS	20.61 /mo	E. Flood 30,000 HPS	20.94 /mo	0.33 /mo	511.
512.					Flood 50,000 HPS	25.56 /mo	Flood 50,000 HPS	25.84 /mo	0.28 /mo	512.
513.					Flood 21,000 MH	22.00 /mo	Flood 21,000 MH	22.37 /mo	0.37 /mo	513.
514.					Flood 36,000 MH	26.82 /mo	Flood 36,000 MH	27.13 /mo	0.31 /mo	514.
515.					F. Post Top gray 8,000 FL	18.54 /mo	F. Post Top gray 8,000 FL	19.06 /mo	0.52 /mo	515.
516.					Post Top gray 9,500 HPS	10.60 /mo	Post Top gray 9,500 HPS	10.82 /mo	0.22 /mo	516.
517.					Post Top black 9,500 HPS	12.21 /mo	Post Top black 9,500 HPS	12.49 /mo	0.28 /mo	517.
518.					Post Top Transit 9,500 HPS	32.47 /mo	Post Top Transit 9,500 HPS	33.49 /mo	1.02 /mo	518.
519.					G. FROZEN 4,000 INC	9.78 /mo	G. FROZEN 4,000 INC	9.70 /mo	(0.08) /mo	519.
520.					FROZEN 7,000 MV	12.67 /mo	FROZEN 7,000 MV	12.82 /mo	0.15 /mo	520.
521.					FROZEN 20,000 MV	24.92 /mo	FROZEN 20,000 MV	25.19 /mo	0.27 /mo	521.
522.					FROZEN Brackets 8ft to 16ft	1.72 /mo	FROZEN Brackets 8ft to 16ft	1.78 /mo	0.06 /mo	522.
523.					**FIXTURES** (Customer Owned)		**FIXTURES** (Customer Owned)			523.
524.					A. Acorn 9,500 HPS	$ 9.22 /mo	A. Acorn 9,500 HPS	$ 7.09 /mo	$ (2.13) /mo	524.
525.					Acorn 16,000 HPS	11.65 /mo	Acorn 16,000 HPS	8.89 /mo	(2.76) /mo	525.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (I) - (F)	Line No.
526.										526.
527.	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES** (Customer Owned) (cont)		**FIXTURES** (Customer Owned) (cont)			527.
528.	(cont)	Service			B. Architectural 9,500 HPS	$ 7.34 /mo	B. Architectural 9,500 HPS	$ 5.61 /mo	(1.73) /mo	528.
529.		(cont)			Architectural 16,000 HPS	9.82 /mo	Architectural 16,000 HPS	7.45 /mo	(2.37) /mo	529.
530.					Architectural 30,000 HPS	12.60 /mo	Architectural 30,000 HPS	9.51 /mo	(3.09) /mo	530.
531.					Architectural 50,000 HPS	18.13 /mo	Architectural 50,000 HPS	13.63 /mo	(4.50) /mo	531.
532.					Architectural 14,000 MH	11.79 /mo	Architectural 14,000 MH	8.98 /mo	(2.81) /mo	532.
533.					Architectural 21,000 MH	14.54 /mo	Architectural 21,000 MH	11.02 /mo	(3.52) /mo	533.
534.					Architectural 36,000 MH	20.00 /mo	Architectural 36,000 MH	15.08 /mo	(4.92) /mo	534.
535.					Architectural 8,000 LPS	9.82 /mo	Architectural 8,000 LPS	7.61 /mo	(2.21) /mo	535.
536.					Architectural 13,500 LPS	11.84 /mo	Architectural 13,500 LPS	9.12 /mo	(2.72) /mo	536.
537.					Architectural 22,500 LPS	14.45 /mo	Architectural 22,500 LPS	11.07 /mo	(3.38) /mo	537.
538.					Architectural 33,000 LPS	17.02 /mo	Architectural 33,000 LPS	13.03 /mo	(3.99) /mo	538.
539.					C. Cobra/Roadway 5,800 HPS	5.16 /mo	C. Cobra/Roadway 5,800 HPS	3.94 /mo	(1.22) /mo	539.
540.					Cobra/Roadway 9,500 HPS	6.32 /mo	Cobra/Roadway 9,500 HPS	4.81 /mo	(1.51) /mo	540.
541.					Cobra/Roadway 16,000 HPS	8.82 /mo	Cobra/Roadway 16,000 HPS	6.66 /mo	(2.16) /mo	541.
542.					Cobra/Roadway 30,000 HPS	11.46 /mo	Cobra/Roadway 30,000 HPS	8.61 /mo	(2.85) /mo	542.
543.					Cobra/Roadway 50,000 HPS	16.37 /mo	Cobra/Roadway 50,000 HPS	12.25 /mo	(4.12) /mo	543.
544.					Cobra/Roadway 14,000 MH	10.20 /mo	Cobra/Roadway 14,000 MH	7.72 /mo	(2.48) /mo	544.
545.					Cobra/Roadway 21,000 MH	12.69 /mo	Cobra/Roadway 21,000 MH	9.57 /mo	(3.12) /mo	545.
546.					Cobra/Roadway 36,000 MH	17.63 /mo	Cobra/Roadway 36,000 MH	13.22 /mo	(4.41) /mo	546.
547.					Cobra/Roadway 8,000 FL	5.04 /mo	Cobra/Roadway 8,000 FL	3.81 /mo	(1.23) /mo	547.
548.					D. Decorative Transit 9,500 HPS	11.11 /mo	D. Decorative Transit 9,500 HPS	8.58 /mo	(2.53) /mo	548.
549.					Decorative Transit 16,000 HPS	6.31 /mo	Decorative Transit 16,000 HPS	6.25 /mo	(0.06) /mo	549.
550.					Decorative Transit 30,000 HPS	16.02 /mo	Decorative Transit 30,000 HPS	12.20 /mo	(3.82) /mo	550.
551.					E. Flood 30,000 HPS	12.81 /mo	E. Flood 30,000 HPS	9.67 /mo	(3.14) /mo	551.
552.					Flood 50,000 HPS	17.77 /mo	Flood 50,000 HPS	13.35 /mo	(4.42) /mo	552.
553.					Flood 21,000 MH	13.53 /mo	Flood 21,000 MH	10.23 /mo	(3.30) /mo	553.
554.					Flood 36,000 MH	18.35 /mo	Flood 36,000 MH	13.79 /mo	(4.56) /mo	554.
555.					F. Post Top gray 8,000 FL	5.23 /mo	F. Post Top gray 8,000 FL	3.96 /mo	(1.27) /mo	555.
556.					Post Top gray 9,500 HPS	6.65 /mo	Post Top gray 9,500 HPS	5.07 /mo	(1.58) /mo	556.
557.					Post Top black 9,500 HPS	6.88 /mo	Post Top black 9,500 HPS	5.25 /mo	(1.63) /mo	557.
558.					Post Top Transit 9,500 HPS	10.24 /mo	Post Top Transit 9,500 HPS	7.90 /mo	(2.34) /mo	558.
559.					G. FROZEN 4,000 INC	5.47 /mo	G. FROZEN 4,000 INC	3.87 /mo	(1.60) /mo	559.
560.					FROZEN 7,000 MV	7.27 /mo	FROZEN 7,000 MV	5.42 /mo	(1.85) /mo	560.
561.					FROZEN 20,000 MV	14.12 /mo	FROZEN 20,000 MV	10.48 /mo	(3.64) /mo	561.
562.					**POLES**		**POLES**			562.
563.					A. Anchor Flush, Round, 1X, 12ft	$ 12.17 /mo	A. Anchor Flush, Round, 1X, 12ft	$ 12.61 /mo	$ 0.44 /mo	563.
564.					Anchor Flush, Round, 1X, 22ft	13.70 /mo	Anchor Flush, Round, 1X, 22ft	14.20 /mo	0.50 /mo	564.
565.					Anchor Flush, Round, 1X, 25ft	14.82 /mo	Anchor Flush, Round, 1X, 25ft	15.36 /mo	0.54 /mo	565.
566.					Anchor Flush, Round, 1X, 30ft	17.03 /mo	Anchor Flush, Round, 1X, 30ft	17.65 /mo	0.62 /mo	566.
567.					Anchor Flush, Round, 1X, 32ft	17.89 /mo	Anchor Flush, Round, 1X, 32ft	18.54 /mo	0.65 /mo	567.
568.					Anchor Flush, Round, 2X, 12ft	12.98 /mo	Anchor Flush, Round, 2X, 12ft	13.45 /mo	0.47 /mo	568.
569.					Anchor Flush, Round, 2X, 22ft	14.91 /mo	Anchor Flush, Round, 2X, 22ft	15.45 /mo	0.54 /mo	569.
570.					Anchor Flush, Round, 2X, 25ft	15.55 /mo	Anchor Flush, Round, 2X, 25ft	16.12 /mo	0.57 /mo	570.
571.					Anchor Flush, Round, 2X, 30ft	18.07 /mo	Anchor Flush, Round, 2X, 30ft	18.73 /mo	0.66 /mo	571.
572.					Anchor Flush, Round, 2X, 32ft	19.28 /mo	Anchor Flush, Round, 2X, 32ft	19.98 /mo	0.70 /mo	572.
573.					Anchor Flush, Square, 5", 13ft	13.95 /mo	Anchor Flush, Square, 5", 13ft	14.46 /mo	0.51 /mo	573.
574.					Anchor Flush, Square, 5", 15ft	12.47 /mo	Anchor Flush, Square, 5", 15ft	12.93 /mo	0.46 /mo	574.
575.					Anchor Flush, Square, 5", 23ft	14.79 /mo	Anchor Flush, Square, 5", 23ft	15.33 /mo	0.54 /mo	575.
576.					Anchor Flush, Square, 5", 25ft	16.26 /mo	Anchor Flush, Square, 5", 25ft	16.85 /mo	0.59 /mo	576.
577.					Anchor Flush, Square, 5", 28ft	18.05 /mo	Anchor Flush, Square, 5", 28ft	18.71 /mo	0.66 /mo	577.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
578.										578.
579.	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**POLES** (cont)		**POLES** (cont)			579.
580.	(cont)	Service			A. Anchor Flush, Square, 5', 32ft	$ 17.95 /mo	A. Anchor Flush, Square, 5', 32ft	$ 18.61 /mo	$ 0.66 /mo	580.
581.		(cont)			Anchor Flush, Concrete, 12ft	41.58 /mo	Anchor Flush, Concrete, 12ft	43.10 /mo	1.52 /mo	581.
582.					Anchor Flush, Fiberglass, 12ft	35.21 /mo	Anchor Flush, Fiberglass, 12ft	36.50 /mo	1.29 /mo	582.
583.					Anchor Flush, Dec Transit Ped, 4', 16ft	34.33 /mo	Anchor Flush, Dec Transit Ped, 4', 16ft	35.58 /mo	1.25 /mo	583.
584.					Anchor Flush, Dec Transit, 6', 30ft	66.28 /mo	Anchor Flush, Dec Transit, 6', 30ft	68.70 /mo	2.42 /mo	584.
585.					B. Anchor Pedstl, Round, 1X, 12ft	11.71 /mo	B. Anchor Pedstl, Round, 1X, 12ft	12.14 /mo	0.43 /mo	585.
586.					Anchor Pedstl, Round, 1X, 22ft	13.24 /mo	Anchor Pedstl, Round, 1X, 22ft	13.72 /mo	0.48 /mo	586.
587.					Anchor Pedstl, Round, 1X, 25ft	14.35 /mo	Anchor Pedstl, Round, 1X, 25ft	14.87 /mo	0.52 /mo	587.
588.					Anchor Pedstl, Round, 1X, 30ft	16.58 /mo	Anchor Pedstl, Round, 1X, 30ft	17.19 /mo	0.61 /mo	588.
589.					Anchor Pedstl, Round, 1X, 32ft	17.41 /mo	Anchor Pedstl, Round, 1X, 32ft	18.05 /mo	0.64 /mo	589.
590.					Anchor Pedstl, Round, 2X, 12ft	12.51 /mo	Anchor Pedstl, Round, 2X, 12ft	12.97 /mo	0.46 /mo	590.
591.					Anchor Pedstl, Round, 2X, 22ft	13.97 /mo	Anchor Pedstl, Round, 2X, 22ft	14.48 /mo	0.51 /mo	591.
592.					Anchor Pedstl, Round, 2X, 25ft	15.08 /mo	Anchor Pedstl, Round, 2X, 25ft	15.63 /mo	0.55 /mo	592.
593.					Anchor Pedstl, Round, 2X, 30ft	17.61 /mo	Anchor Pedstl, Round, 2X, 30ft	18.25 /mo	0.64 /mo	593.
594.					Anchor Pedstl, Round, 2X, 32ft	18.81 /mo	Anchor Pedstl, Round, 2X, 32ft	19.50 /mo	0.69 /mo	594.
595.					Anchor Pedstl, Round, 3 Bolt, 32ft	21.62 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	22.41 /mo	0.79 /mo	595.
596.					Anchor Pedstl, Square, 5', 13ft	13.50 /mo	Anchor Pedstl, Square, 5', 13ft	13.99 /mo	0.49 /mo	596.
597.					Anchor Pedstl, Square, 5', 15ft	13.80 /mo	Anchor Pedstl, Square, 5', 15ft	14.30 /mo	0.50 /mo	597.
598.					Anchor Pedstl, Square, 5', 23ft	14.32 /mo	Anchor Pedstl, Square, 5', 23ft	14.84 /mo	0.52 /mo	598.
599.					Anchor Pedstl, Square, 5', 25ft	15.80 /mo	Anchor Pedstl, Square, 5', 25ft	16.38 /mo	0.58 /mo	599.
600.					Anchor Pedstl, Square, 5', 28ft	17.56 /mo	Anchor Pedstl, Square, 5', 28ft	18.20 /mo	0.64 /mo	600.
601.					Anchor Pedstl, Square, 5', 32ft	18.23 /mo	Anchor Pedstl, Square, 5', 32ft	18.90 /mo	0.67 /mo	601.
602.					C. Direct Bury, Round, 19ft	18.42 /mo	C. Direct Bury, Round, 19ft	19.09 /mo	0.67 /mo	602.
603.					Direct Bury, Round, 30ft	14.38 /mo	Direct Bury, Round, 30ft	14.90 /mo	0.52 /mo	603.
604.					Direct Bury, Round, 38ft	17.55 /mo	Direct Bury, Round, 38ft	18.19 /mo	0.64 /mo	604.
605.					Direct Bury, Self-Support, 40ft	21.62 /mo	Direct Bury, Self-Support, 40ft	22.41 /mo	0.79 /mo	605.
606.					Direct Bury, Stepped, 49ft	64.99 /mo	Direct Bury, Stepped, 49ft	67.36 /mo	2.37 /mo	606.
607.					Direct Bury, Square, 4", 34ft	15.87 /mo	Direct Bury, Square, 4", 34ft	16.45 /mo	0.58 /mo	607.
608.					Direct Bury, Square, 5", 20ft	15.07 /mo	Direct Bury, Square, 5", 20ft	15.62 /mo	0.55 /mo	608.
609.					Direct Bury, Square, 30ft	15.71 /mo	Direct Bury, Square, 30ft	16.28 /mo	0.57 /mo	609.
610.					Direct Bury, Square, 38ft	17.05 /mo	Direct Bury, Square, 38ft	17.67 /mo	0.62 /mo	610.
611.					Decorative Transit 41- 6	20.47 /mo	Decorative Transit 41- 6	21.22 /mo	0.75 /mo	611.
612.					Decorative Transit 47	25.50 /mo	Decorative Transit 47	26.43 /mo	0.93 /mo	612.
613.					Direct Bury, Steel Dist Pole, 35ft	23.54 /mo	Direct Bury, Steel Dist Pole, 35ft	24.40 /mo	0.86 /mo	613.
614.					D. Post Top, Dec Transit, 16ft	35.07 /mo	D. Post Top, Dec Transit, 16ft	36.35 /mo	1.28 /mo	614.
615.					Post Top, Gray Steel/Fiberglass, 23ft	12.16 /mo	Post Top, Gray Steel/Fiberglass, 23ft	12.60 /mo	0.44 /mo	615.
616.					Post Top, Black Steel, 23ft	13.41 /mo	Post Top, Black Steel, 23ft	13.90 /mo	0.49 /mo	616.
617.					E. FROZEN, Wood Poles, 30ft	8.95 /mo	E. FROZEN, Wood Poles, 30ft	9.28 /mo	0.33 /mo	617.
618.					FROZEN, Wood Poles, 35ft	8.95 /mo	FROZEN, Wood Poles, 35ft	9.28 /mo	0.33 /mo	618.
619.					FROZEN, Wood Poles, 40ft	12.73 /mo	FROZEN, Wood Poles, 40ft	13.19 /mo	0.46 /mo	619.
620.					**ANCHOR BASE**		**ANCHOR BASE**			620.
621.					Flush, 4ft	$ 9.91 /mo	Flush, 4ft	$ 10.27 /mo	$ 0.36 /mo	621.
622.					Flush, 6ft	11.82 /mo	Flush, 6ft	12.25 /mo	0.43 /mo	622.
623.					Pedestal, 8ft	13.54 /mo	Pedestal, 8ft	14.03 /mo	0.49 /mo	623.
624.					Pedestal, 32' round steel pole, 4ft 6"	9.39 /mo	Pedestal, 32' round steel pole, 4ft 6"	9.73 /mo	0.34 /mo	624.
625.					**OPTIONAL EQUIPMENT**		**OPTIONAL EQUIPMENT**			625.
626.					1. 100' OH, UG if conduit by customer	$ 3.50 /mo	1. 100' OH, UG if conduit by customer	$ 3.63 /mo	$ 0.13 /mo	626.
627.					2. HPS not accessible by bucket	2.80 /mo	2. HPS not accessible by bucket	2.90 /mo	0.10 /mo	627.
628.					3. MH not accessible by bucket	6.04 /mo	3. MH not accessible by bucket	6.26 /mo	0.22 /mo	628.
629.					**NON-STANDARD FACILITIES**		**NON-STANDARD FACILITIES**			629.
630.					Service Charge	$ 3.35 /mo	Service Charge	$ 3.47 /mo	$ 0.12 /mo	630.
631.					All kWh	0.06345 /kWh	All kWh	0.06577 /kWh	0.00232 /kWh	631.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
632.													632.
633.	E-53	Electric Service for	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU								633.
634.		Athletic Stadiums						RATE E-53 PROPOSE TO CANCEL					634.
635.		and Sports Fields	Minimum	Sum & Win	No bills rendered when no usage								635.
636.													636.
637.	E-54	Seasonal Service	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU			Billed on Rate Schedule E-32 L					637.
638.													638.
639.			Minimum	Sum & Win	"Floor" Annual Minimum	$ 603.49	/yr	"Floor" Annual Minimum	$ 603.49	/yr	$ -	/yr	639.
640.					Monthly Minimum	50.29	/mo	Monthly Minimum	50.29	/mo	-	/mo	640.
641.													641.
642.	E-56	Electric Service for	Basic										642.
643.		Partial Requirements	Service	Sum & Win	Basic Service Charge	per applicable rate schedule		Basic Service Charge	per applicable rate schedule				643.
644.		Service for CG											644.
645.		installations of 100kw											645.
646.			Supplemental										646.
647.			Service	Sum & Win	All Supplemental Charges	per applicable rate schedule		All Supplemental Charges	per applicable rate schedule				647.
648.													648.
649.			Back-Up		Back-Up Service with E-32 On-Peak	0.1184	/kW-day	Back-Up Service with E-32 On-Peak	0.2760	/kW-day	0.15760	/kW-day	649.
650.			Service		Back-Up Service with E-32 Off-Peak	N/A		Back-Up Service with E-32 Off-Peak	N/A		-		650.
651.					Back-Up Service with E-34 On-Peak	0.5756	/kW-day	Back-Up Service with E-34 On-Peak	0.3500	/kW-day	(0.22560)	/kW-day	651.
652.					Back-Up Service with E-34 Off-Peak	N/A		Back-Up Service with E-34 Off-Peak	N/A		-		652.
653.													653.
654.			Maint.		Scheduled Maintenance On-Peak	1/2 Back-up Charge		Scheduled Maintenance On-Peak	1/2 Back-up Charge		-		654.
655.			Service		Scheduled Maintenance Off-Peak	N/A		Scheduled Maintenance Off-Peak	N/A		-		655.
656.													656.
657.			Excess	Sum & Win	Secondary Service Excess Charge	$ 53.17	/kW	Secondary Service Excess Charge	$ 54.64	/kW	$ 1.47	/kW	657.
658.					Primary Service Excess Charge	50.47	/kW	Primary Service Excess Charge	51.87	/kW	1.40	/kW	658.
659.					Transmission Service Excess Charge	37.05	/kW	Transmission Service Excess Charge	38.08	/kW	1.03	/kW	659.
660.													660.
661.	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Investment by Company)			**FIXTURES** (Investment by Company)					661.
662.					A. Acorn 9,500 HPS	$ 27.06	/mo	A. Acorn 9,500 HPS	$ 27.88	/mo	$ 0.82000	/mo	662.
663.					Acorn 16,000 HPS	30.04	/mo	Acorn 16,000 HPS	30.85	/mo	0.81000	/mo	663.
664.					B. Architectural 9,500 HPS	15.38	/mo	B. Architectural 9,500 HPS	15.77	/mo	0.39000	/mo	664.
665.					Architectural 16,000 HPS	17.96	/mo	Architectural 16,000 HPS	18.33	/mo	0.37000	/mo	665.
666.					Architectural 30,000 HPS	21.31	/mo	Architectural 30,000 HPS	21.67	/mo	0.36000	/mo	666.
667.					Architectural 50,000 HPS	26.29	/mo	Architectural 50,000 HPS	26.60	/mo	0.31000	/mo	667.
668.					Architectural 14,000 MH	21.51	/mo	Architectural 14,000 MH	21.99	/mo	0.48000	/mo	668.
669.					Architectural 21,000 MH	24.42	/mo	Architectural 21,000 MH	24.88	/mo	0.46000	/mo	669.
670.					Architectural 36,000 MH	30.54	/mo	Architectural 36,000 MH	30.98	/mo	0.44000	/mo	670.
671.					Architectural 8,000 LPS	22.35	/mo	Architectural 8,000 LPS	23.04	/mo	0.69000	/mo	671.
672.					Architectural 13,500 LPS	26.36	/mo	Architectural 13,500 LPS	27.11	/mo	0.75000	/mo	672.
673.					Architectural 22,500 LPS	30.11	/mo	Architectural 22,500 LPS	30.90	/mo	0.79000	/mo	673.
674.					Architectural 33,000 LPS	36.22	/mo	Architectural 33,000 LPS	37.16	/mo	0.94000	/mo	674.
675.					C. Cobra/Roadway 5,800 HPS	8.73	/mo	C. Cobra/Roadway 5,800 HPS	8.93	/mo	0.20000	/mo	675.
676.					Cobra/Roadway 9,500 HPS	10.28	/mo	Cobra/Roadway 9,500 HPS	10.49	/mo	0.21000	/mo	676.
677.					Cobra/Roadway 16,000 HPS	12.87	/mo	Cobra/Roadway 16,000 HPS	13.05	/mo	0.18000	/mo	677.
678.					Cobra/Roadway 30,000 HPS	15.52	/mo	Cobra/Roadway 30,000 HPS	15.67	/mo	0.15000	/mo	678.
679.					Cobra/Roadway 50,000 HPS	21.06	/mo	Cobra/Roadway 50,000 HPS	21.18	/mo	0.12000	/mo	679.
680.					Cobra/Roadway 14,000 MH	14.97	/mo	Cobra/Roadway 14,000 MH	15.21	/mo	0.24000	/mo	680.
681.					Cobra/Roadway 21,000 MH	17.49	/mo	Cobra/Roadway 21,000 MH	17.70	/mo	0.21000	/mo	681.
682.					Cobra/Roadway 36,000 MH	23.03	/mo	Cobra/Roadway 36,000 MH	23.20	/mo	0.17000	/mo	682.
683.					Cobra/Roadway 8,000 FL	17.20	/mo	Cobra/Roadway 8,000 FL	17.67	/mo	0.47000	/mo	683.
684.					D. Decorative Transit 9,500 HPS	37.09	/mo	D. Decorative Transit 9,500 HPS	38.27	/mo	1.18000	/mo	684.
685.					Decorative Transit 16,000 HPS	36.88	/mo	Decorative Transit 16,000 HPS	37.94	/mo	1.06000	/mo	685.
686.					Decorative Transit 30,000 HPS	42.46	/mo	Decorative Transit 30,000 HPS	43.59	/mo	1.13000	/mo	686.
687.					E. Flood 30,000 HPS	20.61	/mo	E. Flood 30,000 HPS	20.94	/mo	0.33000	/mo	687.
688.					Flood 50,000 HPS	25.56	/mo	Flood 50,000 HPS	25.84	/mo	0.28000	/mo	688.
689.					Flood 21,000 MH	22.00	/mo	Flood 21,000 MH	22.37	/mo	0.37000	/mo	689.
690.					Flood 36,000 MH	26.82	/mo	Flood 36,000 MH	27.13	/mo	0.31000	/mo	690.
691.					F. Post Top gray 8,000 FL	18.54	/mo	F. Post Top gray 8,000 FL	19.06	/mo	0.52000	/mo	691.
692.					Post Top gray 9,500 HPS	10.60	/mo	Post Top gray 9,500 HPS	10.82	/mo	0.22000	/mo	692.
693.					Post Top black 9,500 HPS	12.21	/mo	Post Top black 9,500 HPS	12.49	/mo	0.28000	/mo	693.
694.					Post Top Transit 9,500 HPS	32.47	/mo	Post Top Transit 9,500 HPS	33.49	/mo	1.02000	/mo	694.
695.					G. FROZEN 4,000 INC	9.78	/mo	G. FROZEN 4,000 INC	9.70	/mo	(0.08000)	/mo	695.
696.					FROZEN 7,000 MV	12.67	/mo	FROZEN 7,000 MV	12.82	/mo	0.15000	/mo	696.
697.					FROZEN 11,000 MV	15.87	/mo	FROZEN 11,000 MV	16.04	/mo	0.17000	/mo	697.
698.					FROZEN 20,000 MV	24.92	/mo	FROZEN 20,000 MV	25.19	/mo	0.27000	/mo	698.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
699.													699.
700.	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Investment by Others)			**FIXTURES** (Investment by Others)					700.
701.	(cont)				A. Acom 9,500 HPS	$ 9.22	/mo	A. Acom 9,500 HPS	$ 9.39	/mo	$ 0.17000	/mo	701.
702.					Acom 16,000 HPS	11.65	/mo	Acom 16,000 HPS	11.79	/mo	0.14000	/mo	702.
703.					B. Architectural 9,500 HPS	7.34	/mo	B. Architectural 9,500 HPS	7.44	/mo	0.10000	/mo	703.
704.					Architectural 16,000 HPS	9.82	/mo	Architectural 16,000 HPS	9.89	/mo	0.07000	/mo	704.
705.					Architectural 30,000 HPS	12.60	/mo	Architectural 30,000 HPS	12.64	/mo	0.04000	/mo	705.
706.					Architectural 50,000 HPS	18.13	/mo	Architectural 50,000 HPS	18.14	/mo	0.01000	/mo	706.
707.					Architectural 14,000 MH	11.79	/mo	Architectural 14,000 MH	11.91	/mo	0.12000	/mo	707.
708.					Architectural 21,000 MH	14.54	/mo	Architectural 21,000 MH	14.64	/mo	0.10000	/mo	708.
709.					Architectural 36,000 MH	20.00	/mo	Architectural 36,000 MH	20.06	/mo	0.06000	/mo	709.
710.					Architectural 8,000 LPS	9.82	/mo	Architectural 8,000 LPS	10.05	/mo	0.23000	/mo	710.
711.					Architectural 13,500 LPS	11.84	/mo	B. Architectural 13,500 LPS	12.06	/mo	0.22000	/mo	711.
712.					Architectural 22,500 LPS	14.45	/mo	Architectural 22,500 LPS	14.67	/mo	0.22000	/mo	712.
713.					Architectural 33,000 LPS	17.02	/mo	Architectural 33,000 LPS	17.26	/mo	0.24000	/mo	713.
714.					C. Cobra/Roadway 5,800 HPS	5.16	/mo	C. Cobra/Roadway 5,800 HPS	5.23	/mo	0.07000	/mo	714.
715.					Cobra/Roadway 9,500 HPS	6.32	/mo	Cobra/Roadway 9,500 HPS	6.38	/mo	0.06000	/mo	715.
716.					Cobra/Roadway 16,000 HPS	8.82	/mo	Cobra/Roadway 16,000 HPS	8.85	/mo	0.03000	/mo	716.
717.					Cobra/Roadway 30,000 HPS	11.46	/mo	Cobra/Roadway 30,000 HPS	11.46	/mo	-	/mo	717.
718.					Cobra/Roadway 50,000 HPS	16.37	/mo	Cobra/Roadway 50,000 HPS	16.32	/mo	(0.05000)	/mo	718.
719.					Cobra/Roadway 14,000 MH	10.20	/mo	Cobra/Roadway 14,000 MH	10.26	/mo	0.06000	/mo	719.
720.					Cobra/Roadway 21,000 MH	12.69	/mo	Cobra/Roadway 21,000 MH	12.72	/mo	0.03000	/mo	720.
721.					Cobra/Roadway 36,000 MH	17.63	/mo	Cobra/Roadway 36,000 MH	17.60	/mo	(0.03000)	/mo	721.
722.					Cobra/Roadway 8,000 FL	5.04	/mo	Cobra/Roadway 8,000 FL	5.06	/mo	0.02000	/mo	722.
723.					D. Decorative Transit 9,500 HPS	11.11	/mo	D. Decorative Transit 9,500 HPS	11.35	/mo	0.24000	/mo	723.
724.					Decorative Transit 16,000 HPS	12.41	/mo	Decorative Transit 16,000 HPS	12.57	/mo	0.16000	/mo	724.
725.					Decorative Transit 30,000 HPS	16.02	/mo	Decorative Transit 30,000 HPS	16.18	/mo	0.16000	/mo	725.
726.					E. Flood 30,000 HPS	12.81	/mo	E. Flood 30,000 HPS	12.86	/mo	0.05000	/mo	726.
727.					Flood 50,000 HPS	17.77	/mo	Flood 50,000 HPS	17.77	/mo	-	/mo	727.
728.					Flood 21,000 MH	13.53	/mo	Flood 21,000 MH	13.59	/mo	0.06000	/mo	728.
729.					Flood 36,000 MH	18.35	/mo	Flood 36,000 MH	18.35	/mo	-	/mo	729.
730.					F. Post Top gray 8,000 FL	5.23	/mo	F. Post Top gray 8,000 FL	5.26	/mo	0.03000	/mo	730.
731.					Post Top gray 9,500 HPS	6.65	/mo	Post Top gray 9,500 HPS	6.72	/mo	0.07000	/mo	731.
732.					Post Top black 9,500 HPS	6.88	/mo	Post Top black 9,500 HPS	6.96	/mo	0.08000	/mo	732.
733.					Post Top Transit 9,500 HPS	10.24	/mo	Post Top Transit 9,500 HPS	10.44	/mo	0.20000	/mo	733.
734.					G. FROZEN 4,000 INC	5.47	/mo	G. FROZEN 4,000 INC	5.23	/mo	(0.24000)	/mo	734.
735.					FROZEN 7,000 MV	7.27	/mo	FROZEN 7,000 MV	7.23	/mo	(0.04000)	/mo	735.
736.					FROZEN 11,000 MV	9.68	/mo	FROZEN 11,000 MV	9.62	/mo	(0.06000)	/mo	736.
737.					FROZEN 20,000 MV	14.12	/mo	FROZEN 20,000 MV	14.00	/mo	(0.12000)	/mo	737.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)(G) Present Rates Rates	(H) Proposed Rates Block	(I)(J) Proposed Rates Rates	(K)(L) Change (I) - (F)	Line No.
738.										738.
739.	E-58	Street Lighting Service	Rate	Sum & Win	**POLES** (Investment by Company)		**POLES** (Investment by Company)			739.
740.	(cont)				A. Anchor Flush, Round, 1X, 12ft	$ 12.17 /mo	A. Anchor Flush, Round, 1X, 12ft	$ 12.61 /mo	$ 0.44 /mo	740.
741.					Anchor Flush, Round, 1X, 22ft	13.70 /mo	Anchor Flush, Round, 1X, 22ft	14.20 /mo	0.50 /mo	741.
742.					Anchor Flush, Round, 1X, 25ft	14.82 /mo	Anchor Flush, Round, 1X, 25ft	15.36 /mo	0.54 /mo	742.
743.					Anchor Flush, Round, 1X, 30ft	17.03 /mo	Anchor Flush, Round, 1X, 30ft	17.65 /mo	0.62 /mo	743.
744.					Anchor Flush, Round, 1X, 32ft	17.89 /mo	Anchor Flush, Round, 1X, 32ft	18.54 /mo	0.65 /mo	744.
745.					Anchor Flush, Round, 2X, 12ft	12.98 /mo	Anchor Flush, Round, 2X, 12ft	13.45 /mo	0.47 /mo	745.
746.					Anchor Flush, Round, 2X, 22ft	14.91 /mo	Anchor Flush, Round, 2X, 22ft	15.45 /mo	0.54 /mo	746.
747.					Anchor Flush, Round, 2X, 25ft	15.55 /mo	Anchor Flush, Round, 2X, 25ft	16.12 /mo	0.57 /mo	747.
748.					Anchor Flush, Round, 2X, 30ft	18.07 /mo	Anchor Flush, Round, 2X, 30ft	18.73 /mo	0.66 /mo	748.
749.					Anchor Flush, Round, 2X, 32ft	19.28 /mo	Anchor Flush, Round, 2X, 32ft	19.98 /mo	0.70 /mo	749.
750.					Anchor Flush, Square, 5", 13ft	13.95 /mo	Anchor Flush, Square, 5", 13ft	14.46 /mo	0.51 /mo	750.
751.					Anchor Flush, Square, 5", 15ft	12.47 /mo	Anchor Flush, Square, 5", 15ft	12.93 /mo	0.46 /mo	751.
752.					Anchor Flush, Square, 5", 23ft	14.79 /mo	Anchor Flush, Square, 5", 23ft	15.33 /mo	0.54 /mo	752.
753.					Anchor Flush, Square, 5", 25ft	16.26 /mo	Anchor Flush, Square, 5", 25ft	16.85 /mo	0.59 /mo	753.
754.					Anchor Flush, Square, 5", 28ft	18.05 /mo	Anchor Flush, Square, 5", 28ft	18.71 /mo	0.66 /mo	754.
755.					Anchor Flush, Square, 5", 32ft	17.95 /mo	Anchor Flush, Square, 5", 32ft	18.61 /mo	0.66 /mo	755.
756.					Anchor Flush, Concrete, 12ft	41.58 /mo	Anchor Flush, Concrete, 12ft	43.10 /mo	1.52 /mo	756.
757.					Anchor Flush, Fiberglass, 12ft	35.21 /mo	Anchor Flush, Fiberglass, 12ft	36.50 /mo	1.29 /mo	757.
758.					Anchor Flush, Dec Transit Ped, 4", 16ft	34.33 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft	35.58 /mo	1.25 /mo	758.
759.					Anchor Flush, Dec Transit, 6", 30ft	66.28 /mo	Anchor Flush, Dec Transit, 6", 30ft	68.70 /mo	2.42 /mo	759.
760.					B. Anchor Pedstl, Round, 1X, 12ft	11.71 /mo	B. Anchor Pedstl, Round, 1X, 12ft	12.14 /mo	0.43 /mo	760.
761.					Anchor Pedstl, Round, 1X, 22ft	13.24 /mo	Anchor Pedstl, Round, 1X, 22ft	13.72 /mo	0.48 /mo	761.
762.					Anchor Pedstl, Round, 1X, 25ft	14.35 /mo	Anchor Pedstl, Round, 1X, 25ft	14.87 /mo	0.52 /mo	762.
763.					Anchor Pedstl, Round, 1X, 30ft	16.58 /mo	Anchor Pedstl, Round, 1X, 30ft	17.19 /mo	0.61 /mo	763.
764.					Anchor Pedstl, Round, 1X, 32ft	17.41 /mo	Anchor Pedstl, Round, 1X, 32ft	18.05 /mo	0.64 /mo	764.
765.					Anchor Pedstl, Round, 2X, 12ft	12.51 /mo	Anchor Pedstl, Round, 2X, 12ft	12.97 /mo	0.46 /mo	765.
766.					Anchor Pedstl, Round, 2X, 22ft	13.97 /mo	Anchor Pedstl, Round, 2X, 22ft	14.48 /mo	0.51 /mo	766.
767.					Anchor Pedstl, Round, 2X, 25ft	15.08 /mo	Anchor Pedstl, Round, 2X, 25ft	15.63 /mo	0.55 /mo	767.
768.					Anchor Pedstl, Round, 2X, 30ft	17.61 /mo	Anchor Pedstl, Round, 2X, 30ft	18.25 /mo	0.64 /mo	768.
769.					Anchor Pedstl, Round, 2X, 32ft	18.81 /mo	Anchor Pedstl, Round, 2X, 32ft	19.50 /mo	0.69 /mo	769.
770.					Anchor Pedstl, Round, 3 Bolt, 32ft	21.62 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	22.41 /mo	0.79 /mo	770.
771.					Anchor Pedstl, Square, 5", 13ft	13.50 /mo	Anchor Pedstl, Square, 5", 13ft	13.99 /mo	0.49 /mo	771.
772.					Anchor Pedstl, Square, 5", 15ft	13.80 /mo	Anchor Pedstl, Square, 5", 15ft	14.30 /mo	0.50 /mo	772.
773.					Anchor Pedstl, Square, 5", 23ft	14.32 /mo	Anchor Pedstl, Square, 5", 23ft	14.84 /mo	0.52 /mo	773.
774.					Anchor Pedstl, Square, 5", 25ft	15.80 /mo	Anchor Pedstl, Square, 5", 25ft	16.38 /mo	0.58 /mo	774.
775.					Anchor Pedstl, Square, 5", 28ft	17.56 /mo	Anchor Pedstl, Square, 5", 28ft	18.20 /mo	0.64 /mo	775.
776.					Anchor Pedstl, Square, 5", 32ft	18.23 /mo	Anchor Pedstl, Square, 5", 32ft	18.90 /mo	0.67 /mo	776.
777.					C. Direct Bury, Round, 19ft	18.42 /mo	C. Direct Bury, Round, 19ft	19.09 /mo	0.67 /mo	777.
778.					Direct Bury, Round, 30ft	14.38 /mo	Direct Bury, Round, 30ft	14.90 /mo	0.52 /mo	778.
779.					Direct Bury, Round, 38ft	17.55 /mo	Direct Bury, Round, 38ft	18.19 /mo	0.64 /mo	779.
780.					Direct Bury, Self-Support, 40ft	21.62 /mo	Direct Bury, Self-Support, 40ft	22.41 /mo	0.79 /mo	780.
781.					Direct Bury, Stepped, 49ft	64.99 /mo	Direct Bury, Stepped, 49ft	67.36 /mo	2.37 /mo	781.
782.					Direct Bury, Square, 4", 34ft	15.87 /mo	Direct Bury, Square, 4", 34ft	16.45 /mo	0.58 /mo	782.
783.					Direct Bury, Square, 5", 20ft	15.07 /mo	Direct Bury, Square, 5", 20ft	15.62 /mo	0.55 /mo	783.
784.					Direct Bury, Square, 30ft	15.71 /mo	Direct Bury, Square, 30ft	16.28 /mo	0.57 /mo	784.
785.					Direct Bury, Square, 38ft	17.05 /mo	Direct Bury, Square, 38ft	17.67 /mo	0.62 /mo	785.
786.					Decorative Transit 41- 6	20.47 /mo	Decorative Transit 41- 6	21.22 /mo	0.75 /mo	786.
787.					Decorative Transit 47	25.50 /mo	Decorative Transit 47	26.43 /mo	0.93 /mo	787.
788.					Direct Bury, Steel Dist Pole, 35ft	23.54 /mo	Direct Bury, Steel Dist Pole, 35ft	24.40 /mo	0.86 /mo	788.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)(G) Present Rates Rates	(H) Proposed Rates Block	(I)(J) Proposed Rates Rates	(K)(L) Change (I) - (F)	Line No.
789.										789.
790.	E-58	Street Lighting Service	Rate	Sum & Win	**POLES** (Investment by Company) (cont)		**POLES** (Investment by Company) (cont)			790.
791.	(cont)				D. Post Top, Dec Transit, 16ft	$ 35.07 /mo	D. Post Top, Dec Transit, 16ft	$ 36.35 /mo	$ 1.28 /mo	791.
792.					Post Top, Gray Steel/Fiberglass, 23ft	12.16 /mo	Post Top, Gray Steel/Fiberglass, 23ft	12.60 /mo	0.44 /mo	792.
793.					Post Top, Black Steel, 23ft	13.41 /mo	Post Top, Black Steel, 23ft	13.90 /mo	0.49 /mo	793.
794.					E. Existing Distribution Pole	1.48 /mo	E. Existing Distribution Pole	1.53 /mo	0.05 /mo	794.
795.					F. FROZEN, Wood Poles, 30ft	8.95 /mo	F. FROZEN, Wood Poles, 30ft	9.28 /mo	0.33 /mo	795.
796.					FROZEN, Wood Poles, 35ft	8.95 /mo	FROZEN, Wood Poles, 35ft	9.28 /mo	0.33 /mo	796.
797.					A. Anchor Flush, Round, 1X, 12ft	1.68 /mo	A. Anchor Flush, Round, 1X, 12ft	1.74 /mo	0.06 /mo	797.
798.					Anchor Flush, Round, 1X, 22ft	1.88 /mo	Anchor Flush, Round, 1X, 22ft	1.95 /mo	0.07 /mo	798.
799.					Anchor Flush, Round, 1X, 25ft	2.05 /mo	Anchor Flush, Round, 1X, 25ft	2.12 /mo	0.07 /mo	799.
800.					Anchor Flush, Round, 1X, 30ft	2.34 /mo	Anchor Flush, Round, 1X, 30ft	2.43 /mo	0.09 /mo	800.
801.					Anchor Flush, Round, 1X, 32ft	2.37 /mo	Anchor Flush, Round, 1X, 32ft	2.46 /mo	0.09 /mo	801.
802.					Anchor Flush, Round, 2X, 12ft	1.79 /mo	Anchor Flush, Round, 2X, 12ft	1.86 /mo	0.07 /mo	802.
803.					Anchor Flush, Round, 2X, 22ft	2.06 /mo	Anchor Flush, Round, 2X, 22ft	2.14 /mo	0.08 /mo	803.
804.					Anchor Flush, Round, 2X, 25ft	2.14 /mo	Anchor Flush, Round, 2X, 25ft	2.22 /mo	0.08 /mo	804.
805.					Anchor Flush, Round, 2X, 30ft	2.49 /mo	Anchor Flush, Round, 2X, 30ft	2.58 /mo	0.09 /mo	805.
806.					Anchor Flush, Round, 2X, 32ft	2.66 /mo	Anchor Flush, Round, 2X, 32ft	2.76 /mo	0.10 /mo	806.
807.					Anchor Flush, Square, 5", 13ft	1.92 /mo	Anchor Flush, Square, 5", 13ft	1.99 /mo	0.07 /mo	807.
808.					Anchor Flush, Square, 5", 15ft	1.72 /mo	Anchor Flush, Square, 5", 15ft	1.78 /mo	0.06 /mo	808.
809.					Anchor Flush, Square, 5", 23ft	2.03 /mo	Anchor Flush, Square, 5", 23ft	2.10 /mo	0.07 /mo	809.
810.					Anchor Flush, Square, 5", 25ft	2.23 /mo	Anchor Flush, Square, 5", 25ft	2.31 /mo	0.08 /mo	810.
811.					Anchor Flush, Square, 5", 28ft	2.48 /mo	Anchor Flush, Square, 5", 28ft	2.57 /mo	0.09 /mo	811.
812.					Anchor Flush, Square, 5", 32ft	2.47 /mo	Anchor Flush, Square, 5", 32ft	2.56 /mo	0.09 /mo	812.
813.					Anchor Flush, Concrete, 12ft	5.73 /mo	Anchor Flush, Concrete, 12ft	5.94 /mo	0.21 /mo	813.
814.					Anchor Flush, Fiberglass, 12ft	4.85 /mo	Anchor Flush, Fiberglass, 12ft	5.03 /mo	0.18 /mo	814.
815.					Anchor Flush, Dec Transit Ped, 4", 16ft	4.73 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft	4.90 /mo	0.17 /mo	815.
816.					Anchor Flush, Dec Transit, 6", 30ft	9.13 /mo	Anchor Flush, Dec Transit, 6", 30ft	9.46 /mo	0.33 /mo	816.
817.					B. Anchor Pedstl, Round, 1X, 12ft	1.61 /mo	B. Anchor Pedstl, Round, 1X, 12ft	1.67 /mo	0.06 /mo	817.
818.					Anchor Pedstl, Round, 1X, 22ft	1.82 /mo	Anchor Pedstl, Round, 1X, 22ft	1.89 /mo	0.07 /mo	818.
819.					Anchor Pedstl, Round, 1X, 25ft	1.98 /mo	Anchor Pedstl, Round, 1X, 25ft	2.05 /mo	0.07 /mo	819.
820.					Anchor Pedstl, Round, 1X, 30ft	2.29 /mo	Anchor Pedstl, Round, 1X, 30ft	2.37 /mo	0.08 /mo	820.
821.					Anchor Pedstl, Round, 1X, 32ft	2.40 /mo	Anchor Pedstl, Round, 1X, 32ft	2.49 /mo	0.09 /mo	821.
822.					Anchor Pedstl, Round, 2X, 12ft	1.72 /mo	Anchor Pedstl, Round, 2X, 12ft	1.78 /mo	0.06 /mo	822.
823.					Anchor Pedstl, Round, 2X, 22ft	1.92 /mo	Anchor Pedstl, Round, 2X, 22ft	1.99 /mo	0.07 /mo	823.
824.					Anchor Pedstl, Round, 2X, 25ft	2.07 /mo	Anchor Pedstl, Round, 2X, 25ft	2.15 /mo	0.08 /mo	824.
825.					Anchor Pedstl, Round, 2X, 30ft	2.42 /mo	Anchor Pedstl, Round, 2X, 30ft	2.51 /mo	0.09 /mo	825.
826.					Anchor Pedstl, Round, 2X, 32ft	2.59 /mo	Anchor Pedstl, Round, 2X, 32ft	2.68 /mo	0.09 /mo	826.
827.					Anchor Pedstl, Round, 3 Bolt, 32ft	2.97 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	3.08 /mo	0.11 /mo	827.
828.					Anchor Pedstl, Square, 5", 13ft	1.86 /mo	Anchor Pedstl, Square, 5", 13ft	1.93 /mo	0.07 /mo	828.
829.					Anchor Pedstl, Square, 5", 15ft	1.89 /mo	Anchor Pedstl, Square, 5", 15ft	1.96 /mo	0.07 /mo	829.
830.					Anchor Pedstl, Square, 5", 23ft	1.98 /mo	Anchor Pedstl, Square, 5", 23ft	2.05 /mo	0.07 /mo	830.
831.					Anchor Pedstl, Square, 5", 25ft	2.19 /mo	Anchor Pedstl, Square, 5", 25ft	2.27 /mo	0.08 /mo	831.
832.					Anchor Pedstl, Square, 5", 28ft	2.42 /mo	Anchor Pedstl, Square, 5", 28ft	2.51 /mo	0.09 /mo	832.
833.					Anchor Pedstl, Square, 5", 32ft	2.50 /mo	Anchor Pedstl, Square, 5", 32ft	2.59 /mo	0.09 /mo	833.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
834.										834.
835.	E-58	Street Lighting Service	Rate	Sum & Win	**POLES** (Investment by Others) (cont)		**POLES** (Investment by Others) (cont)			835.
836.	(cont)				C. Direct Bury, Round, 19ft	$ 2.54 /mo	C. Direct Bury, Round, 19ft	$ 2.63 /mo	$ 0.09 /mo	836.
837.					Direct Bury, Round, 30ft	2.66 /mo	Direct Bury, Round, 30ft	2.76 /mo	0.10 /mo	837.
838.					Direct Bury, Round, 38ft	2.73 /mo	Direct Bury, Round, 38ft	2.83 /mo	0.10 /mo	838.
839.					Direct Bury, Self-Support, 40ft	3.42 /mo	Direct Bury, Self-Support, 40ft	3.54 /mo	0.12 /mo	839.
840.					Direct Bury, Stepped, 49ft	8.96 /mo	Direct Bury, Stepped, 49ft	9.29 /mo	0.33 /mo	840.
841.					Direct Bury, Square, 4", 34ft	2.75 /mo	Direct Bury, Square, 4", 34ft	2.85 /mo	0.10 /mo	841.
842.					Direct Bury, Square, 5", 20ft	2.49 /mo	Direct Bury, Square, 5", 20ft	2.58 /mo	0.09 /mo	842.
843.					Direct Bury, Square, 30ft	2.59 /mo	Direct Bury, Square, 30ft	2.68 /mo	0.09 /mo	843.
844.					Direct Bury, Square, 38ft	2.96 /mo	Direct Bury, Square, 38ft	3.07 /mo	0.11 /mo	844.
845.					Decorative Transit 41- 6	3.01 /mo	Decorative Transit 41- 6	3.12 /mo	0.11 /mo	845.
846.					Decorative Transit 47	3.75 /mo	Decorative Transit 47	3.89 /mo	0.14 /mo	846.
847.					Direct Bury, Steel Dist Pole, 35ft	3.10 /mo	Direct Bury, Steel Dist Pole, 35ft	3.21 /mo	0.11 /mo	847.
848.					D. Post Top, Dec Transit, 16ft	4.82 /mo	D. Post Top, Dec Transit, 16ft	5.00 /mo	0.18 /mo	848.
849.					Post Top, Gray Steel/Fiberglass, 23ft	2.00 /mo	Post Top, Gray Steel/Fiberglass, 23ft	2.07 /mo	0.07 /mo	849.
850.					Post Top, Black Steel, 23ft	2.21 /mo	Post Top, Black Steel, 23ft	2.29 /mo	0.08 /mo	850.
851.					E. Existing Distribution Pole	- /mo	E. Existing Distribution Pole	- /mo	- /mo	851.
852.					F. FROZEN, Wood Poles, 30ft	1.55 /mo	F. FROZEN, Wood Poles, 30ft	1.61 /mo	0.06 /mo	852.
853.					FROZEN, Wood Poles, 35ft	1.48 /mo	FROZEN, Wood Poles, 35ft	1.53 /mo	0.05 /mo	853.
854.					**ANCHOR BASE** (Investment by Company)		**ANCHOR BASE** (Investment by Company)			854.
855.					Flush, 4ft	$ 9.91 /mo	Flush, 4ft	$ 10.27 /mo	$ 0.36 /mo	855.
856.					Flush, 6ft	11.82 /mo	Flush, 6ft	12.25 /mo	0.43 /mo	856.
857.					Pedestal, 8ft	13.54 /mo	Pedestal, 8ft	14.03 /mo	0.49 /mo	857.
858.					Pedestal, 32' round steel pole, 4ft 6"	9.39 /mo	Pedestal, 32' round steel pole, 4ft 6"	9.73 /mo	0.34 /mo	858.
859.					**ANCHOR BASE** (Investment by Others)		**ANCHOR BASE** (Investment by Others)			859.
860.					Flush, 4ft	$ 1.36 /mo	Flush, 4ft	$ 1.41 /mo	$ 0.05 /mo	860.
861.					Flush, 6ft	2.05 /mo	Flush, 6ft	2.12 /mo	0.07 /mo	861.
862.					Pedestal, 8ft	2.36 /mo	Pedestal, 8ft	2.45 /mo	0.09 /mo	862.
863.					Pedestal, 32' round steel pole, 4ft 6"	1.63 /mo	Pedestal, 32' round steel pole, 4ft 6"	1.69 /mo	0.06 /mo	863.
864.					**OPTIONAL EQUIPMENT**		**OPTIONAL EQUIPMENT**			864.
865.					Per foot of cable under paving	$ 0.15716 /mo	Per foot of cable under paving	0.16 /mo	0.003 /mo	865.
866.					Per foot of cable not under paving	0.05589 /mo	Per foot of cable not under paving	0.06 /mo	0.004 /mo	866.
867.										867.
868.	E-59	Energy Services for Government		Sum & Win	Service Charge	$ 2.79 /mo	Service Charge	$ 2.89 /mo	$ 0.10 /mo	868.
869.		Owned Streetlighting Systems			Energy Charge	0.06088 /kWh	Energy Charge	0.05876 /kWh	(0.00212) /kWh	869.
870.										870.
871.	E-67	Municipal Lighting	Rate	Sum & Win	All kWh	$ 0.05193 /kWh	All kWh	$ 0.05057 /kWh	$ (0.00136) /kWh	871.
872.		Service -- City of Phoenix								872.

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
873.													873.
874.	E-114	Share the Light	Rate		Billed on Rate Schedule E-58			RATE E-114 PROPOSE TO CANCEL					874.
875.													875.
876.	E-116	Share the Light	Rate		Billed on Rate Schedule E-58			RATE E-116 PROPOSE TO CANCEL					876.
877.													877.
878.	E-145	Share the Light	Rate		Billed on Rate Schedule E-58			RATE E-145 PROPOSE TO CANCEL					878.
879.													879.
880.	E-221	Water Pumping Service	Rate	Sum & Win	Basic Service Charge	$ 0.558	/day	Basic Service Charge	$ 0.588	/day	$ 0.030	/day	880.
881.					All kW	1.880	/kW	All kW	0.867	/kW	(1.013)	/kW	881.
882.					First 240 kWh	0.11680	/kWh	First 240 kWh	0.11680	/kWh	-	/kWh	882.
883.					Next 275 kWh per kW	0.07940	/kWh	Next 275 kWh per kW	0.07940	/kWh	-	/kWh	883.
884.					All additional kWh	0.06519	/kWh	All additional kWh	0.06519	/kWh	-	/kWh	884.
885.													885.
886.		Time of Week Option		Sum & Win	Based on Measured kWh in Control Period:								886.
887.					2 kWh per kW or less	$ (0.00785)	/kWh	RATE E-221 TIME OF WEEK OPTION PROPOSE TO CANCEL					887.
888.					Greater than 8 kWh/kW	0.00393	/kWh						888.
889.													889.
890.			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.558	/day	Minimum Basic Service Charge	$ 0.588	/day	$ 0.030	/day	890.
891.					Minimum Demand Charge	1.88	/kW	Minimum Demand Charge	$ 0.867	/kW	$ (1.013)	/kW	891.
892.					Minimum Annual kW Charge	24.00	/kW	N/A	N/A	/kW	N/A	/kW	892.
893.					Minimum Annual Lump Sum Charge	180.00	-	N/A	N/A	-	N/A	-	893.
894.													894.
895.	E-221-8T	Water Pumping Service	Rate	Sum & Win	Basic Service Charge	$ 0.964	/day	Basic Service Charge	$ 1.015	/day	$ 0.051	/day	895.
896.		Time Of Use			All On-Peak kW	4.474	/kW	All On-Peak kW	4.249	/kW	(0.225)	/kW	896.
897.					All Off-Peak kW	2.673	/kW	All Off-Peak kW	3.486	/kW	0.813	/kW	897.
898.					All On-Peak kWh	0.09576	/kWh	All On-Peak kWh	0.09576	/kWh	0.00000	/kWh	898.
899.					All Off-Peak kWh	0.05151	/kWh	All Off-Peak kWh	0.05151	/kWh	0.00000	/kWh	899.
900.													900.
901.			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.964	/day	Minimum Basic Service Charge	$ 1.015	/day	$ 0.051	/day	901.
902.					Minimum Demand Charge	2.673	/kW	Minimum Demand Charge	1.901	/kW	(0.772)	/kW	902.
903.					Minimum Annual kW Charge	34.20	/kW	N/A	N/A	/kW	N/A	/kW	903.
904.					Minimum Annual Lump Sum Charge	310.44	-	N/A	N/A	-	N/A	-	904.
905.													905.
906.	E-249	Share the Light	Rate	Sum & Win	Billed on Rate Schedule E-58			RATE E-249 PROPOSE TO CANCEL					906.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates	(K) (L) Change (I) - (F)	Line No.
907.										907.
908.	GS-SCHOOLS M	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.014) /day	908.
909.		Elementary and High Schools		Peak	BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	1.328 /kW	0.004 /kW	909.
910.		0-400 kW			BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	3.477 /kW	0.062 /kW	910.
911.					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	26.855 /kW	0.692 /kW	911.
912.					First 100 kW: Secondary	9.597 /kW	First 100 kW: Secondary	8.294 /kW	(1.303) /kW	912.
913.					All remaining kW: Secondary	5.105 /kW	All remaining kW: Secondary	3.644 /kW	(1.461) /kW	913.
914.					First 100 kW: Primary	8.905 /kW	First 100 kW: Primary	7.578 /kW	(1.327) /kW	914.
915.					All remaining kW: Primary	4.412 /kW	All remaining kW: Primary	2.927 /kW	(1.485) /kW	915.
916.					First 100 kW: Transmission	6.942 /kW	First 100 kW: Transmission	5.546 /kW	(1.396) /kW	916.
917.					All remaining kW: Transmission	2.450 /kW	All remaining kW: Transmission	0.895 /kW	(1.555) /kW	917.
918.					All On-Peak kWh:	0.17316 /kWh	All On-Peak kWh:	0.17687 /kWh	0.00371 /kWh	918.
919.					All Shoulder-Peak kWh:	0.12827 /kWh	All Shoulder-Peak kWh:	0.13102 /kWh	0.00275 /kWh	919.
920.					All Off-Peak kWh:	0.06477 /kWh	All Off-Peak kWh:	0.06647 /kWh	0.00170 /kWh	920.
921.									0.02143	921.
922.	GS-SCHOOLS M		Rate	Summer	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.014) /day	922.
923.	(cont)			Shoulder	BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	1.328 /kW	0.004 /kW	923.
924.					BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	3.477 /kW	0.062 /kW	924.
925.					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	26.855 /kW	0.692 /kW	925.
926.					First 100 kW: Secondary	9.597 /kW	First 100 kW: Secondary	8.294 /kW	(1.303) /kW	926.
927.					All remaining kW: Secondary	5.105 /kW	All remaining kW: Secondary	3.644 /kW	(1.461) /kW	927.
928.					First 100 kW: Primary	8.905 /kW	First 100 kW: Primary	7.578 /kW	(1.327) /kW	928.
929.					All remaining kW: Primary	4.412 /kW	All remaining kW: Primary	2.927 /kW	(1.485) /kW	929.
930.					First 100 kW: Transmission	6.942 /kW	First 100 kW: Transmission	5.546 /kW	(1.396) /kW	930.
931.					All remaining kW: Transmission	2.450 /kW	All remaining kW: Transmission	0.895 /kW	(1.555) /kW	931.
932.					All On-Peak kWh:	0.14953 /kWh	All On-Peak kWh:	0.15274 /kWh	0.00321 /kWh	932.
933.					All Shoulder-Peak kWh:	0.11077 /kWh	All Shoulder-Peak kWh:	0.11314 /kWh	0.00237 /kWh	933.
934.					All Off-Peak kWh:	0.05593 /kWh	All Off-Peak kWh:	0.05740 /kWh	0.00147 /kWh	934.
935.										935.
936.			Rate	Winter	BSC: Self-Contained Meters	$ 0.672 /day	BSC: Self-Contained Meters	$ 0.658 /day	$ (0.014) /day	936.
937.					BSC: Instrument-rated Meters	1.324 /kW	BSC: Instrument-rated Meters	1.328 /kW	0.004 /kW	937.
938.					BSC: Primary Meters	3.415 /kW	BSC: Primary Meters	3.477 /kW	0.062 /kW	938.
939.					BSC: Transmission Meters	26.163 /kW	BSC: Transmission Meters	26.855 /kW	0.692 /kW	939.
940.					First 100 kW: Secondary	9.597 /kW	First 100 kW: Secondary	8.294 /kW	(1.303) /kW	940.
941.					All remaining kW: Secondary	5.105 /kW	All remaining kW: Secondary	3.644 /kW	(1.461) /kW	941.
942.					First 100 kW: Primary	8.905 /kW	First 100 kW: Primary	7.578 /kW	(1.327) /kW	942.
943.					All remaining kW: Primary	4.412 /kW	All remaining kW: Primary	2.927 /kW	(1.485) /kW	943.
944.					First 100 kW: Transmission	6.942 /kW	First 100 kW: Transmission	5.546 /kW	(1.396) /kW	944.
945.					All remaining kW: Transmission	2.450 /kW	All remaining kW: Transmission	0.895 /kW	(1.555) /kW	945.
946.					All On-Peak kWh:	0.11589 /kWh	All On-Peak kWh:	0.11799 /kWh	0.00210 /kWh	946.
947.					All Shoulder-Peak kWh:	0.08585 /kWh	All Shoulder-Peak kWh:	0.08740 /kWh	0.00155 /kWh	947.
948.					All Off-Peak kWh:	0.04335 /kWh	All Off-Peak kWh:	0.04434 /kWh	0.00099 /kWh	948.
949.										949.
950.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.672 /day	N/A	N/A /day	N/A /day	950.
951.					BSC: Instrument-rated Meters	1.324 /day	N/A	N/A /day	N/A /day	951.
952.					BSC: Primary Meters	3.415 /day	N/A	N/A /day	N/A /day	952.
953.					BSC: Transmission Meters	26.163 /day	N/A	N/A /day	N/A /day	953.
954.					Minimum Demand Charge:	2.189 /kW	N/A	N/A /kW	N/A /kW	954.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
955.													955.
956.	GS-SCHOOLS L	Time of Use for	Rate	Summer	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.410)	/day	956.
957.		Elementary and High Schools		Peak	BSC: Instrument-rated Meters	1.627	/kW	BSC: Instrument-rated Meters	1.328	/kW	(0.299)	/kW	957.
958.		401 kW and above			BSC: Primary Meters	3.419	/kW	BSC: Primary Meters	3.477	/kW	0.058	/kW	958.
959.					BSC: Transmission Meters	22.915	/kW	BSC: Transmission Meters	26.855	/kW	3.940	/kW	959.
960.					First 100 kW: Secondary	9.384	/kW	First 100 kW: Secondary	8.241	/kW	(1.143)	/kW	960.
961.					All remaining kW: Secondary	4.993	/kW	All remaining kW: Secondary	3.601	/kW	(1.392)	/kW	961.
962.					First 100 kW: Primary	8.703	/kW	First 100 kW: Primary	7.521	/kW	(1.182)	/kW	962.
963.					All remaining kW: Primary	4.315	/kW	All remaining kW: Primary	2.885	/kW	(1.430)	/kW	963.
964.					First 100 kW: Transmission	6.788	/kW	First 100 kW: Transmission	5.498	/kW	(1.290)	/kW	964.
965.					All remaining kW: Transmission	2.396	/kW	All remaining kW: Transmission	0.857	/kW	(1.539)	/kW	965.
966.					All On-Peak kWh:	0.15475	/kWh	All On-Peak kWh:	0.15822	/kWh	0.00347	/kWh	966.
967.					All Shoulder-Peak kWh:	0.11463	/kWh	All Shoulder-Peak kWh:	0.11720	/kWh	0.00257	/kWh	967.
968.					All Off-Peak kWh:	0.06334	/kWh	All Off-Peak kWh:	0.06333	/kWh	(0.00001)	/kWh	968.
969.													969.
970.	GS-SCHOOLS L		Rate	Summer	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.410)	/day	970.
971.	(cont)			Shoulder	BSC: Instrument-rated Meters	1.627	/kW	BSC: Instrument-rated Meters	1.328	/kW	(0.299)	/kW	971.
972.					BSC: Primary Meters	3.419	/kW	BSC: Primary Meters	3.477	/kW	0.058	/kW	972.
973.					BSC: Transmission Meters	22.915	/kW	BSC: Transmission Meters	26.855	/kW	3.940	/kW	973.
974.					First 100 kW: Secondary	9.384	/kW	First 100 kW: Secondary	8.241	/kW	(1.143)	/kW	974.
975.					All remaining kW: Secondary	4.993	/kW	All remaining kW: Secondary	3.601	/kW	(1.392)	/kW	975.
976.					First 100 kW: Primary	8.703	/kW	First 100 kW: Primary	7.521	/kW	(1.182)	/kW	976.
977.					All remaining kW: Primary	4.315	/kW	All remaining kW: Primary	2.885	/kW	(1.430)	/kW	977.
978.					First 100 kW: Transmission	6.788	/kW	First 100 kW: Transmission	5.498	/kW	(1.290)	/kW	978.
979.					All remaining kW: Transmission	2.396	/kW	All remaining kW: Transmission	0.857	/kW	(1.539)	/kW	979.
980.					All On-Peak kWh:	0.13363	/kWh	All On-Peak kWh:	0.13663	/kWh	0.00300	/kWh	980.
981.					All Shoulder-Peak kWh:	0.09898	/kWh	All Shoulder-Peak kWh:	0.10121	/kWh	0.00223	/kWh	981.
982.					All Off-Peak kWh:	0.05470	/kWh	All Off-Peak kWh:	0.05469	/kWh	(0.00001)	/kWh	982.
983.													983.
984.			Rate	Winter	BSC: Self-Contained Meters	$ 1.068	/day	BSC: Self-Contained Meters	$ 0.658	/day	$ (0.410)	/day	984.
985.					BSC: Instrument-rated Meters	1.627	/kW	BSC: Instrument-rated Meters	1.328	/kW	(0.299)	/kW	985.
986.					BSC: Primary Meters	3.419	/kW	BSC: Primary Meters	3.477	/kW	0.058	/kW	986.
987.					BSC: Transmission Meters	22.915	/kW	BSC: Transmission Meters	26.855	/kW	3.940	/kW	987.
988.					First 100 kW: Secondary	9.384	/kW	First 100 kW: Secondary	8.241	/kW	(1.143)	/kW	988.
989.					All remaining kW: Secondary	4.993	/kW	All remaining kW: Secondary	3.601	/kW	(1.392)	/kW	989.
990.					First 100 kW: Primary	8.703	/kW	First 100 kW: Primary	7.521	/kW	(1.182)	/kW	990.
991.					All remaining kW: Primary	4.315	/kW	All remaining kW: Primary	2.885	/kW	(1.430)	/kW	991.
992.					First 100 kW: Transmission	6.788	/kW	First 100 kW: Transmission	5.498	/kW	(1.290)	/kW	992.
993.					All remaining kW: Transmission	2.396	/kW	All remaining kW: Transmission	0.857	/kW	(1.539)	/kW	993.
994.					All On-Peak kWh:	0.10356	/kWh	All On-Peak kWh:	0.10556	/kWh	0.00200	/kWh	994.
995.					All Shoulder-Peak kWh:	0.07671	/kWh	All Shoulder-Peak kWh:	0.07819	/kWh	0.00148	/kWh	995.
996.					All Off-Peak kWh:	0.04239	/kWh	All Off-Peak kWh:	0.04225	/kWh	(0.00014)	/kWh	996.
997.													997.
998.			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 1.068	/day	N/A	N/A	/day	N/A	/day	998.
999.					BSC: Instrument-rated Meters	1.627	/day	N/A	N/A	/day	N/A	/day	999.
1000.					BSC: Primary Meters	3.419	/day	N/A	N/A	/day	N/A	/day	1000.
1001.					BSC: Transmission Meters	22.915	/day	N/A	N/A	/day	N/A	/day	1001.
1002.					Minimum Demand Charge:	2.115	/kW	N/A	N/A	/kW	N/A	/kW	1002.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)(G) Present Rates Rates	(H) Proposed Rates Block	(I)(J) Proposed Rates Rates	(K)(L) Change (I) - (F)	Line No.
1003.										1003.
1004.	CPP-GS	General Service	Rate	Summer	Critical Peak Price	$ 0.40000 /kWh	Critical Peak Price	$ 0.250000 /kWh	$ (0.150000) /kWh	1004.
1005.		Critical Peak Pricing								1005.
1006.					Energy Discount E-32 M	$ (0.014892) /kWh	Energy Discount E-32 M	$ (0.010351) /kWh	$ 0.004541 /kWh	1006.
1007.					Energy Discount E-32 L	(0.014438) /kWh	Energy Discount E-32 L	$ (0.009533) /kWh	$ 0.004905 /kWh	1007.
1008.					Energy Discount E-32 TOU M	(0.014892) /kWh	Energy Discount E-32 TOU M	$ (0.009266) /kWh	$ 0.005626 /kWh	1008.
1009.					Energy Discount E-32 TOU L	(0.014438) /kWh	Energy Discount E-32 TOU L	$ (0.008680) /kWh	$ 0.005758 /kWh	1009.
1010.					Energy Discount E-34	(0.014350) /kWh	Energy Discount E-34	$ (0.008519) /kWh	$ 0.005831 /kWh	1010.
1011.					Energy Discount E-35	(0.012470) /kWh	Energy Discount E-35	$ (0.007396) /kWh	$ 0.005074 /kWh	1011.
1012.					Energy Discount E-221	(0.011755) /kWh	Energy Discount E-221	$ (0.006116) /kWh	$ 0.005639 /kWh	1012.
1013.										1013.
1014.	SC-S	Standard Contract -	Rate	Sum & Win	All kWh	Varies by Customer	All kWh	Varies by Customer		1014.
1015.		Solar			All kW	Varies by Customer	All kW	Varies by Customer		1015.
1016.										1016.
1017.	EPR-2	Purchase Rates for Qualified	9am - 9pm	Summer	Non-Firm On-Peak	$ 0.04236 /kWh				1017.
1018.		Facilities of 100 kW or less	Rate		Non-Firm Off-Peak	0.03734 /kWh				1018.
1019.					Firm On-Peak	0.05447 /kWh				1019.
1020.					Firm Off-Peak	0.03957 /kWh				1020.
1021.										1021.
1022.				Winter	Non-Firm On-Peak	$ 0.03432 /kWh				1022.
1023.					Non-Firm Off-Peak	0.03622 /kWh				1023.
1024.					Firm On-Peak	0.03432 /kWh				1024.
1025.					Firm Off-Peak	0.03622 /kWh				1025.
1026.										1026.
1027.	EPR-2		12pm - 7pm	Summer	Non-Firm On-Peak	$ 0.04473 /kWh				1027.
1028.	(cont)		Rate		Non-Firm Off-Peak	0.03766 /kWh				1028.
1029.					Firm On-Peak	0.06548 /kWh				1029.
1030.					Firm Off-Peak	0.03947 /kWh				1030.
1031.							NO CHANGE			1031.
1032.				Winter	Non-Firm On-Peak	$ 0.03224 /kWh				1032.
1033.					Non-Firm Off-Peak	0.03641 /kWh				1033.
1034.					Firm On-Peak	0.03224 /kWh				1034.
1035.					Firm Off-Peak	0.03641 /kWh				1035.
1036.										1036.
1037.			11am - 9pm	Summer	Non-Firm On-Peak	$ 0.04405 /kWh				1037.
1038.			Rate		Non-Firm Off-Peak	0.03705 /kWh				1038.
1039.					Firm On-Peak	0.05857 /kWh				1039.
1040.					Firm Off-Peak	0.03910 /kWh				1040.
1041.										1041.
1042.				Winter	Non-Firm On-Peak	$ 0.03361 /kWh				1042.
1043.					Non-Firm Off-Peak	0.03636 /kWh				1043.
1044.					Firm On-Peak	0.03381 /kWh				1044.
1045.					Firm Off-Peak	0.03636 /kWh				1045.
1046.										1046.
1047.	EPR-6	Net Metering Rate	Rate	Sum & Win	Energy Credit for Excess Generation	Credited Rates	Energy Credit for Excess Generation	Credited Rates		1047.
1048.		Renewable Resource Facilities				Per Applicable		Per Applicable		1048.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates	(J)	(K) Change (I) - (F)	(L) Line No.
1049.												1049.
1050.	Solar-2	Individual Solar	Initial Fee	Sum & Win	Up to $100,000	5%	one time					1050.
1051.		Electric Service			More than $100,000	10%	one time					1051.
1052.												1052.
1053.			Rate	Sum & Win	Service Fee:							1053.
1054.					Battery: None, sys size up to 2.5 kW	$ 5.00	/mo					1054.
1055.					Battery: None, sys size over 2.5 kW	5.00	/mo					1055.
1056.					Battery: Sealed, sys size up to 2.5 kW	45.00	/mo					1056.
1057.					Battery: Sealed, sys size over 2.5 kW	65.00	/mo	RATE SOLAR-2 PROPOSE TO CANCEL				1057.
1058.					Battery: Flooded, sys size up to 2.5 kW	65.00	/mo					1058.
1059.					Battery: Flooded, sys size over 2.5 kW	85.00	/mo					1059.
1060.												1060.
1061.					Component Fee:							1061.
1062.					Long	1.41%	/mo					1062.
1063.					Medium	1.83%	/mo					1063.
1064.					Short	2.75%	/mo					1064.
1065.												1065.
1066.	Solar-3	Solar Power Pilot Program	Rate	Sum & Win	Solar Power Premium	$ 0.16600	/kWh	RATE SOLAR-3 PROPOSE TO CANCEL				1066.
1067.												1067.
1068.	SP-1	Solar Partners	Rate	Sum & Win	RATE SP-1 CANCELED EFFECTIVE JANUARY 1, 2010 PER A.C.C. DECISION 69663 AND A.C.C. DECISION 71448							1068.
1069.												1069.
1070.												1070.
1071.	CMPW-01	Community Power	Rate	Sum & Win	Solar Charge E-12	$ 0.11242	/kWh					1071.
1072.		Flagstaff SANDVIG 04			Solar Charge ET-2	0.13480	/kWh	NO CHANGE				1072.
1073.					Solar Charge E-32 S, E-32 M, E-32 L	0.09293	/kWh					1073.
1074.					Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L	0.05855	/kWh					1074.
1075.												1075.
1076.	RSSP	Rural Schools Solar Program	Rate	Sum & Win	Solar Charge E-32 S, E-32 M, E-32 L	$ 0.09293	/kWh					1076.
1077.					Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L	0.05855	/kWh	NO CHANGE				1077.
1078.					Solar Charge GS-SCHOOLS M, GS-SCHOOLS L	0.07158	/kWh					1078.
1079.												1079.
1080.	AG-1	Alternative Generation	Rate	Sum & Win	PROPOSE NEW SCHEDULE			Billed on Rate Schedule E-34 or Rate Schedule E-35				1080.
1081.		Extra Large Service						Generation will be scheduled at market price plus uplift.				1081.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
1082.													1082.
1083.	DSMAC-1[1]	Demand Side Management Adjustment Charge	Adjustment	Sum & Win	all kWh all kW	$ 0.001646 0.720083	/kWh /kW	NO CHANGE					1083. 1084.
1084.													1085.
1085.													1086.
1086.	CRCC-1[1]	Competition Rules Compliance Charge	Adjustment	Sum & Win	ADJUSTMENT SCHEDULE CRCC-1 CANCELED EFFECTIVE OCTOBER 7, 2010 PER A.C.C. DECISION 67744								1087.
1087.													1088.
1088.													1089.
1089.	RCDAC-1[1]	Returning Customer Direct	Adjustment	Sum & Win	Customers over 3mW	varies by customer		NO CHANGE					1090.
1090.													1091.
1091.	PSA-1[1,2]	Power Supply Adjustment	Adjustment	Sum & Win	PSA Adjustor PSA Historical PSA Forward PSA Transition	$ (0.005658) (0.002642) (0.003016) -	/kWh /kWh /kWh /kWh	NO CHANGE					1092. 1093. 1094.
1092.													1095.
1093.													1096.
1094.													1097.
1095.													1098.
1096.	REAC-1[1]	Renewable Energy Standard	Adjustment	Sum & Win	All kWh Cap for all Residential Services Cap for General Services under 3MW Cap for General Services 3MW and above	$ 0.010132 4.05 150.53 451.60	/kWh /service /service /service	NO CHANGE					1099. 1100.
1097.													1101.
1098.													1102.
1099.													1103.
1100.													1104.
1101.	EIS[1]	Environmental Improvement Surcharge	Adjustment	Sum & Win	All kWh	$ 0.00016	/kWh	ADJUSTMENT SCHEDULE EIS PROPOSE TO CANCEL					1105.
1102.													1106.
1103.													1107.
1104.	TCA-1[1,3]	Transmission Cost	Adjustment	Sum & Win	All kW and kWh Residential - kWh General service 20 kW or less General service over 20 kW, under 3,000 kW XL General service 3,000 kW and over	$ 0.002144 0.001602 0.740 0.259	/kWh /kWh /kW /kW	ADJUSTMENT SCHEDULE TCA-1 WILL REFLECT TRANSFER OF UNBUNDLED TRANSMISSION COST. THE CHARGES ARE TO BE DETERMINED.					1108. 1109.
1105.													1110.
1106.													1111.
1107.													1112.
1108.													1113.
1109.													1114.
1110.	GPS-1[1]	Green Power Block Schedule	Adjustment	Sum & Win	100 kWh Block	$ 0.40000	/kWh Block	NO CHANGE					1115.
1111.													1116.
1112.	GPS-2[1]	Green Power Percent Schedule	Adjustment	Sum & Win	100.0% total monthly kWh 50.0% total monthly kWh 35.0% total monthly kWh 10.0% total monthly kWh	$ 0.00400 0.00200 0.00140 0.00040	/kWh /kWh /kWh /kWh	NO CHANGE					1117. 1118.
1113.													1119.
1114.													1120.
1115.													1121.
1116.													1122.
1117.	GPS-3[1]	Green Power Block Schedule for Special Events	Adjustment	Sum & Win	100 kWh Block Minimum purchase	$ 0.40000 500.00	/kWh Block /Transaction	NO CHANGE					1123. 1124.
1118.													1125.
1119.													1126.
1120.	SDR	Self Directed Renewable Resources	Adjustement	Sum & Win	Varies per customer			NO CHANGE					1127.
1121.													1128.
1122.													1129.
1123.	EIA-1[1]	Efficiency and Infrastructure Account	Adjustment	Sum & Win	PROPOSE NEW ADJUSTMENT SCHEDULE			% of customer's total monthly bill excluding taxes and fees, and ERA-1					1130.
1124.													1131.
1125.													
1126.	ERA-1[1]	Environmental Reliability Account	Adjustment	Sum & Win	PROPOSE NEW ADJUSTMENT SCHEDULE			% of customer's total monthly bill excluding taxes and fees, and EIA-1					
1127.													
1128.													

1129. [1] These adjustor schedules may be modified outside of a rate case in accordance with the adjustor schedules's Plan of Administration. These schedules do not impact any of the proof of revenue's.
1130. [2] Update to adjustment schedule PSA-1 approved by A.C.C. Decision No. 69663 per the PSA POA.
1131. [3] Unbundled transmission cost removed from proposed base rates.

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 1/01/2010.

Recap Schedules:
N/A

H-4

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	27.34	29.37	1.04	30.41	3.07	11.2%
250	32.04	33.79	1.30	35.09	3.05	9.5%
300	36.74	38.21	1.56	39.77	3.03	8.2%
350	41.44	42.63	1.82	44.45	3.01	7.3%
400	46.14	47.04	2.08	49.12	2.98	6.5%
450	50.84	51.46	2.34	53.80	2.96	5.8%
500	55.54	55.88	2.60	58.48	2.94	5.3%
550	60.23	60.30	2.86	63.16	2.93	4.9%
600	64.93	64.72	3.12	67.84	2.91	4.5%
650	69.63	69.13	3.38	72.51	2.88	4.1%
700	74.33	73.55	3.64	77.19	2.86	3.8%
750	79.03	77.97	3.90	81.87	2.84	3.6%
800	83.73	82.39	4.16	86.55	2.82	3.4%
850	88.42	86.81	4.42	91.23	2.81	3.2%
900	93.12	91.22	4.68	95.90	2.78	3.0%
950	97.82	95.64	4.94	100.58	2.76	2.8%
1,000	102.52	100.06	5.20	105.26	2.74	2.7%
1,100	111.92	108.90	5.72	114.62	2.70	2.4%
1,200	121.31	117.73	6.24	123.97	2.66	2.2%
1,300	130.71	126.57	6.76	133.33	2.62	2.0%
1,400	140.11	135.40	7.28	142.68	2.57	1.8%
1,500	149.51	144.24	7.80	152.04	2.53	1.7%
1,600	158.90	153.08	8.32	161.40	2.50	1.6%
1,700	168.30	161.91	8.84	170.75	2.45	1.5%
1,800	177.70	170.75	9.36	180.11	2.41	1.4%
1,900	187.09	179.58	9.88	189.46	2.37	1.3%
2,000	196.49	188.42	10.40	198.82	2.33	1.2%
2,200	215.28	206.09	11.44	217.53	2.25	1.0%
2,400	234.08	223.76	12.48	236.24	2.16	0.9%
2,600	252.87	241.44	13.52	254.96	2.09	0.8%
2,800	271.67	259.11	14.56	273.67	2.00	0.7%
3,000	290.46	276.78	15.60	292.38	1.92	0.7%
4,000	384.43	365.14	20.80	385.94	1.51	0.4%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	27.89	29.92	1.04	30.96	3.07	11.0%
250	32.73	34.48	1.30	35.78	3.05	9.3%
300	37.56	39.03	1.56	40.59	3.03	8.1%
350	42.40	43.59	1.82	45.41	3.01	7.1%
400	47.23	48.14	2.08	50.22	2.99	6.3%
450	54.10	54.73	2.34	57.07	2.97	5.5%
500	60.97	61.32	2.60	63.92	2.95	4.8%
550	67.84	67.91	2.86	70.77	2.93	4.3%
600	74.71	74.50	3.12	77.62	2.91	3.9%
650	81.58	81.09	3.38	84.47	2.89	3.5%
700	88.45	87.68	3.64	91.32	2.87	3.2%
750	95.32	94.27	3.90	98.17	2.85	3.0%
800	102.19	100.86	4.16	105.02	2.83	2.8%
850	110.33	108.72	4.42	113.14	2.81	2.5%
900	118.47	116.58	4.68	121.26	2.79	2.4%
950	126.61	124.44	4.94	129.38	2.77	2.2%
1,000	134.75	132.31	5.20	137.51	2.76	2.0%
1,100	151.03	148.03	5.72	153.75	2.72	1.8%
1,200	167.31	163.75	6.24	169.99	2.68	1.6%
1,300	183.60	179.48	6.76	186.24	2.64	1.4%
1,400	199.88	195.20	7.28	202.48	2.60	1.3%
1,500	216.16	210.92	7.80	218.72	2.56	1.2%
1,600	232.44	226.64	8.32	234.96	2.52	1.1%
1,700	248.72	242.37	8.84	251.21	2.49	1.0%
1,800	265.00	258.09	9.36	267.45	2.45	0.9%
1,900	281.28	273.81	9.88	283.69	2.41	0.9%
2,000	297.56	289.54	10.40	299.94	2.38	0.8%
2,200	330.12	320.98	11.44	332.42	2.30	0.7%
2,400	362.69	352.43	12.48	364.91	2.22	0.6%
2,600	395.25	383.87	13.52	397.39	2.14	0.5%
2,800	427.81	415.32	14.56	429.88	2.07	0.5%
3,000	460.37	446.77	15.60	462.37	2.00	0.4%
4,000	633.95	614.77	20.80	635.57	1.62	0.3%
5,000	807.53	782.77	26.00	808.77	1.24	0.2%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 L with E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.55	19.87	0.78	20.65	6.10	41.9%
250	17.04	22.89	0.98	23.87	6.83	40.1%
300	19.54	25.92	1.17	27.09	7.55	38.6%
350	22.04	28.95	1.37	30.32	8.28	37.6%
400	24.54	31.97	1.56	33.53	8.99	36.6%
450	33.35	35.00	1.76	36.76	3.41	10.2%
500	36.43	38.03	1.95	39.98	3.55	9.7%
550	39.51	41.05	2.15	43.20	3.69	9.3%
600	42.59	44.08	2.34	46.42	3.83	9.0%
650	45.67	47.10	2.54	49.64	3.97	8.7%
700	48.75	50.13	2.73	52.86	4.11	8.4%
750	51.83	53.16	2.93	56.09	4.26	8.2%
800	54.91	56.18	3.12	59.30	4.39	8.0%
850	67.40	60.95	4.42	65.37	(2.03)	-3.0%
900	70.98	64.98	4.68	69.66	(1.32)	-1.9%
950	74.56	69.02	4.94	73.96	(0.60)	-0.8%
1,000	78.14	73.05	5.20	78.25	0.11	0.1%
1,100	85.30	81.12	5.72	86.84	1.54	1.8%
1,200	92.46	89.19	6.24	95.43	2.97	3.2%
1,300	102.84	97.26	6.76	104.02	1.18	1.1%
1,400	111.17	105.33	7.28	112.61	1.44	1.3%
1,500	119.50	113.40	7.80	121.20	1.70	1.4%
1,600	127.82	121.47	8.32	129.79	1.97	1.5%
1,700	136.15	129.54	8.84	138.38	2.23	1.6%
1,800	144.48	137.61	9.36	146.97	2.49	1.7%
1,900	152.80	145.68	9.88	155.56	2.76	1.8%
2,000	161.13	153.75	10.40	164.15	3.02	1.9%
2,200	177.78	169.89	11.44	181.33	3.55	2.0%
2,400	194.44	186.03	12.48	198.51	4.07	2.1%
2,600	211.09	202.17	13.52	215.69	4.60	2.2%
2,800	227.75	218.31	14.56	232.87	5.12	2.2%
3,000	244.40	234.45	15.60	250.05	5.65	2.3%
4,000	327.67	315.15	20.80	335.95	8.28	2.5%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 L with E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.84	20.25	0.78	21.03	6.19	41.7%
250	17.41	23.37	0.98	24.35	6.94	39.9%
300	19.98	26.49	1.17	27.66	7.68	38.4%
350	22.55	29.61	1.37	30.98	8.43	37.4%
400	25.12	32.73	1.56	34.29	9.17	36.5%
450	35.49	37.25	1.76	39.01	3.52	9.9%
500	39.99	41.77	1.95	43.72	3.73	9.3%
550	44.50	46.30	2.15	48.45	3.95	8.9%
600	49.00	50.82	2.34	53.16	4.16	8.5%
650	53.51	55.34	2.54	57.88	4.37	8.2%
700	58.01	59.87	2.73	62.60	4.59	7.9%
750	62.52	64.39	2.93	67.32	4.80	7.7%
800	67.02	68.91	3.12	72.03	5.01	7.5%
850	84.09	81.08	4.42	85.50	1.41	1.7%
900	90.30	88.28	4.68	92.96	2.66	2.9%
950	96.50	95.48	4.94	100.42	3.92	4.1%
1,000	102.70	102.67	5.20	107.87	5.17	5.0%
1,100	115.11	117.07	5.72	122.79	7.68	6.7%
1,200	127.52	131.47	6.24	137.71	10.19	8.0%
1,300	149.71	145.86	6.76	152.62	2.91	1.9%
1,400	164.13	160.26	7.28	167.54	3.41	2.1%
1,500	178.56	174.65	7.80	182.45	3.89	2.2%
1,600	192.99	189.05	8.32	197.37	4.38	2.3%
1,700	207.41	203.45	8.84	212.29	4.88	2.4%
1,800	221.84	217.84	9.36	227.20	5.36	2.4%
1,900	236.27	232.24	9.88	242.12	5.85	2.5%
2,000	250.69	246.63	10.40	257.03	6.34	2.5%
2,200	279.55	275.43	11.44	286.87	7.32	2.6%
2,400	308.40	304.22	12.48	316.70	8.30	2.7%
2,600	337.26	333.01	13.52	346.53	9.27	2.7%
2,800	366.11	361.80	14.56	376.36	10.25	2.8%
3,000	394.96	390.59	15.60	406.19	11.23	2.8%
4,000	539.23	534.55	20.80	555.35	16.12	3.0%
5,000	683.50	678.51	26.00	704.51	21.01	3.1%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 L with E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.55	19.87	0.78	20.65	6.10	41.9%
250	17.04	22.89	0.98	23.87	6.83	40.1%
300	19.54	25.92	1.17	27.09	7.55	38.6%
350	22.04	28.95	1.37	30.32	8.28	37.6%
400	24.54	31.97	1.56	33.53	8.99	36.6%
450	27.04	35.00	1.76	36.76	9.72	35.9%
500	29.54	38.03	1.95	39.98	10.44	35.3%
550	32.03	41.05	2.15	43.20	11.17	34.9%
600	34.53	44.08	2.34	46.42	11.89	34.4%
650	37.03	47.10	2.54	49.64	12.61	34.1%
700	39.53	50.13	2.73	52.86	13.33	33.7%
750	42.03	53.16	2.93	56.09	14.06	33.5%
800	44.52	56.18	3.12	59.30	14.78	33.2%
850	57.99	42.95	4.42	47.37	(10.62)	-18.3%
900	61.07	46.98	4.68	51.66	(9.41)	-15.4%
950	64.16	51.02	4.94	55.96	(8.20)	-12.8%
1,000	67.24	55.05	5.20	60.25	(6.99)	-10.4%
1,100	73.40	63.12	5.72	68.84	(4.56)	-6.2%
1,200	79.56	71.19	6.24	77.43	(2.13)	-2.7%
1,300	85.72	79.26	6.76	86.02	0.30	0.3%
1,400	91.88	87.33	7.28	94.61	2.73	3.0%
1,500	113.95	95.40	7.80	103.20	(10.75)	-9.4%
1,600	121.11	103.47	8.32	111.79	(9.32)	-7.7%
1,700	128.27	111.54	8.84	120.38	(7.89)	-6.2%
1,800	135.43	119.61	9.36	128.97	(6.46)	-4.8%
1,900	142.59	127.68	9.88	137.56	(5.03)	-3.5%
2,000	149.75	135.75	10.40	146.15	(3.60)	-2.4%
2,200	164.78	151.89	11.44	163.33	(1.45)	-0.9%
2,400	181.44	168.03	12.48	180.51	(0.93)	-0.5%
2,600	198.09	184.17	13.52	197.69	(0.40)	-0.2%
2,800	214.75	200.31	14.56	214.87	0.12	0.1%
3,000	231.40	216.45	15.60	232.05	0.65	0.3%
4,000	314.67	297.15	20.80	317.95	3.28	1.0%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
E-12 L with E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.84	20.25	0.78	21.03	6.19	41.7%
250	17.41	23.37	0.98	24.35	6.94	39.9%
300	19.98	26.49	1.17	27.66	7.68	38.4%
350	22.55	29.61	1.37	30.98	8.43	37.4%
400	25.12	32.73	1.56	34.29	9.17	36.5%
450	28.77	37.25	1.76	39.01	10.24	35.6%
500	32.43	41.77	1.95	43.72	11.29	34.8%
550	36.08	46.30	2.15	48.45	12.37	34.3%
600	39.73	50.82	2.34	53.16	13.43	33.8%
650	43.38	55.34	2.54	57.88	14.50	33.4%
700	47.04	59.87	2.73	62.60	15.56	33.1%
750	50.69	64.39	2.93	67.32	16.63	32.8%
800	54.34	68.91	3.12	72.03	17.69	32.6%
850	72.36	63.08	4.42	67.50	(4.86)	-6.7%
900	77.70	70.28	4.68	74.96	(2.74)	-3.5%
950	83.04	77.48	4.94	82.42	(0.62)	-0.7%
1,000	88.37	84.67	5.20	89.87	1.50	1.7%
1,100	99.05	99.07	5.72	104.79	5.74	5.8%
1,200	109.73	113.47	6.24	119.71	9.98	9.1%
1,300	120.40	127.86	6.76	134.62	14.22	11.8%
1,400	131.08	142.26	7.28	149.54	18.46	14.1%
1,500	164.74	156.65	7.80	164.45	(0.29)	-0.2%
1,600	177.15	171.05	8.32	179.37	2.22	1.3%
1,700	189.56	185.45	8.84	194.29	4.73	2.5%
1,800	201.96	199.84	9.36	209.20	7.24	3.6%
1,900	214.37	214.24	9.88	224.12	9.75	4.5%
2,000	226.78	228.63	10.40	239.03	12.25	5.4%
2,200	266.55	257.43	11.44	268.87	2.32	0.9%
2,400	295.40	286.22	12.48	298.70	3.30	1.1%
2,600	324.26	315.01	13.52	328.53	4.27	1.3%
2,800	353.11	343.80	14.56	358.36	5.25	1.5%
3,000	381.96	372.59	15.60	388.19	6.23	1.6%
4,000	526.23	516.55	20.80	537.35	11.12	2.1%
5,000	670.50	660.51	26.00	686.51	16.01	2.4%

Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	33.72	34.01	1.04	35.05	1.33	3.9%
250	37.98	38.17	1.30	39.47	1.49	3.9%
300	42.24	42.33	1.56	43.89	1.65	3.9%
350	46.49	46.49	1.82	48.31	1.82	3.9%
400	50.75	50.65	2.08	52.73	1.98	3.9%
450	55.01	54.81	2.34	57.15	2.14	3.9%
500	59.27	58.97	2.60	61.57	2.30	3.9%
550	63.53	63.13	2.86	65.99	2.46	3.9%
600	67.79	67.29	3.12	70.41	2.62	3.9%
650	72.05	71.45	3.38	74.83	2.78	3.9%
700	76.31	75.61	3.64	79.25	2.94	3.9%
750	80.57	79.77	3.90	83.67	3.10	3.8%
800	84.83	83.93	4.16	88.09	3.26	3.8%
850	89.09	88.09	4.42	92.51	3.42	3.8%
900	93.35	92.25	4.68	96.93	3.58	3.8%
950	97.61	96.41	4.94	101.35	3.74	3.8%
1,000	101.87	100.58	5.20	105.78	3.91	3.8%
1,100	110.38	108.90	5.72	114.62	4.24	3.8%
1,200	118.90	117.22	6.24	123.46	4.56	3.8%
1,300	127.42	125.54	6.76	132.30	4.88	3.8%
1,400	135.94	133.86	7.28	141.14	5.20	3.8%
1,500	144.46	142.18	7.80	149.98	5.52	3.8%
1,600	152.98	150.50	8.32	158.82	5.84	3.8%
1,700	161.49	158.82	8.84	167.66	6.17	3.8%
1,800	170.01	167.14	9.36	176.50	6.49	3.8%
1,900	178.53	175.46	9.88	185.34	6.81	3.8%
2,000	187.05	183.78	10.40	194.18	7.13	3.8%
2,200	204.09	200.42	11.44	211.86	7.77	3.8%
2,400	221.12	217.06	12.48	229.54	8.42	3.8%
2,600	238.16	233.70	13.52	247.22	9.06	3.8%
2,800	255.20	250.34	14.56	264.90	9.70	3.8%
3,000	272.24	266.99	15.60	282.59	10.35	3.8%

ET-1 Winter Average Energy On-Peak: 33%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	38.14	38.68	1.04	39.72	1.58	4.1%
250	43.51	44.01	1.30	45.31	1.80	4.1%
300	48.88	49.33	1.56	50.89	2.01	4.1%
350	54.24	54.66	1.82	56.48	2.24	4.1%
400	59.61	59.99	2.08	62.07	2.46	4.1%
450	64.97	65.32	2.34	67.66	2.69	4.1%
500	70.34	70.64	2.60	73.24	2.90	4.1%
550	75.70	75.97	2.86	78.83	3.13	4.1%
600	81.07	81.30	3.12	84.42	3.35	4.1%
650	86.44	86.63	3.38	90.01	3.57	4.1%
700	91.80	91.95	3.64	95.59	3.79	4.1%
750	97.17	97.28	3.90	101.18	4.01	4.1%
800	102.53	102.61	4.16	106.77	4.24	4.1%
850	107.90	107.93	4.42	112.35	4.45	4.1%
900	113.27	113.26	4.68	117.94	4.67	4.1%
950	118.63	118.59	4.94	123.53	4.90	4.1%
1,000	124.00	123.92	5.20	129.12	5.12	4.1%
1,100	134.73	134.57	5.72	140.29	5.56	4.1%
1,200	145.46	145.23	6.24	151.47	6.01	4.1%
1,300	156.19	155.88	6.76	162.64	6.45	4.1%
1,400	166.92	166.54	7.28	173.82	6.90	4.1%
1,500	177.66	177.19	7.80	184.99	7.33	4.1%
1,600	188.39	187.84	8.32	196.16	7.77	4.1%
1,700	199.12	198.50	8.84	207.34	8.22	4.1%
1,800	209.85	209.15	9.36	218.51	8.66	4.1%
1,900	220.58	219.81	9.88	229.69	9.11	4.1%
2,000	231.31	230.46	10.40	240.86	9.55	4.1%
2,200	252.78	251.77	11.44	263.21	10.43	4.1%
2,400	274.24	273.08	12.48	285.56	11.32	4.1%
2,600	295.70	294.39	13.52	307.91	12.21	4.1%
2,800	317.17	315.70	14.56	330.26	13.09	4.1%
3,000	338.63	337.01	15.60	352.61	13.98	4.1%

ET-1 Summer Average Energy On-Peak: 41%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 L with E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.92	24.44	0.78	25.22	7.30	40.7%
250	20.18	27.29	0.98	28.27	8.09	40.1%
300	22.44	30.15	1.17	31.32	8.88	39.6%
350	24.71	33.00	1.37	34.37	9.66	39.1%
400	26.97	35.85	1.56	37.41	10.44	38.7%
450	36.05	38.70	1.76	40.46	4.41	12.2%
500	38.84	41.56	1.95	43.51	4.67	12.0%
550	41.63	44.41	2.15	46.56	4.93	11.8%
600	44.42	47.26	2.34	49.60	5.18	11.7%
650	47.21	50.12	2.54	52.66	5.45	11.5%
700	49.99	52.97	2.73	55.70	5.71	11.4%
750	52.78	55.82	2.93	58.75	5.97	11.3%
800	55.57	58.68	3.12	61.80	6.23	11.2%
850	67.83	64.04	4.42	68.46	0.63	0.9%
900	71.07	67.84	4.68	72.52	1.45	2.0%
950	74.31	71.65	4.94	76.59	2.28	3.1%
1,000	77.55	75.45	5.20	80.65	3.10	4.0%
1,100	84.03	83.06	5.72	88.78	4.75	5.7%
1,200	90.52	90.67	6.24	96.91	6.39	7.1%
1,300	99.79	98.27	6.76	105.03	5.24	5.3%
1,400	107.33	105.88	7.28	113.16	5.83	5.4%
1,500	114.87	113.49	7.80	121.29	6.42	5.6%
1,600	122.41	121.10	8.32	129.42	7.01	5.7%
1,700	129.95	128.70	8.84	137.54	7.59	5.8%
1,800	137.48	136.31	9.36	145.67	8.19	6.0%
1,900	145.02	143.92	9.88	153.80	8.78	6.1%
2,000	152.56	151.53	10.40	161.93	9.37	6.1%
2,200	167.64	166.74	11.44	178.18	10.54	6.3%
2,400	182.72	181.96	12.48	194.44	11.72	6.4%
2,600	197.79	197.18	13.52	210.70	12.91	6.5%
2,800	212.87	212.39	14.56	226.95	14.08	6.6%
3,000	227.95	227.61	15.60	243.21	15.26	6.7%

ET-1 Winter Average Energy On-Peak: 33%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 L with E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.27	27.61	0.78	28.39	8.12	40.1%
250	23.12	31.25	0.98	32.23	9.11	39.4%
300	25.97	34.90	1.17	36.07	10.10	38.9%
350	28.82	38.54	1.37	39.91	11.09	38.5%
400	31.67	42.19	1.56	43.75	12.08	38.1%
450	42.57	45.83	1.76	47.59	5.02	11.8%
500	46.08	49.48	1.95	51.43	5.35	11.6%
550	49.60	53.12	2.15	55.27	5.67	11.4%
600	53.11	56.77	2.34	59.11	6.00	11.3%
650	56.63	60.41	2.54	62.95	6.32	11.2%
700	60.14	64.06	2.73	66.79	6.65	11.1%
750	63.65	67.70	2.93	70.63	6.98	11.0%
800	67.17	71.35	3.12	74.47	7.30	10.9%
850	82.14	81.99	4.42	86.41	4.27	5.2%
900	86.23	86.85	4.68	91.53	5.30	6.1%
950	90.31	91.71	4.94	96.65	6.34	7.0%
1,000	94.39	96.57	5.20	101.77	7.38	7.8%
1,100	102.56	106.29	5.72	112.01	9.45	9.2%
1,200	110.73	116.01	6.24	122.25	11.52	10.4%
1,300	125.25	125.73	6.76	132.49	7.24	5.8%
1,400	134.75	135.45	7.28	142.73	7.98	5.9%
1,500	144.25	145.17	7.80	152.97	8.72	6.0%
1,600	153.74	154.89	8.32	163.21	9.47	6.2%
1,700	163.24	164.61	8.84	173.45	10.21	6.3%
1,800	172.74	174.33	9.36	183.69	10.95	6.3%
1,900	182.23	184.05	9.88	193.93	11.70	6.4%
2,000	191.73	193.78	10.40	204.18	12.45	6.5%
2,200	210.72	213.22	11.44	224.66	13.94	6.6%
2,400	229.72	232.66	12.48	245.14	15.42	6.7%
2,600	248.71	252.10	13.52	265.62	16.91	6.8%
2,800	267.71	271.54	14.56	286.10	18.39	6.9%
3,000	286.70	290.98	15.60	306.58	19.88	6.9%

ET-1 Summer Average Energy On-Peak: 41%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 L with E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.92	24.44	0.78	25.22	7.30	40.7%
250	20.18	27.29	0.98	28.27	8.09	40.1%
300	22.44	30.15	1.17	31.32	8.88	39.6%
350	24.71	33.00	1.37	34.37	9.66	39.1%
400	26.97	35.85	1.56	37.41	10.44	38.7%
450	29.23	38.70	1.76	40.46	11.23	38.4%
500	31.49	41.56	1.95	43.51	12.02	38.2%
550	33.75	44.41	2.15	46.56	12.81	38.0%
600	36.01	47.26	2.34	49.60	13.59	37.7%
650	38.27	50.12	2.54	52.66	14.39	37.6%
700	40.54	52.97	2.73	55.70	15.16	37.4%
750	42.80	55.82	2.93	58.75	15.95	37.3%
800	45.06	58.68	3.12	61.80	16.74	37.2%
850	58.36	46.04	4.42	50.46	(7.90)	-13.5%
900	61.15	49.84	4.68	54.52	(6.63)	-10.8%
950	63.94	53.65	4.94	58.59	(5.35)	-8.4%
1,000	66.73	57.45	5.20	62.65	(4.08)	-6.1%
1,100	72.31	65.06	5.72	70.78	(1.53)	-2.1%
1,200	77.89	72.67	6.24	78.91	1.02	1.3%
1,300	83.47	80.27	6.76	87.03	3.56	4.3%
1,400	89.04	87.88	7.28	95.16	6.12	6.9%
1,500	109.97	95.49	7.80	103.29	(6.68)	-6.1%
1,600	116.45	103.10	8.32	111.42	(5.03)	-4.3%
1,700	122.93	110.70	8.84	119.54	(3.39)	-2.8%
1,800	129.42	118.31	9.36	127.67	(1.75)	-1.4%
1,900	135.90	125.92	9.88	135.80	(0.10)	-0.1%
2,000	142.38	133.53	10.40	143.93	1.55	1.1%
2,200	154.64	148.74	11.44	160.18	5.54	3.6%
2,400	169.72	163.96	12.48	176.44	6.72	4.0%
2,600	184.79	179.18	13.52	192.70	7.91	4.3%
2,800	199.87	194.39	14.56	208.95	9.08	4.5%
3,000	214.95	209.61	15.60	225.21	10.26	4.8%

ET-1 Winter Average Energy On-Peak: 33%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-1 L with E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.27	27.61	0.78	28.39	8.12	40.1%
250	23.12	31.25	0.98	32.23	9.11	39.4%
300	25.97	34.90	1.17	36.07	10.10	38.9%
350	28.82	38.54	1.37	39.91	11.09	38.5%
400	31.67	42.19	1.56	43.75	12.08	38.1%
450	34.52	45.83	1.76	47.59	13.07	37.9%
500	37.37	49.48	1.95	51.43	14.06	37.6%
550	40.21	53.12	2.15	55.27	15.06	37.5%
600	43.06	56.77	2.34	59.11	16.05	37.3%
650	45.91	60.41	2.54	62.95	17.04	37.1%
700	48.76	64.06	2.73	66.79	18.03	37.0%
750	51.61	67.70	2.93	70.63	19.02	36.9%
800	54.46	71.35	3.12	74.47	20.01	36.7%
850	70.68	63.99	4.42	68.41	(2.27)	-3.2%
900	74.19	68.85	4.68	73.53	(0.66)	-0.9%
950	77.71	73.71	4.94	78.65	0.94	1.2%
1,000	81.22	78.57	5.20	83.77	2.55	3.1%
1,100	88.25	88.29	5.72	94.01	5.76	6.5%
1,200	95.28	98.01	6.24	104.25	8.97	9.4%
1,300	102.31	107.73	6.76	114.49	12.18	11.9%
1,400	109.33	117.45	7.28	124.73	15.40	14.1%
1,500	135.23	127.17	7.80	134.97	(0.26)	-0.2%
1,600	143.40	136.89	8.32	145.21	1.81	1.3%
1,700	151.57	146.61	8.84	155.45	3.88	2.6%
1,800	159.73	156.33	9.36	165.69	5.96	3.7%
1,900	167.90	166.05	9.88	175.93	8.03	4.8%
2,000	176.07	175.78	10.40	186.18	10.11	5.7%
2,200	197.72	195.22	11.44	206.66	8.94	4.5%
2,400	216.72	214.66	12.48	227.14	10.42	4.8%
2,600	235.71	234.10	13.52	247.62	11.91	5.1%
2,800	254.71	253.54	14.56	268.10	13.39	5.3%
3,000	273.70	272.98	15.60	288.58	14.88	5.4%

ET-1 Summer Average Energy On-Peak: 41%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	33.59	34.60	1.04	35.64	2.05	6.1%
250	37.81	38.91	1.30	40.21	2.40	6.3%
300	42.04	43.22	1.56	44.78	2.74	6.5%
350	46.27	47.53	1.82	49.35	3.08	6.7%
400	50.49	51.84	2.08	53.92	3.43	6.8%
450	54.72	56.14	2.34	58.48	3.76	6.9%
500	58.95	60.45	2.60	63.05	4.10	7.0%
550	63.17	64.76	2.86	67.62	4.45	7.0%
600	67.40	69.07	3.12	72.19	4.79	7.1%
650	71.63	73.38	3.38	76.76	5.13	7.2%
700	75.85	77.68	3.64	81.32	5.47	7.2%
750	80.08	81.99	3.90	85.89	5.81	7.3%
800	84.31	86.30	4.16	90.46	6.15	7.3%
850	88.53	90.61	4.42	95.03	6.50	7.3%
900	92.76	94.92	4.68	99.60	6.84	7.4%
950	96.99	99.23	4.94	104.17	7.18	7.4%
1,000	101.21	103.53	5.20	108.73	7.52	7.4%
1,100	109.66	112.15	5.72	117.87	8.21	7.5%
1,200	118.12	120.77	6.24	127.01	8.89	7.5%
1,300	126.57	129.38	6.76	136.14	9.57	7.6%
1,400	135.02	138.00	7.28	145.28	10.26	7.6%
1,500	143.48	146.62	7.80	154.42	10.94	7.6%
1,600	151.93	155.23	8.32	163.55	11.62	7.6%
1,700	160.38	163.85	8.84	172.69	12.31	7.7%
1,800	168.84	172.46	9.36	181.82	12.98	7.7%
1,900	177.29	181.08	9.88	190.96	13.67	7.7%
2,000	185.74	189.70	10.40	200.10	14.36	7.7%
2,200	202.65	206.93	11.44	218.37	15.72	7.8%
2,400	219.56	224.16	12.48	236.64	17.08	7.8%
2,600	236.46	241.40	13.52	254.92	18.46	7.8%
2,800	253.37	258.63	14.56	273.19	19.82	7.8%
3,000	270.28	275.86	15.60	291.46	21.18	7.8%

ET-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	41.76	41.16	1.04	42.20	0.44	1.1%
250	48.02	47.11	1.30	48.41	0.39	0.8%
300	54.29	53.06	1.56	54.62	0.33	0.6%
350	60.56	59.01	1.82	60.83	0.27	0.4%
400	66.83	64.96	2.08	67.04	0.21	0.3%
450	73.10	70.91	2.34	73.25	0.15	0.2%
500	79.37	76.86	2.60	79.46	0.09	0.1%
550	85.64	82.81	2.86	85.67	0.03	0.0%
600	91.91	88.75	3.12	91.87	(0.04)	0.0%
650	98.17	94.70	3.38	98.08	(0.09)	-0.1%
700	104.44	100.65	3.64	104.29	(0.15)	-0.1%
750	110.71	106.60	3.90	110.50	(0.21)	-0.2%
800	116.98	112.55	4.16	116.71	(0.27)	-0.2%
850	123.25	118.50	4.42	122.92	(0.33)	-0.3%
900	129.52	124.45	4.68	129.13	(0.39)	-0.3%
950	135.79	130.40	4.94	135.34	(0.45)	-0.3%
1,000	142.06	136.34	5.20	141.54	(0.52)	-0.4%
1,100	154.59	148.24	5.72	153.96	(0.63)	-0.4%
1,200	167.13	160.14	6.24	166.38	(0.75)	-0.4%
1,300	179.67	172.04	6.76	178.80	(0.87)	-0.5%
1,400	192.21	183.93	7.28	191.21	(1.00)	-0.5%
1,500	204.74	195.83	7.80	203.63	(1.11)	-0.5%
1,600	217.28	207.73	8.32	216.05	(1.23)	-0.6%
1,700	229.82	219.63	8.84	228.47	(1.35)	-0.6%
1,800	242.36	231.52	9.36	240.88	(1.48)	-0.6%
1,900	254.90	243.42	9.88	253.30	(1.60)	-0.6%
2,000	267.43	255.32	10.40	265.72	(1.71)	-0.6%
2,200	292.51	279.11	11.44	290.55	(1.96)	-0.7%
2,400	317.58	302.91	12.48	315.39	(2.19)	-0.7%
2,600	342.66	326.70	13.52	340.22	(2.44)	-0.7%
2,800	367.73	350.50	14.56	365.06	(2.67)	-0.7%
3,000	392.81	374.29	15.60	389.89	(2.92)	-0.7%

ET-2 Summer Average Energy On-Peak: 35%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 L with E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.84	24.97	0.78	25.75	7.91	44.3%
250	20.08	27.95	0.98	28.93	8.85	44.1%
300	22.32	30.93	1.17	32.10	9.78	43.8%
350	24.56	33.92	1.37	35.29	10.73	43.7%
400	26.80	36.90	1.56	38.46	11.66	43.5%
450	35.82	39.89	1.76	41.65	5.83	16.3%
500	38.58	42.87	1.95	44.82	6.24	16.2%
550	41.35	45.86	2.15	48.01	6.66	16.1%
600	44.11	48.84	2.34	51.18	7.07	16.0%
650	46.88	51.83	2.54	54.37	7.49	16.0%
700	49.64	54.81	2.73	57.54	7.90	15.9%
750	52.40	57.80	2.93	60.73	8.33	15.9%
800	55.17	60.78	3.12	63.90	8.73	15.8%
850	67.33	67.02	4.42	71.44	4.11	6.1%
900	70.54	71.00	4.68	75.68	5.14	7.3%
950	73.75	74.98	4.94	79.92	6.17	8.4%
1,000	76.96	78.96	5.20	84.16	7.20	9.4%
1,100	83.39	86.92	5.72	92.64	9.25	11.1%
1,200	89.81	94.88	6.24	101.12	11.31	12.6%
1,300	96.90	102.83	6.76	109.59	10.69	10.8%
1,400	106.37	110.79	7.28	118.07	11.70	11.0%
1,500	113.84	118.75	7.80	126.55	12.71	11.2%
1,600	121.31	126.71	8.32	135.03	13.72	11.3%
1,700	128.78	134.67	8.84	143.51	14.73	11.4%
1,800	136.25	142.63	9.36	151.99	15.74	11.6%
1,900	143.72	150.59	9.88	160.47	16.75	11.7%
2,000	151.19	158.55	10.40	168.95	17.76	11.7%
2,200	166.13	174.46	11.44	185.90	19.77	11.9%
2,400	181.07	190.38	12.48	202.86	21.79	12.0%
2,600	196.01	206.30	13.52	219.82	23.81	12.1%
2,800	210.96	222.22	14.56	236.78	25.82	12.2%
3,000	225.90	238.13	15.60	253.73	27.83	12.3%

ET-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 L with E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.23	27.45	0.78	28.23	8.00	39.5%
250	23.06	31.05	0.98	32.03	8.97	38.9%
300	25.90	34.66	1.17	35.83	9.93	38.3%
350	28.74	38.26	1.37	39.63	10.89	37.9%
400	31.58	41.87	1.56	43.43	11.85	37.5%
450	42.45	45.47	1.76	47.23	4.78	11.3%
500	45.95	49.08	1.95	51.03	5.08	11.1%
550	49.45	52.68	2.15	54.83	5.38	10.9%
600	52.95	56.29	2.34	58.63	5.68	10.7%
650	56.45	59.89	2.54	62.43	5.98	10.6%
700	59.95	63.50	2.73	66.23	6.28	10.5%
750	63.45	67.10	2.93	70.03	6.58	10.4%
800	66.95	70.71	3.12	73.83	6.88	10.3%
850	81.87	81.08	4.42	85.50	3.63	4.4%
900	85.94	85.89	4.68	90.57	4.63	5.4%
950	90.01	90.70	4.94	95.64	5.63	6.3%
1,000	94.08	95.50	5.20	100.70	6.62	7.0%
1,100	102.21	105.12	5.72	110.84	8.63	8.4%
1,200	110.35	114.73	6.24	120.97	10.62	9.6%
1,300	124.77	124.34	6.76	131.10	6.33	5.1%
1,400	134.23	133.96	7.28	141.24	7.01	5.2%
1,500	143.69	143.57	7.80	151.37	7.68	5.3%
1,600	153.15	153.18	8.32	161.50	8.35	5.5%
1,700	162.61	162.80	8.84	171.64	9.03	5.6%
1,800	172.07	172.41	9.36	181.77	9.70	5.6%
1,900	181.53	182.02	9.88	191.90	10.37	5.7%
2,000	190.99	191.64	10.40	202.04	11.05	5.8%
2,200	209.91	210.86	11.44	222.30	12.39	5.9%
2,400	228.83	230.09	12.48	242.57	13.74	6.0%
2,600	247.75	249.31	13.52	262.83	15.08	6.1%
2,800	266.67	268.54	14.56	283.10	16.43	6.2%
3,000	285.59	287.77	15.60	303.37	17.78	6.2%

ET-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
Flat dollar discounts are applied to column (B) for customers with usage 1201 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 L with E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.84	24.97	0.78	25.75	7.91	44.3%
250	20.08	27.95	0.98	28.93	8.85	44.1%
300	22.32	30.93	1.17	32.10	9.78	43.8%
350	24.56	33.92	1.37	35.29	10.73	43.7%
400	26.80	36.90	1.56	38.46	11.66	43.5%
450	29.04	39.89	1.76	41.65	12.61	43.4%
500	31.28	42.87	1.95	44.82	13.54	43.3%
550	33.53	45.86	2.15	48.01	14.48	43.2%
600	35.77	48.84	2.34	51.18	15.41	43.1%
650	38.01	51.83	2.54	54.37	16.36	43.0%
700	40.25	54.81	2.73	57.54	17.29	43.0%
750	42.49	57.80	2.93	60.73	18.24	42.9%
800	44.73	60.78	3.12	63.90	19.17	42.9%
850	57.93	49.02	4.42	53.44	(4.49)	-7.8%
900	60.70	53.00	4.68	57.68	(3.02)	-5.0%
950	63.46	56.98	4.94	61.92	(1.54)	-2.4%
1,000	66.22	60.96	5.20	66.16	(0.06)	-0.1%
1,100	71.75	68.92	5.72	74.64	2.89	4.0%
1,200	77.28	76.88	6.24	83.12	5.84	7.6%
1,300	82.81	84.83	6.76	91.59	8.78	10.6%
1,400	88.34	92.79	7.28	100.07	11.73	13.3%
1,500	109.08	100.75	7.80	108.55	(0.53)	-0.5%
1,600	115.51	108.71	8.32	117.03	1.52	1.3%
1,700	121.93	116.67	8.84	125.51	3.58	2.9%
1,800	128.36	124.63	9.36	133.99	5.63	4.4%
1,900	134.78	132.59	9.88	142.47	7.69	5.7%
2,000	141.21	140.55	10.40	150.95	9.74	6.9%
2,200	153.13	156.46	11.44	167.90	14.77	9.6%
2,400	168.07	172.38	12.48	184.86	16.79	10.0%
2,600	183.01	188.30	13.52	201.82	18.81	10.3%
2,800	197.96	204.22	14.56	218.78	20.82	10.5%
3,000	212.90	220.13	15.60	235.73	22.83	10.7%

ET-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-2 L with E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.23	27.45	0.78	28.23	8.00	39.5%
250	23.06	31.05	0.98	32.03	8.97	38.9%
300	25.90	34.86	1.17	35.83	9.93	38.3%
350	28.74	38.26	1.37	39.63	10.89	37.9%
400	31.58	41.87	1.56	43.43	11.85	37.5%
450	34.42	45.47	1.76	47.23	12.81	37.2%
500	37.25	49.08	1.95	51.03	13.78	37.0%
550	40.09	52.68	2.15	54.83	14.74	36.8%
600	42.93	56.29	2.34	58.63	15.70	36.6%
650	45.77	59.89	2.54	62.43	16.66	36.4%
700	48.61	63.50	2.73	66.23	17.62	36.2%
750	51.44	67.10	2.93	70.03	18.59	36.1%
800	54.28	70.71	3.12	73.83	19.55	36.0%
850	70.45	63.08	4.42	67.50	(2.95)	-4.2%
900	73.95	67.89	4.68	72.57	(1.38)	-1.9%
950	77.45	72.70	4.94	77.64	0.19	0.2%
1,000	80.95	77.50	5.20	82.70	1.75	2.2%
1,100	87.95	87.12	5.72	92.84	4.89	5.6%
1,200	94.95	96.73	6.24	102.97	8.02	8.4%
1,300	101.95	106.34	6.76	113.10	11.15	10.9%
1,400	108.95	115.96	7.28	123.24	14.29	13.1%
1,500	134.75	125.57	7.80	133.37	(1.38)	-1.0%
1,600	142.89	135.18	8.32	143.50	0.61	0.4%
1,700	151.02	144.80	8.84	153.64	2.62	1.7%
1,800	159.16	154.41	9.36	163.77	4.61	2.9%
1,900	167.30	164.02	9.88	173.90	6.60	3.9%
2,000	175.43	173.64	10.40	184.04	8.61	4.9%
2,200	196.91	192.86	11.44	204.30	7.39	3.8%
2,400	215.83	212.09	12.48	224.57	8.74	4.0%
2,600	234.75	231.31	13.52	244.83	10.08	4.3%
2,800	253.67	250.54	14.56	265.10	11.43	4.5%
3,000	272.59	269.77	15.60	285.37	12.78	4.7%

ET-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts are applied to column (B) for customers with usage 2001 kWh and above, and for column (C) usage of 801 kWh and above.
4) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	63.95	64.37	2.28	66.65	2.70	4.2%
3	30%	657	73.80	73.39	3.42	76.81	3.01	4.1%
3	40%	876	83.65	82.42	4.56	86.98	3.33	4.0%
3	50%	1,095	93.51	91.45	5.69	97.14	3.63	3.9%
3	75%	1,643	118.16	114.04	8.54	122.58	4.42	3.7%
5	20%	730	95.46	95.70	3.80	99.50	4.04	4.2%
5	30%	1,095	111.88	110.74	5.69	116.43	4.55	4.1%
5	40%	1,460	128.30	125.79	7.59	133.38	5.08	4.0%
5	50%	1,825	144.72	140.83	9.49	150.32	5.60	3.9%
5	75%	2,738	185.80	178.46	14.24	192.70	6.90	3.7%
8	20%	1,168	142.74	142.70	6.07	148.77	6.03	4.2%
8	30%	1,752	169.01	166.77	9.11	175.88	6.87	4.1%
8	40%	2,336	195.28	190.84	12.15	202.99	7.71	3.9%
8	50%	2,920	221.55	214.91	15.18	230.09	8.54	3.9%
8	75%	4,380	287.23	275.09	22.78	297.87	10.64	3.7%
10	20%	1,460	174.25	174.03	7.59	181.62	7.37	4.2%
10	30%	2,190	207.09	204.12	11.39	215.51	8.42	4.1%
10	40%	2,920	239.93	234.21	15.18	249.39	9.46	3.9%
10	50%	3,650	272.77	264.30	18.98	283.28	10.51	3.9%
10	75%	5,475	354.87	339.52	28.47	367.99	13.12	3.7%
12	20%	1,752	205.76	205.36	9.11	214.47	8.71	4.2%
12	30%	2,628	245.17	241.47	13.67	255.14	9.97	4.1%
12	40%	3,504	284.58	277.57	18.22	295.79	11.21	3.9%
12	50%	4,380	323.99	313.68	22.78	336.46	12.47	3.8%
12	75%	6,570	422.50	403.95	34.16	438.11	15.61	3.7%
15	20%	2,190	253.03	252.36	11.39	263.75	10.72	4.2%
15	30%	3,285	302.29	297.49	17.08	314.57	12.28	4.1%
15	40%	4,380	351.55	342.62	22.78	365.40	13.85	3.9%
15	50%	5,475	400.81	387.76	28.47	416.23	15.42	3.8%
15	75%	8,213	523.98	500.61	42.71	543.32	19.34	3.7%

ECT-1R Winter Average Energy On-Peak: 32%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	80.75	81.95	2.28	84.23	3.48	4.3%
3	30%	657	92.73	93.18	3.42	96.60	3.87	4.2%
3	40%	876	104.70	104.41	4.56	108.97	4.27	4.1%
3	50%	1,095	116.68	115.64	5.69	121.33	4.65	4.0%
3	75%	1,643	146.65	143.74	8.54	152.28	5.63	3.8%
5	20%	730	123.46	125.00	3.80	128.80	5.34	4.3%
5	30%	1,095	143.43	143.72	5.69	149.41	5.98	4.2%
5	40%	1,460	163.39	162.44	7.59	170.03	6.64	4.1%
5	50%	1,825	183.35	181.15	9.49	190.64	7.29	4.0%
5	75%	2,738	233.28	227.98	14.24	242.22	8.94	3.8%
8	20%	1,168	187.53	189.58	6.07	195.65	8.12	4.3%
8	30%	1,752	219.47	219.53	9.11	228.64	9.17	4.2%
8	40%	2,336	251.41	249.48	12.15	261.63	10.22	4.1%
8	50%	2,920	283.35	279.43	15.18	294.61	11.26	4.0%
8	75%	4,380	363.20	354.30	22.78	377.08	13.88	3.8%
10	20%	1,460	230.25	232.63	7.59	240.22	9.97	4.3%
10	30%	2,190	270.17	270.07	11.39	281.46	11.29	4.2%
10	40%	2,920	310.09	307.50	15.18	322.68	12.59	4.1%
10	50%	3,650	350.02	344.94	18.98	363.92	13.90	4.0%
10	75%	5,475	449.83	438.53	28.47	467.00	17.17	3.8%
12	20%	1,752	272.96	275.68	9.11	284.79	11.83	4.3%
12	30%	2,628	320.87	320.61	13.67	334.28	13.41	4.2%
12	40%	3,504	368.78	365.53	18.22	383.75	14.97	4.1%
12	50%	4,380	416.69	410.45	22.78	433.23	16.54	4.0%
12	75%	6,570	536.46	522.76	34.16	556.92	20.46	3.8%
15	20%	2,190	337.03	340.26	11.39	351.65	14.62	4.3%
15	30%	3,285	396.92	396.42	17.08	413.50	16.58	4.2%
15	40%	4,380	456.80	452.57	22.78	475.35	18.55	4.1%
15	50%	5,475	516.69	508.72	28.47	537.19	20.50	4.0%
15	75%	8,213	666.43	649.13	42.71	691.84	25.41	3.8%

ECT-1R Summer Average Energy On-Peak: 40%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R L with E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	41.92	49.59	1.71	51.30	9.38	22.4%
3	30%	657	48.36	56.58	2.56	59.14	10.78	22.3%
3	40%	876	63.69	66.77	4.56	71.33	7.64	12.0%
3	50%	1,095	71.18	76.10	5.69	81.79	10.61	14.9%
3	75%	1,643	91.55	99.44	8.54	107.98	16.43	17.9%
5	20%	730	62.57	73.96	2.85	76.81	14.24	22.8%
5	30%	1,095	85.20	96.16	5.69	101.85	16.65	19.5%
5	40%	1,460	100.58	111.70	7.59	119.29	18.71	18.6%
5	50%	1,825	115.09	127.25	9.49	136.74	21.65	18.8%
5	75%	2,738	151.38	166.13	14.24	180.37	28.99	19.2%
8	20%	1,168	108.72	129.36	6.07	135.43	26.71	24.6%
8	30%	1,752	136.64	154.23	9.11	163.34	26.70	19.5%
8	40%	2,336	159.85	179.10	12.15	191.25	31.40	19.6%
8	50%	2,920	183.07	203.98	15.18	219.16	36.09	19.7%
8	75%	4,380	241.10	266.16	22.78	288.94	47.84	19.8%
10	20%	1,460	141.33	161.85	7.59	169.44	28.11	19.9%
10	30%	2,190	170.35	192.94	11.39	204.33	33.98	19.9%
10	40%	2,920	199.37	224.04	15.18	239.22	39.85	20.0%
10	50%	3,650	228.38	255.13	18.98	274.11	45.73	20.0%
10	75%	5,475	300.93	332.86	28.47	361.33	60.40	20.1%
12	20%	1,752	169.24	194.35	9.11	203.46	34.22	20.2%
12	30%	2,628	204.06	231.66	13.67	245.33	41.27	20.2%
12	40%	3,504	238.88	268.97	18.22	287.19	48.31	20.2%
12	50%	4,380	273.70	306.28	22.78	329.06	55.36	20.2%
12	75%	6,570	360.76	399.55	34.16	433.71	72.95	20.2%
15	20%	2,190	211.10	243.09	11.39	254.48	43.38	20.5%
15	30%	3,285	254.62	289.73	17.08	306.81	52.19	20.5%
15	40%	4,380	298.15	336.37	22.78	359.15	61.00	20.5%
15	50%	5,475	341.68	383.01	28.47	411.48	69.80	20.4%
15	75%	8,213	450.52	499.62	42.71	542.33	91.81	20.4%

ECT-1R Winter Average Energy On-Peak: 31%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
   Flat dollar discounts are applied to column (D) for customers with usage 1201 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R L with E-3 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	53.00	63.31	1.71	65.02	12.02	22.7%
3	30%	657	60.86	72.03	2.56	74.59	13.73	22.6%
3	40%	876	79.86	89.67	4.56	94.23	14.37	18.0%
3	50%	1,095	89.00	101.29	5.69	106.98	17.98	20.2%
3	75%	1,643	117.07	130.39	8.54	138.93	21.86	18.7%
5	20%	730	81.03	96.83	2.85	99.68	18.65	23.0%
5	30%	1,095	109.40	130.49	5.69	136.18	26.78	24.5%
5	40%	1,460	131.91	149.86	7.59	157.45	25.54	19.4%
5	50%	1,825	149.61	169.24	9.49	178.73	29.12	19.5%
5	75%	2,738	193.90	217.72	14.24	231.96	38.06	19.6%
8	20%	1,168	143.04	178.15	6.07	184.22	41.18	28.8%
8	30%	1,752	181.65	209.16	9.11	218.27	36.62	20.2%
8	40%	2,336	209.98	240.16	12.15	252.31	42.33	20.2%
8	50%	2,920	238.31	271.17	15.18	286.35	48.04	20.2%
8	75%	4,380	309.13	348.68	22.78	371.46	62.33	20.2%
10	20%	1,460	191.21	222.84	7.59	230.43	39.22	20.5%
10	30%	2,190	226.62	261.60	11.39	272.99	46.37	20.5%
10	40%	2,920	262.03	300.36	15.18	315.54	53.51	20.4%
10	50%	3,650	297.44	339.12	18.98	358.10	60.66	20.4%
10	75%	5,475	385.96	436.01	28.47	464.48	78.52	20.3%
12	20%	1,752	229.09	267.54	9.11	276.65	47.56	20.8%
12	30%	2,628	271.58	314.05	13.67	327.72	56.14	20.7%
12	40%	3,504	314.08	360.56	18.22	378.78	64.70	20.6%
12	50%	4,380	356.57	407.06	22.78	429.84	73.27	20.5%
12	75%	6,570	462.79	523.34	34.16	557.50	94.71	20.5%
15	20%	2,190	285.92	334.58	11.39	345.97	60.05	21.0%
15	30%	3,285	339.03	392.72	17.08	409.80	70.77	20.9%
15	40%	4,380	392.15	450.85	22.78	473.63	81.48	20.8%
15	50%	5,475	445.26	508.99	28.47	537.46	92.20	20.7%
15	75%	8,213	578.07	654.35	42.71	697.06	118.99	20.6%

ECT-1R Summer Average Energy On-Peak: 40%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
   Flat dollar discounts are applied to column (D) for customers with usage 1201 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R L with E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	34.03	49.64	1.71	51.35	17.32	50.9%
3	30%	657	39.27	56.67	2.56	59.23	19.96	50.8%
3	40%	876	54.90	48.93	4.56	53.49	(1.41)	-2.6%
3	50%	1,095	61.37	58.29	5.69	63.98	2.61	4.3%
3	75%	1,643	90.12	81.73	8.54	90.27	0.15	0.2%
5	20%	730	50.80	74.06	2.85	76.91	26.11	51.4%
5	30%	1,095	73.43	78.35	5.69	84.04	10.61	14.4%
5	40%	1,460	97.86	93.96	7.59	101.55	3.69	3.8%
5	50%	1,825	110.38	109.57	9.49	119.06	8.68	7.9%
5	75%	2,738	138.78	148.62	14.24	162.86	24.08	17.4%
8	20%	1,168	93.68	111.56	6.07	117.63	23.95	25.6%
8	30%	1,752	128.90	136.54	9.11	145.65	16.75	13.0%
8	40%	2,336	147.19	161.52	12.15	173.67	26.48	18.0%
8	50%	2,920	170.49	186.50	15.18	201.68	31.19	18.3%
8	75%	4,380	228.74	248.94	22.78	271.72	42.98	18.8%
10	20%	1,460	132.90	144.11	7.59	151.70	18.80	14.1%
10	30%	2,190	157.66	175.33	11.39	186.72	29.06	18.4%
10	40%	2,920	186.79	206.56	15.18	221.74	34.95	18.7%
10	50%	3,650	215.91	237.78	18.98	256.76	40.85	18.9%
10	75%	5,475	288.72	315.83	28.47	344.30	55.58	19.3%
12	20%	1,752	156.94	176.66	9.11	185.77	28.83	18.4%
12	30%	2,628	191.44	214.13	13.67	227.80	36.36	19.0%
12	40%	3,504	226.39	251.59	18.22	269.81	43.42	19.2%
12	50%	4,380	261.34	289.06	22.78	311.84	50.50	19.3%
12	75%	6,570	348.71	382.72	34.16	416.88	68.17	19.5%
15	20%	2,190	198.41	225.48	11.39	236.87	38.46	19.4%
15	30%	3,285	242.10	272.32	17.08	289.40	47.30	19.5%
15	40%	4,380	285.79	319.15	22.78	341.93	56.14	19.6%
15	50%	5,475	329.47	365.98	28.47	394.45	64.98	19.7%
15	75%	8,213	438.71	483.08	42.71	525.79	87.08	19.8%

ECT-1R Winter Average Energy On-Peak: 32%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts are applied to column (D) for customers with usage 2001 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-1R L with E-4 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	42.97	63.31	1.71	65.02	22.05	51.3%
3	30%	657	49.34	72.03	2.56	74.59	25.25	51.2%
3	40%	876	68.72	71.67	4.56	76.23	7.51	10.9%
3	50%	1,095	76.58	83.29	5.69	88.98	12.40	16.2%
3	75%	1,643	111.86	112.39	8.54	120.93	9.07	8.1%
5	20%	730	65.70	96.83	2.85	99.68	33.98	51.7%
5	30%	1,095	94.13	112.49	5.69	118.18	24.05	25.5%
5	40%	1,460	124.62	131.86	7.59	139.45	14.83	11.9%
5	50%	1,825	139.85	151.24	9.49	160.73	20.88	14.9%
5	75%	2,738	180.90	199.72	14.24	213.96	33.06	18.3%
8	20%	1,168	123.08	160.15	6.07	166.22	43.14	35.1%
8	30%	1,752	167.40	191.16	9.11	200.27	32.87	19.6%
8	40%	2,336	196.98	222.16	12.15	234.31	37.33	19.0%
8	50%	2,920	225.31	253.17	15.18	268.35	43.04	19.1%
8	75%	4,380	296.13	330.68	22.78	353.46	57.33	19.4%
10	20%	1,460	175.62	204.84	7.59	212.43	36.81	21.0%
10	30%	2,190	213.62	243.60	11.39	254.99	41.37	19.4%
10	40%	2,920	249.03	282.36	15.18	297.54	48.51	19.5%
10	50%	3,650	284.44	321.12	18.98	340.10	55.66	19.6%
10	75%	5,475	372.96	418.01	28.47	446.48	73.52	19.7%
12	20%	1,752	208.20	249.54	9.11	258.65	50.45	24.2%
12	30%	2,628	258.58	296.05	13.67	309.72	51.14	19.8%
12	40%	3,504	301.08	342.56	18.22	360.78	59.70	19.8%
12	50%	4,380	343.57	389.06	22.78	411.84	68.27	19.9%
12	75%	6,570	449.79	505.34	34.16	539.50	89.71	19.9%
15	20%	2,190	272.92	316.58	11.39	327.97	55.05	20.2%
15	30%	3,285	326.03	374.72	17.08	391.80	65.77	20.2%
15	40%	4,380	379.15	432.85	22.78	455.63	76.48	20.2%
15	50%	5,475	432.26	490.99	28.47	519.46	87.20	20.2%
15	75%	8,213	565.07	636.35	42.71	679.06	113.99	20.2%

ECT-1R Summer Average Energy On-Peak: 40%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts are applied to column (D) for customers with usage 2001 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	64.15	64.53	2.28	66.81	2.66	4.1%
3	30%	657	74.08	73.63	3.42	77.05	2.97	4.0%
3	40%	876	84.02	82.73	4.56	87.29	3.27	3.9%
3	50%	1,095	93.95	91.84	5.69	97.53	3.58	3.8%
3	75%	1,643	118.80	114.61	8.54	123.15	4.35	3.7%
5	20%	730	95.80	95.97	3.80	99.77	3.97	4.1%
5	30%	1,095	112.35	111.14	5.69	116.83	4.48	4.0%
5	40%	1,460	128.91	126.31	7.59	133.90	4.99	3.9%
5	50%	1,825	145.46	141.48	9.49	150.97	5.51	3.8%
5	75%	2,738	186.87	179.42	14.24	193.66	6.79	3.6%
8	20%	1,168	143.27	143.13	6.07	149.20	5.93	4.1%
8	30%	1,752	169.76	167.41	9.11	176.52	6.76	4.0%
8	40%	2,336	196.24	191.68	12.15	203.83	7.59	3.9%
8	50%	2,920	222.73	215.95	15.18	231.13	8.40	3.8%
8	75%	4,380	288.94	276.62	22.78	299.40	10.46	3.6%
10	20%	1,460	174.92	174.58	7.59	182.17	7.25	4.1%
10	30%	2,190	208.03	204.91	11.39	216.30	8.27	4.0%
10	40%	2,920	241.14	235.25	15.18	250.43	9.29	3.9%
10	50%	3,650	274.24	265.59	18.98	284.57	10.33	3.8%
10	75%	5,475	357.01	341.43	28.47	369.90	12.89	3.6%
12	20%	1,752	206.57	206.02	9.11	215.13	8.56	4.1%
12	30%	2,628	246.30	242.42	13.67	256.09	9.79	4.0%
12	40%	3,504	286.03	278.83	18.22	297.05	11.02	3.9%
12	50%	4,380	325.75	315.23	22.78	338.01	12.26	3.8%
12	75%	6,570	425.07	406.25	34.16	440.41	15.34	3.6%
15	20%	2,190	254.04	253.18	11.39	264.57	10.53	4.1%
15	30%	3,285	303.70	298.69	17.08	315.77	12.07	4.0%
15	40%	4,380	353.36	344.19	22.78	366.97	13.61	3.9%
15	50%	5,475	403.02	389.70	28.47	418.17	15.15	3.8%
15	75%	8,213	527.20	503.49	42.71	546.20	19.00	3.6%

ECT-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	80.91	82.11	2.28	84.39	3.48	4.3%
3	30%	657	92.92	93.39	3.42	96.81	3.89	4.2%
3	40%	876	104.93	104.67	4.56	109.23	4.30	4.1%
3	50%	1,095	116.94	115.95	5.69	121.64	4.70	4.0%
3	75%	1,643	146.98	144.17	8.54	152.71	5.73	3.9%
5	20%	730	123.73	125.27	3.80	129.07	5.34	4.3%
5	30%	1,095	143.74	144.07	5.69	149.76	6.02	4.2%
5	40%	1,460	163.76	162.86	7.59	170.45	6.69	4.1%
5	50%	1,825	183.77	181.66	9.49	191.15	7.38	4.0%
5	75%	2,738	233.84	228.68	14.24	242.92	9.08	3.9%
8	20%	1,168	187.96	190.00	6.07	196.07	8.11	4.3%
8	30%	1,752	219.98	220.08	9.11	229.19	9.21	4.2%
8	40%	2,336	252.00	250.16	12.15	262.31	10.31	4.1%
8	50%	2,920	284.03	280.24	15.18	295.42	11.39	4.0%
8	75%	4,380	364.09	355.43	22.78	378.21	14.12	3.9%
10	20%	1,460	230.78	233.16	7.59	240.75	9.97	4.3%
10	30%	2,190	270.80	270.76	11.39	282.15	11.35	4.2%
10	40%	2,920	310.83	308.36	15.18	323.54	12.71	4.1%
10	50%	3,650	350.86	345.95	18.98	364.93	14.07	4.0%
10	75%	5,475	450.94	439.95	28.47	468.42	17.48	3.9%
12	20%	1,752	273.59	276.32	9.11	285.43	11.84	4.3%
12	30%	2,628	321.63	321.44	13.67	335.11	13.48	4.2%
12	40%	3,504	369.67	366.55	18.22	384.77	15.10	4.1%
12	50%	4,380	417.70	411.67	22.78	434.45	16.75	4.0%
12	75%	6,570	537.79	524.46	34.16	558.62	20.83	3.9%
15	20%	2,190	337.82	341.06	11.39	352.45	14.63	4.3%
15	30%	3,285	397.87	397.46	17.08	414.54	16.67	4.2%
15	40%	4,380	457.91	453.85	22.78	476.63	18.72	4.1%
15	50%	5,475	517.96	510.25	28.47	538.72	20.76	4.0%
15	75%	8,213	668.09	651.26	42.71	693.97	25.88	3.9%

ECT-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 L with E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	44.82	45.36	1.71	47.07	2.25	5.0%
3	30%	657	50.94	51.54	2.56	54.10	3.16	6.2%
3	40%	876	66.31	58.95	4.56	63.51	(2.80)	-4.2%
3	50%	1,095	73.43	67.19	5.69	72.88	(0.55)	-0.7%
3	75%	1,643	93.07	87.80	8.54	96.34	3.27	3.5%
5	20%	730	66.13	66.91	2.85	69.76	3.63	5.5%
5	30%	1,095	88.71	84.95	5.69	90.64	1.93	2.2%
5	40%	1,460	103.94	98.67	7.59	106.26	2.32	2.2%
5	50%	1,825	117.72	112.40	9.49	121.89	4.17	3.5%
5	75%	2,738	152.20	146.74	14.24	160.98	8.78	5.8%
8	20%	1,168	114.01	114.33	6.07	120.40	6.39	5.6%
8	30%	1,752	141.62	136.29	9.11	145.40	3.78	2.7%
8	40%	2,336	163.68	158.26	12.15	170.41	6.73	4.1%
8	50%	2,920	185.73	180.22	15.18	195.40	9.67	5.2%
8	75%	4,380	240.86	235.14	22.78	257.92	17.06	7.1%
10	20%	1,460	148.37	143.06	7.59	150.65	2.28	1.5%
10	30%	2,190	175.94	170.52	11.39	181.91	5.97	3.4%
10	40%	2,920	203.50	197.98	15.18	213.16	9.66	4.7%
10	50%	3,650	231.07	225.44	18.98	244.42	13.35	5.8%
10	75%	5,475	299.98	294.08	28.47	322.55	22.57	7.5%
12	20%	1,752	177.17	171.80	9.11	180.91	3.74	2.1%
12	30%	2,628	210.25	204.75	13.67	218.42	8.17	3.9%
12	40%	3,504	243.33	237.70	18.22	255.92	12.59	5.2%
12	50%	4,380	276.41	270.65	22.78	293.43	17.02	6.2%
12	75%	6,570	359.11	353.02	34.16	387.18	28.07	7.8%
15	20%	2,190	220.37	214.91	11.39	226.30	5.93	2.7%
15	30%	3,285	261.72	256.10	17.08	273.18	11.46	4.4%
15	40%	4,380	303.07	297.28	22.78	320.06	16.99	5.6%
15	50%	5,475	344.42	338.47	28.47	366.94	22.52	6.5%
15	75%	8,213	447.81	441.45	42.71	484.16	36.35	8.1%

ECT-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts are applied to column (D) for customers with usage 1201 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 L with E-3 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	53.04	57.47	1.71	59.18	6.14	11.6%
3	30%	657	60.91	65.15	2.56	67.71	6.80	11.2%
3	40%	876	79.93	79.10	4.56	83.66	3.73	4.7%
3	50%	1,095	89.08	89.33	5.69	95.02	5.94	6.7%
3	75%	1,643	117.19	114.95	8.54	123.49	6.30	5.4%
5	20%	730	81.10	87.10	2.85	89.95	8.85	10.9%
5	30%	1,095	109.49	115.19	5.69	120.88	11.39	10.4%
5	40%	1,460	132.04	132.25	7.59	139.84	7.80	5.9%
5	50%	1,825	149.77	149.31	9.49	158.80	9.03	6.0%
5	75%	2,738	194.10	191.98	14.24	206.22	12.12	6.2%
8	20%	1,168	143.17	157.40	6.07	163.47	20.30	14.2%
8	30%	1,752	181.83	184.69	9.11	193.80	11.97	6.6%
8	40%	2,336	210.19	211.98	12.15	224.13	13.94	6.6%
8	50%	2,920	238.55	239.28	15.18	254.46	15.91	6.7%
8	75%	4,380	309.45	307.51	22.78	330.29	20.84	6.7%
10	20%	1,460	191.39	196.90	7.59	204.49	13.10	6.8%
10	30%	2,190	226.84	231.02	11.39	242.41	15.57	6.9%
10	40%	2,920	262.29	265.14	15.18	280.32	18.03	6.9%
10	50%	3,650	297.74	299.25	18.98	318.23	20.49	6.9%
10	75%	5,475	386.37	384.54	28.47	413.01	26.64	6.9%
12	20%	1,752	229.31	236.41	9.11	245.52	16.21	7.1%
12	30%	2,628	271.85	277.35	13.67	291.02	19.17	7.1%
12	40%	3,504	314.39	318.29	18.22	336.51	22.12	7.0%
12	50%	4,380	356.93	359.23	22.78	382.01	25.08	7.0%
12	75%	6,570	463.29	461.58	34.16	495.74	32.45	7.0%
15	20%	2,190	286.19	295.67	11.39	307.06	20.87	7.3%
15	30%	3,285	339.37	346.84	17.08	363.92	24.55	7.2%
15	40%	4,380	392.54	398.02	22.78	420.80	28.26	7.2%
15	50%	5,475	445.72	449.19	28.47	477.66	31.94	7.2%
15	75%	8,213	578.68	577.15	42.71	619.86	41.18	7.1%

ECT-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
   Flat dollar discounts are applied to column (D) for customers with usage 1201 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 L with E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	34.10	45.36	1.71	47.07	12.97	38.0%
3	30%	657	39.38	51.54	2.56	54.10	14.72	37.4%
3	40%	876	55.07	40.95	4.56	45.51	(9.56)	-17.4%
3	50%	1,095	61.58	49.19	5.69	54.88	(6.70)	-10.9%
3	75%	1,643	90.49	69.80	8.54	78.34	(12.15)	-13.4%
5	20%	730	50.92	66.91	2.85	69.76	18.84	37.0%
5	30%	1,095	73.64	66.95	5.69	72.64	(1.00)	-1.4%
5	40%	1,460	98.19	80.67	7.59	88.26	(9.93)	-10.1%
5	50%	1,825	110.80	94.40	9.49	103.89	(6.91)	-6.2%
5	75%	2,738	139.50	128.74	14.24	142.98	3.48	2.5%
8	20%	1,168	93.91	96.33	6.07	102.40	8.49	9.0%
8	30%	1,752	129.30	118.29	9.11	127.40	(1.90)	-1.5%
8	40%	2,336	147.81	140.26	12.15	152.41	4.60	3.1%
8	50%	2,920	171.26	162.22	15.18	177.40	6.14	3.6%
8	75%	4,380	229.90	217.14	22.78	239.92	10.02	4.4%
10	20%	1,460	133.24	125.06	7.59	132.65	(0.59)	-0.4%
10	30%	2,190	158.25	152.52	11.39	163.91	5.66	3.6%
10	40%	2,920	187.56	179.98	15.18	195.16	7.60	4.1%
10	50%	3,650	216.88	207.44	18.98	226.42	9.54	4.4%
10	75%	5,475	290.18	276.08	28.47	304.55	14.37	5.0%
12	20%	1,752	157.34	153.80	9.11	162.91	5.57	3.5%
12	30%	2,628	192.14	186.75	13.67	200.42	8.28	4.3%
12	40%	3,504	227.32	219.70	18.22	237.92	10.60	4.7%
12	50%	4,380	262.50	252.65	22.78	275.43	12.93	4.9%
12	75%	6,570	350.46	335.02	34.16	369.18	18.72	5.3%
15	20%	2,190	199.00	196.91	11.39	208.30	9.30	4.7%
15	30%	3,285	242.97	238.10	17.08	255.18	12.21	5.0%
15	40%	4,380	286.95	279.28	22.78	302.06	15.11	5.3%
15	50%	5,475	330.93	320.47	28.47	348.94	18.01	5.4%
15	75%	8,213	440.89	423.45	42.71	466.16	25.27	5.7%

ECT-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
   Flat dollar discounts are applied to column (D) for customers with usage 2001 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ECT-2 L with E-4 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	43.00	57.47	1.71	59.18	16.18	37.6%
3	30%	657	49.38	65.15	2.56	67.71	18.33	37.1%
3	40%	876	68.78	61.10	4.56	65.66	(3.12)	-4.5%
3	50%	1,095	76.65	71.33	5.69	77.02	0.37	0.5%
3	75%	1,643	111.96	96.95	8.54	105.49	(6.47)	-5.8%
5	20%	730	65.75	87.10	2.85	89.95	24.20	36.8%
5	30%	1,095	94.21	97.19	5.69	102.88	8.67	9.2%
5	40%	1,460	124.74	114.25	7.59	121.84	(2.90)	-2.3%
5	50%	1,825	139.98	131.31	9.49	140.80	0.82	0.6%
5	75%	2,738	181.10	173.98	14.24	188.22	7.12	3.9%
8	20%	1,168	123.19	139.40	6.07	145.47	22.28	18.1%
8	30%	1,752	167.56	166.69	9.11	175.80	8.24	4.9%
8	40%	2,336	197.19	193.98	12.15	206.13	8.94	4.5%
8	50%	2,920	225.55	221.28	15.18	236.46	10.91	4.8%
8	75%	4,380	296.45	289.51	22.78	312.29	15.84	5.3%
10	20%	1,460	175.78	178.90	7.59	186.49	10.71	6.1%
10	30%	2,190	213.84	213.02	11.39	224.41	10.57	4.9%
10	40%	2,920	249.29	247.14	15.18	262.32	13.03	5.2%
10	50%	3,650	284.74	281.25	18.98	300.23	15.49	5.4%
10	75%	5,475	373.37	366.54	28.47	395.01	21.64	5.8%
12	20%	1,752	208.39	218.41	9.11	227.52	19.13	9.2%
12	30%	2,628	258.85	259.35	13.67	273.02	14.17	5.5%
12	40%	3,504	301.39	300.29	18.22	318.51	17.12	5.7%
12	50%	4,380	343.93	341.23	22.78	364.01	20.08	5.8%
12	75%	6,570	450.29	443.58	34.16	477.74	27.45	6.1%
15	20%	2,190	273.19	277.67	11.39	289.06	15.87	5.8%
15	30%	3,285	326.37	328.84	17.08	345.92	19.55	6.0%
15	40%	4,380	379.54	380.02	22.78	402.80	23.26	6.1%
15	50%	5,475	432.72	431.19	28.47	459.66	26.94	6.2%
15	75%	8,213	565.68	559.15	42.71	601.86	36.18	6.4%

ECT-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts are applied to column (D) for customers with usage 2001 kWh and above, and for column (E) usage of 801 kWh and above.
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-SP Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	32.14	33.05	1.04	34.09	1.95	6.1%
250	36.01	36.97	1.30	38.27	2.26	6.3%
300	39.87	40.89	1.56	42.45	2.58	6.5%
350	43.74	44.81	1.82	46.63	2.89	6.6%
400	47.60	48.72	2.08	50.80	3.20	6.7%
450	51.47	52.64	2.34	54.98	3.51	6.8%
500	55.33	56.56	2.60	59.16	3.83	6.9%
550	59.20	60.48	2.86	63.34	4.14	7.0%
600	63.06	64.40	3.12	67.52	4.46	7.1%
650	66.93	68.32	3.38	71.70	4.77	7.1%
700	70.79	72.24	3.64	75.88	5.09	7.2%
750	74.66	76.16	3.90	80.06	5.40	7.2%
800	78.52	80.08	4.16	84.24	5.72	7.3%
850	82.39	84.00	4.42	88.42	6.03	7.3%
900	86.25	87.92	4.68	92.60	6.35	7.4%
950	90.12	91.84	4.94	96.78	6.66	7.4%
1,000	93.98	95.76	5.20	100.96	6.98	7.4%
1,100	101.71	103.60	5.72	109.32	7.61	7.5%
1,200	109.44	111.43	6.24	117.67	8.23	7.5%
1,300	117.17	119.27	6.76	126.03	8.86	7.6%
1,400	124.90	127.11	7.28	134.39	9.49	7.6%
1,500	132.63	134.95	7.80	142.75	10.12	7.6%
1,600	140.36	142.79	8.32	151.11	10.75	7.7%
1,700	148.09	150.63	8.84	159.47	11.38	7.7%
1,800	155.82	158.47	9.36	167.83	12.01	7.7%
1,900	163.55	166.31	9.88	176.19	12.64	7.7%
2,000	171.28	174.14	10.40	184.54	13.26	7.7%
2,200	186.75	189.82	11.44	201.26	14.51	7.8%
2,400	202.21	205.50	12.48	217.98	15.77	7.8%
2,600	217.67	221.18	13.52	234.70	17.03	7.8%
2,800	233.13	236.85	14.56	251.41	18.28	7.8%
3,000	248.59	252.53	15.60	268.13	19.54	7.9%

ET-SP Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-SP Summer (May, September & October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	40.62	39.95	1.04	40.99	0.37	0.9%
250	46.61	45.60	1.30	46.90	0.29	0.6%
300	52.59	51.24	1.56	52.80	0.21	0.4%
350	58.58	56.89	1.82	58.71	0.13	0.2%
400	64.56	62.53	2.08	64.61	0.05	0.1%
450	70.55	68.18	2.34	70.52	(0.03)	0.0%
500	76.53	73.82	2.60	76.42	(0.11)	-0.1%
550	82.52	79.47	2.86	82.33	(0.19)	-0.2%
600	88.51	85.12	3.12	88.24	(0.27)	-0.3%
650	94.49	90.76	3.38	94.14	(0.35)	-0.4%
700	100.48	96.41	3.64	100.05	(0.43)	-0.4%
750	106.46	102.05	3.90	105.95	(0.51)	-0.5%
800	112.45	107.70	4.16	111.86	(0.59)	-0.5%
850	118.43	113.34	4.42	117.76	(0.67)	-0.6%
900	124.42	118.99	4.68	123.67	(0.75)	-0.6%
950	130.40	124.63	4.94	129.57	(0.83)	-0.6%
1,000	136.39	130.28	5.20	135.48	(0.91)	-0.7%
1,100	148.36	141.57	5.72	147.29	(1.07)	-0.7%
1,200	160.33	152.86	6.24	159.10	(1.23)	-0.8%
1,300	172.30	164.15	6.76	170.91	(1.39)	-0.8%
1,400	184.27	175.44	7.28	182.72	(1.55)	-0.8%
1,500	196.24	186.73	7.80	194.53	(1.71)	-0.9%
1,600	208.21	198.02	8.32	206.34	(1.87)	-0.9%
1,700	220.18	209.31	8.84	218.15	(2.03)	-0.9%
1,800	232.16	220.61	9.36	229.97	(2.19)	-0.9%
1,900	244.13	231.90	9.88	241.78	(2.35)	-1.0%
2,000	256.10	243.19	10.40	253.59	(2.51)	-1.0%
2,200	280.04	265.77	11.44	277.21	(2.83)	-1.0%
2,400	303.98	288.35	12.48	300.83	(3.15)	-1.0%
2,600	327.92	310.93	13.52	324.45	(3.47)	-1.1%
2,800	351.86	333.51	14.56	348.07	(3.79)	-1.1%
3,000	375.81	356.10	15.60	371.70	(4.11)	-1.1%

ET-SP Summer Average Energy On-Peak: 35%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Bill Analysis
ET-SP Super Peak Summer (June-August)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	48.12	47.45	1.04	48.49	0.37	0.8%
250	55.98	54.97	1.30	56.27	0.29	0.5%
300	63.84	62.49	1.56	64.05	0.21	0.3%
350	71.70	70.01	1.82	71.83	0.13	0.2%
400	79.56	77.53	2.08	79.61	0.05	0.1%
450	87.42	85.05	2.34	87.39	(0.03)	0.0%
500	95.28	92.57	2.60	95.17	(0.11)	-0.1%
550	103.14	100.09	2.86	102.95	(0.19)	-0.2%
600	111.01	107.62	3.12	110.74	(0.27)	-0.2%
650	118.87	115.14	3.38	118.52	(0.35)	-0.3%
700	126.73	122.66	3.64	126.30	(0.43)	-0.3%
750	134.59	130.18	3.90	134.08	(0.51)	-0.4%
800	142.45	137.70	4.16	141.86	(0.59)	-0.4%
850	150.31	145.22	4.42	149.64	(0.67)	-0.4%
900	158.17	152.74	4.68	157.42	(0.75)	-0.5%
950	166.03	160.26	4.94	165.20	(0.83)	-0.5%
1,000	173.89	167.78	5.20	172.98	(0.91)	-0.5%
1,100	189.61	182.82	5.72	188.54	(1.07)	-0.6%
1,200	205.33	197.86	6.24	204.10	(1.23)	-0.6%
1,300	221.05	212.90	6.76	219.66	(1.39)	-0.6%
1,400	236.77	227.94	7.28	235.22	(1.55)	-0.7%
1,500	252.49	242.98	7.80	250.78	(1.71)	-0.7%
1,600	268.21	258.02	8.32	266.34	(1.87)	-0.7%
1,700	283.93	273.06	8.84	281.90	(2.03)	-0.7%
1,800	299.66	288.11	9.36	297.47	(2.19)	-0.7%
1,900	315.38	303.15	9.88	313.03	(2.35)	-0.7%
2,000	331.10	318.19	10.40	328.59	(2.51)	-0.8%
2,200	362.54	348.27	11.44	359.71	(2.83)	-0.8%
2,400	393.98	378.35	12.48	390.83	(3.15)	-0.8%
2,600	425.42	408.43	13.52	421.95	(3.47)	-0.8%
2,800	456.86	438.51	14.56	453.07	(3.79)	-0.8%
3,000	488.31	468.60	15.60	484.20	(4.11)	-0.8%

ET-SP Summer Average Energy Super-Peak (Jun-Aug): 15%
ET-SP Summer Average Energy On-Peak (Jun-Aug): 20%
Unbundled Transmission Charge: 0.00520 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-20 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill: Base	Components of Proposed Bill: Transmission	Monthly Bill under Proposed Rates (E) + (F)	Change: Amount ($) (G) - (D)	Change: % (H) / (D)
15	20%	2,190	244.21	235.60	9.29	244.89	0.68	0.3%
15	30%	3,285	334.17	326.51	13.93	340.44	6.27	1.9%
15	40%	4,380	424.13	417.43	18.57	436.00	11.87	2.8%
15	50%	5,475	514.09	508.35	23.21	531.56	17.47	3.4%
15	75%	8,213	739.04	735.68	34.82	770.50	31.46	4.3%
30	20%	4,380	456.47	436.78	47.55	484.33	27.86	6.1%
30	30%	6,570	636.39	618.62	47.55	666.17	29.78	4.7%
30	40%	8,760	816.31	800.45	47.55	848.00	31.69	3.9%
30	50%	10,950	996.24	982.29	47.55	1,029.84	33.60	3.4%
30	75%	16,425	1,446.04	1,436.87	47.55	1,484.42	38.38	2.7%
50	20%	7,300	739.49	705.03	79.25	784.28	44.79	6.1%
50	30%	10,950	1,039.36	1,008.09	79.25	1,087.34	47.98	4.6%
50	40%	14,600	1,339.22	1,311.14	79.25	1,390.39	51.17	3.8%
50	50%	18,250	1,639.09	1,614.20	79.25	1,693.45	54.36	3.3%
50	75%	27,375	2,388.77	2,371.85	79.25	2,451.10	62.33	2.6%
100	20%	14,600	1,447.02	1,375.64	158.50	1,534.14	87.12	6.0%
100	30%	21,900	2,046.76	1,981.76	158.50	2,140.26	93.50	4.6%
100	40%	29,200	2,646.50	2,587.88	158.50	2,746.38	99.88	3.8%
100	50%	36,500	3,246.24	3,193.99	158.50	3,352.49	106.25	3.3%
100	75%	54,750	4,745.58	4,709.29	158.50	4,867.79	122.21	2.6%
150	20%	21,900	2,154.56	2,046.26	237.75	2,284.01	129.45	6.0%
150	30%	32,850	3,054.17	2,955.44	237.75	3,193.19	139.02	4.6%
150	40%	43,800	3,953.77	3,864.61	237.75	4,102.36	148.59	3.8%
150	50%	54,750	4,853.38	4,773.79	237.75	5,011.54	158.16	3.3%
150	75%	82,125	7,102.40	7,046.72	237.75	7,284.47	182.07	2.6%

General Service TOU Average Energy On-Peak:	31%	
Unbundled Transmission Charge (<=20 kW):	0.00424	$/kWh
Unbundled Transmission Charge (>20 kW and <3,000):	1.585	$/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-20 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill: Base	Components of Proposed Bill: Transmission	Monthly Bill under Proposed Rates (E) + (F)	Change: Amount ($) (G) - (D)	Change: % (H) / (D)
15	20%	2,190	270.39	258.50	9.29	267.79	(2.60)	-1.0%
15	30%	3,285	371.67	360.86	13.93	374.79	3.12	0.8%
15	40%	4,380	472.96	463.23	18.57	481.80	8.84	1.9%
15	50%	5,475	574.24	565.60	23.21	588.81	14.57	2.5%
15	75%	8,213	827.51	821.56	34.82	856.38	28.87	3.5%
30	20%	4,380	508.82	482.58	47.55	530.13	21.31	4.2%
30	30%	6,570	711.40	687.32	47.55	734.87	23.47	3.3%
30	40%	8,760	913.97	892.05	47.55	939.60	25.63	2.8%
30	50%	10,950	1,116.54	1,096.79	47.55	1,144.34	27.80	2.5%
30	75%	16,425	1,622.97	1,608.63	47.55	1,656.18	33.21	2.0%
50	20%	7,300	826.74	781.36	79.25	860.61	33.87	4.1%
50	30%	10,950	1,164.36	1,122.59	79.25	1,201.84	37.48	3.2%
50	40%	14,600	1,501.98	1,463.81	79.25	1,543.06	41.08	2.7%
50	50%	18,250	1,839.60	1,805.04	79.25	1,884.29	44.69	2.4%
50	75%	27,375	2,683.65	2,658.10	79.25	2,737.35	53.70	2.0%
100	20%	14,600	1,621.53	1,528.31	158.50	1,686.81	65.28	4.0%
100	30%	21,900	2,296.77	2,210.76	158.50	2,369.26	72.49	3.2%
100	40%	29,200	2,972.01	2,893.22	158.50	3,051.72	79.71	2.7%
100	50%	36,500	3,647.25	3,575.67	158.50	3,734.17	86.92	2.4%
100	75%	54,750	5,335.34	5,281.80	158.50	5,440.30	104.96	2.0%
150	20%	21,900	2,416.32	2,275.26	237.75	2,513.01	96.69	4.0%
150	30%	32,850	3,429.18	3,298.94	237.75	3,536.69	107.51	3.1%
150	40%	43,800	4,442.03	4,322.62	237.75	4,560.37	118.34	2.7%
150	50%	54,750	5,454.89	5,346.30	237.75	5,584.05	129.16	2.4%
150	75%	82,125	7,987.04	7,905.49	237.75	8,143.24	156.20	2.0%

General Service TOU Average Energy On-Peak:	31%	
Unbundled Transmission Charge (<=20 kW):	0.00424	$/kWh
Unbundled Transmission Charge (>20 kW and <3,000):	1.585	$/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-30 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
30	13.22	13.11	0.13	13.24	0.02	0.2%
40	14.52	14.43	0.17	14.60	0.08	0.6%
50	15.81	15.76	0.21	15.97	0.16	1.0%
60	17.11	17.08	0.25	17.33	0.22	1.3%
70	18.41	18.40	0.30	18.70	0.29	1.6%
80	19.70	19.72	0.34	20.06	0.36	1.8%
90	21.00	21.04	0.38	21.42	0.42	2.0%
100	22.30	22.36	0.42	22.78	0.48	2.2%
125	25.54	25.67	0.53	26.20	0.66	2.6%
150	28.78	28.97	0.64	29.61	0.83	2.9%
175	32.02	32.27	0.74	33.01	0.99	3.1%
200	35.26	35.57	0.85	36.42	1.16	3.3%
225	38.51	38.88	0.95	39.83	1.32	3.4%
250	41.75	42.18	1.06	43.24	1.49	3.6%
275	44.99	45.48	1.17	46.65	1.66	3.7%
300	48.23	48.79	1.27	50.06	1.83	3.8%
325	51.47	52.09	1.38	53.47	2.00	3.9%
350	54.71	55.39	1.48	56.87	2.16	3.9%
375	57.96	58.70	1.59	60.29	2.33	4.0%
400	61.20	62.00	1.70	63.70	2.50	4.1%
425	64.44	65.30	1.80	67.10	2.66	4.1%
450	67.68	68.60	1.91	70.51	2.83	4.2%
475	70.92	71.91	2.01	73.92	3.00	4.2%
500	74.17	75.21	2.12	77.33	3.16	4.3%
600	87.13	88.42	2.54	90.96	3.83	4.4%
700	100.10	101.63	2.97	104.60	4.50	4.5%
800	113.07	114.85	3.39	118.24	5.17	4.6%
900	126.03	128.06	3.82	131.88	5.85	4.6%
1,000	139.00	141.27	4.24	145.51	6.51	4.7%
1,500	203.84	207.33	6.36	213.69	9.85	4.8%
2,000	268.67	273.39	8.48	281.87	13.20	4.9%
2,500	333.51	339.45	10.60	350.05	16.54	5.0%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-30 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
30	13.66	13.58	0.13	13.71	0.05	0.4%
40	15.11	15.06	0.17	15.23	0.12	0.8%
50	16.55	16.54	0.21	16.75	0.20	1.2%
60	18.00	18.02	0.25	18.27	0.27	1.5%
70	19.44	19.49	0.30	19.79	0.35	1.8%
80	20.89	20.97	0.34	21.31	0.42	2.0%
90	22.33	22.45	0.38	22.83	0.50	2.2%
100	23.78	23.93	0.42	24.35	0.57	2.4%
125	27.39	27.62	0.53	28.15	0.76	2.8%
150	31.00	31.32	0.64	31.96	0.96	3.1%
175	34.61	35.01	0.74	35.75	1.14	3.3%
200	38.22	38.70	0.85	39.55	1.33	3.5%
225	41.84	42.40	0.95	43.35	1.51	3.6%
250	45.45	46.09	1.06	47.15	1.70	3.7%
275	49.06	49.79	1.17	50.96	1.90	3.9%
300	52.67	53.48	1.27	54.75	2.08	3.9%
325	56.28	57.18	1.38	58.56	2.28	4.1%
350	59.89	60.87	1.48	62.35	2.46	4.1%
375	63.51	64.56	1.59	66.15	2.64	4.2%
400	67.12	68.26	1.70	69.96	2.84	4.2%
425	70.73	71.95	1.80	73.75	3.02	4.3%
450	74.34	75.65	1.91	77.56	3.22	4.3%
475	77.95	79.34	2.01	81.35	3.40	4.4%
500	81.57	83.04	2.12	85.16	3.59	4.4%
600	96.01	97.81	2.54	100.35	4.34	4.5%
700	110.46	112.59	2.97	115.56	5.10	4.6%
800	124.91	127.37	3.39	130.76	5.85	4.7%
900	139.35	142.14	3.82	145.96	6.61	4.7%
1,000	153.80	156.92	4.24	161.16	7.36	4.8%
1,500	226.04	230.81	6.36	237.17	11.13	4.9%
2,000	298.27	304.69	8.48	313.17	14.90	5.0%
2,500	370.51	378.58	10.60	389.18	18.67	5.0%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 XS Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
5	15%	548	83.25	82.22	2.32	84.54	1.29	1.5%
5	30%	1,095	146.22	144.59	4.64	149.23	3.01	2.1%
5	45%	1,643	209.30	207.07	6.97	214.04	4.74	2.3%
5	60%	2,190	272.27	269.44	9.29	278.73	6.46	2.4%
5	75%	2,738	335.36	331.93	11.61	343.54	8.18	2.4%
10	15%	1,095	146.22	144.59	4.64	149.23	3.01	2.1%
10	30%	2,190	272.27	269.44	9.29	278.73	6.46	2.4%
10	45%	3,285	398.33	394.30	13.93	408.23	9.90	2.5%
10	60%	4,380	524.39	519.15	18.57	537.72	13.33	2.5%
10	75%	5,475	621.89	614.51	23.21	637.72	15.83	2.5%
15	15%	1,643	209.30	207.07	6.97	214.04	4.74	2.3%
15	30%	3,285	398.33	394.30	13.93	408.23	9.90	2.5%
15	45%	4,928	587.47	581.63	20.89	602.52	15.05	2.6%
15	60%	6,570	682.13	671.37	27.86	699.23	17.10	2.5%
15	75%	8,213	772.51	756.69	34.82	791.51	19.00	2.5%
20	15%	2,190	272.27	269.44	9.29	278.73	6.46	2.4%
20	30%	4,380	524.39	519.15	18.57	537.72	13.33	2.5%
20	45%	6,570	682.13	671.37	27.86	699.23	17.10	2.5%
20	60%	8,760	802.60	785.10	37.14	822.24	19.64	2.4%
20	75%	10,950	923.07	898.82	46.43	945.25	22.18	2.4%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 XS Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
5	15%	548	92.83	92.13	2.32	94.45	1.62	1.7%
5	30%	1,095	165.37	164.38	4.64	169.02	3.65	2.2%
5	45%	1,643	238.04	236.76	6.97	243.73	5.69	2.4%
5	60%	2,190	310.58	309.02	9.29	318.31	7.73	2.5%
5	75%	2,738	383.25	381.40	11.61	393.01	9.76	2.5%
10	15%	1,095	165.37	164.38	4.64	169.02	3.65	2.2%
10	30%	2,190	310.58	309.02	9.29	318.31	7.73	2.5%
10	45%	3,285	455.78	453.66	13.93	467.59	11.81	2.6%
10	60%	4,380	600.99	598.29	18.57	616.86	15.87	2.6%
10	75%	5,475	717.65	713.44	23.21	736.65	19.00	2.6%
15	15%	1,643	238.04	236.76	6.97	243.73	5.69	2.4%
15	30%	3,285	455.78	453.66	13.93	467.59	11.81	2.6%
15	45%	4,928	673.66	670.68	20.89	691.57	17.91	2.7%
15	60%	6,570	797.05	790.11	27.86	817.97	20.92	2.6%
15	75%	8,213	916.18	905.13	34.82	939.95	23.77	2.6%
20	15%	2,190	310.58	309.02	9.29	318.31	7.73	2.5%
20	30%	4,380	600.99	598.29	18.57	616.86	15.87	2.6%
20	45%	6,570	797.05	790.11	27.86	817.97	20.92	2.6%
20	60%	8,760	955.85	943.43	37.14	980.57	24.72	2.6%
20	75%	10,950	1,114.64	1,096.75	46.43	1,143.18	28.54	2.6%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 S Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
21	15%	2,300	423.18	399.10	33.29	432.39	9.21	2.2%
21	30%	4,599	605.71	585.76	33.29	619.05	13.34	2.2%
21	45%	6,899	706.19	688.00	33.29	721.29	15.10	2.1%
21	60%	9,198	806.64	790.19	33.29	823.48	16.84	2.1%
21	75%	11,498	907.12	892.42	33.29	925.71	18.59	2.0%
40	15%	4,380	787.74	742.24	63.40	805.64	17.90	2.3%
40	30%	8,760	1,135.48	1,097.88	63.40	1,161.28	25.80	2.3%
40	45%	13,140	1,326.85	1,292.57	63.40	1,355.97	29.12	2.2%
40	60%	17,520	1,518.21	1,487.26	63.40	1,550.66	32.45	2.1%
40	75%	21,900	1,709.57	1,681.95	63.40	1,745.35	35.78	2.1%
60	15%	6,570	1,171.53	1,103.49	95.10	1,198.59	27.06	2.3%
60	30%	13,140	1,693.15	1,636.95	95.10	1,732.05	38.90	2.3%
60	45%	19,710	1,980.19	1,928.98	95.10	2,024.08	43.89	2.2%
60	60%	26,280	2,267.23	2,221.02	95.10	2,316.12	48.89	2.2%
60	75%	32,850	2,554.28	2,513.06	95.10	2,608.16	53.88	2.1%
80	15%	8,760	1,555.32	1,464.75	126.80	1,591.55	36.23	2.3%
80	30%	17,520	2,250.81	2,176.02	126.80	2,302.82	52.01	2.3%
80	45%	26,280	2,633.53	2,565.40	126.80	2,692.20	58.67	2.2%
80	60%	35,040	3,016.26	2,954.78	126.80	3,081.58	65.32	2.2%
80	75%	43,800	3,398.98	3,344.16	126.80	3,470.96	71.98	2.1%
90	15%	9,855	1,747.21	1,645.37	142.65	1,788.02	40.81	2.3%
90	30%	19,710	2,529.64	2,445.55	142.65	2,588.20	58.56	2.3%
90	45%	29,565	2,960.20	2,883.61	142.65	3,026.26	66.06	2.2%
90	60%	39,420	3,390.77	3,321.66	142.65	3,464.31	73.54	2.2%
90	75%	49,275	3,821.33	3,759.72	142.65	3,902.37	81.04	2.1%
100	15%	10,950	1,939.11	1,826.00	158.50	1,984.50	45.39	2.3%
100	30%	21,900	2,808.47	2,715.09	158.50	2,873.59	65.12	2.3%
100	45%	32,850	3,286.88	3,201.81	158.50	3,360.31	73.43	2.2%
100	60%	43,800	3,765.28	3,688.54	158.50	3,847.04	81.76	2.2%
100	75%	54,750	4,243.69	4,175.27	158.50	4,333.77	90.08	2.1%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 S Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
21	15%	2,300	462.60	439.67	33.29	472.96	10.36	2.2%
21	30%	4,599	684.53	666.89	33.29	700.18	15.65	2.3%
21	45%	6,899	824.44	809.70	33.29	842.99	18.55	2.3%
21	60%	9,198	964.29	952.44	33.29	985.73	21.44	2.2%
21	75%	11,498	1,104.20	1,095.25	33.29	1,128.54	24.34	2.2%
40	15%	4,380	862.81	819.51	63.40	882.91	20.10	2.3%
40	30%	8,760	1,285.63	1,252.41	63.40	1,315.81	30.18	2.3%
40	45%	13,140	1,552.07	1,524.36	63.40	1,587.76	35.69	2.3%
40	60%	17,520	1,818.50	1,796.31	63.40	1,859.71	41.21	2.3%
40	75%	21,900	2,084.94	2,068.27	63.40	2,131.67	46.73	2.2%
60	15%	6,570	1,284.14	1,219.39	95.10	1,314.49	30.35	2.4%
60	30%	13,140	1,918.37	1,868.74	95.10	1,963.84	45.47	2.4%
60	45%	19,710	2,318.02	2,276.67	95.10	2,371.77	53.75	2.3%
60	60%	26,280	2,717.67	2,684.60	95.10	2,779.70	62.03	2.3%
60	75%	32,850	3,117.33	3,092.53	95.10	3,187.63	70.30	2.3%
80	15%	8,760	1,705.46	1,619.27	126.80	1,746.07	40.61	2.4%
80	30%	17,520	2,551.10	2,485.07	126.80	2,611.87	60.77	2.4%
80	45%	26,280	3,083.97	3,028.98	126.80	3,155.78	71.81	2.3%
80	60%	35,040	3,616.84	3,572.89	126.80	3,699.69	82.85	2.3%
80	75%	43,800	4,149.71	4,116.80	126.80	4,243.60	93.89	2.3%
90	15%	9,855	1,916.13	1,819.21	142.65	1,961.86	45.73	2.4%
90	30%	19,710	2,867.47	2,793.24	142.65	2,935.89	68.42	2.4%
90	45%	29,565	3,466.95	3,405.13	142.65	3,547.78	80.83	2.3%
90	60%	39,420	4,066.43	4,017.03	142.65	4,159.68	93.25	2.3%
90	75%	49,275	4,665.91	4,628.93	142.65	4,771.58	105.67	2.3%
100	15%	10,950	2,126.79	2,019.15	158.50	2,177.65	50.86	2.4%
100	30%	21,900	3,183.84	3,101.40	158.50	3,259.90	76.06	2.4%
100	45%	32,850	3,849.93	3,781.29	158.50	3,939.79	89.86	2.3%
100	60%	43,800	4,516.01	4,461.17	158.50	4,619.67	103.66	2.3%
100	75%	54,750	5,182.10	5,141.06	158.50	5,299.56	117.46	2.3%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 M Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	1,957.79	1,853.57	160.09	2,013.66	55.87	2.9%
101	30%	22,119	2,828.73	2,749.09	160.09	2,909.18	80.45	2.8%
101	45%	33,179	3,308.07	3,239.38	160.09	3,399.47	91.40	2.8%
101	60%	44,238	3,787.37	3,729.62	160.09	3,889.71	102.34	2.7%
101	75%	55,298	4,266.71	4,219.91	160.09	4,380.00	113.29	2.7%
150	15%	16,425	2,670.34	2,507.84	237.75	2,745.59	75.25	2.8%
150	30%	32,850	3,963.89	3,837.88	237.75	4,075.63	111.74	2.8%
150	45%	49,275	4,675.75	4,566.00	237.75	4,803.75	128.00	2.7%
150	60%	65,700	5,387.61	5,294.12	237.75	5,531.87	144.26	2.7%
150	75%	82,125	6,099.47	6,022.24	237.75	6,259.99	160.52	2.6%
200	15%	21,900	3,397.48	3,175.51	317.00	3,492.51	95.03	2.8%
200	30%	43,800	5,122.21	4,948.89	317.00	5,265.89	143.68	2.8%
200	45%	65,700	6,071.36	5,919.72	317.00	6,236.72	165.36	2.7%
200	60%	87,600	7,020.50	6,890.55	317.00	7,207.55	187.05	2.7%
200	75%	109,500	7,969.65	7,861.38	317.00	8,178.38	208.73	2.6%
300	15%	32,850	4,851.76	4,510.85	475.50	4,986.35	134.59	2.8%
300	30%	65,700	7,438.86	7,170.92	475.50	7,646.42	207.56	2.8%
300	45%	98,550	8,862.58	8,627.16	475.50	9,102.66	240.08	2.7%
300	60%	131,400	10,286.30	10,083.40	475.50	10,558.90	272.60	2.7%
300	75%	164,250	11,710.02	11,539.64	475.50	12,015.14	305.12	2.6%
350	15%	38,325	5,578.90	5,178.52	554.75	5,733.27	154.37	2.8%
350	30%	76,650	8,597.18	8,281.93	554.75	8,836.68	239.50	2.8%
350	45%	114,975	10,258.19	9,980.88	554.75	10,535.63	277.44	2.7%
350	60%	153,300	11,919.19	11,679.83	554.75	12,234.58	315.39	2.6%
350	75%	191,625	13,580.20	13,378.78	554.75	13,933.53	353.33	2.6%
400	15%	43,800	6,306.04	5,846.19	634.00	6,480.19	174.15	2.8%
400	30%	87,600	9,755.50	9,392.95	634.00	10,026.95	271.45	2.8%
400	45%	131,400	11,653.80	11,334.60	634.00	11,968.60	314.80	2.7%
400	60%	175,200	13,552.09	13,276.26	634.00	13,910.26	358.17	2.6%
400	75%	219,000	15,450.38	15,217.91	634.00	15,851.91	401.53	2.6%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 M Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	2,145.92	2,048.34	160.09	2,208.43	62.51	2.9%
101	30%	22,119	3,204.96	3,138.56	160.09	3,298.65	93.69	2.9%
101	45%	33,179	3,872.32	3,823.40	160.09	3,983.49	111.17	2.9%
101	60%	44,238	4,539.62	4,508.17	160.09	4,668.26	128.64	2.8%
101	75%	55,298	5,206.98	5,193.01	160.09	5,353.10	146.12	2.8%
150	15%	16,425	2,949.73	2,797.09	237.75	3,034.84	85.11	2.9%
150	30%	32,850	4,522.64	4,416.31	237.75	4,654.06	131.42	2.9%
150	45%	49,275	5,513.72	5,433.35	237.75	5,671.10	157.38	2.9%
150	60%	65,700	6,504.81	6,450.38	237.75	6,688.13	183.32	2.8%
150	75%	82,125	7,495.89	7,467.42	237.75	7,705.17	209.28	2.8%
200	15%	21,900	3,770.00	3,561.17	317.00	3,878.17	108.17	2.9%
200	30%	43,800	5,867.21	5,720.14	317.00	6,037.14	169.93	2.9%
200	45%	65,700	7,188.66	7,076.18	317.00	7,393.18	204.52	2.8%
200	60%	87,600	8,510.10	8,432.23	317.00	8,749.23	239.13	2.8%
200	75%	109,500	9,831.55	9,788.28	317.00	10,105.28	273.73	2.8%
300	15%	32,850	5,410.54	5,089.34	475.50	5,564.84	154.30	2.9%
300	30%	65,700	8,556.36	8,327.78	475.50	8,803.28	246.92	2.9%
300	45%	98,550	10,538.53	10,361.86	475.50	10,837.36	298.83	2.8%
300	60%	131,400	12,520.70	12,395.93	475.50	12,871.43	350.73	2.8%
300	75%	164,250	14,502.87	14,430.00	475.50	14,905.50	402.63	2.8%
350	15%	38,325	6,230.81	5,853.42	554.75	6,408.17	177.36	2.8%
350	30%	76,650	9,900.93	9,631.61	554.75	10,186.36	285.43	2.9%
350	45%	114,975	12,213.46	12,004.69	554.75	12,559.44	345.98	2.8%
350	60%	153,300	14,525.99	14,377.78	554.75	14,932.53	406.54	2.8%
350	75%	191,625	16,838.52	16,750.86	554.75	17,305.61	467.09	2.8%
400	15%	43,800	7,051.08	6,617.50	634.00	7,251.50	200.42	2.8%
400	30%	87,600	11,245.50	10,935.43	634.00	11,569.43	323.93	2.9%
400	45%	131,400	13,888.40	13,647.53	634.00	14,281.53	393.13	2.8%
400	60%	175,200	16,531.29	16,359.62	634.00	16,993.62	462.33	2.8%
400	75%	219,000	19,174.18	19,071.72	634.00	19,705.72	531.54	2.8%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 L Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Monthly Bill	Components of Proposed Bill		Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	6,191.72	7,301.69	635.59	7,937.28	1,745.56	28.2%
401	30%	87,819	9,573.93	9,167.38	635.59	9,802.97	229.04	2.4%
401	45%	131,729	11,435.28	11,033.12	635.59	11,668.71	233.43	2.0%
401	60%	175,638	13,296.58	12,898.81	635.59	13,534.40	237.82	1.8%
401	75%	219,548	15,157.92	14,764.55	635.59	15,400.14	242.22	1.6%
600	15%	65,700	9,022.22	10,677.83	951.00	11,628.83	2,606.61	28.9%
600	30%	131,400	14,082.96	13,469.43	951.00	14,420.43	337.47	2.4%
600	45%	197,100	16,867.98	16,261.02	951.00	17,212.02	344.04	2.0%
600	60%	262,800	19,653.00	19,052.61	951.00	20,003.61	350.61	1.8%
600	75%	328,500	22,438.03	21,844.21	951.00	22,795.21	357.18	1.6%
800	15%	87,600	11,866.99	14,070.96	1,268.00	15,338.96	3,471.97	29.3%
800	30%	175,200	18,614.64	17,793.09	1,268.00	19,061.09	446.45	2.4%
800	45%	262,800	22,328.00	21,515.21	1,268.00	22,783.21	455.21	2.0%
800	60%	350,400	26,041.37	25,237.34	1,268.00	26,505.34	463.97	1.8%
800	75%	438,000	29,754.73	28,959.46	1,268.00	30,227.46	472.73	1.6%
1,000	15%	109,500	14,711.76	17,464.10	1,585.00	19,049.10	4,337.34	29.5%
1,000	30%	219,000	23,146.32	22,116.75	1,585.00	23,701.75	555.43	2.4%
1,000	45%	328,500	27,788.03	26,769.41	1,585.00	28,354.41	566.38	2.0%
1,000	60%	438,000	32,429.73	31,422.06	1,585.00	33,007.06	577.33	1.8%
1,000	75%	547,500	37,071.44	36,074.72	1,585.00	37,659.72	588.28	1.6%
1,500	15%	164,250	21,823.69	25,946.92	2,377.50	28,324.42	6,500.73	29.8%
1,500	30%	328,500	34,475.53	32,925.91	2,377.50	35,303.41	827.88	2.4%
1,500	45%	492,750	41,438.08	39,904.89	2,377.50	42,282.39	844.31	2.0%
1,500	60%	657,000	48,400.64	46,883.87	2,377.50	49,261.37	860.73	1.8%
1,500	75%	821,250	55,363.20	53,862.85	2,377.50	56,240.35	877.15	1.6%
3,000	15%	328,500	43,159.46	51,395.41	4,755.00	56,150.41	12,990.95	30.1%
3,000	30%	657,000	68,463.14	65,353.37	4,755.00	70,108.37	1,645.23	2.4%
3,000	45%	985,500	82,388.26	79,311.34	4,755.00	84,066.34	1,678.08	2.0%
3,000	60%	1,314,000	96,313.37	93,269.30	4,755.00	98,024.30	1,710.93	1.8%
3,000	75%	1,642,500	110,238.49	107,227.27	4,755.00	111,982.27	1,743.78	1.6%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 L Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	6,921.94	8,042.01	635.59	8,677.60	1,755.66	25.4%
401	30%	87,819	11,034.36	10,648.01	635.59	11,283.60	249.24	2.3%
401	45%	131,729	13,625.93	13,254.07	635.59	13,889.66	263.73	1.9%
401	60%	175,638	16,217.44	15,860.07	635.59	16,495.66	278.22	1.7%
401	75%	219,548	18,809.01	18,466.13	635.59	19,101.72	292.71	1.6%
600	15%	65,700	10,114.81	11,785.54	951.00	12,736.54	2,621.73	25.9%
600	30%	131,400	16,268.14	15,684.83	951.00	16,635.83	367.69	2.3%
600	45%	197,100	20,145.75	19,584.13	951.00	20,535.13	389.38	1.9%
600	60%	262,800	24,023.37	23,483.42	951.00	24,434.42	411.05	1.7%
600	75%	328,500	27,900.98	27,382.72	951.00	28,333.72	432.74	1.6%
800	15%	87,600	13,323.78	15,547.90	1,268.00	16,815.90	3,492.12	26.2%
800	30%	175,200	21,528.21	20,746.96	1,268.00	22,014.96	486.75	2.3%
800	45%	262,800	26,698.37	25,946.02	1,268.00	27,214.02	515.65	1.9%
800	60%	350,400	31,868.52	31,145.08	1,268.00	32,413.08	544.56	1.7%
800	75%	438,000	37,038.67	36,344.14	1,268.00	37,612.14	573.47	1.5%
1,000	15%	109,500	16,532.75	19,310.27	1,585.00	20,895.27	4,362.52	26.4%
1,000	30%	219,000	26,788.29	25,809.09	1,585.00	27,394.09	605.80	2.3%
1,000	45%	328,500	33,250.98	32,307.92	1,585.00	33,892.92	641.94	1.9%
1,000	60%	438,000	39,713.67	38,806.74	1,585.00	40,391.74	678.07	1.7%
1,000	75%	547,500	46,176.36	45,305.57	1,585.00	46,890.57	714.21	1.5%
1,500	15%	164,250	24,555.16	28,716.18	2,377.50	31,093.68	6,538.52	26.6%
1,500	30%	328,500	39,938.48	38,464.42	2,377.50	40,841.92	903.44	2.3%
1,500	45%	492,750	49,632.52	48,212.65	2,377.50	50,590.15	957.63	1.9%
1,500	60%	657,000	59,326.55	57,960.89	2,377.50	60,338.39	1,011.84	1.7%
1,500	75%	821,250	69,020.59	67,709.13	2,377.50	70,086.63	1,066.04	1.5%
3,000	15%	328,500	48,622.42	56,933.92	4,755.00	61,688.92	13,066.50	26.9%
3,000	30%	657,000	79,389.05	76,430.39	4,755.00	81,185.39	1,796.34	2.3%
3,000	45%	985,500	98,777.12	95,926.87	4,755.00	100,681.87	1,904.75	1.9%
3,000	60%	1,314,000	118,165.19	115,423.34	4,755.00	120,178.34	2,013.15	1.7%
3,000	75%	1,642,500	137,553.26	134,919.82	4,755.00	139,674.82	2,121.56	1.5%

Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU XS Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
5	7.5	15%	821	120.22	117.60	3.48	121.08	0.86	0.7%
5	7.5	30%	1,643	219.26	215.58	6.97	222.55	3.29	1.5%
5	7.5	45%	2,464	318.18	313.44	10.45	323.89	5.71	1.8%
5	7.5	60%	3,285	417.10	411.31	13.93	425.24	8.14	2.0%
5	7.5	75%	4,106	516.02	509.17	17.41	526.58	10.56	2.0%
10	12	15%	1,314	179.62	176.37	5.57	181.94	2.32	1.3%
10	12	30%	2,628	337.94	332.99	11.14	344.13	6.19	1.8%
10	12	45%	3,942	496.26	489.62	16.71	506.33	10.07	2.0%
10	12	60%	5,256	654.58	646.25	22.29	668.54	13.96	2.1%
10	12	75%	6,570	812.90	802.87	27.86	830.73	17.83	2.2%
15	20	15%	2,190	285.17	280.78	9.29	290.07	4.90	1.7%
15	20	30%	4,380	549.04	541.83	18.57	560.40	11.36	2.1%
15	20	45%	6,570	812.90	802.87	27.86	830.73	17.83	2.2%
15	20	60%	8,760	998.39	983.08	37.14	1,020.22	21.83	2.2%
15	20	75%	10,950	1,148.85	1,127.17	46.43	1,173.60	24.75	2.2%
20	25	15%	2,738	351.20	346.10	11.61	357.71	6.51	1.9%
20	25	30%	5,475	680.97	672.35	23.21	695.56	14.59	2.1%
20	25	45%	8,213	960.81	947.09	34.82	981.91	21.10	2.2%
20	25	60%	10,950	1,148.85	1,127.17	46.43	1,173.60	24.75	2.2%
20	25	75%	13,688	1,336.96	1,307.31	58.04	1,365.35	28.39	2.1%

General Service TOU Average Energy On-Peak: 31%
Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU XS Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
5	7.5	15%	821	134.60	132.18	3.48	135.66	1.06	0.8%
5	7.5	30%	1,643	248.03	244.75	6.97	251.72	3.69	1.5%
5	7.5	45%	2,464	361.33	357.18	10.45	367.63	6.30	1.7%
5	7.5	60%	3,285	474.62	469.62	13.93	483.55	8.93	1.9%
5	7.5	75%	4,106	587.92	582.05	17.41	599.46	11.54	2.0%
10	12	15%	1,314	202.63	199.69	5.57	205.26	2.63	1.3%
10	12	30%	2,628	383.96	379.64	11.14	390.78	6.82	1.8%
10	12	45%	3,942	565.29	559.59	16.71	576.30	11.01	1.9%
10	12	60%	5,256	746.62	739.54	22.29	761.83	15.21	2.0%
10	12	75%	6,570	927.95	919.49	27.86	947.35	19.40	2.1%
15	20	15%	2,190	323.52	319.66	9.29	328.95	5.43	1.7%
15	20	30%	4,380	625.73	619.58	18.57	638.15	12.42	2.0%
15	20	45%	6,570	927.95	919.49	27.86	947.35	19.40	2.1%
15	20	60%	8,760	1,146.83	1,133.55	37.14	1,170.69	23.86	2.1%
15	20	75%	10,950	1,328.48	1,309.24	46.43	1,355.67	27.19	2.0%
20	25	15%	2,738	399.14	394.71	11.61	406.32	7.18	1.8%
20	25	30%	5,475	776.84	769.54	23.21	792.75	15.91	2.0%
20	25	45%	8,213	1,101.46	1,089.67	34.82	1,124.49	23.03	2.1%
20	25	60%	10,950	1,328.48	1,309.24	46.43	1,355.67	27.19	2.0%
20	25	75%	13,688	1,555.58	1,528.90	58.04	1,586.94	31.36	2.0%

General Service TOU Average Energy On-Peak: 31%
Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU S Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
21	30	15%	3,285	636.39	618.95	33.29	652.24	15.85	2.5%
21	30	30%	6,570	785.96	769.18	33.29	802.47	16.51	2.1%
21	30	45%	9,855	935.53	919.41	33.29	952.70	17.17	1.8%
21	30	60%	13,140	1,085.10	1,069.64	33.29	1,102.93	17.83	1.6%
21	30	75%	16,425	1,234.66	1,219.87	33.29	1,253.16	18.50	1.5%
40	50	15%	5,475	1,118.06	1,084.57	63.40	1,147.97	29.91	2.7%
40	50	30%	10,950	1,367.34	1,334.96	63.40	1,398.36	31.02	2.3%
40	50	45%	16,425	1,616.62	1,585.34	63.40	1,648.74	32.12	2.0%
40	50	60%	21,900	1,865.90	1,835.72	63.40	1,899.12	33.22	1.8%
40	50	75%	27,375	2,115.18	2,086.10	63.40	2,149.50	34.32	1.6%
60	70	15%	7,665	1,614.05	1,563.43	95.10	1,658.53	44.48	2.8%
60	70	30%	15,330	1,963.05	1,913.96	95.10	2,009.06	46.01	2.3%
60	70	45%	22,995	2,312.04	2,264.50	95.10	2,359.60	47.56	2.1%
60	70	60%	30,660	2,661.03	2,615.03	95.10	2,710.13	49.10	1.8%
60	70	75%	38,325	3,010.02	2,965.57	95.10	3,060.67	50.65	1.7%
80	100	15%	10,950	2,214.82	2,149.41	126.80	2,276.21	61.39	2.8%
80	100	30%	21,900	2,713.38	2,650.17	126.80	2,776.97	63.59	2.3%
80	100	45%	32,850	3,211.94	3,150.94	126.80	3,277.74	65.80	2.0%
80	100	60%	43,800	3,710.50	3,651.70	126.80	3,778.50	68.00	1.8%
80	100	75%	54,750	4,209.07	4,152.47	126.80	4,279.27	70.20	1.7%
90	110	15%	12,045	2,438.49	2,363.56	142.65	2,506.21	67.72	2.8%
90	110	30%	24,090	2,986.90	2,914.40	142.65	3,057.05	70.15	2.3%
90	110	45%	36,135	3,535.32	3,465.25	142.65	3,607.90	72.58	2.1%
90	110	60%	48,180	4,083.74	4,016.09	142.65	4,158.74	75.00	1.8%
90	110	75%	60,225	4,632.16	4,566.93	142.65	4,709.58	77.42	1.7%
100	120	15%	13,140	2,662.15	2,577.72	158.50	2,736.22	74.07	2.8%
100	120	30%	26,280	3,260.43	3,178.64	158.50	3,337.14	76.71	2.4%
100	120	45%	39,420	3,858.70	3,779.56	158.50	3,938.06	79.36	2.1%
100	120	60%	52,560	4,456.97	4,380.47	158.50	4,538.97	82.00	1.8%
100	120	75%	65,700	5,055.25	4,981.39	158.50	5,139.89	84.64	1.7%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU S Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
21	30	15%	3,285	692.40	675.80	33.29	709.09	16.69	2.4%
21	30	30%	6,570	897.98	882.89	33.29	916.18	18.20	2.0%
21	30	45%	9,855	1,103.55	1,089.97	33.29	1,123.26	19.71	1.8%
21	30	60%	13,140	1,309.13	1,297.05	33.29	1,330.34	21.21	1.6%
21	30	75%	16,425	1,514.71	1,504.13	33.29	1,537.42	22.71	1.5%
40	50	15%	5,475	1,211.41	1,179.33	63.40	1,242.73	31.32	2.6%
40	50	30%	10,950	1,554.04	1,524.47	63.40	1,587.87	33.83	2.2%
40	50	45%	16,425	1,896.67	1,869.60	63.40	1,933.00	36.33	1.9%
40	50	60%	21,900	2,239.30	2,214.74	63.40	2,278.14	38.84	1.7%
40	50	75%	27,375	2,581.93	2,559.88	63.40	2,623.28	41.35	1.6%
60	70	15%	7,665	1,744.74	1,696.08	95.10	1,791.18	46.44	2.7%
60	70	30%	15,330	2,224.42	2,179.28	95.10	2,274.38	49.96	2.2%
60	70	45%	22,995	2,704.10	2,662.47	95.10	2,757.57	53.47	2.0%
60	70	60%	30,660	3,183.78	3,145.66	95.10	3,240.76	56.98	1.8%
60	70	75%	38,325	3,663.47	3,628.86	95.10	3,723.96	60.49	1.7%
80	100	15%	10,950	2,401.52	2,338.92	126.80	2,465.72	64.20	2.7%
80	100	30%	21,900	3,086.78	3,029.19	126.80	3,155.99	69.21	2.2%
80	100	45%	32,850	3,772.04	3,719.47	126.80	3,846.27	74.23	2.0%
80	100	60%	43,800	4,457.29	4,409.74	126.80	4,536.54	79.25	1.8%
80	100	75%	54,750	5,142.55	5,100.02	126.80	5,226.82	84.27	1.6%
90	110	15%	12,045	2,643.85	2,572.02	142.65	2,714.67	70.82	2.7%
90	110	30%	24,090	3,397.64	3,331.33	142.65	3,473.98	76.34	2.2%
90	110	45%	36,135	4,151.42	4,090.63	142.65	4,233.28	81.86	2.0%
90	110	60%	48,180	4,905.21	4,849.93	142.65	4,992.58	87.37	1.8%
90	110	75%	60,225	5,658.99	5,609.24	142.65	5,751.89	92.90	1.6%
100	120	15%	13,140	2,886.19	2,805.13	158.50	2,963.63	77.44	2.7%
100	120	30%	26,280	3,708.50	3,633.46	158.50	3,791.96	83.46	2.3%
100	120	45%	39,420	4,530.81	4,461.79	158.50	4,620.29	89.48	2.0%
100	120	60%	52,560	5,353.12	5,290.12	158.50	5,448.62	95.50	1.8%
100	120	75%	65,700	6,175.43	6,118.46	158.50	6,276.96	101.53	1.6%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU M Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
101	120	15%	13,140	2,669.43	2,619.30	160.09	2,779.39	109.96	4.1%
101	120	30%	26,280	3,263.01	3,215.92	160.09	3,376.01	113.00	3.5%
101	120	45%	39,420	3,856.59	3,812.54	160.09	3,972.63	116.04	3.0%
101	120	60%	52,560	4,450.17	4,409.16	160.09	4,569.25	119.08	2.7%
101	120	75%	65,700	5,043.75	5,005.78	160.09	5,165.87	122.12	2.4%
150	170	15%	18,615	3,541.25	3,445.82	237.75	3,683.57	142.32	4.0%
150	170	30%	37,230	4,382.16	4,291.03	237.75	4,528.78	146.62	3.3%
150	170	45%	55,845	5,223.06	5,136.24	237.75	5,373.99	150.93	2.9%
150	170	60%	74,460	6,063.97	5,981.45	237.75	6,219.20	155.23	2.6%
150	170	75%	93,075	6,904.87	6,826.66	237.75	7,064.41	159.54	2.3%
200	220	15%	24,090	4,422.73	4,280.86	317.00	4,597.86	175.13	4.0%
200	220	30%	48,180	5,510.96	5,374.66	317.00	5,691.66	180.70	3.3%
200	220	45%	72,270	6,599.19	6,468.46	317.00	6,785.46	186.27	2.8%
200	220	60%	96,360	7,687.42	7,562.27	317.00	7,879.27	191.85	2.5%
200	220	75%	120,450	8,775.65	8,656.07	317.00	8,973.07	197.42	2.2%
300	320	15%	35,040	6,185.68	5,950.94	475.50	6,426.44	240.76	3.9%
300	320	30%	70,080	7,768.56	7,541.93	475.50	8,017.43	248.87	3.2%
300	320	45%	105,120	9,351.44	9,132.91	475.50	9,608.41	256.97	2.7%
300	320	60%	140,160	10,934.32	10,723.90	475.50	11,199.40	265.08	2.4%
300	320	75%	175,200	12,517.20	12,314.88	475.50	12,790.38	273.18	2.2%
350	370	15%	40,515	7,067.15	6,785.99	554.75	7,340.74	273.59	3.9%
350	370	30%	81,030	8,897.36	8,625.56	554.75	9,180.31	282.95	3.2%
350	370	45%	121,545	10,727.56	10,465.14	554.75	11,019.89	292.33	2.7%
350	370	60%	162,060	12,557.77	12,304.71	554.75	12,859.46	301.69	2.4%
350	370	75%	202,575	14,387.97	14,144.29	554.75	14,699.04	311.07	2.2%
400	420	15%	45,990	7,948.63	7,621.03	634.00	8,255.03	306.40	3.9%
400	420	30%	91,980	10,026.16	9,709.19	634.00	10,343.19	317.03	3.2%
400	420	45%	137,970	12,103.69	11,797.36	634.00	12,431.36	327.67	2.7%
400	420	60%	183,960	14,181.22	13,885.53	634.00	14,519.53	338.31	2.4%
400	420	75%	229,950	16,258.75	15,973.69	634.00	16,607.69	348.94	2.1%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU M Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
101	120	15%	13,140	2,891.63	2,844.96	160.09	3,005.05	113.42	3.9%
101	120	30%	26,280	3,707.40	3,667.23	160.09	3,827.32	119.92	3.2%
101	120	45%	39,420	4,523.18	4,489.50	160.09	4,649.59	126.41	2.8%
101	120	60%	52,560	5,338.96	5,311.78	160.09	5,471.87	132.91	2.5%
101	120	75%	65,700	6,154.73	6,134.05	160.09	6,294.14	139.41	2.3%
150	170	15%	18,615	3,856.03	3,765.50	237.75	4,003.25	147.22	3.8%
150	170	30%	37,230	5,011.72	4,930.39	237.75	5,168.14	156.42	3.1%
150	170	45%	55,845	6,167.40	6,095.27	237.75	6,333.02	165.62	2.7%
150	170	60%	74,460	7,323.09	7,260.16	237.75	7,497.91	174.82	2.4%
150	170	75%	93,075	8,478.77	8,425.05	237.75	8,662.80	184.03	2.2%
200	220	15%	24,090	4,830.09	4,694.56	317.00	5,011.56	181.47	3.8%
200	220	30%	48,180	6,325.68	6,202.06	317.00	6,519.06	193.38	3.1%
200	220	45%	72,270	7,821.27	7,709.56	317.00	8,026.56	205.29	2.6%
200	220	60%	96,360	9,316.87	9,217.07	317.00	9,534.07	217.20	2.3%
200	220	75%	120,450	10,812.46	10,724.57	317.00	11,041.57	229.11	2.1%
300	320	15%	35,040	6,778.21	6,552.69	475.50	7,028.19	249.98	3.7%
300	320	30%	70,080	8,953.61	8,745.42	475.50	9,220.92	267.31	3.0%
300	320	45%	105,120	11,129.02	10,938.15	475.50	11,413.65	284.63	2.6%
300	320	60%	140,160	13,304.42	13,130.88	475.50	13,606.38	301.96	2.3%
300	320	75%	175,200	15,479.83	15,323.61	475.50	15,799.11	319.28	2.1%
350	370	15%	40,515	7,752.26	7,481.75	554.75	8,036.50	284.24	3.7%
350	370	30%	81,030	10,267.58	10,017.10	554.75	10,571.85	304.27	3.0%
350	370	45%	121,545	12,782.89	12,552.44	554.75	13,107.19	324.30	2.5%
350	370	60%	162,060	15,298.20	15,087.78	554.75	15,642.53	344.33	2.3%
350	370	75%	202,575	17,813.52	17,623.13	554.75	18,177.88	364.36	2.0%
400	420	15%	45,990	8,726.32	8,410.82	634.00	9,044.82	318.50	3.6%
400	420	30%	91,980	11,581.54	11,288.78	634.00	11,922.78	341.24	2.9%
400	420	45%	137,970	14,436.76	14,166.73	634.00	14,800.73	363.97	2.5%
400	420	60%	183,960	17,291.98	17,044.69	634.00	17,678.69	386.71	2.2%
400	420	75%	229,950	20,147.20	19,922.65	634.00	20,556.65	409.45	2.0%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU L Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
401	441	15%	48,290	7,950.15	7,682.19	635.59	8,317.78	367.63	4.6%
401	441	30%	96,579	10,083.76	9,839.43	635.59	10,475.02	391.26	3.9%
401	441	45%	144,869	12,217.42	11,996.71	635.59	12,632.30	414.88	3.4%
401	441	60%	193,158	14,351.04	14,153.95	635.59	14,789.54	438.50	3.1%
401	441	75%	241,448	16,484.70	16,311.23	635.59	16,946.82	462.12	2.8%
600	640	15%	70,080	11,382.12	10,953.48	951.00	11,904.48	522.36	4.6%
600	640	30%	140,160	14,478.55	14,084.20	951.00	15,035.20	556.65	3.8%
600	640	45%	210,240	17,574.99	17,214.92	951.00	18,165.92	590.93	3.4%
600	640	60%	280,320	20,671.42	20,345.64	951.00	21,296.64	625.22	3.0%
600	640	75%	350,400	23,767.86	23,476.35	951.00	24,427.35	659.49	2.8%
800	860	15%	94,170	14,987.50	14,402.42	1,268.00	15,670.42	682.92	4.6%
800	860	30%	188,340	19,148.33	18,609.33	1,268.00	19,877.33	729.00	3.8%
800	860	45%	282,510	23,309.17	22,816.23	1,268.00	24,084.23	775.06	3.3%
800	860	60%	376,680	27,470.00	27,023.13	1,268.00	28,291.13	821.13	3.0%
800	860	75%	470,850	31,630.84	31,230.04	1,268.00	32,498.04	867.20	2.7%
1,000	1,200	15%	131,400	19,529.74	18,818.54	1,585.00	20,403.54	873.80	4.5%
1,000	1,200	30%	262,800	25,335.55	24,688.64	1,585.00	26,273.64	938.09	3.7%
1,000	1,200	45%	394,200	31,141.37	30,558.73	1,585.00	32,143.73	1,002.36	3.2%
1,000	1,200	60%	525,600	36,947.19	36,428.83	1,585.00	38,013.83	1,066.64	2.9%
1,000	1,200	75%	657,000	42,753.01	42,298.93	1,585.00	43,883.93	1,130.92	2.6%
1,500	1,700	15%	186,150	28,152.83	27,037.91	2,377.50	29,415.41	1,262.58	4.5%
1,500	1,700	30%	372,300	36,377.73	35,353.88	2,377.50	37,731.38	1,353.65	3.7%
1,500	1,700	45%	558,450	44,602.64	43,669.86	2,377.50	46,047.36	1,444.72	3.2%
1,500	1,700	60%	744,600	52,827.55	51,985.83	2,377.50	54,363.33	1,535.78	2.9%
1,500	1,700	75%	930,750	61,052.46	60,301.80	2,377.50	62,679.30	1,626.84	2.7%
3,000	3,200	15%	350,400	54,022.10	51,696.03	4,755.00	56,451.03	2,428.93	4.5%
3,000	3,200	30%	700,800	69,504.28	67,349.63	4,755.00	72,104.63	2,600.35	3.7%
3,000	3,200	45%	1,051,200	84,986.46	83,003.22	4,755.00	87,758.22	2,771.76	3.3%
3,000	3,200	60%	1,401,600	100,468.63	98,656.82	4,755.00	103,411.82	2,943.19	2.9%
3,000	3,200	75%	1,752,000	115,950.81	114,310.41	4,755.00	119,065.41	3,114.60	2.7%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-32 TOU L Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
401	441	15%	48,290	8,749.35	8,499.26	635.59	9,134.85	385.50	4.4%
401	441	30%	96,579	11,682.15	11,473.55	635.59	12,109.14	426.99	3.7%
401	441	45%	144,869	14,615.01	14,447.90	635.59	15,083.49	468.48	3.2%
401	441	60%	193,158	17,547.80	17,422.18	635.59	18,057.77	509.97	2.9%
401	441	75%	241,448	20,480.66	20,396.53	635.59	21,032.12	551.46	2.7%
600	640	15%	70,080	12,541.94	12,139.23	951.00	13,090.23	548.29	4.4%
600	640	30%	140,160	16,798.20	16,455.70	951.00	17,406.70	608.50	3.6%
600	640	45%	210,240	21,054.46	20,772.18	951.00	21,723.18	668.72	3.2%
600	640	60%	280,320	25,310.72	25,088.65	951.00	26,039.65	728.93	2.9%
600	640	75%	350,400	29,566.98	29,405.12	951.00	30,356.12	789.14	2.7%
800	860	15%	94,170	16,546.01	15,995.78	1,268.00	17,263.78	717.77	4.3%
800	860	30%	188,340	22,265.36	21,796.04	1,268.00	23,064.04	798.68	3.6%
800	860	45%	282,510	27,984.71	27,596.30	1,268.00	28,864.30	879.59	3.1%
800	860	60%	376,680	33,704.06	33,396.56	1,268.00	34,664.56	960.50	2.8%
800	860	75%	470,850	39,423.41	39,196.82	1,268.00	40,464.82	1,041.41	2.6%
1,000	1,200	15%	131,400	21,704.41	21,041.83	1,585.00	22,626.83	922.42	4.2%
1,000	1,200	30%	262,800	29,684.89	29,135.21	1,585.00	30,720.21	1,035.32	3.5%
1,000	1,200	45%	394,200	37,665.38	37,228.60	1,585.00	38,813.60	1,148.22	3.0%
1,000	1,200	60%	525,600	45,645.87	45,321.98	1,585.00	46,906.98	1,261.11	2.8%
1,000	1,200	75%	657,000	53,626.36	53,415.37	1,585.00	55,000.37	1,374.01	2.6%
1,500	1,700	15%	186,150	31,233.61	30,187.57	2,377.50	32,565.07	1,331.46	4.3%
1,500	1,700	30%	372,300	42,539.30	41,653.20	2,377.50	44,030.70	1,491.40	3.5%
1,500	1,700	45%	558,450	53,844.99	53,118.83	2,377.50	55,496.33	1,651.34	3.1%
1,500	1,700	60%	744,600	65,150.68	64,584.46	2,377.50	66,961.96	1,811.28	2.8%
1,500	1,700	75%	930,750	76,456.37	76,050.09	2,377.50	78,427.59	1,971.22	2.6%
3,000	3,200	15%	350,400	59,821.22	57,624.80	4,755.00	62,379.80	2,558.58	4.3%
3,000	3,200	30%	700,800	81,102.52	79,207.16	4,755.00	83,962.16	2,859.64	3.5%
3,000	3,200	45%	1,051,200	102,383.82	100,789.53	4,755.00	105,544.53	3,160.71	3.1%
3,000	3,200	60%	1,401,600	123,665.11	122,371.89	4,755.00	127,126.89	3,461.78	2.8%
3,000	3,200	75%	1,752,000	144,946.41	143,954.25	4,755.00	148,709.25	3,762.84	2.6%

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-34

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Monthly Bill	Components of Proposed Bill		Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3,000	20%	438,000	70,667.88	68,627.88	5,328.00	73,955.88	3,288.00	4.7%
3,000	30%	657,000	79,909.68	77,952.90	5,328.00	83,280.90	3,371.22	4.2%
3,000	40%	876,000	89,151.48	87,277.92	5,328.00	92,605.92	3,454.44	3.9%
3,000	50%	1,095,000	98,393.28	96,602.94	5,328.00	101,930.94	3,537.66	3.6%
3,000	75%	1,642,500	121,497.78	119,915.49	5,328.00	125,243.49	3,745.71	3.1%
3,500	20%	511,000	82,436.98	80,059.22	6,216.00	86,275.22	3,838.24	4.7%
3,500	30%	766,500	93,219.08	90,938.41	6,216.00	97,154.41	3,935.33	4.2%
3,500	40%	1,022,000	104,001.18	101,817.60	6,216.00	108,033.60	4,032.42	3.9%
3,500	50%	1,277,500	114,783.28	112,696.79	6,216.00	118,912.79	4,129.51	3.6%
3,500	75%	1,916,250	141,738.53	139,894.77	6,216.00	146,110.77	4,372.24	3.1%
4,000	20%	584,000	94,206.08	91,490.56	7,104.00	98,594.56	4,388.48	4.7%
4,000	30%	876,000	106,528.48	103,923.92	7,104.00	111,027.92	4,499.44	4.2%
4,000	40%	1,168,000	118,850.88	116,357.28	7,104.00	123,461.28	4,610.40	3.9%
4,000	50%	1,460,000	131,173.28	128,790.64	7,104.00	135,894.64	4,721.36	3.6%
4,000	75%	2,190,000	161,979.28	159,874.04	7,104.00	166,978.04	4,998.76	3.1%
4,500	20%	657,000	105,975.18	102,921.90	7,992.00	110,913.90	4,938.72	4.7%
4,500	30%	985,500	119,837.88	116,909.43	7,992.00	124,901.43	5,063.55	4.2%
4,500	40%	1,314,000	133,700.58	130,896.96	7,992.00	138,888.96	5,188.38	3.9%
4,500	50%	1,642,500	147,563.28	144,884.49	7,992.00	152,876.49	5,313.21	3.6%
4,500	75%	2,463,750	182,220.03	179,853.32	7,992.00	187,845.32	5,625.29	3.1%
5,000	20%	730,000	117,744.28	114,353.24	8,880.00	123,233.24	5,488.96	4.7%
5,000	30%	1,095,000	133,147.28	129,894.94	8,880.00	138,774.94	5,627.66	4.2%
5,000	40%	1,460,000	148,550.28	145,436.64	8,880.00	154,316.64	5,766.36	3.9%
5,000	50%	1,825,000	163,953.28	160,978.34	8,880.00	169,858.34	5,905.06	3.6%
5,000	75%	2,737,500	202,460.78	199,832.59	8,880.00	208,712.59	6,251.81	3.1%
6,000	20%	876,000	141,282.48	137,215.92	10,656.00	147,871.92	6,589.44	4.7%
6,000	30%	1,314,000	159,766.08	155,865.96	10,656.00	166,521.96	6,755.88	4.2%
6,000	40%	1,752,000	178,249.68	174,516.00	10,656.00	185,172.00	6,922.32	3.9%
6,000	50%	2,190,000	196,733.28	193,166.04	10,656.00	203,822.04	7,088.76	3.6%
6,000	75%	3,285,000	242,942.28	239,791.14	10,656.00	250,447.14	7,504.86	3.1%
7,000	20%	1,022,000	164,820.68	160,078.60	12,432.00	172,510.60	7,689.92	4.7%
7,000	30%	1,533,000	186,384.88	181,836.98	12,432.00	194,268.98	7,884.10	4.2%
7,000	50%	2,555,000	229,513.28	225,353.74	12,432.00	237,785.74	8,272.46	3.6%
7,000	75%	3,832,500	283,423.78	279,749.69	12,432.00	292,181.69	8,757.91	3.1%

Unbundled Transmission Charge (>=3,000 kW): 1.776 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis
E-35

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
3,000	4,000	20%	438,000	73,253.75	72,024.92	5,328.00	77,352.92	4,099.17	5.6%
3,000	4,000	30%	657,000	81,749.19	80,600.96	5,328.00	85,928.96	4,179.77	5.1%
3,000	4,000	40%	876,000	90,244.64	89,177.00	5,328.00	94,505.00	4,260.36	4.7%
3,000	4,000	50%	1,095,000	98,740.09	97,753.04	5,328.00	103,081.04	4,340.95	4.4%
3,000	4,000	75%	1,642,500	119,978.71	119,193.14	5,328.00	124,521.14	4,542.43	3.8%
3,500	4,500	20%	511,000	84,998.06	83,531.60	6,216.00	89,747.60	4,749.54	5.6%
3,500	4,500	30%	766,500	94,909.42	93,536.98	6,216.00	99,752.98	4,843.56	5.1%
3,500	4,500	40%	1,022,000	104,820.77	103,542.36	6,216.00	109,758.36	4,937.59	4.7%
3,500	4,500	50%	1,277,500	114,732.13	113,547.74	6,216.00	119,763.74	5,031.61	4.4%
3,500	4,500	75%	1,916,250	139,510.52	138,561.19	6,216.00	144,777.19	5,266.67	3.8%
4,000	5,000	20%	584,000	96,742.38	95,038.28	7,104.00	102,142.28	5,399.90	5.6%
4,000	5,000	30%	876,000	108,069.64	106,473.00	7,104.00	113,577.00	5,507.36	5.1%
4,000	5,000	40%	1,168,000	119,396.91	117,907.72	7,104.00	125,011.72	5,614.81	4.7%
4,000	5,000	50%	1,460,000	130,724.17	129,342.44	7,104.00	136,446.44	5,722.27	4.4%
4,000	5,000	75%	2,190,000	159,042.33	157,929.24	7,104.00	165,033.24	5,990.91	3.8%
4,500	6,000	20%	657,000	109,853.69	108,017.46	7,992.00	116,009.46	6,155.77	5.6%
4,500	6,000	30%	985,500	122,596.87	120,881.52	7,992.00	128,873.52	6,276.65	5.1%
4,500	6,000	40%	1,314,000	135,340.04	133,745.58	7,992.00	141,737.58	6,397.54	4.7%
4,500	6,000	50%	1,642,500	148,083.21	146,609.64	7,992.00	154,601.64	6,518.43	4.4%
4,500	6,000	75%	2,463,750	179,941.14	178,769.79	7,992.00	186,761.79	6,820.65	3.8%
5,000	7,000	20%	730,000	122,965.01	120,996.64	8,880.00	129,876.64	6,911.63	5.6%
5,000	7,000	30%	1,095,000	137,124.09	135,290.04	8,880.00	144,170.04	7,045.95	5.1%
5,000	7,000	40%	1,460,000	151,283.17	149,583.44	8,880.00	158,463.44	7,180.27	4.7%
5,000	7,000	50%	1,825,000	165,442.25	163,876.84	8,880.00	172,756.84	7,314.59	4.4%
5,000	7,000	75%	2,737,500	200,839.95	199,610.34	8,880.00	208,490.34	7,650.39	3.8%
6,000	8,000	20%	876,000	146,453.64	144,010.00	10,656.00	154,666.00	8,212.36	5.6%
6,000	8,000	30%	1,314,000	163,444.54	161,162.08	10,656.00	171,818.08	8,373.54	5.1%
6,000	8,000	40%	1,752,000	180,435.43	178,314.16	10,656.00	188,970.16	8,534.73	4.7%
6,000	8,000	50%	2,190,000	197,426.33	195,466.24	10,656.00	206,122.24	8,695.91	4.4%
6,000	8,000	75%	3,285,000	239,903.57	238,346.44	10,656.00	249,002.44	9,098.87	3.8%
7,000	8,500	20%	1,022,000	168,575.27	165,550.86	12,432.00	177,982.86	9,407.59	5.6%
7,000	8,500	30%	1,533,000	188,397.99	185,561.62	12,432.00	197,993.62	9,595.63	5.1%
7,000	8,500	50%	2,555,000	228,043.41	225,583.14	12,432.00	238,015.14	9,971.73	4.4%
7,000	8,500	75%	3,832,500	277,600.19	275,610.04	12,432.00	288,042.04	10,441.85	3.8%

E-35 Average Energy On-Peak: 30%
Unbundled Transmission Charge (>=3,000 kW): 1.776 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-47

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
HPS, cobra / roadway	5,800	29	Company	8.73	8.93	0.12	9.05	0.32	3.7%
		29	Customer	5.16	3.94	0.12	4.06	(1.10)	-21.3%
HPS, cobra / roadway	9,500	41	Company	10.28	10.49	0.17	10.66	0.38	3.7%
		41	Customer	6.32	4.81	0.17	4.98	(1.34)	-21.2%
HPS, architectural	9,500	41	Company	15.38	15.77	0.17	15.94	0.56	3.6%
		41	Customer	7.34	5.61	0.17	5.78	(1.56)	-21.3%
HPS, acorn luminaire	9,500	41	Company	27.06	27.88	0.17	28.05	0.99	3.7%
		41	Customer	9.22	7.09	0.17	7.26	(1.96)	-21.3%
HPS, cobra / roadway	16,000	69	Company	12.87	13.05	0.29	13.34	0.47	3.7%
		69	Customer	8.82	6.66	0.29	6.95	(1.87)	-21.2%
HPS, architectural	16,000	69	Company	17.96	18.33	0.29	18.62	0.66	3.7%
		69	Customer	9.82	7.45	0.29	7.74	(2.08)	-21.2%
HPS, acorn luminaire	16,000	69	Company	30.04	30.85	0.29	31.14	1.10	3.7%
		69	Customer	11.65	8.89	0.29	9.18	(2.47)	-21.2%
HPS, cobra / roadway	30,000	99	Company	15.52	15.67	0.42	16.09	0.57	3.7%
		99	Customer	11.46	8.61	0.42	9.03	(2.43)	-21.2%
HPS, architectural	30,000	99	Company	21.31	21.67	0.42	22.09	0.78	3.7%
		99	Customer	12.60	9.51	0.42	9.93	(2.67)	-21.2%
HPS, cobra / roadway	50,000	153	Company	21.06	21.18	0.65	21.83	0.77	3.7%
		153	Customer	16.37	12.25	0.65	12.90	(3.47)	-21.2%
HPS, architectural	50,000	153	Company	26.29	26.60	0.65	27.25	0.96	3.7%
		153	Customer	18.13	13.63	0.65	14.28	(3.85)	-21.2%
LPS, architectural	8,000	30	Company	22.35	23.04	0.13	23.17	0.82	3.7%
		30	Customer	9.82	7.61	0.13	7.74	(2.08)	-21.2%
LPS, architectural	13,500	50	Company	26.36	27.11	0.21	27.32	0.96	3.6%
LPS, architectural	22,500	72	Company	30.11	30.90	0.31	31.21	1.10	3.7%
		72	Customer	14.45	11.07	0.31	11.38	(3.07)	-21.2%
LPS, architectural	33,000	90	Company	36.22	37.16	0.38	37.54	1.32	3.6%
		90	Customer	17.02	13.03	0.38	13.41	(3.61)	-21.2%
Type of Pole	Height	Desc.							
Direct Bury	30 FT	Round Steel	Company	14.38	14.90	-	14.90	0.52	3.6%
			Customer	N/A					N/A
Direct Bury	34 FT	Square Steel	Company	15.87	16.45	-	16.45	0.58	3.7%
			Customer	N/A	N/A				N/A

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-58

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
HPS, cobra / roadway	5,800	29	Inv. By Co.	8.73	8.93	0.12	9.05	0.32	3.7%
		29	Inv. By Others	5.16	5.23	0.12	5.35	0.19	3.7%
HPS, cobra / roadway	9,500	41	Inv. By Co.	10.28	10.49	0.17	10.66	0.38	3.7%
		41	Inv. By Others	6.32	6.38	0.17	6.55	0.23	3.6%
HPS, architectural	9,500	41	Inv. By Co.	15.38	15.77	0.17	15.94	0.56	3.6%
		41	Inv. By Others	7.34	7.44	0.17	7.61	0.27	3.7%
HPS, acorn luminaire	9,500	41	Inv. By Co.	27.06	27.88	0.17	28.05	0.99	3.7%
		41	Inv. By Others	9.22	9.39	0.17	9.56	0.34	3.7%
HPS, cobra / roadway	16,000	69	Inv. By Co.	12.87	13.05	0.29	13.34	0.47	3.7%
		69	Inv. By Others	8.82	8.85	0.29	9.14	0.32	3.6%
HPS, architectural	16,000	69	Inv. By Co.	17.96	18.33	0.29	18.62	0.66	3.7%
		69	Inv. By Others	9.82	9.89	0.29	10.18	0.36	3.7%
HPS, acorn luminaire	16,000	69	Inv. By Co.	30.04	30.85	0.29	31.14	1.10	3.7%
		69	Inv. By Others	11.65	11.79	0.29	12.08	0.43	3.7%
HPS, cobra / roadway	30,000	99	Inv. By Co.	15.52	15.67	0.42	16.09	0.57	3.7%
		99	Inv. By Others	11.46	11.46	0.42	11.88	0.42	3.7%
HPS, architectural	30,000	99	Inv. By Co.	21.31	21.67	0.42	22.09	0.78	3.7%
		99	Inv. By Others	12.60	12.64	0.42	13.06	0.46	3.7%
HPS, cobra / roadway	50,000	153	Inv. By Co.	21.06	21.18	0.65	21.83	0.77	3.7%
		153	Inv. By Others	16.37	16.32	0.65	16.97	0.60	3.7%
HPS, architectural	50,000	153	Inv. By Co.	26.29	26.60	0.65	27.25	0.96	3.7%
		153	Inv. By Others	18.13	18.14	0.65	18.79	0.66	3.6%
LPS, architectural	8,000	30	Inv. By Co.	22.35	23.04	0.13	23.17	0.82	3.7%
		30	Inv. By Others	9.82	10.05	0.13	10.18	0.36	3.7%
LPS, architectural	13,500	50	Inv. By Co.	26.36	27.11	0.21	27.32	0.96	3.6%
LPS, architectural	22,500	72	Inv. By Co.	30.11	30.90	0.31	31.21	1.10	3.7%
		72	Inv. By Others	14.45	14.67	0.31	14.98	0.53	3.7%
LPS, architectural	33,000	90	Inv. By Co.	36.22	37.16	0.38	37.54	1.32	3.6%
		90	Inv. By Others	17.02	17.26	0.38	17.64	0.62	3.6%
Type of Pole	Height	Desc.							
Direct Bury	30 FT	Round	Inv. By Co.	14.38	14.90	-	14.90	0.52	3.6%
		Steel	Inv. By Others	2.66	2.76	-	2.76	0.10	3.8%
Direct Bury	34 FT	Square	Inv. By Co.	15.87	16.45	-	16.45	0.58	3.7%
		Steel	Inv. By Others	2.75	2.85	-	2.85	0.10	3.6%
Direct Bury	38 FT	Square	Inv. By Co.	17.05	17.67	-	17.67	0.62	3.6%
		Steel	Inv. By Others	2.96	3.07	-	3.07	0.11	3.7%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-59

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
Lamps	kWh per Lamp	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
50	30	1,500	230.82	232.64	6.36	239.00	8.18	3.5%
50	60	3,000	322.14	320.78	12.72	333.50	11.36	3.5%
50	75	3,750	367.80	364.85	15.90	380.75	12.95	3.5%
50	100	5,000	443.90	438.30	21.20	459.50	15.60	3.5%
50	150	7,500	596.10	585.20	31.80	617.00	20.90	3.5%
100	30	3,000	461.64	465.28	12.72	478.00	16.36	3.5%
100	60	6,000	644.28	641.56	25.44	667.00	22.72	3.5%
100	75	7,500	735.60	729.70	31.80	761.50	25.90	3.5%
100	100	10,000	887.80	876.60	42.40	919.00	31.20	3.5%
100	150	15,000	1,192.20	1,170.40	63.60	1,234.00	41.80	3.5%
200	30	6,000	923.28	930.56	25.44	956.00	32.72	3.5%
200	60	12,000	1,288.56	1,283.12	50.88	1,334.00	45.44	3.5%
200	75	15,000	1,471.20	1,459.40	63.60	1,523.00	51.80	3.5%
200	100	20,000	1,775.60	1,753.20	84.80	1,838.00	62.40	3.5%
200	150	30,000	2,384.40	2,340.80	127.20	2,468.00	83.60	3.5%
500	30	15,000	2,308.20	2,326.40	63.60	2,390.00	81.80	3.5%
500	60	30,000	3,221.40	3,207.80	127.20	3,335.00	113.60	3.5%
500	75	37,500	3,678.00	3,648.50	159.00	3,807.50	129.50	3.5%
500	100	50,000	4,439.00	4,383.00	212.00	4,595.00	156.00	3.5%
500	150	75,000	5,961.00	5,852.00	318.00	6,170.00	209.00	3.5%
1,000	30	30,000	4,616.40	4,652.80	127.20	4,780.00	163.60	3.5%
1,000	60	60,000	6,442.80	6,415.60	254.40	6,670.00	227.20	3.5%
1,000	75	75,000	7,356.00	7,297.00	318.00	7,615.00	259.00	3.5%
1,000	100	100,000	8,878.00	8,766.00	424.00	9,190.00	312.00	3.5%
1,000	150	150,000	11,922.00	11,704.00	636.00	12,340.00	418.00	3.5%
2,000	30	60,000	9,232.80	9,305.60	254.40	9,560.00	327.20	3.5%
2,000	60	120,000	12,885.60	12,831.20	508.80	13,340.00	454.40	3.5%
2,000	75	150,000	14,712.00	14,594.00	636.00	15,230.00	518.00	3.5%
2,000	100	200,000	17,756.00	17,532.00	848.00	18,380.00	624.00	3.5%
2,000	150	300,000	23,844.00	23,408.00	1,272.00	24,680.00	836.00	3.5%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-67

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
30	1.56	1.52	0.13	1.65	0.09	5.6%
40	2.08	2.02	0.17	2.19	0.11	5.3%
50	2.60	2.53	0.21	2.74	0.14	5.5%
60	3.12	3.03	0.25	3.28	0.16	5.3%
70	3.64	3.54	0.30	3.84	0.20	5.4%
80	4.15	4.05	0.34	4.39	0.24	5.8%
90	4.67	4.55	0.38	4.93	0.26	5.6%
100	5.19	5.06	0.42	5.48	0.29	5.7%
125	6.49	6.32	0.53	6.85	0.36	5.5%
150	7.79	7.59	0.64	8.23	0.44	5.6%
175	9.09	8.85	0.74	9.59	0.50	5.5%
200	10.39	10.11	0.85	10.96	0.57	5.5%
225	11.68	11.38	0.95	12.33	0.65	5.6%
250	12.98	12.64	1.06	13.70	0.72	5.5%
275	14.28	13.91	1.17	15.08	0.80	5.6%
300	15.58	15.17	1.27	16.44	0.86	5.5%
325	16.88	16.44	1.38	17.82	0.94	5.6%
350	18.18	17.70	1.48	19.18	1.00	5.5%
375	19.47	18.96	1.59	20.55	1.08	5.5%
400	20.77	20.23	1.70	21.93	1.16	5.6%
425	22.07	21.49	1.80	23.29	1.22	5.5%
450	23.37	22.76	1.91	24.67	1.30	5.6%
475	24.67	24.02	2.01	26.03	1.36	5.5%
500	25.97	25.29	2.12	27.41	1.44	5.5%
600	31.16	30.34	2.54	32.88	1.72	5.5%
700	36.35	35.40	2.97	38.37	2.02	5.6%
800	41.54	40.46	3.39	43.85	2.31	5.6%
900	46.74	45.51	3.82	49.33	2.59	5.5%
1,000	51.93	50.57	4.24	54.81	2.88	5.5%
1,500	77.90	75.86	6.36	82.22	4.32	5.5%
2,000	103.86	101.14	8.48	109.62	5.76	5.5%
2,500	129.83	126.43	10.60	137.03	7.20	5.5%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (D) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-221 Water Pumping

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
10	20%	1,460	160.44	151.21	6.19	157.40	-3.04	-1.9%
10	35%	2,555	247.38	238.15	10.83	248.98	1.60	0.6%
10	50%	3,650	324.95	315.72	15.48	331.20	6.25	1.9%
10	65%	4,745	396.33	387.10	20.12	407.22	10.89	2.7%
10	80%	5,840	467.71	458.48	24.76	483.24	15.53	3.3%
30	20%	4,380	429.89	400.40	47.55	447.95	18.06	4.2%
30	35%	7,665	690.72	661.23	47.55	708.78	18.06	2.6%
30	50%	10,950	916.59	887.10	47.55	934.65	18.06	2.0%
30	65%	14,235	1,130.74	1,101.25	47.55	1,148.80	18.06	1.6%
30	80%	17,520	1,344.89	1,315.40	47.55	1,362.95	18.06	1.3%
75	20%	10,950	1,036.15	961.07	118.88	1,079.95	43.81	4.2%
75	35%	19,163	1,688.26	1,613.18	118.88	1,732.06	43.81	2.6%
75	50%	27,375	2,247.78	2,172.71	118.88	2,291.59	43.81	1.9%
75	65%	35,588	2,783.19	2,708.11	118.88	2,826.99	43.81	1.6%
75	80%	43,800	3,318.53	3,243.45	118.88	3,362.33	43.81	1.3%
100	20%	14,600	1,372.96	1,272.56	158.50	1,431.06	58.10	4.2%
100	35%	25,550	2,242.39	2,141.99	158.50	2,300.49	58.10	2.6%
100	50%	36,500	2,987.34	2,886.94	158.50	3,045.44	58.10	1.9%
100	65%	47,450	3,701.17	3,600.77	158.50	3,759.27	58.10	1.6%
100	80%	58,400	4,415.00	4,314.60	158.50	4,473.10	58.10	1.3%
150	20%	21,900	2,046.58	1,895.53	237.75	2,133.28	86.70	4.2%
150	35%	38,325	3,350.72	3,199.67	237.75	3,437.42	86.70	2.6%
150	50%	54,750	4,466.44	4,315.39	237.75	4,553.14	86.70	1.9%
150	65%	71,175	5,537.19	5,386.14	237.75	5,623.89	86.70	1.6%
150	80%	87,600	6,607.93	6,456.88	237.75	6,694.63	86.70	1.3%
200	20%	29,200	2,720.20	2,518.50	317.00	2,835.50	115.30	4.2%
200	35%	51,100	4,459.06	4,257.36	317.00	4,574.36	115.30	2.6%
200	50%	73,000	5,945.55	5,743.85	317.00	6,060.85	115.30	1.9%
200	65%	94,900	7,373.21	7,171.51	317.00	7,488.51	115.30	1.6%
200	80%	116,800	8,800.87	8,599.17	317.00	8,916.17	115.30	1.3%
300	20%	43,800	4,067.44	3,764.44	475.50	4,239.94	172.50	4.2%
300	50%	109,500	8,903.76	8,600.76	475.50	9,076.26	172.50	1.9%
300	65%	142,350	11,045.25	10,742.25	475.50	11,217.75	172.50	1.6%
300	80%	175,200	13,186.74	12,883.74	475.50	13,359.24	172.50	1.3%

Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
E-221-8T Time-of-Use Water Pumping

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
					Base	Transmission	(F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
10	30	20%	1,460	248.44	272.11	6.19	278.30	29.86	12.0%
10	30	35%	2,555	319.38	343.05	10.83	353.88	34.50	10.8%
10	30	50%	3,650	390.32	413.99	15.48	429.47	39.15	10.0%
10	30	65%	4,745	461.25	484.92	20.12	505.04	43.79	9.5%
10	30	80%	5,840	532.19	555.86	24.76	580.62	48.43	9.1%
30	90	20%	4,380	687.47	755.42	47.55	802.97	115.50	16.8%
30	90	35%	7,665	900.29	968.24	47.55	1,015.79	115.50	12.8%
30	90	50%	10,950	1,113.11	1,181.06	47.55	1,228.61	115.50	10.4%
30	90	65%	14,235	1,325.92	1,393.87	47.55	1,441.42	115.50	8.7%
30	90	80%	17,520	1,538.74	1,606.69	47.55	1,654.24	115.50	7.5%
75	225	20%	10,950	1,675.29	1,842.87	118.88	1,961.75	286.46	17.1%
75	225	35%	19,163	2,207.37	2,374.95	118.88	2,493.83	286.46	13.0%
75	225	50%	27,375	2,739.38	2,906.96	118.88	3,025.84	286.46	10.5%
75	225	65%	35,588	3,271.46	3,439.04	118.88	3,557.92	286.46	8.8%
75	225	80%	43,800	3,803.48	3,971.06	118.88	4,089.94	286.46	7.5%
100	300	20%	14,600	2,224.08	2,447.01	158.50	2,605.51	381.43	17.2%
100	300	35%	25,550	2,933.48	3,156.41	158.50	3,314.91	381.43	13.0%
100	300	50%	36,500	3,642.87	3,865.80	158.50	4,024.30	381.43	10.5%
100	300	65%	47,450	4,352.27	4,575.20	158.50	4,733.70	381.43	8.8%
100	300	80%	58,400	5,061.66	5,284.59	158.50	5,443.09	381.43	7.5%
150	450	20%	21,900	3,321.66	3,655.29	237.75	3,893.04	571.38	17.2%
150	450	35%	38,325	4,385.76	4,719.39	237.75	4,957.14	571.38	13.0%
150	450	50%	54,750	5,449.85	5,783.48	237.75	6,021.23	571.38	10.5%
150	450	65%	71,175	6,513.94	6,847.57	237.75	7,085.32	571.38	8.8%
150	450	80%	87,600	7,578.04	7,911.67	237.75	8,149.42	571.38	7.5%
200	600	20%	29,200	4,419.24	4,863.57	317.00	5,180.57	761.33	17.2%
200	600	35%	51,100	5,838.03	6,282.36	317.00	6,599.36	761.33	13.0%
200	600	50%	73,000	7,256.83	7,701.16	317.00	8,018.16	761.33	10.5%
200	600	65%	94,900	8,675.62	9,119.95	317.00	9,436.95	761.33	8.8%
200	600	80%	116,800	10,094.41	10,538.74	317.00	10,855.74	761.33	7.5%
300	900	20%	43,800	6,614.40	7,280.13	475.50	7,755.63	1,141.23	17.3%
300	900	50%	109,500	10,870.78	11,536.51	475.50	12,012.01	1,141.23	10.5%
300	900	65%	142,350	12,998.96	13,664.69	475.50	14,140.19	1,141.23	8.8%
300	900	80%	175,200	15,127.15	15,792.88	475.50	16,268.38	1,141.23	7.5%

E-221-8T Average Energy On-Peak: 30%
Unbundled Transmission Charge (<=20 kW): 0.00424 $/kWh
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
3) Column (G) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS M Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	1,756.43	1,639.74	160.09	1,799.83	43.40	2.5%
101	30%	22,119	2,508.28	2,406.53	160.09	2,566.62	58.34	2.3%
101	45%	33,179	3,260.19	3,173.39	160.09	3,333.48	73.29	2.2%
101	60%	44,238	4,012.03	3,940.18	160.09	4,100.27	88.24	2.2%
101	75%	55,298	4,763.94	4,707.04	160.09	4,867.13	103.19	2.2%
150	15%	16,425	2,371.32	2,190.29	237.75	2,428.04	56.72	2.4%
150	30%	32,850	3,487.96	3,329.13	237.75	3,566.88	78.92	2.3%
150	45%	49,275	4,604.61	4,467.98	237.75	4,705.73	101.12	2.2%
150	60%	65,700	5,721.26	5,606.83	237.75	5,844.58	123.32	2.2%
150	75%	82,125	6,837.91	6,745.68	237.75	6,983.43	145.52	2.1%
200	15%	21,900	2,998.78	2,752.10	317.00	3,069.10	70.32	2.3%
200	30%	43,800	4,487.65	4,270.57	317.00	4,587.57	99.92	2.2%
200	45%	65,700	5,976.51	5,789.03	317.00	6,106.03	129.52	2.2%
200	60%	87,600	7,465.37	7,307.49	317.00	7,624.49	159.12	2.1%
200	75%	109,500	8,954.23	8,825.95	317.00	9,142.95	188.72	2.1%
300	15%	32,850	4,253.71	3,875.73	475.50	4,351.23	97.52	2.3%
300	30%	65,700	6,487.01	6,153.43	475.50	6,628.93	141.92	2.2%
300	45%	98,550	8,720.30	8,431.12	475.50	8,906.62	186.32	2.1%
300	60%	131,400	10,953.60	10,708.82	475.50	11,184.32	230.72	2.1%
300	75%	164,250	13,186.89	12,986.51	475.50	13,462.01	275.12	2.1%
350	15%	38,325	4,881.18	4,437.55	554.75	4,992.30	111.12	2.3%
350	30%	76,650	7,486.69	7,094.86	554.75	7,649.61	162.92	2.2%
350	45%	114,975	10,092.20	9,752.17	554.75	10,306.92	214.72	2.1%
350	60%	153,300	12,697.71	12,409.48	554.75	12,964.23	266.52	2.1%
350	75%	191,625	15,303.22	15,066.79	554.75	15,621.54	318.32	2.1%
400	15%	43,800	5,508.65	4,999.37	634.00	5,633.37	124.72	2.3%
400	30%	87,600	8,486.37	8,036.29	634.00	8,670.29	183.92	2.2%
400	45%	131,400	11,464.10	11,073.22	634.00	11,707.22	243.12	2.1%
400	60%	175,200	14,441.82	14,110.14	634.00	14,744.14	302.32	2.1%
400	75%	219,000	17,419.55	17,147.07	634.00	17,781.07	361.52	2.1%

GS-SCHOOLS M Average Energy On-Peak %:	24%	
GS-SCHOOLS M Average Energy Shoulder-Peak %:	17%	
Unbundled Transmission Charge (>20 kW and <3,000):	1.585	$/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS M Summer Shoulder (May, September & October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	1,953.24	1,843.70	160.09	2,003.79	50.55	2.6%
101	30%	22,119	2,901.87	2,814.43	160.09	2,974.52	72.65	2.5%
101	45%	33,179	3,850.58	3,785.25	160.09	3,945.34	94.76	2.5%
101	60%	44,238	4,799.21	4,755.98	160.09	4,916.07	116.86	2.4%
101	75%	55,298	5,747.92	5,726.80	160.09	5,886.89	138.97	2.4%
150	15%	16,425	2,663.59	2,493.18	237.75	2,730.93	67.34	2.5%
150	30%	32,850	4,072.50	3,934.93	237.75	4,172.68	100.18	2.5%
150	45%	49,275	5,481.42	5,376.67	237.75	5,614.42	133.00	2.4%
150	60%	65,700	6,890.34	6,818.42	237.75	7,056.17	165.83	2.4%
150	75%	82,125	8,299.25	8,260.16	237.75	8,497.91	198.66	2.4%
200	15%	21,900	3,388.48	3,155.97	317.00	3,472.97	84.49	2.5%
200	30%	43,800	5,267.03	5,078.29	317.00	5,395.29	128.26	2.4%
200	45%	65,700	7,145.59	7,000.62	317.00	7,317.62	172.03	2.4%
200	60%	87,600	9,024.14	8,922.94	317.00	9,239.94	215.80	2.4%
200	75%	109,500	10,902.70	10,845.27	317.00	11,162.27	259.57	2.4%
300	15%	32,850	4,838.25	4,481.53	475.50	4,957.03	118.78	2.5%
300	30%	65,700	7,656.09	7,365.02	475.50	7,840.52	184.43	2.4%
300	45%	98,550	10,473.92	10,248.50	475.50	10,724.00	250.08	2.4%
300	60%	131,400	13,291.75	13,131.99	475.50	13,607.49	315.74	2.4%
300	75%	164,250	16,109.59	16,015.48	475.50	16,490.98	381.39	2.4%
350	15%	38,325	5,563.14	5,144.31	554.75	5,699.06	135.92	2.4%
350	30%	76,650	8,850.62	8,508.38	554.75	9,063.13	212.51	2.4%
350	45%	114,975	12,138.09	11,872.45	554.75	12,427.20	289.11	2.4%
350	60%	153,300	15,425.56	15,236.52	554.75	15,791.27	365.71	2.4%
350	75%	191,625	18,713.03	18,600.58	554.75	19,155.33	442.30	2.4%
400	15%	43,800	6,288.03	5,807.09	634.00	6,441.09	153.06	2.4%
400	30%	87,600	10,045.14	9,651.74	634.00	10,285.74	240.60	2.4%
400	45%	131,400	13,802.25	13,496.39	634.00	14,130.39	328.14	2.4%
400	60%	175,200	17,559.37	17,341.04	634.00	17,975.04	415.67	2.4%
400	75%	219,000	21,316.48	21,185.69	634.00	21,819.69	503.21	2.4%

GS-SCHOOLS M Average Energy On-Peak %:	19%
GS-SCHOOLS M Average Energy Shoulder-Peak %:	22%
Unbundled Transmission Charge (>20 kW and <3,000):	1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS M Summer Peak (June-August)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	2,077.13	1,970.61	160.09	2,130.70	53.57	2.6%
101	30%	22,119	3,149.63	3,068.24	160.09	3,228.33	78.70	2.5%
101	45%	33,179	4,222.23	4,165.97	160.09	4,326.06	103.83	2.5%
101	60%	44,238	5,294.74	5,263.59	160.09	5,423.68	128.94	2.4%
101	75%	55,298	6,367.34	6,361.32	160.09	6,521.41	154.07	2.4%
150	15%	16,425	2,847.57	2,681.65	237.75	2,919.40	71.83	2.5%
150	30%	32,850	4,440.47	4,311.87	237.75	4,549.62	109.15	2.5%
150	45%	49,275	6,033.37	5,942.08	237.75	6,179.83	146.46	2.4%
150	60%	65,700	7,626.27	7,572.30	237.75	7,810.05	183.78	2.4%
150	75%	82,125	9,219.17	9,202.51	237.75	9,440.26	221.09	2.4%
200	15%	21,900	3,633.79	3,407.26	317.00	3,724.26	90.47	2.5%
200	30%	43,800	5,757.65	5,580.88	317.00	5,897.88	140.23	2.4%
200	45%	65,700	7,881.52	7,754.50	317.00	8,071.50	189.98	2.4%
200	60%	87,600	10,005.39	9,928.12	317.00	10,245.12	239.73	2.4%
200	75%	109,500	12,129.25	12,101.73	317.00	12,418.73	289.48	2.4%
300	15%	32,850	5,206.22	4,858.47	475.50	5,333.97	127.75	2.5%
300	30%	65,700	8,392.02	8,118.90	475.50	8,594.40	202.38	2.4%
300	45%	98,550	11,577.82	11,379.32	475.50	11,854.82	277.00	2.4%
300	60%	131,400	14,763.62	14,639.75	475.50	15,115.25	351.63	2.4%
300	75%	164,250	17,949.42	17,900.18	475.50	18,375.68	426.26	2.4%
350	15%	38,325	5,992.44	5,584.07	554.75	6,138.82	146.38	2.4%
350	30%	76,650	9,709.20	9,387.91	554.75	9,942.66	233.46	2.4%
350	45%	114,975	13,425.97	13,191.74	554.75	13,746.49	320.52	2.4%
350	60%	153,300	17,142.73	16,995.57	554.75	17,550.32	407.59	2.4%
350	75%	191,625	20,859.50	20,799.40	554.75	21,354.15	494.65	2.4%
400	15%	43,800	6,778.65	6,309.68	634.00	6,943.68	165.03	2.4%
400	30%	87,600	11,026.39	10,656.92	634.00	11,290.92	264.53	2.4%
400	45%	131,400	15,274.12	15,004.15	634.00	15,638.15	364.03	2.4%
400	60%	175,200	19,521.85	19,351.39	634.00	19,985.39	463.54	2.4%
400	75%	219,000	23,769.58	23,698.63	634.00	24,332.63	563.05	2.4%

GS-SCHOOLS M Average Energy On-Peak %: 18%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 20%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS L Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	5,240.48	4,726.49	635.59	5,362.08	121.60	2.3%
401	30%	87,819	7,990.80	7,505.07	635.59	8,140.66	149.86	1.9%
401	45%	131,729	10,741.17	10,283.72	635.59	10,919.31	178.14	1.7%
401	60%	175,638	13,491.49	13,062.30	635.59	13,697.89	206.40	1.5%
401	75%	219,548	16,241.87	15,840.95	635.59	16,476.54	234.67	1.4%
600	15%	65,700	7,598.94	6,821.97	951.00	7,772.97	174.03	2.3%
600	30%	131,400	11,714.17	10,979.50	951.00	11,930.50	216.33	1.8%
600	45%	197,100	15,829.40	15,137.03	951.00	16,088.03	258.63	1.6%
600	60%	262,800	19,944.63	19,294.56	951.00	20,245.56	300.93	1.5%
600	75%	328,500	24,059.87	23,452.08	951.00	24,403.08	343.21	1.4%
800	15%	87,600	9,969.28	8,928.01	1,268.00	10,196.01	226.73	2.3%
800	30%	175,200	15,456.26	14,471.38	1,268.00	15,739.38	283.12	1.8%
800	45%	262,800	20,943.23	20,014.76	1,268.00	21,282.76	339.53	1.6%
800	60%	350,400	26,430.21	25,558.13	1,268.00	26,826.13	395.92	1.5%
800	75%	438,000	31,917.18	31,101.50	1,268.00	32,369.50	452.32	1.4%
1,000	15%	109,500	12,339.63	11,034.05	1,585.00	12,619.05	279.42	2.3%
1,000	30%	219,000	19,198.35	17,963.27	1,585.00	19,548.27	349.92	1.8%
1,000	45%	328,500	26,057.07	24,892.48	1,585.00	26,477.48	420.41	1.6%
1,000	60%	438,000	32,915.78	31,821.70	1,585.00	33,406.70	490.92	1.5%
1,000	75%	547,500	39,774.50	38,750.91	1,585.00	40,335.91	561.41	1.4%
1,500	15%	164,250	18,265.49	16,299.16	2,377.50	18,676.66	411.17	2.3%
1,500	30%	328,500	28,553.57	26,692.98	2,377.50	29,070.48	516.91	1.8%
1,500	45%	492,750	38,841.64	37,086.81	2,377.50	39,464.31	622.67	1.6%
1,500	60%	657,000	49,129.72	47,480.63	2,377.50	49,858.13	728.41	1.5%
1,500	75%	821,250	59,417.80	57,874.45	2,377.50	60,251.95	834.15	1.4%
3,000	15%	328,500	36,043.07	32,094.48	4,755.00	36,849.48	806.41	2.2%
3,000	30%	657,000	56,619.22	52,882.13	4,755.00	57,637.13	1,017.91	1.8%
3,000	45%	985,500	77,195.38	73,669.77	4,755.00	78,424.77	1,229.39	1.6%
3,000	60%	1,314,000	97,771.53	94,457.42	4,755.00	99,212.42	1,440.89	1.5%
3,000	75%	1,642,500	118,347.69	115,245.06	4,755.00	120,000.06	1,652.37	1.4%

GS-SCHOOLS L Average Energy On-Peak %:	23%	
GS-SCHOOLS L Average Energy Shoulder-Peak %:	18%	
Unbundled Transmission Charge (>20 kW and <3,000):	1.585	$/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS L Summer Shoulder (May, September & October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	5,865.81	5,364.60	635.59	6,000.19	134.38	2.3%
401	30%	87,819	9,241.43	8,781.28	635.59	9,416.87	175.44	1.9%
401	45%	131,729	12,617.14	12,198.04	635.59	12,833.63	216.49	1.7%
401	60%	175,638	15,992.77	15,614.73	635.59	16,250.32	257.55	1.6%
401	75%	219,548	19,368.47	19,031.49	635.59	19,667.08	298.61	1.5%
600	15%	65,700	8,534.58	7,776.74	951.00	8,727.74	193.16	2.3%
600	30%	131,400	13,585.45	12,889.04	951.00	13,840.04	254.59	1.9%
600	45%	197,100	18,636.32	18,001.34	951.00	18,952.34	316.02	1.7%
600	60%	262,800	23,687.20	23,113.64	951.00	24,064.64	377.44	1.6%
600	75%	328,500	28,738.07	28,225.94	951.00	29,176.94	438.87	1.5%
800	15%	87,600	11,216.81	10,201.04	1,268.00	11,469.04	252.23	2.2%
800	30%	175,200	17,951.30	17,017.44	1,268.00	18,285.44	334.14	1.9%
800	45%	262,800	24,685.80	23,833.84	1,268.00	25,101.84	416.04	1.7%
800	60%	350,400	31,420.29	30,650.25	1,268.00	31,918.25	497.96	1.6%
800	75%	438,000	38,154.79	37,466.65	1,268.00	38,734.65	579.86	1.5%
1,000	15%	109,500	13,899.03	12,625.34	1,585.00	14,210.34	311.31	2.2%
1,000	30%	219,000	22,317.15	21,145.84	1,585.00	22,730.84	413.69	1.9%
1,000	45%	328,500	30,735.27	29,666.34	1,585.00	31,251.34	516.07	1.7%
1,000	60%	438,000	39,153.39	38,186.85	1,585.00	39,771.85	618.46	1.6%
1,000	75%	547,500	47,571.51	46,707.35	1,585.00	48,292.35	720.84	1.5%
1,500	15%	164,250	20,604.59	18,686.09	2,377.50	21,063.59	459.00	2.2%
1,500	30%	328,500	33,231.77	31,466.84	2,377.50	33,844.34	612.57	1.8%
1,500	45%	492,750	45,858.95	44,247.60	2,377.50	46,625.10	766.15	1.7%
1,500	60%	657,000	58,486.12	57,028.35	2,377.50	59,405.85	919.73	1.6%
1,500	75%	821,250	71,113.30	69,809.10	2,377.50	72,186.60	1,073.30	1.5%
3,000	15%	328,500	40,721.27	36,868.34	4,755.00	41,623.34	902.07	2.2%
3,000	30%	657,000	65,975.62	62,429.85	4,755.00	67,184.85	1,209.23	1.8%
3,000	45%	985,500	91,229.98	87,991.35	4,755.00	92,746.35	1,516.37	1.7%
3,000	60%	1,314,000	116,484.34	113,552.86	4,755.00	118,307.86	1,823.52	1.6%
3,000	75%	1,642,500	141,738.70	139,114.36	4,755.00	143,869.36	2,130.66	1.5%

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 18%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis
GS-SCHOOLS L Summer Peak (June-August)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	6,354.19	5,857.12	635.59	6,492.71	138.52	2.2%
401	30%	87,819	10,218.19	9,766.31	635.59	10,401.90	183.71	1.8%
401	45%	131,729	14,082.28	13,675.59	635.59	14,311.18	228.90	1.6%
401	60%	175,638	17,946.28	17,584.79	635.59	18,220.38	274.10	1.5%
401	75%	219,548	21,810.37	21,494.07	635.59	22,129.66	319.29	1.5%
600	15%	65,700	9,265.32	8,513.67	951.00	9,464.67	199.35	2.2%
600	30%	131,400	15,046.94	14,362.90	951.00	15,313.90	266.96	1.8%
600	45%	197,100	20,828.55	20,212.13	951.00	21,163.13	334.58	1.6%
600	60%	262,800	26,610.16	26,061.37	951.00	27,012.37	402.21	1.5%
600	75%	328,500	32,391.78	31,910.60	951.00	32,861.60	469.82	1.5%
800	15%	87,600	12,191.13	11,183.62	1,268.00	12,451.62	260.49	2.1%
800	30%	175,200	19,899.95	18,982.59	1,268.00	20,250.59	350.64	1.8%
800	45%	262,800	27,608.76	26,781.57	1,268.00	28,049.57	440.81	1.6%
800	60%	350,400	35,317.58	34,580.54	1,268.00	35,848.54	530.96	1.5%
800	75%	438,000	43,026.40	42,379.52	1,268.00	43,647.52	621.12	1.4%
1,000	15%	109,500	15,116.93	13,853.56	1,585.00	15,438.56	321.63	2.1%
1,000	30%	219,000	24,752.95	23,602.28	1,585.00	25,187.28	434.33	1.8%
1,000	45%	328,500	34,388.98	33,351.00	1,585.00	34,936.00	547.02	1.6%
1,000	60%	438,000	44,025.00	43,099.72	1,585.00	44,684.72	659.72	1.5%
1,000	75%	547,500	53,661.02	52,848.44	1,585.00	54,433.44	772.42	1.4%
1,500	15%	164,250	22,431.44	20,528.42	2,377.50	22,905.92	474.48	2.1%
1,500	30%	328,500	36,885.48	35,151.50	2,377.50	37,529.00	643.52	1.7%
1,500	45%	492,750	51,339.51	49,774.58	2,377.50	52,152.08	812.57	1.6%
1,500	60%	657,000	65,793.54	64,397.66	2,377.50	66,775.16	981.62	1.5%
1,500	75%	821,250	80,247.57	79,020.73	2,377.50	81,398.23	1,150.66	1.4%
3,000	15%	328,500	44,374.98	40,553.00	4,755.00	45,308.00	933.02	2.1%
3,000	30%	657,000	73,283.04	69,799.16	4,755.00	74,554.16	1,271.12	1.7%
3,000	45%	985,500	102,191.11	99,045.31	4,755.00	103,800.31	1,609.20	1.6%
3,000	60%	1,314,000	131,099.17	128,291.47	4,755.00	133,046.47	1,947.30	1.5%
3,000	75%	1,642,500	160,007.24	157,537.63	4,755.00	162,292.63	2,285.39	1.4%

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 16%
Unbundled Transmission Charge (>20 kW and <3,000): 1.585 $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Column (F) is the unbundled transmission currently in Present Rates. This is shown here for comparison purposes only since the transmission is being proposed to be removed from base rates and included in Schedule TCA-1.

Arizona Public Service Company
Test Year Ending December 2010
Typical General Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
						Change	
			Monthly Bill	Components of Proposed Bill			
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following General Service Rate Schedules:

Arizona Public Service Company
Test Year Ending December 2010
Typical Classified Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
				Components of Proposed Bill		Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following Classified Service Rate Schedules:

E-36 XL
E-56

Arizona Public Service Company
Test Year Ending December 2010
Typical Residential Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
				Components of Proposed Bill		Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following Residential Service Rate Schedules:

H-5

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-12**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	82,603	-	82,603	3.10%	-	0.00%	67,737	-	67,737	2.49%	-	0.00%	1.
2.	1-50	112,032	2,650,297	194,635	7.30%	2,650,297	0.13%	124,860	2,997,241	192,597	7.07%	2,997,241	0.19%	2.
3.	51-100	103,566	8,116,790	298,201	11.19%	10,767,087	0.52%	116,816	8,798,039	309,413	11.36%	11,795,280	0.73%	3.
4.	101-150	103,555	13,391,616	401,755	15.07%	24,158,703	1.16%	113,155	14,207,679	422,568	15.51%	26,002,958	1.61%	4.
5.	151-200	101,297	18,363,500	503,052	18.87%	42,522,202	2.05%	120,527	21,212,305	543,095	19.94%	47,215,263	2.91%	5.
6.	201-250	103,558	24,128,814	606,610	22.76%	66,651,016	3.21%	133,896	30,253,513	676,991	24.86%	77,468,776	4.78%	6.
7.	251-300	105,997	30,169,003	712,607	26.73%	96,820,020	4.66%	145,626	40,172,176	822,617	30.20%	117,640,952	7.26%	7.
8.	301-350	107,611	36,186,174	820,218	30.77%	133,006,193	6.40%	152,137	49,551,141	974,754	35.79%	167,192,093	10.32%	8.
9.	351-400	108,906	42,229,120	929,124	34.86%	175,235,313	8.43%	154,049	57,833,613	1,128,803	41.44%	225,025,706	13.89%	9.
10.	401-450	107,768	47,342,342	1,036,892	38.90%	222,577,655	10.71%	149,870	63,762,516	1,278,673	46.95%	288,788,223	17.83%	10.
11.	451-500	105,809	51,932,705	1,142,702	42.87%	274,510,360	13.21%	143,343	68,131,869	1,422,016	52.21%	356,920,092	22.03%	11.
12.	501-550	101,928	55,297,849	1,244,630	46.69%	329,808,210	15.87%	134,133	70,450,835	1,556,149	57.13%	427,370,926	26.38%	12.
13.	551-600	97,952	58,195,759	1,342,582	50.37%	388,003,968	18.67%	123,437	70,995,310	1,679,585	61.67%	498,366,236	30.77%	13.
14.	601-650	93,069	60,093,314	1,435,650	53.86%	448,097,282	21.56%	113,147	70,736,351	1,792,733	65.82%	569,102,587	35.13%	14.
15.	651-700	88,135	61,461,195	1,523,785	57.17%	509,558,478	24.51%	102,474	69,188,907	1,895,207	69.58%	638,291,494	39.40%	15.
16.	701-750	83,288	62,376,155	1,607,073	60.29%	571,934,633	27.51%	91,094	66,061,420	1,986,301	72.93%	704,352,915	43.48%	16.
17.	751-800	77,805	62,292,094	1,684,878	63.21%	634,226,728	30.51%	81,447	63,122,011	2,067,748	75.92%	767,474,926	47.38%	17.
18.	801-850	72,212	61,537,211	1,757,090	65.92%	695,763,939	33.47%	71,616	59,086,306	2,139,364	78.55%	826,561,233	51.03%	18.
19.	851-900	67,888	61,358,414	1,824,979	68.47%	757,122,353	36.42%	64,132	56,123,682	2,203,496	80.90%	882,684,915	54.49%	19.
20.	901-950	63,495	60,665,403	1,888,474	70.85%	817,787,756	39.34%	56,241	52,017,275	2,259,736	82.97%	934,702,190	57.70%	20.
21.	951-1,000	59,293	59,711,915	1,947,767	73.07%	877,499,671	42.21%	49,484	48,251,221	2,309,220	84.78%	982,953,411	60.68%	21.
22.	1,001-1,100	106,536	115,434,860	2,054,303	77.07%	992,934,531	47.77%	82,354	86,372,721	2,391,575	87.81%	1,069,326,132	66.01%	22.
23.	1,101-1,200	92,163	109,394,938	2,146,465	80.53%	1,102,329,469	53.03%	63,953	73,455,608	2,455,528	90.16%	1,142,781,740	70.55%	23.
24.	1,201-1,300	78,980	101,884,888	2,225,446	83.49%	1,204,214,357	57.93%	50,225	62,713,005	2,505,753	92.00%	1,205,494,746	74.42%	24.
25.	1,301-1,400	67,326	93,806,358	2,292,771	86.02%	1,298,020,715	62.44%	39,722	53,573,785	2,545,475	93.46%	1,259,068,531	77.73%	25.
26.	1,401-1,500	57,886	86,634,759	2,350,658	88.19%	1,384,655,475	66.61%	31,570	45,732,580	2,577,045	94.62%	1,304,801,111	80.55%	26.
27.	1,501-1,600	49,572	79,306,747	2,400,229	90.05%	1,463,962,221	70.43%	25,638	39,704,585	2,602,682	95.56%	1,344,505,696	83.00%	27.
28.	1,601-1,700	41,740	71,090,997	2,441,969	91.61%	1,535,053,218	73.85%	20,222	33,337,904	2,622,904	96.30%	1,377,843,601	85.06%	28.
29.	1,701-1,800	35,144	63,475,485	2,477,113	92.93%	1,598,528,704	76.90%	16,200	28,343,085	2,639,104	96.90%	1,406,186,685	86.81%	29.
30.	1,801-1,900	29,748	56,807,044	2,506,861	94.05%	1,655,335,747	79.63%	13,330	24,644,781	2,652,434	97.38%	1,430,831,466	88.33%	30.
31.	1,901-2,000	24,955	50,231,623	2,531,817	94.98%	1,705,567,371	82.05%	10,861	21,169,541	2,663,295	97.78%	1,452,001,007	89.64%	31.
32.	2,001-2,250	75,286	172,149,317	2,607,103	97.81%	1,877,716,687	90.33%	32,513	71,990,901	2,695,807	98.98%	1,523,991,908	94.08%	32.
33.	2,251-2,500	30,784	86,237,298	2,637,887	98.96%	1,963,953,985	94.48%	13,917	37,835,273	2,709,725	99.49%	1,561,827,181	96.42%	33.
34.	2,501-3,000	19,335	67,414,767	2,657,222	99.69%	2,031,368,753	97.72%	9,531	32,288,533	2,719,256	99.84%	1,594,115,714	98.41%	34.
35.	3,001-4,000	4,872	22,157,762	2,662,093	99.87%	2,053,526,515	98.79%	2,512	11,062,309	2,721,768	99.93%	1,605,178,023	99.09%	35.
36.	4,001-5,000	3,178	20,690,164	2,665,271	99.99%	2,074,216,679	99.78%	1,693	10,708,421	2,723,462	99.99%	1,615,886,444	99.76%	36.
37.	5,001-10,000	211	2,745,698	2,665,482	100.00%	2,076,962,377	99.91%	168	2,150,718	2,723,629	100.00%	1,618,037,162	99.89%	37.
38.	10,001-20,000	52	1,770,752	2,665,534	100.00%	2,078,733,129	100.00%	44	1,802,870	2,723,673	100.00%	1,619,840,032	100.00%	38.
39.	over 20,000	-	-	2,665,534	100.00%	2,078,733,129	100.00%	-	-	2,723,673	100.00%	1,619,840,032	100.00%	39.
	Average Number of Customers:			444,256				Average Number of Customers:		453,946				
	Average Consumption:			780	kWh per bill			Average Consumption:		595	kWh per bill			
	Median Consumption:			595	kWh per bill			Median Consumption:		479	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-12 Low Income w/E-3, E-12 Low Income w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	922	-	922	0.42%	-	0.00%	330	-	330	0.15%	-	0.00%	1.
2.	1-50	1,509	11,962	2,431	1.11%	11,962	0.01%	874	15,408	1,203	0.56%	15,408	0.01%	2.
3.	51-100	2,368	40,750	4,799	2.19%	52,711	0.03%	1,427	70,827	2,630	1.21%	86,235	0.06%	3.
4.	101-150	4,176	79,397	8,976	4.10%	132,108	0.07%	1,682	137,674	4,312	1.99%	223,909	0.16%	4.
5.	151-200	6,212	116,599	15,188	6.93%	248,707	0.13%	2,125	244,628	6,437	2.97%	468,537	0.33%	5.
6.	201-250	8,053	168,762	23,240	10.61%	417,469	0.22%	3,147	464,565	9,585	4.43%	933,102	0.66%	6.
7.	251-300	9,302	244,313	32,542	14.86%	661,782	0.35%	4,398	791,501	13,983	6.46%	1,724,603	1.22%	7.
8.	301-350	10,128	340,605	42,670	19.48%	1,002,387	0.54%	5,658	1,201,089	19,641	9.07%	2,925,692	2.07%	8.
9.	351-400	10,756	453,100	53,426	24.39%	1,455,487	0.78%	6,761	1,653,739	26,402	12.20%	4,579,431	3.23%	9.
10.	401-450	10,910	588,035	64,336	29.37%	2,043,522	1.10%	7,666	2,122,811	34,068	15.74%	6,702,242	4.73%	10.
11.	451-500	10,671	711,696	75,008	34.24%	2,755,218	1.48%	8,306	2,569,742	42,374	19.57%	9,271,985	6.55%	11.
12.	501-550	10,591	851,294	85,599	39.07%	3,606,512	1.93%	8,762	2,995,235	51,136	23.62%	12,267,220	8.66%	12.
13.	551-600	9,939	1,002,815	95,539	43.61%	4,609,327	2.47%	8,924	3,339,783	60,059	27.74%	15,607,003	11.02%	13.
14.	601-650	9,669	1,162,248	105,208	48.03%	5,771,575	3.10%	9,048	3,680,610	69,108	31.92%	19,287,613	13.62%	14.
15.	651-700	9,234	1,290,910	114,442	52.24%	7,062,484	3.79%	8,979	3,943,632	78,086	36.07%	23,231,245	16.40%	15.
16.	701-750	8,646	1,459,725	123,088	56.19%	8,522,209	4.57%	8,890	4,193,301	86,976	40.18%	27,424,546	19.36%	16.
17.	751-800	8,206	1,593,503	131,293	59.93%	10,115,712	5.43%	8,598	4,335,760	95,574	44.15%	31,760,306	22.42%	17.
18.	801-850	7,357	1,727,400	138,650	63.29%	11,843,112	6.35%	8,387	4,501,557	103,962	48.02%	36,261,863	25.60%	18.
19.	851-900	6,855	1,875,511	145,505	66.42%	13,718,623	7.36%	8,130	4,627,233	112,091	51.78%	40,889,096	28.86%	19.
20.	901-950	6,352	2,025,364	151,856	69.32%	15,743,987	8.45%	7,774	4,678,324	119,865	55.37%	45,567,420	32.17%	20.
21.	951-1,000	5,995	2,156,854	157,851	72.06%	17,900,841	9.60%	7,404	4,695,806	127,269	58.79%	50,263,226	35.48%	21.
22.	1,001-1,100	10,624	4,748,769	168,475	76.91%	22,649,610	12.15%	13,640	9,308,963	140,909	65.09%	59,572,189	42.05%	22.
23.	1,101-1,200	9,048	5,313,612	177,523	81.04%	27,963,222	15.00%	11,994	8,963,193	152,903	70.63%	68,535,382	48.38%	23.
24.	1,201-1,300	7,657	5,779,533	185,180	84.53%	33,742,755	18.10%	10,491	8,523,287	163,394	75.48%	77,058,669	54.40%	24.
25.	1,301-1,400	6,354	6,197,488	191,533	87.43%	39,940,243	21.42%	8,882	7,792,007	172,276	79.58%	84,850,676	59.90%	25.
26.	1,401-1,500	5,287	6,624,182	196,821	89.85%	46,564,425	24.98%	7,531	7,095,922	179,808	83.06%	91,946,598	64.91%	26.
27.	1,501-1,600	4,416	6,873,995	201,237	91.86%	53,438,420	28.66%	6,303	6,348,984	186,111	85.97%	98,295,582	69.39%	27.
28.	1,601-1,700	3,605	7,167,974	204,842	93.51%	60,606,394	32.51%	5,242	5,621,016	191,354	88.39%	103,916,598	73.35%	28.
29.	1,701-1,800	2,841	7,310,374	207,683	94.80%	67,916,768	36.43%	4,274	4,861,125	195,628	90.37%	108,777,723	76.79%	29.
30.	1,801-1,900	2,330	7,451,369	210,013	95.87%	75,368,137	40.43%	3,523	4,235,619	199,151	91.99%	113,013,343	79.78%	30.
31.	1,901-2,000	1,804	7,427,449	211,818	96.69%	82,795,586	44.41%	2,919	3,699,379	202,070	93.34%	116,712,722	82.39%	31.
32.	2,001-2,250	4,831	34,316,853	216,649	98.90%	117,112,439	62.82%	8,374	12,035,081	210,444	97.21%	128,747,802	90.88%	32.
33.	2,251-2,500	1,554	26,300,339	218,202	99.61%	143,412,779	76.93%	3,261	5,754,694	213,705	98.72%	134,502,496	94.95%	33.
34.	2,501-3,000	689	27,574,707	218,892	99.92%	170,987,485	91.72%	1,978	4,340,145	215,683	99.63%	138,842,641	98.01%	34.
35.	3,001-4,000	98	9,200,378	218,990	99.97%	180,187,863	96.65%	488	1,401,589	216,171	99.86%	140,244,230	99.00%	35.
36.	4,001-5,000	39	5,698,877	219,029	99.98%	185,886,740	99.71%	290	1,173,878	216,461	99.99%	141,418,108	99.83%	36.
37.	5,001-10,000	20	451,665	219,049	99.99%	186,338,405	99.95%	21	174,039	216,482	100.00%	141,592,147	99.95%	37.
38.	10,001-20,000	17	87,221	219,066	100.00%	186,425,626	100.00%	3	70,964	216,485	100.00%	141,663,111	100.00%	38.
39.	over 20,000	-	-	219,066	100.00%	186,425,626	100.00%	-	-	216,485	100.00%	141,663,111	100.00%	39.
	Average Number of Customers:			36,511				Average Number of Customers:		36,081				
	Average Consumption:			851	kWh per bill			Average Consumption:		654	kWh per bill			
	Median Consumption:			674	kWh per bill			Median Consumption:		505	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ET-1**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	2,528	145,197	2,528	0.15%	145,197	0.01%	5,149	526,664	5,149	0.30%	526,664	0.03%	2.
3.	51-100	6,652	494,634	9,180	0.56%	639,831	0.02%	13,399	2,762,160	18,549	1.09%	3,288,824	0.21%	3.
4.	101-150	7,956	963,745	17,136	1.05%	1,603,576	0.06%	23,768	8,684,153	42,316	2.48%	11,972,977	0.78%	4.
5.	151-200	9,499	1,415,318	26,635	1.63%	3,018,895	0.12%	45,664	20,328,050	87,981	5.16%	32,301,027	2.10%	5.
6.	201-250	9,958	2,048,492	36,593	2.24%	5,067,387	0.20%	77,434	34,204,593	165,415	9.70%	66,505,620	4.32%	6.
7.	251-300	11,193	2,965,561	47,786	2.92%	8,032,947	0.31%	102,122	47,081,897	267,537	15.69%	113,587,517	7.38%	7.
8.	301-350	13,272	4,134,385	61,058	3.73%	12,167,332	0.47%	115,274	57,825,405	382,811	22.45%	171,412,922	11.14%	8.
9.	351-400	15,681	5,499,897	76,740	4.69%	17,667,230	0.68%	119,983	66,284,329	502,794	29.49%	237,697,251	15.44%	9.
10.	401-450	18,087	7,137,780	94,827	5.80%	24,805,009	0.95%	119,256	71,633,365	622,050	36.48%	309,330,616	20.10%	10.
11.	451-500	20,722	8,638,822	115,549	7.07%	33,443,831	1.29%	113,720	76,222,679	735,770	43.15%	385,553,295	25.05%	11.
12.	501-550	22,450	10,333,317	137,999	8.44%	43,777,148	1.69%	108,315	76,976,151	844,085	49.50%	462,529,446	30.05%	12.
13.	551-600	24,297	12,172,525	162,296	9.93%	55,949,673	2.15%	99,022	77,529,636	943,107	55.31%	540,059,083	35.09%	13.
14.	601-650	26,149	14,107,783	188,445	11.52%	70,057,456	2.70%	91,081	75,364,565	1,034,188	60.65%	615,423,648	39.98%	14.
15.	651-700	27,882	15,669,528	216,327	13.23%	85,726,984	3.30%	81,478	75,037,660	1,115,666	65.43%	690,461,307	44.86%	15.
16.	701-750	28,676	17,718,671	245,004	14.98%	103,445,655	3.98%	75,068	69,275,404	1,190,734	69.83%	759,736,711	49.36%	16.
17.	751-800	30,199	19,342,514	275,202	16.83%	122,788,169	4.73%	64,545	64,972,151	1,255,280	73.62%	824,708,863	53.58%	17.
18.	801-850	30,838	20,967,805	306,041	18.72%	143,755,974	5.53%	56,605	59,679,700	1,311,884	76.94%	884,388,563	57.46%	18.
19.	851-900	31,401	22,765,630	337,441	20.64%	166,521,604	6.41%	48,865	54,384,902	1,360,750	79.81%	938,773,465	60.99%	19.
20.	901-950	32,152	24,584,601	369,593	22.60%	191,106,205	7.36%	41,984	51,761,325	1,402,733	82.27%	990,534,790	64.35%	20.
21.	951-1,000	32,848	26,180,669	402,441	24.61%	217,286,874	8.36%	37,801	45,039,131	1,440,534	84.48%	1,035,573,920	67.28%	21.
22.	1,001-1,100	33,185	57,642,272	435,626	26.64%	274,929,146	10.58%	31,206	79,440,196	1,471,740	86.31%	1,115,014,117	72.44%	22.
23.	1,101-1,200	67,849	64,498,545	503,476	30.79%	339,427,691	13.07%	51,216	65,934,918	1,522,956	89.32%	1,180,949,035	76.73%	23.
24.	1,201-1,300	69,313	70,154,054	572,789	35.03%	409,581,744	15.77%	38,791	55,079,683	1,561,746	91.59%	1,236,028,718	80.30%	24.
25.	1,301-1,400	69,383	75,227,342	642,172	39.27%	484,809,086	18.66%	29,814	43,817,617	1,591,560	93.34%	1,279,846,335	83.15%	25.
26.	1,401-1,500	68,884	80,406,718	711,056	43.49%	565,215,804	21.76%	21,966	38,055,945	1,613,527	94.63%	1,317,902,280	85.62%	26.
27.	1,501-1,600	68,555	83,439,034	779,612	47.68%	648,654,839	24.97%	17,752	32,398,457	1,631,279	95.67%	1,350,300,737	87.73%	27.
28.	1,601-1,700	66,548	87,007,452	846,160	51.75%	735,662,290	28.32%	14,142	27,054,789	1,645,420	96.50%	1,377,355,526	89.49%	28.
29.	1,701-1,800	65,191	88,735,960	911,351	55.73%	824,398,250	31.74%	11,087	23,551,360	1,656,508	97.15%	1,400,906,886	91.02%	29.
30.	1,801-1,900	62,686	90,447,413	974,037	59.57%	914,845,663	35.22%	9,093	20,387,749	1,665,600	97.68%	1,421,294,635	92.34%	30.
31.	1,901-2,000	60,455	90,157,060	1,034,493	63.27%	1,005,002,723	38.69%	7,453	15,697,160	1,673,054	98.12%	1,436,991,794	93.36%	31.
32.	2,001-2,250	57,168	416,550,351	1,091,661	66.76%	1,421,553,073	54.73%	5,443	53,324,408	1,678,497	98.44%	1,490,316,203	96.83%	32.
33.	2,251-2,500	230,605	319,243,015	1,322,266	80.86%	1,740,796,088	67.02%	16,291	24,866,823	1,694,788	99.40%	1,515,183,026	98.44%	33.
34.	2,501-3,000	144,702	334,711,747	1,466,969	89.71%	2,075,507,835	79.90%	6,178	16,332,666	1,700,966	99.76%	1,531,515,692	99.50%	34.
35.	3,001-4,000	121,994	334,711,747	1,588,963	97.18%	2,410,219,582	92.79%	3,286	3,455,419	1,704,252	99.95%	1,534,971,110	99.73%	35.
36.	4,001-5,000	31,458	111,677,509	1,620,421	99.10%	2,521,897,091	97.09%	533	2,443,543	1,704,785	99.98%	1,537,414,653	99.89%	36.
37.	5,001-10,000	14,157	69,175,025	1,634,578	99.96%	2,591,072,116	99.75%	271	590,495	1,705,056	100.00%	1,538,005,148	99.92%	37.
38.	10,001-20,000	544	5,482,470	1,635,122	100.00%	2,596,554,586	99.96%	31	1,171,259	1,705,087	100.00%	1,539,176,407	100.00%	38.
39.	over 20,000	33	1,058,721	1,635,155	100.00%	2,597,613,307	100.00%	-	-	1,705,087	100.00%	1,539,176,407	100.00%	39.
		Average Number of Customers:		272,526				Average Number of Customers:		284,181				
		Average Consumption:		1589	kWh per bill			Average Consumption:		903	kWh per bill			
		Median Consumption:		1558	kWh per bill			Median Consumption:		877	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ET-1 Low Income w/E-3, ET-1 Low Income w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	87	2,690	87	0.10%	2,690	0.00%	97	1,641	97	0.10%	1,641	0.00%	2.
3.	51-100	170	5,496	256	0.28%	8,186	0.01%	154	3,870	251	0.27%	5,511	0.01%	3.
4.	101-150	175	18,242	432	0.48%	26,428	0.02%	255	18,008	505	0.54%	23,520	0.03%	4.
5.	151-200	257	43,790	689	0.76%	70,218	0.05%	521	61,002	1,026	1.11%	84,521	0.11%	5.
6.	201-250	321	77,346	1,010	1.12%	147,564	0.11%	952	156,428	1,978	2.13%	240,949	0.32%	6.
7.	251-300	524	161,798	1,535	1.70%	309,362	0.24%	1,677	349,229	3,655	3.94%	590,178	0.78%	7.
8.	301-350	675	252,359	2,210	2.45%	561,722	0.43%	2,468	627,079	6,123	6.59%	1,217,257	1.60%	8.
9.	351-400	895	395,004	3,105	3.44%	956,726	0.73%	2,875	862,097	8,998	9.69%	2,079,354	2.74%	9.
10.	401-450	1,045	530,482	4,150	4.59%	1,487,207	1.13%	3,480	1,203,024	12,478	13.44%	3,282,378	4.32%	10.
11.	451-500	1,180	679,393	5,330	5.90%	2,166,600	1.65%	3,789	1,481,120	16,267	17.52%	4,763,498	6.27%	11.
12.	501-550	1,400	899,958	6,730	7.45%	3,066,558	2.34%	4,259	1,862,197	20,526	22.10%	6,625,695	8.72%	12.
13.	551-600	1,472	1,047,051	8,202	9.08%	4,113,609	3.13%	4,402	2,126,506	24,928	26.85%	8,752,201	11.52%	13.
14.	601-650	1,684	1,309,341	9,885	10.94%	5,422,950	4.13%	4,646	2,458,431	29,574	31.85%	11,210,632	14.75%	14.
15.	651-700	1,867	1,579,051	11,753	13.01%	7,002,002	5.33%	4,659	2,677,942	34,232	36.87%	13,888,573	18.28%	15.
16.	701-750	1,839	1,681,099	13,592	15.04%	8,683,101	6.62%	4,509	2,799,205	38,741	41.72%	16,687,778	21.96%	16.
17.	751-800	1,967	1,929,738	15,559	17.22%	10,612,839	8.09%	4,444	2,962,987	43,185	46.51%	19,650,765	25.86%	17.
18.	801-850	2,079	2,179,478	17,638	19.52%	12,792,317	9.75%	4,338	3,092,887	47,523	51.18%	22,743,652	29.93%	18.
19.	851-900	2,120	2,365,993	19,758	21.87%	15,158,310	11.55%	4,204	3,191,396	51,727	55.71%	25,935,048	34.13%	19.
20.	901-950	2,230	2,638,720	21,988	24.33%	17,797,030	13.56%	3,814	3,067,566	55,542	59.81%	29,002,613	38.16%	20.
21.	951-1,000	2,177	2,721,712	24,165	26.74%	20,518,742	15.63%	3,548	3,017,713	59,090	63.64%	32,020,327	42.14%	21.
22.	1,001-1,100	2,385	3,141,535	26,549	29.38%	23,660,276	18.03%	3,295	2,953,802	62,385	67.18%	34,974,129	46.02%	22.
23.	1,101-1,200	4,625	6,567,016	31,174	34.50%	30,227,293	23.03%	5,880	5,673,642	68,265	73.52%	40,647,770	53.49%	23.
24.	1,201-1,300	4,667	7,256,936	35,841	39.67%	37,484,229	28.56%	4,770	5,037,427	73,035	78.65%	45,685,197	60.12%	24.
25.	1,301-1,400	4,727	7,984,941	40,568	44.90%	45,469,170	34.64%	3,867	4,438,292	76,902	82.82%	50,123,489	65.96%	25.
26.	1,401-1,500	4,590	8,379,686	45,158	49.98%	53,848,856	41.03%	3,261	4,044,603	80,162	86.33%	54,168,092	71.28%	26.
27.	1,501-1,600	4,433	8,684,636	49,591	54.88%	62,533,492	47.64%	2,526	3,361,923	82,689	89.05%	57,530,015	75.70%	27.
28.	1,601-1,700	4,265	8,940,189	53,855	59.60%	71,473,681	54.46%	2,111	3,004,067	84,800	91.32%	60,534,083	79.66%	28.
29.	1,701-1,800	4,103	9,146,565	57,958	64.14%	80,620,246	61.43%	1,635	2,478,217	86,435	93.08%	63,012,300	82.92%	29.
30.	1,801-1,900	3,916	9,255,799	61,874	68.48%	89,876,045	68.48%	1,272	2,044,977	87,707	94.45%	65,057,277	85.61%	30.
31.	1,901-2,000	3,543	8,857,922	65,417	72.40%	98,733,967	75.23%	1,052	1,787,557	88,759	95.59%	66,844,834	87.96%	31.
32.	2,001-2,250	3,223	8,488,925	68,639	75.97%	107,222,892	81.69%	801	1,435,192	89,561	96.45%	68,280,026	89.85%	32.
33.	2,251-2,500	11,569	8,123,683	80,208	88.77%	115,346,575	87.88%	2,095	4,234,633	91,656	98.71%	72,514,659	95.42%	33.
34.	2,501-3,000	5,821	8,066,035	86,029	95.21%	123,412,610	94.03%	699	1,745,310	92,355	99.46%	74,259,969	97.72%	34.
35.	3,001-4,000	3,569	2,871,440	89,598	99.16%	126,284,049	96.22%	394	1,221,860	92,749	99.88%	75,481,829	99.33%	35.
36.	4,001-5,000	584	3,457,842	90,182	99.81%	129,741,891	98.85%	71	289,435	92,820	99.96%	75,771,265	99.71%	36.
37.	5,001-10,000	165	1,307,759	90,346	99.99%	131,049,649	99.85%	36	207,615	92,856	100.00%	75,978,879	99.98%	37.
38.	10,001-20,000	9	151,670	90,355	100.00%	131,201,319	99.96%	1	14,388	92,857	100.00%	75,993,267	100.00%	38.
39.	over 20,000	1	48,482	90,356	100.00%	131,249,801	100.00%	-	-	92,857	100.00%	75,993,267	100.00%	39.
	Average Number of Customers:			15,059				Average Number of Customers:		15,476				
	Average Consumption:			1,453	kWh per bill			Average Consumption:		818	kWh per bill			
	Median Consumption:			2,075	kWh per bill			Median Consumption:		1,148	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ET-2**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	5,328	-	5,328	0.74%	-	0.00%	5,271	-	5,271	0.81%	-	0.00%	1.
2.	1-50	6,400	182,019	11,728	1.63%	182,019	0.01%	7,878	261,581	13,149	2.02%	261,581	0.03%	2.
3.	51-100	5,463	514,452	17,192	2.38%	696,471	0.05%	7,553	792,673	20,702	3.18%	1,054,254	0.13%	3.
4.	101-150	5,769	899,536	22,961	3.18%	1,596,008	0.11%	8,050	1,395,329	28,752	4.41%	2,449,584	0.30%	4.
5.	151-200	5,898	1,287,862	28,859	4.00%	2,883,869	0.20%	9,342	2,273,351	38,094	5.84%	4,722,934	0.58%	5.
6.	201-250	6,225	1,748,579	35,084	4.86%	4,632,449	0.33%	11,708	3,661,862	49,802	7.64%	8,384,797	1.03%	6.
7.	251-300	7,320	2,511,969	42,404	5.88%	7,144,417	0.51%	15,200	5,798,745	65,002	9.97%	14,183,541	1.74%	7.
8.	301-350	8,173	3,317,605	50,576	7.01%	10,462,023	0.74%	18,704	8,416,999	83,706	12.84%	22,600,540	2.77%	8.
9.	351-400	9,279	4,339,350	59,856	8.30%	14,801,372	1.05%	21,981	11,402,810	105,687	16.21%	34,003,350	4.17%	9.
10.	401-450	10,184	5,394,976	70,039	9.71%	20,196,348	1.43%	24,692	14,509,966	130,379	20.00%	48,513,317	5.96%	10.
11.	451-500	11,194	6,628,268	81,233	11.26%	26,824,617	1.90%	26,685	17,513,139	157,064	24.09%	66,026,455	8.11%	11.
12.	501-550	12,028	7,868,002	93,261	12.93%	34,692,619	2.45%	27,931	20,248,328	184,995	28.38%	86,274,783	10.59%	12.
13.	551-600	12,581	9,014,693	105,842	14.67%	43,707,312	3.09%	28,697	22,785,888	213,692	32.78%	109,060,671	13.39%	13.
14.	601-650	13,233	10,302,261	119,075	16.50%	54,009,573	3.82%	28,713	24,771,089	242,406	37.18%	133,831,760	16.43%	14.
15.	651-700	13,673	11,490,495	132,748	18.40%	65,500,068	4.63%	28,699	26,736,723	271,105	41.59%	160,568,483	19.71%	15.
16.	701-750	13,992	12,634,353	146,740	20.34%	78,134,421	5.53%	27,601	27,618,491	298,706	45.82%	188,186,974	23.10%	16.
17.	751-800	14,747	14,228,840	161,487	22.38%	92,363,261	6.53%	27,270	29,160,120	325,976	50.00%	217,347,094	26.68%	17.
18.	801-850	15,029	15,435,135	176,517	24.46%	107,798,397	7.62%	25,598	29,138,170	351,574	53.93%	246,485,263	30.26%	18.
19.	851-900	15,113	16,464,391	191,630	26.56%	124,262,788	8.79%	24,738	29,863,743	376,313	57.73%	276,349,006	33.93%	19.
20.	901-950	15,469	17,817,474	207,099	28.70%	142,080,262	10.05%	23,550	30,053,499	399,863	61.34%	306,402,505	37.62%	20.
21.	951-1,000	15,698	19,055,960	222,797	30.88%	161,136,222	11.40%	22,139	29,779,953	422,002	64.73%	336,182,459	41.27%	21.
22.	1,001-1,100	31,171	40,745,056	253,968	35.20%	201,881,278	14.28%	40,055	57,957,330	462,057	70.88%	394,139,789	48.39%	22.
23.	1,101-1,200	31,352	44,864,154	285,320	39.54%	246,745,432	17.45%	33,869	53,703,809	495,926	76.07%	447,843,598	54.98%	23.
24.	1,201-1,300	31,720	49,351,371	317,039	43.94%	296,096,804	20.94%	28,833	49,657,438	524,759	80.50%	497,501,036	61.08%	24.
25.	1,301-1,400	30,962	52,025,488	348,001	48.23%	348,122,291	24.62%	23,997	44,648,782	548,756	84.18%	542,149,819	66.56%	25.
26.	1,401-1,500	30,345	54,745,762	378,346	52.44%	402,868,053	28.50%	19,532	39,036,292	568,288	87.17%	581,186,111	71.35%	26.
27.	1,501-1,600	29,474	56,845,867	407,820	56.52%	459,713,920	32.52%	15,887	33,934,196	584,175	89.61%	615,120,307	75.52%	27.
28.	1,601-1,700	28,663	58,845,734	436,483	60.50%	518,559,654	36.68%	12,784	29,065,080	596,959	91.57%	644,185,387	79.09%	28.
29.	1,701-1,800	27,354	59,565,877	463,836	64.29%	578,125,532	40.89%	10,363	24,992,761	607,322	93.16%	669,178,147	82.15%	29.
30.	1,801-1,900	25,516	58,721,941	489,352	67.82%	636,847,473	45.05%	8,313	21,185,120	615,635	94.44%	690,363,267	84.75%	30.
31.	1,901-2,000	24,364	59,105,646	513,716	71.20%	695,953,119	49.23%	6,794	18,254,835	622,428	95.48%	708,618,102	87.00%	31.
32.	2,001-2,250	95,309	264,707,266	609,025	84.41%	960,660,385	67.95%	17,979	54,619,017	640,407	98.24%	763,237,119	93.70%	32.
33.	2,251-2,500	56,286	190,826,900	665,311	92.21%	1,151,487,285	81.45%	6,487	24,251,845	646,895	99.23%	787,488,964	96.68%	33.
34.	2,501-3,000	42,815	180,262,276	708,126	98.14%	1,331,749,561	94.20%	3,604	16,761,362	650,499	99.79%	804,250,326	98.74%	34.
35.	3,001-4,000	9,600	52,349,523	717,726	99.47%	1,384,099,085	97.90%	871	5,313,124	651,370	99.92%	809,563,450	99.39%	35.
36.	4,001-5,000	3,648	27,194,141	721,374	99.98%	1,411,293,226	99.82%	488	4,223,712	651,858	99.99%	813,787,162	99.91%	36.
37.	5,001-10,000	129	1,978,420	721,503	100.00%	1,413,271,646	99.96%	31	540,173	651,889	100.00%	814,327,335	99.97%	37.
38.	10,001-20,000	15	516,988	721,518	100.00%	1,413,788,634	100.00%	5	217,438	651,894	100.00%	814,544,773	100.00%	38.
39.	over 20,000	-	-	721,518	100.00%	1,413,788,634	100.00%	-	-	651,894	100.00%	814,544,773	100.00%	39.
		Average Number of Customers:		120,253				Average Number of Customers:		108,649				
		Average Consumption:		1,959	kWh per bill			Average Consumption:		1,250	kWh per bill			
		Median Consumption:		1,442	kWh per bill			Median Consumption:		800	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ET-2 Low Income w/E-3, ET-2 Low Income w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	227	7,809	227	0.42%	7,809	0.01%	233	12,239	233	0.48%	12,239	0.02%	2.
3.	51-100	172	23,304	400	0.73%	31,113	0.03%	242	36,483	475	0.98%	48,722	0.07%	3.
4.	101-150	181	40,365	580	1.07%	71,479	0.06%	224	84,733	699	1.44%	133,454	0.20%	4.
5.	151-200	185	65,758	765	1.40%	137,237	0.12%	310	208,244	1,009	2.08%	341,699	0.51%	5.
6.	201-250	219	113,889	984	1.81%	251,125	0.22%	554	384,264	1,563	3.22%	725,963	1.08%	6.
7.	251-300	294	182,558	1,278	2.35%	433,684	0.38%	800	638,834	2,363	4.87%	1,364,797	2.04%	7.
8.	301-350	385	276,953	1,663	3.05%	710,637	0.63%	1,094	948,537	3,457	7.12%	2,313,333	3.45%	8.
9.	351-400	493	329,049	2,156	3.96%	1,039,685	0.92%	1,376	1,220,688	4,833	9.95%	3,534,021	5.28%	9.
10.	401-450	509	468,317	2,665	4.89%	1,508,002	1.34%	1,536	1,568,039	6,369	13.11%	5,102,060	7.62%	10.
11.	451-500	638	612,262	3,303	6.06%	2,120,265	1.88%	1,743	2,074,003	8,112	16.70%	7,176,063	10.72%	11.
12.	501-550	748	678,993	4,051	7.44%	2,799,258	2.48%	2,072	2,390,005	10,184	20.97%	9,566,068	14.28%	12.
13.	551-600	754	832,161	4,805	8.82%	3,631,419	3.22%	2,152	2,616,609	12,337	25.40%	12,182,677	18.19%	13.
14.	601-650	841	1,005,503	5,646	10.36%	4,636,923	4.11%	2,156	2,876,932	14,493	29.84%	15,059,609	22.49%	14.
15.	651-700	935	1,128,855	6,581	12.08%	5,765,778	5.11%	2,178	3,188,718	16,671	34.32%	18,248,327	27.25%	15.
16.	701-750	971	1,336,927	7,552	13.86%	7,102,705	6.30%	2,239	3,379,199	18,909	38.93%	21,627,526	32.29%	16.
17.	751-800	1,070	1,493,043	8,623	15.83%	8,595,748	7.62%	2,207	3,459,246	21,117	43.48%	25,086,772	37.46%	17.
18.	801-850	1,119	1,689,167	9,742	17.88%	10,284,915	9.12%	2,114	3,478,264	23,231	47.83%	28,565,037	42.65%	18.
19.	851-900	1,189	1,894,454	10,931	20.06%	12,179,369	10.80%	1,996	47,839	25,227	51.94%	28,612,876	42.72%	19.
20.	901-950	1,258	2,068,334	12,189	22.37%	14,247,703	12.63%	2,121	3,681,108	27,348	56.31%	32,293,983	48.22%	20.
21.	951-1,000	1,299	2,155,480	13,488	24.76%	16,403,183	14.54%	1,885	3,561,410	29,233	60.19%	35,855,393	53.54%	21.
22.	1,001-1,100	1,284	4,972,027	14,772	27.11%	21,375,210	18.95%	1,730	3,271,031	30,963	63.75%	39,126,423	58.42%	22.
23.	1,101-1,200	2,752	5,445,912	17,524	32.16%	26,821,123	23.78%	3,226	2,689,878	34,189	70.39%	41,816,301	62.44%	23.
24.	1,201-1,300	2,753	6,121,785	20,277	37.22%	32,942,908	29.21%	2,701	2,272,986	36,890	75.95%	44,089,287	65.83%	24.
25.	1,301-1,400	2,846	6,587,053	23,123	42.44%	39,529,960	35.04%	2,334	1,688,639	39,224	80.76%	45,777,926	68.35%	25.
26.	1,401-1,500	2,836	6,751,277	25,959	47.65%	46,281,237	41.03%	1,954	686,905	41,179	84.78%	46,464,831	69.38%	26.
27.	1,501-1,600	2,708	7,033,872	28,667	52.62%	53,315,109	47.27%	1,490	3,871,519	42,669	87.85%	50,336,350	75.16%	27.
28.	1,601-1,700	2,638	7,009,744	31,305	57.46%	60,324,853	53.48%	1,185	3,556,574	43,854	90.29%	53,892,924	80.47%	28.
29.	1,701-1,800	2,471	6,897,051	33,776	61.99%	67,221,903	59.59%	1,022	2,763,897	44,876	92.39%	56,656,821	84.60%	29.
30.	1,801-1,900	2,292	7,107,812	36,068	66.20%	74,329,716	65.90%	749	2,272,053	45,625	93.94%	58,928,874	87.99%	30.
31.	1,901-2,000	2,234	6,860,386	38,302	70.30%	81,190,101	71.98%	584	1,991,849	46,208	95.14%	60,920,723	90.97%	31.
32.	2,001-2,250	2,047	12,020,587	40,348	74.06%	93,210,688	82.64%	484	2,060,936	46,693	96.14%	62,981,660	94.04%	32.
33.	2,251-2,500	7,414	1,702,643	47,762	87.66%	94,913,331	84.14%	1,279	2,039,452	47,972	98.77%	65,021,111	97.09%	33.
34.	2,501-3,000	3,860	13,624,936	51,622	94.75%	108,538,267	96.22%	358	1,282,213	48,330	99.51%	66,303,324	99.00%	34.
35.	3,001-4,000	2,353	2,813,167	53,975	99.07%	111,351,434	98.72%	182	310,094	48,511	99.88%	66,613,418	99.47%	35.
36.	4,001-5,000	376	1,309,964	54,351	99.76%	112,661,398	99.88%	33	289,636	48,544	99.95%	66,903,054	99.90%	36.
37.	5,001-10,000	128	94,557	54,479	99.99%	112,755,955	99.96%	24	50,317	48,568	100.00%	66,953,371	99.97%	37.
38.	10,001-20,000	4	41,988	54,483	100.00%	112,797,943	100.00%	2	17,709	48,570	100.00%	66,971,080	100.00%	38.
39.	over 20,000	-	-	54,483	100.00%	112,797,943	100.00%	-	-	48,570	100.00%	66,971,080	100.00%	39.
	Average Number of Customers:			9,081				Average Number of Customers:		8,095				
	Average Consumption:			2,070	kWh per bill			Average Consumption:		1,379	kWh per bill			
	Median Consumption:			1,447	kWh per bill			Median Consumption:		927	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-1**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	607	-	607	0.22%	-	0.00%	583	-	583	0.20%	-	0.00%	1.
2.	0-0.4	602	161	1,209	0.43%	161	0.01%	962	254	1,545	0.54%	254	0.01%	2.
3.	0.4-0.8	533	361	1,742	0.62%	523	0.02%	1,055	710	2,600	0.90%	964	0.04%	3.
4.	0.8-1.2	432	472	2,174	0.77%	995	0.03%	1,559	1,689	4,159	1.44%	2,653	0.12%	4.
5.	1.2-1.6	504	762	2,678	0.95%	1,757	0.06%	2,385	3,546	6,545	2.27%	6,199	0.29%	5.
6.	1.6-2.0	786	1,517	3,464	1.23%	3,274	0.11%	3,716	7,017	10,261	3.56%	13,216	0.61%	6.
7.	2.0-2.4	1,083	2,541	4,547	1.62%	5,815	0.20%	5,189	11,916	15,450	5.37%	25,132	1.17%	7.
8.	2.4-2.8	1,397	3,843	5,945	2.12%	9,658	0.33%	6,591	17,795	22,041	7.65%	42,926	2.00%	8.
9.	2.8-3.2	1,906	6,030	7,851	2.80%	15,688	0.53%	8,061	25,027	30,102	10.45%	67,953	3.16%	9.
10.	3.2-3.6	2,601	9,293	10,452	3.72%	24,981	0.85%	9,499	33,332	39,601	13.75%	101,286	4.71%	10.
11.	3.6-4.0	3,582	14,288	14,034	5.00%	39,269	1.33%	11,051	43,287	50,652	17.59%	144,573	6.72%	11.
12.	4.0-4.4	4,471	19,692	18,505	6.59%	58,961	2.00%	12,176	52,611	62,828	21.82%	197,183	9.17%	12.
13.	4.4-4.8	5,714	27,496	24,219	8.63%	86,457	2.93%	13,657	64,548	76,485	26.56%	261,731	12.17%	13.
14.	4.8-5.2	6,849	35,796	31,068	11.07%	122,253	4.15%	14,458	74,212	90,943	31.58%	335,943	15.62%	14.
15.	5.2-5.6	8,232	46,437	39,300	14.01%	168,691	5.72%	14,934	82,714	105,877	36.77%	418,656	19.46%	15.
16.	5.6-6.0	9,253	55,980	48,554	17.30%	224,670	7.62%	15,200	90,324	121,077	42.05%	508,980	23.66%	16.
17.	6.0-6.4	9,975	64,496	58,529	20.86%	289,166	9.81%	14,986	95,104	136,063	47.25%	604,085	28.08%	17.
18.	6.4-6.8	10,615	72,991	69,144	24.64%	362,157	12.28%	14,473	97,729	150,536	52.28%	701,813	32.63%	18.
19.	6.8-7.2	11,175	81,493	80,319	28.62%	443,650	15.04%	13,997	100,235	164,533	57.14%	802,049	37.29%	19.
20.	7.2-7.6	11,487	88,491	91,805	32.72%	532,141	18.04%	12,910	97,683	177,443	61.62%	899,732	41.83%	20.
21.	7.6-8.0	11,683	94,847	103,488	36.88%	626,988	21.26%	11,911	94,964	189,354	65.76%	994,696	46.24%	21.
22.	8.0-8.4	11,872	101,262	115,361	41.11%	728,251	24.69%	11,026	92,404	200,380	69.59%	1,087,099	50.54%	22.
23.	8.4-8.8	11,696	104,596	127,057	45.28%	832,847	28.24%	10,226	89,827	210,606	73.14%	1,176,926	54.72%	23.
24.	8.8-9.2	11,179	104,611	138,236	49.26%	937,458	31.79%	8,893	81,747	219,499	76.23%	1,258,673	58.52%	24.
25.	9.2-9.6	11,208	109,521	149,444	53.26%	1,046,979	35.50%	8,007	76,850	227,505	79.01%	1,335,523	62.09%	25.
26.	9.6-10.0	10,863	110,643	160,307	57.13%	1,157,622	39.25%	7,194	71,962	234,699	81.51%	1,407,485	65.43%	26.
27.	10.0-10.4	10,120	107,232	170,427	60.74%	1,264,854	42.89%	6,295	65,530	240,994	83.69%	1,473,015	68.48%	27.
28.	10.4-10.8	9,642	106,164	180,069	64.17%	1,371,019	46.49%	5,545	59,969	246,538	85.62%	1,532,983	71.27%	28.
29.	10.8-11.2	9,092	103,864	189,161	67.41%	1,474,883	50.01%	4,846	54,384	251,384	87.30%	1,587,367	73.80%	29.
30.	11.2-12.0	16,025	192,937	205,187	73.12%	1,667,820	56.55%	7,948	93,960	259,331	90.06%	1,681,328	78.16%	30.
31.	12.0 - 13.0	16,979	219,956	222,165	79.17%	1,887,776	64.01%	7,249	92,235	266,580	92.58%	1,773,563	82.45%	31.
32.	13.0 - 14.0	13,239	185,186	235,404	83.89%	2,072,962	70.29%	5,358	73,631	271,939	94.44%	1,847,194	85.88%	32.
33.	14.0 - 15.0	10,279	154,387	245,683	87.55%	2,227,349	75.53%	3,714	54,800	275,653	95.73%	1,901,993	88.42%	33.
34.	15.0 - 16.0	7,793	125,188	253,476	90.33%	2,352,537	79.77%	2,897	45,700	278,550	96.74%	1,947,693	90.55%	34.
35.	16.0 - 17.0	5,693	97,342	259,170	92.36%	2,449,879	83.07%	1,982	33,284	280,532	97.42%	1,980,977	92.10%	35.
36.	17.0 - 18.0	4,451	80,669	263,620	93.95%	2,530,548	85.81%	1,565	27,873	282,097	97.97%	2,008,850	93.39%	36.
37.	18.0 - 19.0	3,346	64,120	266,967	95.14%	2,594,668	87.98%	1,148	21,607	283,245	98.37%	2,030,457	94.40%	37.
38.	19.0 - 20.0	2,667	53,872	269,634	96.09%	2,648,540	89.81%	929	18,463	284,175	98.69%	2,048,920	95.25%	38.
39.	20.0 - 25.0	6,595	150,709	276,229	98.44%	2,799,248	94.92%	2,282	51,211	286,457	99.48%	2,100,132	97.63%	39.
40.	25.0 - 30.0	2,372	66,715	278,601	99.29%	2,865,963	97.18%	770	21,252	287,226	99.75%	2,121,383	98.62%	40.
41.	Over 30.0	2,006	83,166	280,607	100.00%	2,949,129	100.00%	725	29,627	287,951	100.00%	2,151,010	100.00%	41.
	Average Number of Customers:			46,768				Average Number of Customers:		47,992				
	Average Load:			11.0	kW per bill			Average Load:		7.0	kW per bill			
	Median Load:			9.3	kW per bill			Median Load:		6.7	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-1**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	211	-	211	0.08%	-	0.00%	226	-	226	0.08%	-	0.00%	1.
2.	1-50	268	7,307	479	0.17%	7,307	0.00%	324	8,630	551	0.19%	8,630	0.00%	2.
3.	51-100	340	24,890	818	0.29%	32,197	0.00%	512	37,650	1,063	0.37%	46,280	0.01%	3.
4.	101-150	475	56,838	1,294	0.46%	89,036	0.01%	706	83,806	1,769	0.61%	130,086	0.03%	4.
5.	151-200	489	82,583	1,783	0.64%	171,619	0.02%	831	137,457	2,600	0.90%	267,543	0.06%	5.
6.	201-250	561	121,043	2,344	0.84%	292,662	0.04%	981	208,945	3,581	1.24%	476,488	0.10%	6.
7.	251-300	554	146,153	2,898	1.03%	438,816	0.06%	1,370	355,728	4,951	1.72%	832,216	0.18%	7.
8.	301-350	724	224,974	3,622	1.29%	663,790	0.09%	1,834	561,888	6,786	2.36%	1,394,104	0.30%	8.
9.	351-400	913	327,652	4,535	1.62%	991,442	0.13%	2,392	845,551	9,178	3.19%	2,239,654	0.49%	9.
10.	401-450	1,057	428,868	5,592	1.99%	1,420,310	0.19%	2,839	1,135,854	12,017	4.17%	3,375,509	0.73%	10.
11.	451-500	1,185	537,965	6,777	2.42%	1,958,274	0.26%	3,528	1,575,881	15,545	5.40%	4,951,390	1.08%	11.
12.	501-550	1,424	714,762	8,201	2.92%	2,673,037	0.36%	4,000	1,974,144	19,545	6.79%	6,925,534	1.50%	12.
13.	551-600	1,518	833,870	9,719	3.46%	3,506,907	0.47%	4,523	2,445,109	24,068	8.36%	9,370,643	2.03%	13.
14.	601-650	1,731	1,033,868	11,450	4.08%	4,540,775	0.61%	5,118	3,008,293	29,186	10.14%	12,378,936	2.69%	14.
15.	651-700	1,870	1,205,608	13,320	4.75%	5,746,383	0.78%	5,432	3,446,489	34,618	12.02%	15,825,425	3.44%	15.
16.	701-750	2,051	1,420,268	15,371	5.48%	7,166,651	0.97%	5,967	4,067,113	40,585	14.09%	19,892,538	4.32%	16.
17.	751-800	2,320	1,719,005	17,691	6.30%	8,885,656	1.20%	6,231	4,535,557	46,816	16.26%	24,428,095	5.30%	17.
18.	801-850	2,436	1,919,104	20,126	7.17%	10,804,759	1.46%	6,659	5,161,777	53,474	18.57%	29,589,872	6.43%	18.
19.	851-900	2,477	2,068,688	22,603	8.05%	12,873,448	1.74%	6,855	5,636,362	60,330	20.95%	35,226,234	7.65%	19.
20.	901-950	2,686	2,372,930	25,289	9.01%	15,246,377	2.06%	7,148	6,211,096	67,478	23.43%	41,437,330	9.00%	20.
21.	951-1,000	2,772	2,580,401	28,061	10.00%	17,826,778	2.41%	7,436	6,809,853	74,914	26.02%	48,247,183	10.48%	21.
22.	1,001-1,100	6,073	6,091,066	34,133	12.16%	23,917,845	3.24%	15,263	15,056,519	90,177	31.32%	63,303,702	13.75%	22.
23.	1,101-1,200	6,594	7,240,969	40,727	14.51%	31,158,814	4.21%	15,552	16,790,744	105,729	36.72%	80,094,446	17.39%	23.
24.	1,201-1,300	7,012	8,373,661	47,738	17.01%	39,532,475	5.35%	15,428	18,102,649	121,158	42.08%	98,197,095	21.32%	24.
25.	1,301-1,400	7,183	9,263,601	54,921	19.57%	48,796,075	6.60%	14,832	18,796,212	135,990	47.23%	116,993,307	25.41%	25.
26.	1,401-1,500	7,639	10,576,745	62,560	22.29%	59,372,820	8.03%	14,298	19,455,129	150,288	52.19%	136,448,436	29.63%	26.
27.	1,501-1,600	7,802	11,544,663	70,362	25.08%	70,917,483	9.59%	13,432	19,541,470	163,719	56.86%	155,989,906	33.88%	27.
28.	1,601-1,700	8,142	12,828,412	78,504	27.98%	83,745,895	11.33%	12,599	19,511,743	176,318	61.23%	175,501,649	38.11%	28.
29.	1,701-1,800	8,212	13,713,851	86,716	30.90%	97,459,746	13.18%	11,727	19,262,781	188,045	65.30%	194,764,431	42.30%	29.
30.	1,801-1,900	8,439	14,899,044	95,155	33.91%	112,358,791	15.20%	10,332	17,936,884	198,377	68.89%	212,701,314	46.19%	30.
31.	1,901-2,000	8,563	15,938,023	103,718	36.96%	128,296,814	17.35%	9,455	17,302,205	207,832	72.18%	230,003,519	49.95%	31.
32.	2,001-2,250	41,003	87,976,800	144,721	51.57%	216,273,614	29.26%	33,921	70,918,524	241,753	83.96%	300,922,043	65.35%	32.
33.	2,251-2,500	36,714	96,153,786	181,435	64.66%	312,427,400	42.26%	18,677	47,780,633	260,430	90.44%	348,702,676	75.73%	33.
34.	2,501-3,000	51,091	168,249,397	232,526	82.87%	480,676,797	65.02%	16,447	52,630,178	276,878	96.15%	401,332,853	87.15%	34.
35.	3,001-4,000	24,965	105,656,688	257,490	91.76%	586,333,485	79.31%	5,873	24,356,470	282,751	98.19%	425,689,323	92.44%	35.
36.	4,001-5,000	21,296	128,454,474	278,786	99.35%	714,787,959	96.69%	4,766	28,380,051	287,517	99.85%	454,069,374	98.61%	36.
37.	5,001-10,000	1,659	19,818,272	280,445	99.94%	734,606,231	99.37%	381	4,642,263	287,898	99.98%	458,711,637	99.62%	37.
38.	10,001-20,000	162	4,645,195	280,607	100.00%	739,251,426	100.00%	53	1,772,311	287,951	100.00%	460,483,948	100.00%	38.
39.	over 20,000	-	-	280,607	100.00%	739,251,426	100.00%	-	-	287,951	100.00%	460,483,948	100.00%	39.
	Average Number of Customers:			46,768				Average Number of Customers:		47,992				
	Average Consumption:			2,634	kWh per bill			Average Consumption:		1,599	kWh per bill			
	Median Consumption:			2,733	kWh per bill			Median Consumption:		1,944	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-1 Low Income w/E-3, ECT-1 Low Income w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	6	151	6	0.10%	151	0.00%	5	126	5	0.08%	126	0.00%	2.
3.	51-100	6	186	12	0.20%	337	0.00%	12	229	17	0.28%	355	0.01%	3.
4.	101-150	6	512	18	0.30%	849	0.01%	8	575	25	0.41%	930	0.01%	4.
5.	151-200	8	969	26	0.44%	1,818	0.02%	11	1,292	36	0.59%	2,222	0.03%	5.
6.	201-250	20	3,357	46	0.77%	5,175	0.04%	36	5,778	72	1.18%	8,000	0.11%	6.
7.	251-300	24	5,285	70	1.18%	10,461	0.09%	44	9,217	115	1.90%	17,217	0.24%	7.
8.	301-350	18	4,798	87	1.48%	15,258	0.13%	96	24,522	212	3.49%	41,739	0.59%	8.
9.	351-400	30	9,388	117	1.99%	24,647	0.20%	109	32,783	321	5.29%	74,522	1.05%	9.
10.	401-450	30	10,744	147	2.49%	35,391	0.29%	111	38,732	432	7.12%	113,254	1.60%	10.
11.	451-500	30	12,091	177	3.00%	47,482	0.39%	124	48,773	557	9.17%	162,027	2.28%	11.
12.	501-550	49	22,273	226	3.82%	69,755	0.58%	146	63,656	703	11.58%	225,683	3.18%	12.
13.	551-600	53	26,454	278	4.71%	96,209	0.80%	153	74,157	856	14.10%	299,840	4.23%	13.
14.	601-650	64	35,095	342	5.79%	131,303	1.09%	167	88,518	1,023	16.85%	388,358	5.47%	14.
15.	651-700	60	36,013	402	6.80%	167,317	1.39%	198	113,935	1,221	20.11%	502,293	7.08%	15.
16.	701-750	55	35,536	456	7.73%	202,853	1.68%	188	116,739	1,409	23.21%	619,032	8.72%	16.
17.	751-800	69	47,647	525	8.89%	250,500	2.08%	195	130,088	1,603	26.42%	749,120	10.56%	17.
18.	801-850	85	63,747	610	10.34%	314,247	2.61%	217	154,792	1,820	29.99%	903,911	12.74%	18.
19.	851-900	81	63,837	691	11.70%	378,084	3.13%	203	154,067	2,023	33.33%	1,057,978	14.91%	19.
20.	901-950	81	67,417	771	13.07%	445,501	3.69%	203	163,124	2,226	36.67%	1,221,102	17.21%	20.
21.	951-1,000	91	81,215	863	14.62%	526,716	4.37%	212	180,460	2,438	40.16%	1,401,562	19.75%	21.
22.	1,001-1,100	85	80,021	948	16.06%	606,737	5.03%	186	166,955	2,623	43.22%	1,568,517	22.11%	22.
23.	1,101-1,200	182	184,003	1,130	19.14%	790,740	6.56%	374	361,338	2,997	49.38%	1,929,855	27.20%	23.
24.	1,201-1,300	192	212,301	1,322	22.39%	1,003,041	8.31%	360	381,162	3,357	55.31%	2,311,017	32.57%	24.
25.	1,301-1,400	183	219,701	1,505	25.49%	1,222,742	10.14%	303	349,226	3,660	60.30%	2,660,244	37.49%	25.
26.	1,401-1,500	230	297,726	1,734	29.38%	1,520,468	12.60%	319	397,367	3,979	65.56%	3,057,611	43.09%	26.
27.	1,501-1,600	234	325,673	1,968	33.34%	1,846,140	15.30%	261	348,529	4,241	69.87%	3,406,140	48.00%	27.
28.	1,601-1,700	201	298,847	2,169	36.74%	2,144,988	17.78%	254	362,172	4,495	74.06%	3,768,312	53.11%	28.
29.	1,701-1,800	216	342,269	2,384	40.39%	2,487,257	20.62%	207	313,829	4,702	77.46%	4,082,141	57.53%	29.
30.	1,801-1,900	220	370,503	2,604	44.12%	2,857,760	23.69%	198	317,993	4,900	80.72%	4,400,134	62.01%	30.
31.	1,901-2,000	234	414,830	2,838	48.07%	3,272,590	27.13%	173	294,286	5,073	83.57%	4,694,420	66.16%	31.
32.	2,001-2,250	201	376,991	3,038	51.47%	3,649,581	30.25%	151	270,857	5,224	86.06%	4,965,277	69.98%	32.
33.	2,251-2,500	923	1,987,784	3,962	67.12%	5,637,365	46.73%	452	921,735	5,676	93.51%	5,887,012	82.97%	33.
34.	2,501-3,000	743	1,958,334	4,705	79.71%	7,595,699	62.97%	190	474,783	5,866	96.64%	6,361,795	89.66%	34.
35.	3,001-4,000	844	2,782,289	5,549	94.01%	10,377,988	86.03%	145	449,967	6,011	99.03%	6,811,762	96.00%	35.
36.	4,001-5,000	251	1,074,173	5,801	98.27%	11,452,161	94.94%	38	152,351	6,049	99.66%	6,964,112	98.15%	36.
37.	5,001-10,000	97	550,320	5,898	99.92%	12,002,481	99.50%	19	108,824	6,068	99.97%	7,072,936	99.68%	37.
38.	10,001-20,000	5	60,643	5,903	100.00%	12,063,124	100.00%	2	22,747	6,070	100.00%	7,095,683	100.00%	38.
39.	over 20,000	-	-	5,903	100.00%	12,063,124	100.00%	-	-	6,070	100.00%	7,095,683	100.00%	39.
	Average Number of Customers:			984				Average Number of Customers:		1,012				
	Average Consumption:			2,044	kWh per bill			Average Consumption:		1,169	kWh per bill			
	Median Consumption:			1,872	kWh per bill			Median Consumption:		1,019	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-2**
DESCRIPTION: Residential Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1,379	-	1,379	0.59%	-	0.00%	1,295	-	1,295	0.58%	-	0.00%	1.
2.	0-0.4	624	155	2,004	0.86%	155	0.01%	1,002	268	2,297	1.03%	268	0.02%	2.
3.	0.4-0.8	629	414	2,633	1.12%	569	0.03%	1,503	999	3,799	1.71%	1,267	0.09%	3.
4.	0.8-1.2	755	809	3,388	1.45%	1,378	0.07%	2,137	2,289	5,936	2.67%	3,556	0.26%	4.
5.	1.2-1.6	1,012	1,485	4,400	1.88%	2,863	0.14%	3,506	5,124	9,443	4.25%	8,680	0.64%	5.
6.	1.6-2.0	1,344	2,504	5,744	2.45%	5,366	0.26%	4,817	8,973	14,260	6.42%	17,653	1.30%	6.
7.	2.0-2.4	1,591	3,589	7,335	3.13%	8,956	0.43%	6,714	15,167	20,974	9.45%	32,820	2.42%	7.
8.	2.4-2.8	2,039	5,438	9,374	4.00%	14,393	0.68%	8,222	21,815	29,196	13.15%	54,635	4.03%	8.
9.	2.8-3.2	3,001	9,190	12,375	5.28%	23,584	1.12%	10,205	31,180	39,401	17.75%	85,815	6.32%	9.
10.	3.2-3.6	3,595	12,455	15,969	6.82%	36,038	1.71%	10,743	37,068	50,143	22.59%	122,882	9.05%	10.
11.	3.6-4.0	4,712	18,154	20,681	8.83%	54,192	2.58%	11,792	45,409	61,936	27.90%	168,291	12.40%	11.
12.	4.0-4.4	5,719	24,368	26,400	11.27%	78,560	3.73%	13,274	56,436	75,210	33.88%	224,728	16.56%	12.
13.	4.4-4.8	6,525	30,365	32,925	14.06%	108,925	5.18%	13,189	61,342	88,398	39.82%	286,069	21.08%	13.
14.	4.8-5.2	7,250	36,642	40,175	17.15%	145,568	6.92%	12,975	65,459	101,374	45.67%	351,528	25.90%	14.
15.	5.2-5.6	8,141	44,405	48,315	20.63%	189,973	9.03%	12,512	68,245	113,886	51.30%	419,773	30.93%	15.
16.	5.6-6.0	9,092	53,178	57,407	24.51%	243,151	11.56%	11,606	67,845	125,492	56.53%	487,618	35.93%	16.
17.	6.0-6.4	9,857	61,639	67,265	28.72%	304,790	14.49%	11,201	69,975	136,693	61.58%	557,593	41.09%	17.
18.	6.4-6.8	9,993	66,501	77,258	32.99%	371,291	17.65%	10,636	70,700	147,329	66.37%	628,293	46.30%	18.
19.	6.8-7.2	10,094	71,176	87,352	37.30%	442,466	21.03%	9,672	68,215	157,000	70.73%	696,508	51.32%	19.
20.	7.2-7.6	10,331	76,970	97,683	41.71%	519,437	24.69%	8,718	64,878	165,718	74.65%	761,386	56.10%	20.
21.	7.6-8.0	10,255	80,484	107,938	46.09%	599,920	28.51%	7,791	61,131	173,509	78.16%	822,516	60.61%	21.
22.	8.0-8.4	10,401	85,784	118,339	50.53%	685,704	32.59%	6,736	55,556	180,244	81.20%	878,073	64.70%	22.
23.	8.4-8.8	9,812	84,895	128,151	54.72%	770,599	36.62%	5,744	49,688	185,989	83.79%	927,760	68.36%	23.
24.	8.8-9.2	9,661	87,414	137,812	58.84%	858,013	40.78%	5,030	45,478	191,019	86.05%	973,238	71.71%	24.
25.	9.2-9.6	8,881	83,882	146,693	62.63%	941,895	44.76%	4,508	42,606	195,527	88.08%	1,015,844	74.85%	25.
26.	9.6-10.0	8,473	83,434	155,166	66.25%	1,025,329	48.73%	3,741	36,820	199,268	89.77%	1,052,665	77.57%	26.
27.	10.0-10.4	8,010	82,090	163,175	69.67%	1,107,419	52.63%	3,298	33,775	202,566	91.25%	1,086,440	80.06%	27.
28.	10.4-10.8	7,642	81,367	170,818	72.93%	1,188,787	56.50%	2,664	28,370	205,231	92.46%	1,114,809	82.15%	28.
29.	10.8-11.2	6,973	77,059	177,790	75.91%	1,265,845	60.16%	2,163	23,893	207,394	93.43%	1,138,702	83.91%	29.
30.	11.2-12.0	11,957	139,138	189,747	81.02%	1,404,983	66.77%	3,528	41,032	210,922	95.02%	1,179,734	86.93%	30.
31.	12.0 - 13.0	11,655	145,975	201,402	85.99%	1,550,958	73.71%	2,808	35,124	213,730	96.28%	1,214,858	89.52%	31.
32.	13.0 - 14.0	8,785	118,871	210,187	89.74%	1,669,829	79.36%	2,153	29,101	215,883	97.25%	1,243,959	91.66%	32.
33.	14.0 - 15.0	6,454	93,725	216,641	92.50%	1,763,553	83.81%	1,684	24,446	217,567	98.01%	1,268,405	93.46%	33.
34.	15.0 - 16.0	4,526	70,284	221,167	94.43%	1,833,838	87.15%	1,007	15,668	218,574	98.47%	1,284,073	94.62%	34.
35.	16.0 - 17.0	3,358	55,486	224,525	95.86%	1,889,324	89.79%	730	12,079	219,304	98.79%	1,296,152	95.51%	35.
36.	17.0 - 18.0	2,225	39,022	226,750	96.81%	1,928,346	91.65%	549	9,592	219,853	99.04%	1,305,744	96.21%	36.
37.	18.0 - 19.0	1,515	28,072	228,265	97.46%	1,956,418	92.98%	341	6,293	220,194	99.20%	1,312,037	96.68%	37.
38.	19.0 - 20.0	1,233	24,096	229,499	97.99%	1,980,514	94.13%	362	7,115	220,556	99.36%	1,319,152	97.20%	38.
39.	20.0 - 25.0	2,910	64,000	232,409	99.23%	2,044,515	97.17%	783	17,342	221,340	99.71%	1,336,494	98.48%	39.
40.	25.0 - 30.0	931	25,284	233,340	99.63%	2,069,798	98.37%	341	9,329	221,681	99.87%	1,345,823	99.17%	40.
41.	Over 30.0	871	34,332	234,211	100.00%	2,104,131	100.00%	298	11,294	221,979	100.00%	1,357,117	100.00%	41.
	Average Number of Customers:			39,035				Average Number of Customers:		36,997				
	Average Load:			9.0	kW per bill			Average Load:		6.0	kW per bill			
	Median Load:			8.4	kW per bill			Median Load:		5.6	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-2**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	793	-	793	0.34%	-	0.00%	751	-	751	0.34%	-	0.00%	1.
2.	1-50	637	17,996	1,430	0.61%	17,996	0.00%	854	26,399	1,604	0.72%	26,399	0.01%	2.
3.	51-100	632	54,518	2,063	0.88%	72,514	0.01%	840	77,253	2,444	1.10%	103,652	0.03%	3.
4.	101-150	660	93,570	2,723	1.16%	166,084	0.02%	935	139,824	3,379	1.52%	243,476	0.06%	4.
5.	151-200	604	119,765	3,326	1.42%	285,849	0.04%	944	198,715	4,324	1.95%	442,191	0.11%	5.
6.	201-250	655	167,049	3,982	1.70%	452,897	0.07%	1,058	286,412	5,382	2.42%	728,603	0.18%	6.
7.	251-300	666	207,393	4,647	1.98%	660,290	0.10%	1,512	501,753	6,894	3.11%	1,230,356	0.31%	7.
8.	301-350	853	313,025	5,500	2.35%	973,316	0.15%	1,841	719,984	8,735	3.94%	1,950,339	0.49%	8.
9.	351-400	873	370,317	6,374	2.72%	1,343,633	0.20%	2,366	1,067,094	11,101	5.00%	3,017,433	0.76%	9.
10.	401-450	1,071	514,691	7,445	3.18%	1,858,324	0.28%	2,976	1,519,924	14,077	6.34%	4,537,357	1.15%	10.
11.	451-500	1,202	645,295	8,646	3.69%	2,503,619	0.37%	3,456	1,968,657	17,533	7.90%	6,506,014	1.65%	11.
12.	501-550	1,331	789,026	9,978	4.26%	3,292,646	0.49%	4,104	2,585,322	21,637	9.75%	9,091,336	2.30%	12.
13.	551-600	1,475	957,041	11,453	4.89%	4,249,687	0.64%	4,607	3,179,860	26,243	11.82%	12,271,196	3.11%	13.
14.	601-650	1,704	1,203,337	13,157	5.62%	5,453,024	0.82%	4,939	3,702,592	31,182	14.05%	15,973,788	4.05%	14.
15.	651-700	1,900	1,445,631	15,057	6.43%	6,898,654	1.03%	5,508	4,460,284	36,690	16.53%	20,434,073	5.18%	15.
16.	701-750	2,066	1,689,428	17,123	7.31%	8,588,082	1.29%	5,693	4,949,358	42,383	19.09%	25,383,431	6.43%	16.
17.	751-800	2,042	1,784,231	19,165	8.18%	10,372,313	1.55%	5,693	5,289,961	48,076	21.66%	30,673,392	7.77%	17.
18.	801-850	2,327	2,165,721	21,491	9.18%	12,538,034	1.88%	6,057	5,993,053	54,133	24.39%	36,666,445	9.29%	18.
19.	851-900	2,437	2,403,750	23,928	10.22%	14,941,785	2.24%	6,549	6,872,524	60,682	27.34%	43,538,969	11.03%	19.
20.	901-950	2,494	2,602,199	26,422	11.28%	17,543,983	2.63%	6,308	6,996,408	66,990	30.18%	50,535,377	12.80%	20.
21.	951-1,000	2,541	2,792,580	28,963	12.37%	20,336,563	3.05%	6,640	7,760,568	73,630	33.17%	58,295,945	14.77%	21.
22.	1,001-1,100	5,491	6,505,795	34,454	14.71%	26,842,358	4.02%	13,108	16,496,791	86,738	39.07%	74,792,736	18.94%	22.
23.	1,101-1,200	5,856	7,596,966	40,310	17.21%	34,439,324	5.16%	13,023	17,950,136	99,761	44.94%	92,742,872	23.49%	23.
24.	1,201-1,300	6,140	8,654,345	46,450	19.83%	43,093,669	6.45%	12,396	18,564,027	112,157	50.53%	111,306,900	28.19%	24.
25.	1,301-1,400	6,586	10,027,753	53,036	22.64%	53,121,421	7.96%	11,757	19,017,392	123,914	55.82%	130,324,291	33.01%	25.
26.	1,401-1,500	6,415	10,485,517	59,451	25.38%	63,606,938	9.53%	10,878	18,896,662	134,792	60.72%	149,220,953	37.80%	26.
27.	1,501-1,600	6,692	11,695,481	66,143	28.24%	75,302,419	11.28%	9,981	18,532,678	144,773	65.22%	167,753,631	42.49%	27.
28.	1,601-1,700	7,022	13,063,476	73,165	31.24%	88,365,895	13.24%	9,087	17,957,846	153,860	69.31%	185,711,478	47.04%	28.
29.	1,701-1,800	6,906	13,624,640	80,071	34.19%	101,990,535	15.28%	8,151	17,084,396	162,011	72.98%	202,795,874	51.37%	29.
30.	1,801-1,900	7,099	14,803,462	87,170	37.22%	116,793,997	17.49%	7,223	16,013,358	169,234	76.24%	218,809,232	55.42%	30.
31.	1,901-2,000	7,195	15,816,512	94,365	40.29%	132,610,509	19.86%	6,394	14,938,821	175,628	79.12%	233,748,053	59.21%	31.
32.	2,001-2,250	35,478	89,875,901	129,844	55.44%	222,486,410	33.32%	22,386	59,546,963	198,013	89.20%	293,295,016	74.29%	32.
33.	2,251-2,500	31,470	97,281,440	161,314	68.88%	319,767,850	47.90%	10,721	34,957,384	208,734	94.03%	328,252,400	83.15%	33.
34.	2,501-3,000	41,894	162,657,838	203,208	86.76%	482,425,688	72.26%	8,366	34,088,223	217,100	97.80%	362,340,623	91.78%	34.
35.	3,001-4,000	18,461	92,040,237	221,669	94.65%	574,465,925	86.05%	2,776	14,733,225	219,876	99.05%	377,073,848	95.51%	35.
36.	4,001-5,000	11,795	81,746,267	233,464	99.68%	656,212,192	98.29%	1,935	14,656,728	221,811	99.92%	391,730,576	99.22%	36.
37.	5,001-10,000	692	9,661,367	234,156	99.98%	665,873,559	99.74%	148	2,196,888	221,959	99.99%	393,927,463	99.78%	37.
38.	10,001-20,000	55	1,759,026	234,211	100.00%	667,632,585	100.00%	20	864,349	221,979	100.00%	394,791,812	100.00%	38.
39.	over 20,000	-	-	234,211	100.00%	667,632,585	100.00%	-	-	221,979	100.00%	394,791,812	100.00%	39.
	Average Number of Customers:			39,035				Average Number of Customers:		36,997				
	Average Consumption:			2,851	kWh per bill			Average Consumption:		1,779	kWh per bill			
	Median Consumption:			2,317	kWh per bill			Median Consumption:		1,291	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ECT-2 Low Income w/E-3, ECT-2 Low Income w/E-4**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	27	183	27	0.31%	183	0.00%	25	-	25	0.30%	-	0.00%	2.
3.	51-100	12	338	39	0.44%	521	0.00%	13	26	39	0.47%	26	0.00%	3.
4.	101-150	9	856	48	0.54%	1,377	0.01%	32	3,277	71	0.85%	3,303	0.02%	4.
5.	151-200	17	2,600	65	0.73%	3,977	0.02%	44	6,971	115	1.38%	10,274	0.08%	5.
6.	201-250	23	4,898	88	0.99%	8,874	0.04%	30	6,686	145	1.75%	16,961	0.13%	6.
7.	251-300	21	5,708	110	1.24%	14,582	0.06%	57	16,665	202	2.44%	33,626	0.25%	7.
8.	301-350	26	8,715	136	1.53%	23,297	0.10%	77	27,131	280	3.37%	60,757	0.46%	8.
9.	351-400	35	13,725	171	1.92%	37,022	0.16%	99	41,612	379	4.57%	102,369	0.77%	9.
10.	401-450	38	17,047	209	2.35%	54,069	0.24%	173	82,855	552	6.66%	185,224	1.40%	10.
11.	451-500	49	24,876	257	2.90%	78,945	0.34%	167	91,384	719	8.66%	276,608	2.09%	11.
12.	501-550	81	46,057	338	3.80%	125,002	0.54%	227	137,435	946	11.40%	414,043	3.13%	12.
13.	551-600	64	40,345	402	4.53%	165,348	0.72%	251	168,382	1,197	14.43%	582,425	4.40%	13.
14.	601-650	68	46,979	470	5.29%	212,326	0.92%	216	158,925	1,413	17.03%	741,349	5.60%	14.
15.	651-700	80	59,955	549	6.19%	272,282	1.19%	251	200,457	1,664	20.05%	941,806	7.11%	15.
16.	701-750	113	92,018	663	7.47%	364,300	1.59%	241	207,960	1,904	22.95%	1,149,766	8.68%	16.
17.	751-800	105	91,180	767	8.65%	455,480	1.98%	295	273,865	2,199	26.50%	1,423,631	10.75%	17.
18.	801-850	107	99,463	874	9.85%	554,943	2.42%	290	287,917	2,489	29.99%	1,711,547	12.92%	18.
19.	851-900	118	117,141	992	11.18%	672,084	2.93%	258	273,169	2,746	33.10%	1,984,716	14.99%	19.
20.	901-950	93	97,956	1,085	12.23%	770,040	3.35%	271	304,076	3,017	36.36%	2,288,792	17.28%	20.
21.	951-1,000	116	129,408	1,202	13.54%	899,448	3.92%	359	425,605	3,376	40.69%	2,714,397	20.50%	21.
22.	1,001-1,100	122	142,202	1,324	14.92%	1,041,650	4.54%	296	369,621	3,672	44.26%	3,084,018	23.29%	22.
23.	1,101-1,200	287	361,276	1,611	18.16%	1,402,926	6.11%	559	749,990	4,232	50.99%	3,834,008	28.95%	23.
24.	1,201-1,300	308	426,171	1,920	21.63%	1,829,097	7.97%	505	743,715	4,737	57.08%	4,577,724	34.57%	24.
25.	1,301-1,400	317	475,465	2,237	25.21%	2,304,562	10.04%	409	653,762	5,146	62.01%	5,231,486	39.50%	25.
26.	1,401-1,500	360	583,503	2,597	29.26%	2,888,065	12.58%	411	710,042	5,557	66.96%	5,941,528	44.87%	26.
27.	1,501-1,600	335	582,182	2,931	33.03%	3,470,247	15.12%	347	643,387	5,904	71.14%	6,584,915	49.72%	27.
28.	1,601-1,700	308	574,230	3,240	36.51%	4,044,477	17.62%	323	641,467	6,227	75.04%	7,226,381	54.57%	28.
29.	1,701-1,800	323	639,394	3,563	40.15%	4,683,871	20.40%	305	641,978	6,532	78.71%	7,868,359	59.42%	29.
30.	1,801-1,900	319	669,782	3,882	43.75%	5,353,653	23.32%	237	531,709	6,769	81.57%	8,400,068	63.43%	30.
31.	1,901-2,000	308	683,230	4,191	47.22%	6,036,883	26.30%	241	571,239	7,010	84.48%	8,971,307	67.75%	31.
32.	2,001-2,250	320	747,842	4,511	50.83%	6,784,725	29.55%	172	428,566	7,182	86.55%	9,399,873	70.98%	32.
33.	2,251-2,500	1,437	3,863,909	5,947	67.02%	10,648,634	46.38%	625	1,778,715	7,806	94.07%	11,178,588	84.41%	33.
34.	2,501-3,000	1,151	3,779,336	7,099	80.00%	14,427,970	62.85%	249	866,295	8,056	97.08%	12,044,883	90.95%	34.
35.	3,001-4,000	1,126	4,630,721	8,225	92.69%	19,058,691	83.02%	177	764,570	8,232	99.21%	12,809,452	96.73%	35.
36.	4,001-5,000	438	2,318,286	8,663	97.63%	21,376,977	93.12%	44	253,241	8,276	99.74%	13,062,694	98.64%	36.
37.	5,001-10,000	207	1,496,700	8,870	99.96%	22,873,677	99.64%	20	155,335	8,296	99.98%	13,218,028	99.81%	37.
38.	10,001-20,000	3	38,636	8,873	99.99%	22,912,313	99.80%	2	24,701	8,298	100.00%	13,242,729	100.00%	38.
39.	over 20,000	1	45,002	8,874	100.00%	22,957,315	100.00%	-	-	8,298	100.00%	13,242,729	100.00%	39.
	Average Number of Customers:			1,479				Average Number of Customers:		1,383				
	Average Consumption:			2,587	kWh per bill			Average Consumption:		1,596	kWh per bill			
	Median Consumption:			1,975	kWh per bill			Median Consumption:		1,086	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **ET-SP**
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-50	6	123	6	0.75%	123	0.01%	6	201	6	1.14%	201	0.03%	2.
3.	51-100	6	199	12	1.63%	322	0.02%	13	554	19	3.41%	755	0.11%	3.
4.	101-150	11	1,027	23	3.13%	1,349	0.10%	13	1,415	32	5.68%	2,170	0.33%	4.
5.	151-200	13	2,020	36	4.88%	3,369	0.26%	16	3,132	48	8.60%	5,302	0.81%	5.
6.	201-250	10	2,380	46	6.26%	5,749	0.44%	18	4,714	66	11.85%	10,015	1.52%	6.
7.	251-300	7	2,133	54	7.26%	7,882	0.60%	21	7,050	87	15.58%	17,065	2.59%	7.
8.	301-350	9	3,256	63	8.51%	11,138	0.85%	14	5,734	101	18.02%	22,799	3.47%	8.
9.	351-400	16	6,678	79	10.64%	17,815	1.36%	17	8,386	118	21.10%	31,185	4.74%	9.
10.	401-450	10	4,889	89	12.02%	22,705	1.73%	22	12,218	140	25.00%	43,403	6.60%	10.
11.	451-500	11	6,149	100	13.52%	28,854	2.20%	22	13,921	161	28.90%	57,324	8.71%	11.
12.	501-550	12	7,370	112	15.14%	36,224	2.77%	14	9,703	175	31.33%	67,027	10.19%	12.
13.	551-600	11	7,594	123	16.65%	43,818	3.35%	24	19,422	199	35.71%	86,449	13.14%	13.
14.	601-650	16	11,777	139	18.77%	55,595	4.25%	28	24,477	227	40.75%	110,926	16.86%	14.
15.	651-700	16	12,845	154	20.90%	68,440	5.23%	24	23,208	252	45.13%	134,133	20.39%	15.
16.	701-750	21	18,788	175	23.78%	87,227	6.66%	30	30,320	282	50.49%	164,453	25.00%	16.
17.	751-800	14	13,063	189	25.66%	100,291	7.66%	24	26,773	306	54.87%	191,227	29.07%	17.
18.	801-850	21	21,701	211	28.54%	121,991	9.32%	21	24,425	327	58.60%	215,651	32.78%	18.
19.	851-900	18	20,103	229	31.04%	142,095	10.85%	19	23,730	346	62.01%	239,382	36.39%	19.
20.	901-950	19	22,179	248	33.67%	164,273	12.55%	29	38,168	375	67.21%	277,550	42.19%	20.
21.	951-1,000	19	23,403	268	36.30%	187,676	14.33%	25	35,341	400	71.75%	312,891	47.56%	21.
22.	1,001-1,100	16	20,004	284	38.42%	207,680	15.86%	19	27,991	419	75.16%	340,881	51.82%	22.
23.	1,101-1,200	41	55,737	324	43.93%	263,418	20.12%	22	34,283	441	79.06%	375,165	57.03%	23.
24.	1,201-1,300	42	62,201	366	49.56%	325,619	24.87%	17	29,492	458	82.14%	404,656	61.51%	24.
25.	1,301-1,400	44	72,662	410	55.57%	398,280	30.42%	24	44,487	482	86.36%	449,143	68.28%	25.
26.	1,401-1,500	32	57,312	442	59.95%	455,592	34.79%	15	31,348	497	89.12%	480,491	73.04%	26.
27.	1,501-1,600	30	57,905	473	64.08%	513,498	39.22%	12	25,395	509	91.23%	505,886	76.90%	27.
28.	1,601-1,700	31	63,507	504	68.34%	577,005	44.07%	5	12,786	515	92.21%	518,672	78.84%	28.
29.	1,701-1,800	19	41,770	524	70.96%	618,774	47.26%	9	22,517	524	93.83%	541,189	82.27%	29.
30.	1,801-1,900	19	44,204	543	73.59%	662,978	50.63%	6	16,638	530	94.97%	557,827	84.80%	30.
31.	1,901-2,000	18	42,562	561	75.97%	705,540	53.88%	9	25,424	539	96.59%	583,250	88.66%	31.
32.	2,001-2,250	19	49,506	580	78.60%	755,046	57.66%	-	-	539	96.59%	583,250	88.66%	32.
33.	2,251-2,500	81	237,618	661	89.61%	992,663	75.81%	12	38,822	551	98.70%	622,072	94.56%	33.
34.	2,501-3,000	45	159,833	707	95.74%	1,152,496	88.02%	4	14,588	554	99.35%	636,661	96.78%	34.
35.	3,001-4,000	24	105,073	731	99.00%	1,257,569	96.04%	3	15,373	557	99.84%	652,034	99.12%	35.
36.	4,001-5,000	4	21,182	734	99.50%	1,278,751	97.66%	1	5,809	558	100.00%	657,843	100.00%	36.
37.	5,001-10,000	4	30,638	738	100.00%	1,309,389	100.00%	-	-	558	100.00%	657,843	100.00%	37.
38.	10,001-20,000	-	-	738	100.00%	1,309,389	100.00%	-	-	558	100.00%	657,843	100.00%	38.
39.	over 20,000	-	-	738	100.00%	1,309,389	100.00%	-	-	558	100.00%	657,843	100.00%	39.
		Average Number of Customers:		123				Average Number of Customers:		93				
		Average Consumption:		1,774	kWh per bill			Average Consumption:		1,179	kWh per bill			
		Median Consumption:		1,458	kWh per bill			Median Consumption:		948	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	12	-	12	0.61%	-	0.00%	2	-	2	0.10%	-	0.00%	1.
2.	1-10	80	498	92	4.65%	498	0.37%	198	1,320	200	10.27%	1,320	1.52%	2.
3.	11-20	195	3,046	287	14.45%	3,544	2.65%	401	6,202	601	30.81%	7,522	8.67%	3.
4.	21-30	283	7,067	570	28.70%	10,611	7.93%	311	7,816	912	46.76%	15,338	17.68%	4.
5.	31-40	258	8,984	828	41.69%	19,595	14.64%	313	11,049	1,225	62.80%	26,387	30.42%	5.
6.	41-50	175	7,843	1,003	50.48%	27,437	20.49%	218	9,736	1,443	73.99%	36,123	41.64%	6.
7.	51-60	172	9,482	1,174	59.12%	36,920	27.58%	144	7,933	1,587	81.40%	44,056	50.79%	7.
8.	61-70	162	10,429	1,336	67.26%	47,349	35.37%	67	4,394	1,654	84.82%	48,450	55.86%	8.
9.	71-80	137	10,296	1,473	74.18%	57,645	43.06%	44	3,342	1,698	87.07%	51,793	59.71%	9.
10.	81-90	102	8,672	1,576	79.33%	66,317	49.53%	36	3,114	1,734	88.91%	54,906	63.30%	10.
11.	91-100	66	6,314	1,642	82.67%	72,631	54.25%	48	4,575	1,782	91.36%	59,481	68.57%	11.
12.	101-200	259	35,374	1,901	95.70%	108,005	80.67%	139	18,722	1,921	98.52%	78,203	90.16%	12.
13.	201-300	55	13,259	1,956	98.48%	121,264	90.58%	12	2,874	1,933	99.13%	81,077	93.47%	13.
14.	301-400	16	5,408	1,972	99.29%	126,672	94.62%	17	5,664	1,950	100.00%	86,741	100.00%	14.
15.	401-500	9	3,866	1,981	99.75%	130,539	97.50%	-	-	1,950	100.00%	86,741	100.00%	15.
16.	501-600	3	1,694	1,984	99.90%	132,233	98.77%	-	-	1,950	100.00%	86,741	100.00%	16.
17.	601-700	1	619	1,985	99.95%	132,852	99.23%	-	-	1,950	100.00%	86,741	100.00%	17.
18.	701-800	-	-	1,985	99.95%	132,852	99.23%	-	-	1,950	100.00%	86,741	100.00%	18.
19.	801-900	-	-	1,985	99.95%	132,852	99.23%	-	-	1,950	100.00%	86,741	100.00%	19.
20.	901-1000	-	-	1,985	99.95%	132,852	99.23%	-	-	1,950	100.00%	86,741	100.00%	20.
21.	1001-1100	1	1,027	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	21.
22.	1101-1200	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	22.
23.	1201-1300	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	23.
24.	1301-1400	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	24.
25.	1401-1500	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	25.
26.	1501-1600	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	26.
27.	1601-1700	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	27.
28.	1701-1800	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	28.
29.	1801-1900	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	29.
30.	1901-2000	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	30.
31.	2001-2100	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	31.
32.	2101-2200	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	32.
33.	2201-2300	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	33.
34.	2301-2400	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	34.
35.	2401-2500	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	35.
36.	2501-2600	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	36.
37.	2601-2700	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	37.
38.	2701-2800	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	38.
39.	2801-2900	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	39.
40.	2901-3000	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	40.
41.	Over 3000	-	-	1,986	100.00%	133,879	100.00%	-	-	1,950	100.00%	86,741	100.00%	41.

Average Number of Customers:	331		Average Number of Customers:	325	
Average Load:	67	kW per bill	Average Load:	44	kW per bill
Median Load:	54	kW per bill	Median Load:	35	kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-20**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	6	-	6	0.30%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100	6	275	12	0.61%	275	0.00%	2	122	2	0.10%	122	0.00%	2.
3.	101-200	4	723	16	0.81%	998	0.00%	5	792	7	0.36%	914	0.01%	3.
4.	201-300	6	1,662	22	1.11%	2,660	0.01%	9	2,485	16	0.82%	3,398	0.03%	4.
5.	301-400	5	1,759	27	1.37%	4,419	0.02%	17	6,191	33	1.69%	9,589	0.07%	5.
6.	401-500	4	1,977	31	1.57%	6,397	0.03%	15	7,161	48	2.45%	16,750	0.12%	6.
7.	501-750	45	29,330	76	3.84%	35,727	0.15%	86	55,346	134	6.85%	72,096	0.53%	7.
8.	751-1,000	44	39,276	120	6.07%	75,003	0.32%	89	80,290	222	11.39%	152,385	1.12%	8.
9.	1,001-1,500	84	109,863	205	10.31%	184,866	0.80%	174	226,385	397	20.34%	378,770	2.79%	9.
10.	1,501-2,000	109	196,979	314	15.82%	381,845	1.65%	153	282,944	550	28.21%	661,714	4.87%	10.
11.	2,001-3,000	209	521,584	523	26.34%	903,429	3.91%	244	632,885	794	40.73%	1,294,599	9.54%	11.
12.	3,001-4,000	164	578,901	687	34.58%	1,482,329	6.42%	232	847,355	1,026	52.63%	2,141,955	15.78%	12.
13.	4,001-5,000	161	734,900	847	42.67%	2,217,229	9.60%	168	787,658	1,195	61.27%	2,929,612	21.58%	13.
14.	5,001-7,500	277	1,737,587	1,125	56.62%	3,954,817	17.13%	287	1,837,811	1,482	75.98%	4,767,423	35.12%	14.
15.	7,501-10,000	204	1,791,399	1,328	66.89%	5,746,216	24.89%	143	1,297,951	1,625	83.34%	6,065,374	44.68%	15.
16.	10,001-15,000	241	2,969,847	1,569	79.02%	8,716,063	37.75%	128	1,602,836	1,753	89.88%	7,668,211	56.49%	16.
17.	15,001-20,000	132	2,284,942	1,701	85.64%	11,001,005	47.65%	63	1,125,901	1,815	93.10%	8,794,112	64.78%	17.
18.	20,001-25,000	83	1,862,593	1,784	89.84%	12,863,598	55.71%	40	950,954	1,855	95.15%	9,745,066	71.79%	18.
19.	25,001-30,000	42	1,167,447	1,826	91.96%	14,031,045	60.77%	40	1,147,592	1,895	97.19%	10,892,658	80.24%	19.
20.	30,001-35,000	31	1,025,075	1,857	93.53%	15,056,120	65.21%	14	470,539	1,909	97.90%	11,363,197	83.71%	20.
21.	35,001-40,000	22	835,896	1,880	94.64%	15,892,016	68.83%	13	507,753	1,922	98.57%	11,870,950	87.45%	21.
22.	40,001-50,000	38	1,698,359	1,918	96.56%	17,590,375	76.19%	14	645,235	1,936	99.28%	12,516,185	92.20%	22.
23.	50,001-75,000	49	2,980,900	1,967	99.04%	20,571,274	89.10%	8	555,345	1,944	99.69%	13,071,530	96.29%	23.
24.	75,001-100,000	8	712,994	1,975	99.44%	21,284,268	92.18%	6	503,753	1,950	100.00%	13,575,283	100.00%	24.
25.	100,001-125,000	5	574,110	1,980	99.70%	21,858,378	94.67%	-	-	1,950	100.00%	13,575,283	100.00%	25.
26.	125,001-150,000	4	535,009	1,984	99.90%	22,393,387	96.99%	-	-	1,950	100.00%	13,575,283	100.00%	26.
27.	150,001-200,000	-	-	1,984	99.90%	22,393,387	96.99%	-	-	1,950	100.00%	13,575,283	100.00%	27.
28.	200,001-300,000	1	262,596	1,985	99.95%	22,655,984	98.13%	-	-	1,950	100.00%	13,575,283	100.00%	28.
29.	300,001-400,000	-	-	1,985	99.95%	22,655,984	98.13%	-	-	1,950	100.00%	13,575,283	100.00%	29.
30.	400,001-500,000	1	432,793	1,986	100.00%	23,088,777	100.00%	-	-	1,950	100.00%	13,575,283	100.00%	30.
31.	500,001-750,000	-	-	1,986	100.00%	23,088,777	100.00%	-	-	1,950	100.00%	13,575,283	100.00%	31.
32.	750,001-1,000,000	-	-	1,986	100.00%	23,088,777	100.00%	-	-	1,950	100.00%	13,575,283	100.00%	32.
33.	Over 1,000,000	-	-	1,986	100.00%	23,088,777	100.00%	-	-	1,950	100.00%	13,575,283	100.00%	33.

Average Number of Customers:	331		Average Number of Customers:	325	
Average Consumption:	11,626	kWh per bill	Average Consumption:	6,962	kWh per bill
Median Consumption:	6,960	kWh per bill	Median Consumption:	4,120	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-30**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	19	-	19	0.07%	-	0.00%	20	-	20	0.07%	-	0.00%	1.
2.	1-100	19,816	522,334	19,835	70.83%	522,334	15.87%	19,832	532,594	19,852	71.60%	532,594	17.42%	2.
3.	101-200	4,005	572,382	23,840	85.14%	1,094,716	33.25%	4,025	588,232	23,877	86.12%	1,120,827	36.67%	3.
4.	201-300	1,266	305,510	25,106	89.66%	1,400,227	42.53%	1,264	312,111	25,141	90.68%	1,432,938	46.88%	4.
5.	301-400	958	303,483	26,064	93.08%	1,703,710	51.75%	956	309,719	26,097	94.12%	1,742,657	57.01%	5.
6.	401-500	449	182,121	26,513	94.68%	1,885,831	57.28%	453	187,909	26,550	95.76%	1,930,566	63.16%	6.
7.	501-750	127	69,295	26,640	95.14%	1,955,126	59.39%	125	69,893	26,675	96.21%	2,000,459	65.45%	7.
8.	751-1,000	743	610,879	27,383	97.79%	2,566,006	77.95%	465	391,325	27,140	97.89%	2,391,784	78.25%	8.
9.	1,001-1,500	551	568,160	27,934	99.76%	3,134,166	95.20%	552	583,061	27,692	99.88%	2,974,845	97.33%	9.
10.	1,501-2,000	34	54,534	27,967	99.88%	3,188,700	96.86%	13	21,973	27,706	99.93%	2,996,818	98.05%	10.
11.	2,001-3,000	11	24,280	27,979	99.92%	3,212,980	97.60%	7	13,575	27,713	99.95%	3,010,393	98.49%	11.
12.	3,001-4,000	16	47,948	27,994	99.97%	3,260,928	99.06%	7	18,992	27,719	99.98%	3,029,385	99.11%	12.
13.	4,001-5,000	8	31,102	28,002	100.00%	3,292,030	100.00%	7	27,149	27,726	100.00%	3,056,534	100.00%	13.
14.	5,001-7,500	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	14.
15.	7,501-10,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	15.
16.	10,001-15,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	16.
17.	15,001-20,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	17.
18.	20,001-25,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	18.
19.	25,001-30,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	19.
20.	30,001-35,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	20.
21.	35,001-40,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	21.
22.	40,001-50,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	22.
23.	50,001-75,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	23.
24.	75,001-100,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	24.
25.	100,001-125,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	25.
26.	125,001-150,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	26.
27.	150,001-200,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	27.
28.	200,001-300,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	28.
29.	300,001-400,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	29.
30.	400,001-500,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	30.
31.	500,001-750,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	31.
32.	750,001-1,000,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	32.
33.	Over 1,000,000	-	-	28,002	100.00%	3,292,030	100.00%	-	-	27,726	100.00%	3,056,534	100.00%	33.

Average Number of Customers:	4,667		Average Number of Customers:	4,621	
Average Consumption:	118	kWh per bill	Average Consumption:	110	kWh per bill
Median Consumption:	37	kWh per bill	Median Consumption:	37	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	127,684	-	127,684	19.05%	-	0.00%	130,558	-	130,558	19.45%	-	0.00%	1.
2.	1-10	314,309	1,266,283	441,992	65.94%	1,266,283	16.04%	337,344	1,356,816	467,903	69.70%	1,356,816	20.26%	2.
3.	11-20	114,435	1,666,448	556,427	83.01%	2,932,731	37.16%	112,887	1,620,630	580,790	86.51%	2,977,446	44.47%	3.
4.	21-30	46,717	1,161,551	603,143	89.98%	4,094,282	51.88%	40,061	989,428	620,851	92.48%	3,966,875	59.25%	4.
5.	31-40	23,000	809,276	626,143	93.41%	4,903,558	62.13%	19,450	682,715	640,301	95.38%	4,649,589	69.44%	5.
6.	41-50	13,592	618,339	639,735	95.44%	5,521,897	69.97%	11,573	523,845	651,874	97.10%	5,173,435	77.27%	6.
7.	51-60	10,200	568,066	649,935	96.96%	6,089,962	77.16%	7,729	428,038	659,603	98.25%	5,601,473	83.66%	7.
8.	61-70	6,537	430,758	656,472	97.93%	6,520,720	82.62%	4,393	287,757	663,996	98.91%	5,889,230	87.96%	8.
9.	71-80	5,147	390,719	661,618	98.70%	6,911,439	87.57%	2,865	216,531	666,860	99.33%	6,105,762	91.19%	9.
10.	81-90	3,664	315,984	665,282	99.25%	7,227,423	91.58%	1,634	140,001	668,494	99.58%	6,245,763	93.28%	10.
11.	91-100	2,406	230,979	667,688	99.61%	7,458,402	94.50%	971	92,980	669,465	99.72%	6,338,742	94.67%	11.
12.	101-200	2,241	274,383	669,929	99.94%	7,732,786	97.98%	1,497	193,502	670,962	99.94%	6,532,245	97.56%	12.
13.	201-300	220	54,284	670,149	99.97%	7,787,070	98.67%	217	52,309	671,179	99.98%	6,584,554	98.34%	13.
14.	301-400	79	27,650	670,228	99.98%	7,814,719	99.02%	69	24,243	671,248	99.99%	6,608,797	98.70%	14.
15.	401-500	46	21,483	670,274	99.99%	7,836,202	99.29%	21	9,393	671,269	99.99%	6,618,190	98.84%	15.
16.	501-600	22	12,051	670,296	99.99%	7,848,253	99.44%	15	8,467	671,284	99.99%	6,626,658	98.97%	16.
17.	601-700	9	5,774	670,304	100.00%	7,854,028	99.52%	17	11,007	671,300	99.99%	6,637,665	99.13%	17.
18.	701-800	10	7,590	670,314	100.00%	7,861,617	99.61%	9	6,798	671,309	99.99%	6,644,462	99.24%	18.
19.	801-900	8	6,712	670,322	100.00%	7,868,329	99.70%	6	5,075	671,315	100.00%	6,649,537	99.31%	19.
20.	901-1000	1	957	670,323	100.00%	7,869,286	99.71%	4	3,782	671,319	100.00%	6,653,319	99.37%	20.
21.	1001-1100	-	-	670,323	100.00%	7,869,286	99.71%	1	1,001	671,320	100.00%	6,654,320	99.38%	21.
22.	1101-1200	-	-	670,323	100.00%	7,869,286	99.71%	3	3,420	671,323	100.00%	6,657,740	99.43%	22.
23.	1201-1300	-	-	670,323	100.00%	7,869,286	99.71%	-	-	671,323	100.00%	6,657,740	99.43%	23.
24.	1301-1400	-	-	670,323	100.00%	7,869,286	99.71%	3	4,036	671,326	100.00%	6,661,776	99.49%	24.
25.	1401-1500	-	-	670,323	100.00%	7,869,286	99.71%	7	10,079	671,333	100.00%	6,671,855	99.64%	25.
26.	1501-1600	2	3,048	670,325	100.00%	7,872,334	99.75%	3	4,552	671,336	100.00%	6,676,407	99.71%	26.
27.	1601-1700	2	3,354	670,327	100.00%	7,875,688	99.79%	2	3,283	671,338	100.00%	6,679,690	99.76%	27.
28.	1701-1800	-	-	670,327	100.00%	7,875,688	99.79%	-	-	671,338	100.00%	6,679,690	99.76%	28.
29.	1801-1900	-	-	670,327	100.00%	7,875,688	99.79%	-	-	671,338	100.00%	6,679,690	99.76%	29.
30.	1901-2000	-	-	670,327	100.00%	7,875,688	99.79%	1	1,926	671,339	100.00%	6,681,616	99.79%	30.
31.	2001-2100	-	-	670,327	100.00%	7,875,688	99.79%	-	-	671,339	100.00%	6,681,616	99.79%	31.
32.	2101-2200	-	-	670,327	100.00%	7,875,688	99.79%	1	2,116	671,340	100.00%	6,683,732	99.82%	32.
33.	2201-2300	5	11,097	670,332	100.00%	7,886,785	99.93%	-	-	671,340	100.00%	6,683,732	99.82%	33.
34.	2301-2400	-	-	670,332	100.00%	7,886,785	99.93%	-	-	671,340	100.00%	6,683,732	99.82%	34.
35.	2401-2500	-	-	670,332	100.00%	7,886,785	99.93%	1	2,453	671,341	100.00%	6,686,185	99.86%	35.
36.	2501-2600	-	-	670,332	100.00%	7,886,785	99.93%	2	5,071	671,343	100.00%	6,691,256	99.93%	36.
37.	2601-2700	-	-	670,332	100.00%	7,886,785	99.93%	-	-	671,343	100.00%	6,691,256	99.93%	37.
38.	2701-2800	-	-	670,332	100.00%	7,886,785	99.93%	-	-	671,343	100.00%	6,691,256	99.93%	38.
39.	2801-2900	-	-	670,332	100.00%	7,886,785	99.93%	-	-	671,343	100.00%	6,691,256	99.93%	39.
40.	2901-3000	-	-	670,332	100.00%	7,886,785	99.93%	-	-	671,343	100.00%	6,691,256	99.93%	40.
41.	Over 3000	1	5,460	670,333	100.00%	7,892,245	100.00%	1	4,400	671,344	100.00%	6,695,656	100.00%	41.
		Average Number of Customers:		111,722				Average Number of Customers:		111,891				
		Average Load:		12	kW per bill			Average Load:		10	kW per bill			
		Median Load:		5	kW per bill			Median Load:		5	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 XS and S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	28,080	-	28,080	4.19%	-	0.00%	28,780	-	28,780	4.29%	-	0.00%	1.
2.	1-100	79,286	3,231,757	107,365	16.02%	3,231,757	0.14%	78,784	3,267,062	107,564	16.02%	3,267,062	0.19%	2.
3.	101-200	44,511	6,745,849	151,876	22.66%	9,977,605	0.45%	47,103	7,056,801	154,667	23.04%	10,323,863	0.60%	3.
4.	201-300	33,883	8,557,648	185,759	27.71%	18,535,254	0.83%	37,106	9,283,239	191,773	28.57%	19,607,102	1.13%	4.
5.	301-400	28,443	10,116,702	214,202	31.95%	28,651,955	1.28%	32,762	11,526,110	224,536	33.45%	31,133,212	1.80%	5.
6.	401-500	25,571	11,725,462	239,772	35.77%	40,377,417	1.80%	29,801	13,482,657	254,337	37.88%	44,615,869	2.58%	6.
7.	501-750	53,619	33,797,715	293,391	43.77%	74,175,132	3.31%	64,412	40,147,725	318,749	47.48%	84,763,594	4.90%	7.
8.	751-1,000	40,506	35,873,708	333,897	49.81%	110,048,840	4.91%	49,028	42,849,627	367,776	54.78%	127,613,221	7.38%	8.
9.	1,001-1,500	58,600	73,714,293	392,497	58.55%	183,763,133	8.20%	65,319	80,750,047	433,096	64.51%	208,363,268	12.05%	9.
10.	1,501-2,000	42,511	75,185,065	435,009	64.89%	258,948,199	11.55%	42,778	74,613,992	475,874	70.88%	282,977,260	16.36%	10.
11.	2,001-3,000	57,543	144,409,097	492,551	73.48%	403,357,295	18.00%	52,936	130,700,223	528,809	78.77%	413,677,483	23.92%	11.
12.	3,001-4,000	37,706	133,211,546	530,257	79.10%	536,568,842	23.94%	32,666	113,934,570	561,475	83.63%	527,612,053	30.50%	12.
13.	4,001-5,000	25,275	114,999,446	555,532	82.87%	651,568,287	29.07%	21,229	95,489,459	582,704	86.80%	623,101,512	36.03%	13.
14.	5,001-7,500	38,032	236,442,602	593,564	88.55%	888,010,889	39.62%	32,588	199,927,009	615,292	91.65%	823,028,521	47.58%	14.
15.	7,501-10,000	21,376	188,075,482	614,940	91.74%	1,076,086,371	48.01%	17,432	151,546,083	632,723	94.25%	974,574,603	56.35%	15.
16.	10,001-15,000	22,882	284,091,387	637,821	95.15%	1,360,177,758	60.69%	17,294	211,432,681	650,017	96.82%	1,186,007,284	68.57%	16.
17.	15,001-20,000	11,636	204,710,745	649,457	96.89%	1,564,888,503	69.82%	8,997	156,601,667	659,014	98.16%	1,342,608,951	77.62%	17.
18.	20,001-25,000	7,440	169,355,157	656,897	98.00%	1,734,243,660	77.38%	5,434	121,923,897	664,448	98.97%	1,464,532,848	84.67%	18.
19.	25,001-30,000	5,150	143,460,694	662,047	98.76%	1,877,704,354	83.78%	3,163	86,717,166	667,611	99.44%	1,551,250,013	89.69%	19.
20.	30,001-35,000	3,448	113,236,052	665,495	99.28%	1,990,940,406	88.83%	1,573	50,970,061	669,184	99.68%	1,602,220,075	92.63%	20.
21.	35,001-40,000	2,064	78,294,392	667,559	99.59%	2,069,234,798	92.32%	806	30,184,396	669,991	99.80%	1,632,404,471	94.38%	21.
22.	40,001-50,000	1,760	78,648,180	669,318	99.85%	2,147,882,978	95.83%	701	31,107,363	670,692	99.90%	1,663,511,834	96.18%	22.
23.	50,001-75,000	654	38,069,658	669,973	99.95%	2,185,952,636	97.53%	394	23,099,441	671,086	99.96%	1,686,611,275	97.51%	23.
24.	75,001-100,000	123	10,881,384	670,096	99.96%	2,196,834,020	98.02%	80	7,046,898	671,167	99.97%	1,693,658,173	97.92%	24.
25.	100,001-125,000	88	9,854,268	670,184	99.98%	2,206,688,289	98.46%	68	7,724,372	671,235	99.98%	1,701,382,545	98.37%	25.
26.	125,001-150,000	47	6,561,279	670,231	99.98%	2,213,249,568	98.75%	35	4,749,847	671,270	99.99%	1,706,132,393	98.64%	26.
27.	150,001-200,000	50	8,836,517	670,282	99.99%	2,222,086,085	99.14%	25	4,238,695	671,294	99.99%	1,710,371,088	98.89%	27.
28.	200,001-300,000	33	8,114,219	670,314	100.00%	2,230,200,305	99.51%	22	5,160,145	671,316	100.00%	1,715,531,233	99.18%	28.
29.	300,001-400,000	10	3,549,818	670,324	100.00%	2,233,750,122	99.66%	9	3,090,561	671,325	100.00%	1,718,621,794	99.36%	29.
30.	400,001-500,000	6	2,669,653	670,330	100.00%	2,236,419,775	99.78%	4	1,759,557	671,329	100.00%	1,720,381,351	99.47%	30.
31.	500,001-750,000	2	1,221,392	670,332	100.00%	2,237,641,167	99.84%	15	9,250,064	671,344	100.00%	1,729,631,415	100.00%	31.
32.	750,001-1,000,000	-	-	670,332	100.00%	2,237,641,167	99.84%	-	-	671,344	100.00%	1,729,631,415	100.00%	32.
33.	Over 1,000,000	1	3,651,264	670,333	100.00%	2,241,292,431	100.00%	-	-	671,344	100.00%	1,729,631,415	100.00%	33.

Average Number of Customers:	111,722		Average Number of Customers:	111,891	
Average Consumption:	3,344	kWh per bill	Average Consumption:	2,576	kWh per bill
Median Consumption:	1,010	kWh per bill	Median Consumption:	823	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	104	-	104	0.39%	-	0.00%	139	-	139	0.52%	-	0.00%	1.
2.	1-10	98	466	202	0.76%	466	0.01%	170	802	309	1.16%	802	0.02%	2.
3.	11-20	72	1,076	274	1.03%	1,542	0.03%	119	1,828	428	1.61%	2,630	0.06%	3.
4.	21-30	80	2,015	354	1.34%	3,557	0.07%	139	3,575	567	2.13%	6,204	0.15%	4.
5.	31-40	85	3,057	439	1.66%	6,614	0.13%	165	5,981	731	2.75%	12,185	0.29%	5.
6.	41-50	94	4,275	533	2.01%	10,889	0.22%	308	14,028	1,039	3.91%	26,214	0.62%	6.
7.	51-60	103	5,745	636	2.40%	16,634	0.33%	663	36,974	1,703	6.40%	63,187	1.49%	7.
8.	61-70	165	10,868	801	3.02%	27,502	0.55%	1,017	66,825	2,720	10.23%	130,013	3.07%	8.
9.	71-80	331	24,983	1,132	4.27%	52,485	1.06%	1,644	124,384	4,364	16.41%	254,397	6.00%	9.
10.	81-90	604	51,845	1,736	6.55%	104,330	2.10%	1,994	170,727	6,358	23.91%	425,123	10.03%	10.
11.	91-100	1,167	111,664	2,903	10.95%	215,995	4.34%	1,956	186,467	8,314	31.26%	611,590	14.43%	11.
12.	101-200	14,212	2,016,649	17,115	64.57%	2,232,644	44.89%	11,619	1,644,215	19,933	74.95%	2,255,805	53.23%	12.
13.	201-300	5,829	1,428,056	22,943	86.56%	3,660,700	73.60%	4,563	1,116,615	24,497	92.11%	3,372,420	79.58%	13.
14.	301-400	2,900	992,616	25,843	97.50%	4,653,316	93.56%	1,527	516,364	26,023	97.85%	3,888,784	91.76%	14.
15.	401-500	531	228,823	26,374	99.50%	4,882,139	98.16%	330	146,099	26,353	99.09%	4,034,883	95.21%	15.
16.	501-600	64	34,556	26,438	99.74%	4,916,695	98.85%	93	50,072	26,446	99.44%	4,084,955	96.39%	16.
17.	601-700	30	19,276	26,468	99.85%	4,935,971	99.24%	42	27,038	26,488	99.59%	4,111,993	97.03%	17.
18.	701-800	15	11,223	26,483	99.91%	4,947,194	99.47%	16	12,074	26,504	99.65%	4,124,067	97.31%	18.
19.	801-900	11	9,552	26,494	99.95%	4,956,746	99.66%	16	13,499	26,520	99.71%	4,137,567	97.63%	19.
20.	901-1000	3	2,766	26,497	99.96%	4,959,512	99.71%	17	16,102	26,537	99.78%	4,153,669	98.01%	20.
21.	1001-1100	2	2,118	26,499	99.97%	4,961,630	99.76%	9	9,513	26,546	99.81%	4,163,182	98.24%	21.
22.	1101-1200	4	4,586	26,503	99.98%	4,966,216	99.85%	9	10,415	26,555	99.85%	4,173,597	98.48%	22.
23.	1201-1300	-	-	26,503	99.98%	4,966,216	99.85%	5	6,238	26,560	99.86%	4,179,835	98.63%	23.
24.	1301-1400	1	1,327	26,504	99.99%	4,967,543	99.87%	10	13,542	26,570	99.90%	4,193,377	98.95%	24.
25.	1401-1500	2	2,934	26,506	100.00%	4,970,477	99.93%	6	8,678	26,576	99.92%	4,202,055	99.15%	25.
26.	1501-1600	-	-	26,506	100.00%	4,970,477	99.93%	5	7,852	26,581	99.94%	4,209,907	99.34%	26.
27.	1601-1700	-	-	26,506	100.00%	4,970,477	99.93%	7	11,501	26,588	99.97%	4,221,408	99.61%	27.
28.	1701-1800	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,588	99.97%	4,221,408	99.61%	28.
29.	1801-1900	-	-	26,506	100.00%	4,970,477	99.93%	1	1,831	26,589	99.97%	4,223,239	99.65%	29.
30.	1901-2000	-	-	26,506	100.00%	4,970,477	99.93%	3	5,903	26,592	99.98%	4,229,142	99.79%	30.
31.	2001-2100	-	-	26,506	100.00%	4,970,477	99.93%	1	2,076	26,593	99.99%	4,231,218	99.84%	31.
32.	2101-2200	-	-	26,506	100.00%	4,970,477	99.93%	2	4,323	26,595	100.00%	4,235,541	99.94%	32.
33.	2201-2300	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,595	100.00%	4,235,541	99.94%	33.
34.	2301-2400	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,595	100.00%	4,235,541	99.94%	34.
35.	2401-2500	-	-	26,506	100.00%	4,970,477	99.93%	1	2,419	26,596	100.00%	4,237,960	100.00%	35.
36.	2501-2600	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,596	100.00%	4,237,960	100.00%	36.
37.	2601-2700	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,596	100.00%	4,237,960	100.00%	37.
38.	2701-2800	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,596	100.00%	4,237,960	100.00%	38.
39.	2801-2900	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,596	100.00%	4,237,960	100.00%	39.
40.	2901-3000	-	-	26,506	100.00%	4,970,477	99.93%	-	-	26,596	100.00%	4,237,960	100.00%	40.
41.	Over 3000	1	3,324	26,507	100.00%	4,973,801	100.00%	-	-	26,596	100.00%	4,237,960	100.00%	41.
	Average Number of Customers:			4,418				Average Number of Customers:		4,433				
	Average Load:			188	kW per bill			Average Load:		159	kW per bill			
	Median Load:			186	kW per bill			Median Load:		141	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	59	-	59	0.22%	-	0.00%	82	-	82	0.31%	-	0.00%	1.
2.	1-100	8	592	67	0.25%	592	0.00%	16	1,051	98	0.37%	1,051	0.00%	2.
3.	101-200	14	2,117	81	0.31%	2,709	0.00%	25	3,423	123	0.46%	4,474	0.00%	3.
4.	201-300	13	3,275	94	0.35%	5,984	0.00%	27	6,502	150	0.56%	10,976	0.00%	4.
5.	301-400	23	8,260	117	0.44%	14,244	0.00%	23	7,870	173	0.65%	18,846	0.00%	5.
6.	401-500	8	3,834	125	0.47%	18,078	0.00%	14	6,446	187	0.70%	25,292	0.00%	6.
7.	501-750	28	18,155	153	0.58%	36,232	0.00%	55	34,968	242	0.91%	60,260	0.00%	7.
8.	751-1,000	43	37,757	196	0.74%	73,989	0.00%	34	29,977	276	1.04%	90,238	0.01%	8.
9.	1,001-1,500	42	52,154	238	0.90%	126,144	0.01%	70	84,569	346	1.30%	174,807	0.01%	9.
10.	1,501-2,000	41	71,717	279	1.05%	197,861	0.01%	44	75,436	390	1.47%	250,243	0.02%	10.
11.	2,001-3,000	67	171,462	346	1.31%	369,322	0.02%	143	358,314	533	2.00%	608,557	0.04%	11.
12.	3,001-4,000	82	292,098	428	1.62%	661,421	0.04%	127	445,445	660	2.48%	1,054,002	0.07%	12.
13.	4,001-5,000	88	393,774	516	1.95%	1,055,195	0.06%	120	535,925	780	2.93%	1,589,927	0.11%	13.
14.	5,001-7,500	238	1,508,637	754	2.85%	2,563,831	0.14%	386	2,417,854	1,166	4.38%	4,007,780	0.27%	14.
15.	7,501-10,000	267	2,344,132	1,021	3.85%	4,907,963	0.27%	447	3,875,837	1,613	6.06%	7,883,617	0.54%	15.
16.	10,001-15,000	672	8,531,577	1,694	6.39%	13,439,540	0.74%	1,028	12,856,595	2,640	9.93%	20,740,213	1.41%	16.
17.	15,001-20,000	807	14,203,791	2,501	9.43%	27,643,331	1.53%	1,449	25,333,413	4,089	15.37%	46,073,625	3.13%	17.
18.	20,001-25,000	949	21,350,225	3,450	13.02%	48,993,555	2.71%	1,820	40,758,771	5,908	22.22%	86,832,396	5.90%	18.
19.	25,001-30,000	1,129	31,050,945	4,579	17.28%	80,044,500	4.43%	2,019	54,959,700	7,928	29.81%	141,792,096	9.63%	19.
20.	30,001-35,000	1,378	44,840,176	5,958	22.48%	124,884,677	6.91%	2,129	68,560,301	10,057	37.82%	210,352,397	14.29%	20.
21.	35,001-40,000	1,567	58,818,296	7,525	28.39%	183,702,972	10.16%	2,128	78,778,627	12,186	45.82%	289,131,024	19.64%	21.
22.	40,001-50,000	3,553	159,897,785	11,078	41.79%	343,600,757	19.01%	3,377	149,427,559	15,563	58.52%	438,558,583	29.80%	22.
23.	50,001-75,000	6,651	407,310,434	17,729	66.89%	750,911,191	41.54%	5,095	307,745,271	20,658	77.67%	746,303,854	50.71%	23.
24.	75,001-100,000	3,694	319,019,222	21,423	80.82%	1,069,930,414	59.19%	2,572	219,271,082	23,230	87.34%	965,574,936	65.60%	24.
25.	100,001-125,000	2,104	233,130,550	23,527	88.76%	1,303,060,964	72.08%	1,350	148,296,256	24,580	92.42%	1,113,871,191	75.68%	25.
26.	125,001-150,000	1,219	165,734,506	24,746	93.36%	1,468,795,469	81.25%	781	105,573,108	25,360	95.35%	1,219,444,299	82.85%	26.
27.	150,001-200,000	1,234	211,640,200	25,981	98.02%	1,680,435,669	92.96%	845	142,511,749	26,205	98.53%	1,361,956,048	92.54%	27.
28.	200,001-300,000	478	107,752,138	26,459	99.82%	1,788,187,808	98.92%	283	63,251,294	26,488	99.59%	1,425,207,343	96.83%	28.
29.	300,001-400,000	32	10,829,503	26,491	99.94%	1,799,017,311	99.52%	60	20,531,844	26,548	99.82%	1,445,739,187	98.23%	29.
30.	400,001-500,000	11	4,767,114	26,502	99.98%	1,803,784,425	99.78%	29	12,950,568	26,577	99.93%	1,458,689,755	99.11%	30.
31.	500,001-750,000	4	2,381,316	26,506	100.00%	1,806,165,741	99.91%	15	8,879,879	26,592	99.98%	1,467,569,634	99.71%	31.
32.	750,001-1,000,000	-	-	26,506	100.00%	1,806,165,741	99.91%	1	865,412	26,593	99.99%	1,468,435,045	99.77%	32.
33.	Over 1,000,000	1	1,569,545	26,507	100.00%	1,807,735,286	100.00%	3	3,371,577	26,596	100.00%	1,471,806,622	100.00%	33.
	Average Number of Customers:			4,418				Average Number of Customers:		4,433				
	Average Consumption:			68,198	kWh per bill			Average Consumption:		55,339	kWh per bill			
	Median Consumption:			63,486	kWh per bill			Median Consumption:		49,835	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 Large**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	16	-	16	0.26%	-	0.00%	14	-	14	0.23%	-	0.00%	1.
2.	1-10	4	26	21	0.33%	26	0.00%	3	17	17	0.28%	17	0.00%	2.
3.	11-20	1	12	22	0.35%	38	0.00%	5	100	22	0.36%	117	0.00%	3.
4.	21-30	5	142	27	0.43%	180	0.00%	3	85	26	0.41%	202	0.01%	4.
5.	31-40	3	105	30	0.48%	285	0.01%	-	-	26	0.41%	202	0.01%	5.
6.	41-50	4	182	34	0.54%	467	0.01%	3	133	29	0.46%	335	0.01%	6.
7.	51-60	5	276	39	0.63%	743	0.02%	2	116	31	0.50%	451	0.01%	7.
8.	61-70	4	267	43	0.69%	1,010	0.02%	2	133	33	0.53%	584	0.02%	8.
9.	71-80	6	463	49	0.79%	1,473	0.03%	3	236	36	0.58%	820	0.02%	9.
10.	81-90	4	360	53	0.86%	1,833	0.04%	2	170	38	0.61%	990	0.03%	10.
11.	91-100	4	384	57	0.92%	2,217	0.05%	6	574	44	0.71%	1,564	0.04%	11.
12.	101-200	41	6,048	98	1.58%	8,265	0.19%	104	16,717	148	2.39%	18,280	0.49%	12.
13.	201-300	86	21,746	185	2.97%	30,012	0.68%	425	109,259	573	9.26%	127,539	3.41%	13.
14.	301-400	549	196,116	733	11.80%	226,127	5.14%	1,376	476,087	1,949	31.47%	603,626	16.13%	14.
15.	401-500	1,402	616,481	2,135	34.37%	842,609	19.14%	1,287	565,530	3,235	52.24%	1,169,156	31.24%	15.
16.	501-600	1,211	648,399	3,346	53.86%	1,491,008	33.86%	894	478,698	4,130	66.68%	1,647,854	44.03%	16.
17.	601-700	732	460,269	4,079	65.65%	1,951,277	44.32%	483	305,873	4,613	74.49%	1,953,727	52.21%	17.
18.	701-800	432	315,102	4,511	72.60%	2,266,379	51.47%	344	251,881	4,957	80.05%	2,205,608	58.94%	18.
19.	801-900	377	312,030	4,888	78.67%	2,578,409	58.56%	271	224,192	5,228	84.42%	2,429,800	64.93%	19.
20.	901-1000	235	218,073	5,123	82.45%	2,796,482	63.51%	148	137,305	5,376	86.82%	2,567,106	68.60%	20.
21.	1001-1100	200	203,966	5,323	85.67%	3,000,448	68.15%	139	141,974	5,515	89.06%	2,709,079	72.39%	21.
22.	1101-1200	173	194,211	5,496	88.46%	3,194,659	72.56%	130	145,877	5,645	91.16%	2,854,956	76.29%	22.
23.	1201-1300	145	176,243	5,641	90.79%	3,370,902	76.56%	119	144,914	5,764	93.07%	2,999,870	80.16%	23.
24.	1301-1400	81	106,676	5,722	92.09%	3,477,578	78.98%	76	100,185	5,839	94.29%	3,100,055	82.84%	24.
25.	1401-1500	70	98,737	5,791	93.22%	3,576,315	81.23%	73	102,939	5,912	95.46%	3,202,994	85.59%	25.
26.	1501-1600	61	91,673	5,852	94.19%	3,667,988	83.31%	53	80,538	5,965	96.32%	3,283,532	87.74%	26.
27.	1601-1700	53	85,836	5,905	95.05%	3,753,824	85.26%	55	89,353	6,020	97.21%	3,372,885	90.13%	27.
28.	1701-1800	58	99,441	5,964	95.99%	3,853,265	87.52%	32	54,137	6,052	97.72%	3,427,022	91.57%	28.
29.	1801-1900	43	77,960	6,007	96.68%	3,931,225	89.29%	34	60,897	6,086	98.27%	3,487,919	93.20%	29.
30.	1901-2000	37	70,046	6,044	97.28%	4,001,271	90.88%	27	50,687	6,112	98.70%	3,538,606	94.56%	30.
31.	2001-2100	35	69,754	6,079	97.84%	4,071,025	92.46%	31	61,555	6,143	99.19%	3,600,161	96.20%	31.
32.	2101-2200	30	62,324	6,108	98.32%	4,133,349	93.88%	20	42,950	6,163	99.52%	3,643,111	97.35%	32.
33.	2201-2300	29	62,833	6,137	98.78%	4,196,182	95.30%	6	13,579	6,169	99.62%	3,656,690	97.71%	33.
34.	2301-2400	26	58,789	6,163	99.19%	4,254,971	96.64%	5	11,731	6,175	99.70%	3,668,421	98.02%	34.
35.	2401-2500	13	32,048	6,176	99.41%	4,287,019	97.37%	1	2,419	6,176	99.72%	3,670,840	98.09%	35.
36.	2501-2600	4	10,227	6,180	99.47%	4,297,246	97.60%	-	-	6,176	99.72%	3,670,840	98.09%	36.
37.	2601-2700	8	21,123	6,188	99.60%	4,318,369	98.08%	2	5,278	6,178	99.75%	3,676,118	98.23%	37.
38.	2701-2800	7	19,180	6,196	99.72%	4,337,549	98.51%	3	8,238	6,181	99.80%	3,684,356	98.45%	38.
39.	2801-2900	2	5,752	6,198	99.75%	4,343,301	98.65%	1	2,846	6,182	99.82%	3,687,202	98.53%	39.
40.	2901-3000	2	5,909	6,200	99.79%	4,349,210	98.78%	1	3,000	6,183	99.83%	3,690,202	98.61%	40.
41.	Over 3000	13	53,742	6,213	100.00%	4,402,952	100.00%	10	52,136	6,193	100.00%	3,742,338	100.00%	41.
	Average Number of Customers:			1,036				Average Number of Customers:		1,032				
	Average Load:			709	kW per bill			Average Load:		604	kW per bill			
	Median Load:			580	kW per bill			Median Load:		490	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 Large**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	11	-	11	0.18%	-	0.00%	14	-	14	0.23%	-	0.00%	1.
2.	1-100	-	-	11	0.18%	-	0.00%	-	-	14	0.23%	-	0.00%	2.
3.	101-200	-	-	11	0.18%	-	0.00%	-	-	14	0.23%	-	0.00%	3.
4.	201-300	-	-	11	0.18%	-	0.00%	-	-	14	0.23%	-	0.00%	4.
5.	301-400	-	-	11	0.18%	-	0.00%	-	-	14	0.23%	-	0.00%	5.
6.	401-500	-	-	11	0.18%	-	0.00%	1	494	15	0.25%	494	0.00%	6.
7.	501-750	-	-	11	0.18%	-	0.00%	-	-	15	0.25%	494	0.00%	7.
8.	751-1,000	1	990	12	0.20%	990	0.00%	1	823	16	0.26%	1,316	0.00%	8.
9.	1,001-1,500	-	-	12	0.20%	990	0.00%	-	-	16	0.26%	1,316	0.00%	9.
10.	1,501-2,000	1	1,650	13	0.21%	2,639	0.00%	-	-	16	0.26%	1,316	0.00%	10.
11.	2,001-3,000	2	4,949	15	0.25%	7,588	0.00%	5	12,831	21	0.35%	14,147	0.00%	11.
12.	3,001-4,000	4	14,846	19	0.31%	22,433	0.00%	3	11,926	25	0.40%	26,074	0.00%	12.
13.	4,001-5,000	1	4,701	21	0.33%	27,134	0.00%	5	22,866	30	0.48%	48,940	0.00%	13.
14.	5,001-7,500	7	46,207	28	0.45%	73,341	0.00%	9	56,301	39	0.63%	105,241	0.01%	14.
15.	7,501-10,000	10	92,784	38	0.61%	166,125	0.01%	8	76,864	47	0.76%	182,105	0.01%	15.
16.	10,001-15,000	16	204,559	54	0.87%	370,684	0.02%	13	167,875	60	0.97%	349,980	0.02%	16.
17.	15,001-20,000	6	109,073	61	0.97%	479,757	0.02%	14	256,254	75	1.20%	606,234	0.04%	17.
18.	20,001-25,000	16	374,643	77	1.24%	854,400	0.04%	18	413,663	93	1.50%	1,019,897	0.06%	18.
19.	25,001-30,000	13	374,272	90	1.45%	1,228,672	0.06%	18	515,655	111	1.80%	1,535,552	0.09%	19.
20.	30,001-35,000	16	525,820	107	1.72%	1,754,492	0.09%	21	708,863	133	2.15%	2,244,415	0.13%	20.
21.	35,001-40,000	13	495,757	120	1.93%	2,250,249	0.11%	20	767,879	153	2.48%	3,012,294	0.18%	21.
22.	40,001-50,000	24	1,098,794	144	2.31%	3,349,043	0.17%	44	2,009,978	197	3.19%	5,022,272	0.30%	22.
23.	50,001-75,000	143	9,216,380	286	4.61%	12,565,423	0.63%	223	14,415,198	420	6.78%	19,437,470	1.17%	23.
24.	75,001-100,000	187	16,576,246	473	7.61%	29,141,669	1.47%	371	33,057,729	791	12.77%	52,495,199	3.15%	24.
25.	100,001-125,000	277	31,389,753	750	12.07%	60,531,422	3.05%	465	52,808,021	1,256	20.28%	105,303,220	6.33%	25.
26.	125,001-150,000	355	49,151,846	1,105	17.78%	109,683,268	5.53%	529	73,469,803	1,786	28.83%	178,773,023	10.74%	26.
27.	150,001-200,000	912	161,738,586	2,016	32.45%	271,421,853	13.69%	1,111	196,136,441	2,897	46.77%	374,909,464	22.53%	27.
28.	200,001-300,000	1,901	475,264,957	3,918	63.06%	746,686,811	37.65%	1,581	390,055,220	4,478	72.31%	764,964,684	45.97%	28.
29.	300,001-400,000	936	323,802,288	4,854	78.13%	1,070,489,099	53.98%	700	241,828,090	5,178	83.61%	1,006,792,775	60.50%	29.
30.	400,001-500,000	464	207,091,054	5,318	85.59%	1,277,580,152	64.42%	359	160,947,619	5,537	89.40%	1,167,740,394	70.18%	30.
31.	500,001-750,000	518	315,144,800	5,836	93.93%	1,592,724,953	80.31%	409	250,118,026	5,946	96.01%	1,417,858,420	85.21%	31.
32.	750,001-1,000,000	231	199,926,406	6,066	97.64%	1,792,651,358	90.40%	165	140,325,955	6,110	98.66%	1,558,184,375	93.64%	32.
33.	Over 1,000,000	147	190,475,591	6,213	100.00%	1,983,126,949	100.00%	83	105,827,285	6,193	100.00%	1,664,011,660	100.00%	33.

Average Number of Customers:	1,036		Average Number of Customers:	1,032	
Average Consumption:	319,190	kWh per bill	Average Consumption:	268,692	kWh per bill
Median Consumption:	262,889	kWh per bill	Median Consumption:	214,676	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	12	-	12	0.66%	-	0.00%	19	-	19	1.05%	-	0.00%	1.
2.	1-10	458	2,416	470	26.26%	2,416	3.15%	467	2,463	486	27.37%	2,463	3.76%	2.
3.	11-20	261	3,860	731	40.88%	6,276	8.18%	281	4,106	767	43.20%	6,569	10.03%	3.
4.	21-30	188	4,847	919	51.37%	11,123	14.49%	239	6,097	1,005	56.64%	12,665	19.33%	4.
5.	31-40	214	7,621	1,133	63.35%	18,744	24.42%	213	7,630	1,218	68.63%	20,295	30.98%	5.
6.	41-50	156	7,218	1,290	72.09%	25,962	33.82%	184	8,459	1,402	79.01%	28,754	43.90%	6.
7.	51-60	150	8,349	1,440	80.49%	34,312	44.70%	133	7,410	1,536	86.51%	36,163	55.21%	7.
8.	61-70	111	7,306	1,551	86.70%	41,617	54.22%	84	5,482	1,619	91.23%	41,645	63.58%	8.
9.	71-80	60	4,570	1,611	90.05%	46,188	60.17%	50	3,819	1,670	94.06%	45,464	69.41%	9.
10.	81-90	69	5,948	1,680	93.90%	52,135	67.92%	36	3,117	1,706	96.11%	48,581	74.16%	10.
11.	91-100	46	4,513	1,726	96.48%	56,649	73.80%	22	2,094	1,728	97.33%	50,675	77.36%	11.
12.	101-200	49	6,436	1,775	99.23%	63,085	82.19%	33	4,229	1,760	99.17%	54,905	83.82%	12.
13.	201-300	4	1,031	1,779	99.45%	64,116	83.53%	12	2,843	1,772	99.83%	57,748	88.16%	13.
14.	301-400	5	1,704	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	14.
15.	401-500	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	15.
16.	501-600	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	16.
17.	601-700	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	17.
18.	701-800	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	18.
19.	801-900	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	19.
20.	901-1000	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	20.
21.	1001-1100	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	21.
22.	1101-1200	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	22.
23.	1201-1300	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	23.
24.	1301-1400	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	24.
25.	1401-1500	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	25.
26.	1501-1600	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	26.
27.	1601-1700	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	27.
28.	1701-1800	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	28.
29.	1801-1900	-	-	1,784	99.73%	65,820	85.75%	-	-	1,772	99.83%	57,748	88.16%	29.
30.	1901-2000	-	-	1,784	99.73%	65,820	85.75%	1	1,969	1,773	99.89%	59,717	91.16%	30.
31.	2001-2100	2	4,083	1,786	99.84%	69,903	91.07%	1	2,033	1,774	99.94%	61,750	94.27%	31.
32.	2101-2200	1	2,119	1,787	99.89%	72,022	93.83%	-	-	1,774	99.94%	61,750	94.27%	32.
33.	2201-2300	-	-	1,787	99.89%	72,022	93.83%	-	-	1,774	99.94%	61,750	94.27%	33.
34.	2301-2400	2	4,734	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	34.
35.	2401-2500	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	35.
36.	2501-2600	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	36.
37.	2601-2700	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	37.
38.	2701-2800	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	38.
39.	2801-2900	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	39.
40.	2901-3000	-	-	1,789	100.00%	76,756	100.00%	-	-	1,774	99.94%	61,750	94.27%	40.
41.	Over 3000	-	-	1,789	100.00%	76,756	100.00%	1	3,755	1,775	100.00%	65,505	100.00%	41.
		Average Number of Customers:		298				Average Number of Customers:		296				
		Average Load:		43	kW per bill			Average Load:		37	kW per bill			
		Median Load:		29	kW per bill			Median Load:		25	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU XS & S**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	4	-	4	0.22%	-	0.00%	18	-	18	1.00%	-	0.00%	1.
2.	1-100	16	1,111	20	1.10%	1,111	0.00%	12	952	30	1.67%	952	0.00%	2.
3.	101-200	15	2,299	34	1.92%	3,410	0.01%	21	3,537	50	2.83%	4,489	0.02%	3.
4.	201-300	15	3,687	49	2.75%	7,097	0.03%	33	8,681	83	4.67%	13,169	0.06%	4.
5.	301-400	27	9,389	76	4.23%	16,485	0.06%	21	7,518	104	5.83%	20,688	0.10%	5.
6.	401-500	18	7,917	93	5.22%	24,402	0.10%	13	5,966	116	6.56%	26,654	0.13%	6.
7.	501-750	71	43,627	164	9.18%	68,029	0.27%	62	39,982	178	10.06%	66,636	0.32%	7.
8.	751-1,000	57	49,833	221	12.37%	117,863	0.46%	57	52,409	236	13.28%	119,045	0.57%	8.
9.	1,001-1,500	78	95,594	299	16.71%	213,456	0.84%	79	100,557	315	17.72%	219,602	1.06%	9.
10.	1,501-2,000	76	132,551	375	20.95%	346,007	1.36%	66	118,514	381	21.44%	338,116	1.63%	10.
11.	2,001-3,000	140	356,566	514	28.75%	702,573	2.77%	216	572,401	597	33.61%	910,517	4.38%	11.
12.	3,001-4,000	160	554,140	675	37.71%	1,256,713	4.95%	103	368,448	699	39.39%	1,278,965	6.15%	12.
13.	4,001-5,000	88	388,300	762	42.61%	1,645,013	6.48%	77	362,317	776	43.72%	1,641,282	7.89%	13.
14.	5,001-7,500	139	866,466	901	50.36%	2,511,479	9.90%	168	1,065,730	944	53.17%	2,707,011	13.01%	14.
15.	7,501-10,000	126	1,106,949	1,027	57.39%	3,618,428	14.26%	155	1,427,455	1,099	61.89%	4,134,466	19.87%	15.
16.	10,001-15,000	234	2,964,500	1,261	70.48%	6,582,928	25.95%	246	3,130,039	1,344	75.72%	7,264,505	34.92%	16.
17.	15,001-20,000	140	2,416,774	1,401	78.28%	8,999,702	35.47%	128	2,327,951	1,472	82.94%	9,592,457	46.11%	17.
18.	20,001-25,000	111	2,508,046	1,512	84.50%	11,507,749	45.36%	120	2,850,509	1,593	89.72%	12,442,966	59.81%	18.
19.	25,001-30,000	101	2,715,341	1,613	90.16%	14,223,090	56.06%	65	1,845,543	1,658	93.39%	14,288,510	68.68%	19.
20.	30,001-35,000	47	1,526,975	1,660	92.80%	15,750,065	62.08%	29	958,717	1,686	95.00%	15,247,227	73.28%	20.
21.	35,001-40,000	38	1,430,022	1,699	94.94%	17,180,087	67.72%	36	1,384,219	1,722	97.00%	16,631,446	79.94%	21.
22.	40,001-50,000	53	2,391,829	1,752	97.91%	19,571,916	77.14%	30	1,379,940	1,751	98.67%	18,011,386	86.57%	22.
23.	50,001-75,000	22	1,231,043	1,773	99.12%	20,802,959	82.00%	15	898,451	1,766	99.50%	18,909,837	90.89%	23.
24.	75,001-100,000	6	485,474	1,779	99.45%	21,288,433	83.91%	4	370,350	1,770	99.72%	19,280,188	92.67%	24.
25.	100,001-125,000	2	227,640	1,781	99.56%	21,516,073	84.81%	2	223,450	1,772	99.83%	19,503,638	93.74%	25.
26.	125,001-150,000	3	428,623	1,784	99.73%	21,944,696	86.50%	-	-	1,772	99.83%	19,503,638	93.74%	26.
27.	150,001-200,000	-	-	1,784	99.73%	21,944,696	86.50%	-	-	1,772	99.83%	19,503,638	93.74%	27.
28.	200,001-300,000	1	209,259	1,785	99.78%	22,153,956	87.32%	1	221,701	1,773	99.89%	19,725,339	94.81%	28.
29.	300,001-400,000	-	-	1,785	99.78%	22,153,956	87.32%	1	372,417	1,774	99.94%	20,097,757	96.60%	29.
30.	400,001-500,000	1	422,451	1,786	99.84%	22,576,406	88.99%	-	-	1,774	99.94%	20,097,757	96.60%	30.
31.	500,001-750,000	-	-	1,786	99.84%	22,576,406	88.99%	1	707,901	1,775	100.00%	20,805,658	100.00%	31.
32.	750,001-1,000,000	2	1,745,631	1,788	99.95%	24,322,037	95.87%	-	-	1,775	100.00%	20,805,658	100.00%	32.
33.	Over 1,000,000	1	1,048,362	1,789	100.00%	25,370,399	100.00%	-	-	1,775	100.00%	20,805,658	100.00%	33.

Average Number of Customers:	298		
Average Consumption:	14,181	kWh per bill	
Median Consumption:	7,338	kWh per bill	

Average Number of Customers:	296
Average Consumption:	11,721
Median Consumption:	6,432

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	4	-	4	0.90%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-10	-	-	4	0.90%	-	0.00%	2	9	2	0.44%	9	0.01%	2.
3.	11-20	1	18	5	1.12%	18	0.02%	4	54	6	1.32%	63	0.07%	3.
4.	21-30	-	-	5	1.12%	18	0.02%	1	21	7	1.54%	84	0.10%	4.
5.	31-40	1	36	6	1.35%	54	0.06%	-	-	7	1.54%	84	0.10%	5.
6.	41-50	2	87	8	1.79%	141	0.15%	-	-	7	1.54%	84	0.10%	6.
7.	51-60	2	114	10	2.24%	255	0.27%	10	554	17	3.74%	638	0.76%	7.
8.	61-70	1	66	11	2.47%	321	0.34%	13	857	30	6.61%	1,495	1.77%	8.
9.	71-80	1	77	11	2.69%	398	0.42%	19	1,445	48	10.79%	2,940	3.49%	9.
10.	81-90	11	953	22	5.16%	1,351	1.43%	45	3,812	93	20.70%	6,752	8.01%	10.
11.	91-100	17	1,710	39	9.19%	3,061	3.24%	26	2,488	119	26.43%	9,240	10.96%	11.
12.	101-200	199	29,536	238	55.83%	32,597	34.55%	196	27,849	314	70.04%	37,089	43.98%	12.
13.	201-300	123	31,488	361	84.53%	64,085	67.92%	73	18,139	388	86.34%	55,228	65.48%	13.
14.	301-400	37	13,518	398	93.27%	77,603	82.25%	34	11,618	421	93.83%	66,847	79.26%	14.
15.	401-500	10	4,369	408	95.52%	81,972	86.88%	7	3,294	428	95.37%	70,140	83.16%	15.
16.	501-600	7	3,731	415	97.09%	85,703	90.84%	12	6,589	440	98.02%	76,729	90.98%	16.
17.	601-700	10	6,308	424	99.33%	92,011	97.52%	6	3,779	446	99.34%	80,508	95.46%	17.
18.	701-800	2	1,484	426	99.78%	93,495	99.09%	1	701	447	99.56%	81,209	96.29%	18.
19.	801-900	1	855	427	100.00%	94,350	100.00%	1	869	448	99.78%	82,078	97.32%	19.
20.	901-1000	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	20.
21.	1001-1100	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	21.
22.	1101-1200	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	22.
23.	1201-1300	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	23.
24.	1301-1400	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	24.
25.	1401-1500	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	25.
26.	1501-1600	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	26.
27.	1601-1700	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	27.
28.	1701-1800	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	28.
29.	1801-1900	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	29.
30.	1901-2000	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	30.
31.	2001-2100	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	31.
32.	2101-2200	-	-	427	100.00%	94,350	100.00%	-	-	448	99.78%	82,078	97.32%	32.
33.	2201-2300	-	-	427	100.00%	94,350	100.00%	1	2,262	449	100.00%	84,340	100.00%	33.
34.	2301-2400	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	34.
35.	2401-2500	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	35.
36.	2501-2600	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	36.
37.	2601-2700	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	37.
38.	2701-2800	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	38.
39.	2801-2900	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	39.
40.	2901-3000	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	40.
41.	Over 3000	-	-	427	100.00%	94,350	100.00%	-	-	449	100.00%	84,340	100.00%	41.
		Average Number of Customers:		71				Average Number of Customers:		75				
		Average Load:		221	kW per bill			Average Load:		188	kW per bill			
		Median Load:		186	kW per bill			Median Load:		141	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU Medium**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	101-200	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	201-300	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	301-400	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	401-500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	501-750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	751-1,000	-	-	-	0.00%	-	0.00%	1	805	1	0.22%	805	0.00%	8.
9.	1,001-1,500	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	805	0.00%	9.
10.	1,501-2,000	-	-	-	0.00%	-	0.00%	-	-	1	0.22%	805	0.00%	10.
11.	2,001-3,000	-	-	-	0.00%	-	0.00%	2	5,638	3	0.66%	6,443	0.02%	11.
12.	3,001-4,000	-	-	-	0.00%	-	0.00%	1	3,926	4	0.88%	10,370	0.03%	12.
13.	4,001-5,000	2	9,028	2	0.45%	9,028	0.02%	2	9,363	6	1.32%	19,733	0.06%	13.
14.	5,001-7,500	-	-	2	0.45%	9,028	0.02%	5	33,304	11	2.43%	53,036	0.16%	14.
15.	7,501-10,000	1	8,154	3	0.67%	17,182	0.05%	3	25,552	14	3.09%	78,588	0.24%	15.
16.	10,001-15,000	13	175,683	16	3.81%	192,865	0.51%	17	221,227	31	6.84%	299,815	0.92%	16.
17.	15,001-20,000	9	154,696	25	5.83%	347,560	0.93%	23	396,988	54	11.92%	696,803	2.15%	17.
18.	20,001-25,000	9	198,223	34	7.85%	545,783	1.46%	26	591,475	79	17.66%	1,288,277	3.97%	18.
19.	25,001-30,000	11	294,442	44	10.31%	840,225	2.24%	18	501,389	97	21.63%	1,789,667	5.51%	19.
20.	30,001-35,000	20	655,825	64	15.02%	1,496,051	3.99%	21	684,017	118	26.27%	2,473,683	7.62%	20.
21.	35,001-40,000	18	688,228	82	19.28%	2,184,279	5.83%	36	1,363,885	154	34.22%	3,837,569	11.82%	21.
22.	40,001-50,000	59	2,736,217	142	33.18%	4,920,497	13.13%	75	3,450,125	229	50.99%	7,287,693	22.45%	22.
23.	50,001-75,000	102	6,329,124	244	57.17%	11,249,620	30.02%	80	4,909,250	309	68.87%	12,196,944	37.58%	23.
24.	75,001-100,000	52	4,534,903	296	69.28%	15,784,523	42.12%	49	4,203,125	358	79.69%	16,400,069	50.52%	24.
25.	100,001-125,000	38	4,343,650	334	78.25%	20,128,173	53.71%	23	2,613,241	381	84.77%	19,013,310	58.57%	25.
26.	125,001-150,000	30	4,101,821	364	85.20%	24,229,994	64.65%	23	3,177,996	403	89.85%	22,191,306	68.36%	26.
27.	150,001-200,000	36	6,056,387	400	93.72%	30,286,381	80.81%	22	3,793,049	425	94.70%	25,984,355	80.05%	27.
28.	200,001-300,000	25	6,243,194	425	99.55%	36,529,576	97.47%	19	4,626,269	444	98.90%	30,610,624	94.30%	28.
29.	300,001-400,000	-	-	425	99.55%	36,529,576	97.47%	3	946,561	447	99.56%	31,557,185	97.22%	29.
30.	400,001-500,000	2	946,928	427	100.00%	37,476,504	100.00%	2	902,867	449	100.00%	32,460,052	100.00%	30.
31.	500,001-750,000	-	-	427	100.00%	37,476,504	100.00%	-	-	449	100.00%	32,460,052	100.00%	31.
32.	750,001-1,000,000	-	-	427	100.00%	37,476,504	100.00%	-	-	449	100.00%	32,460,052	100.00%	32.
33.	Over 1,000,000	-	-	427	100.00%	37,476,504	100.00%	-	-	449	100.00%	32,460,052	100.00%	33.

Average Number of Customers:	71		Average Number of Customers:	75	
Average Consumption:	87,767	kWh per bill	Average Consumption:	72,294	kWh per bill
Median Consumption:	63,486	kWh per bill	Median Consumption:	49,835	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU Large**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	2	-	2	0.72%	-	0.00%	4	-	4	1.42%	-	0.00%	1.
2.	1-10	-	-	2	0.72%	-	0.00%	1	10	5	1.78%	10	0.00%	2.
3.	11-20	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	3.
4.	21-30	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	4.
5.	31-40	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	5.
6.	41-50	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	6.
7.	51-60	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	7.
8.	61-70	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	8.
9.	71-80	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	9.
10.	81-90	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	10.
11.	91-100	-	-	2	0.72%	-	0.00%	-	-	5	1.78%	10	0.00%	11.
12.	101-200	4	699	6	2.16%	699	0.23%	2	243	7	2.49%	253	0.09%	12.
13.	201-300	-	-	6	2.16%	699	0.23%	-	-	7	2.49%	253	0.09%	13.
14.	301-400	5	1,851	11	3.96%	2,550	0.84%	27	9,610	34	12.10%	9,863	3.60%	14.
15.	401-500	33	14,886	44	15.83%	17,436	5.73%	45	19,969	79	28.11%	29,832	10.90%	15.
16.	501-600	40	21,989	83	30.22%	39,425	12.96%	23	12,622	102	36.30%	42,454	15.51%	16.
17.	601-700	26	17,172	109	39.57%	56,597	18.60%	21	14,007	123	43.77%	56,461	20.62%	17.
18.	701-800	8	5,943	117	42.45%	62,540	20.56%	29	21,592	153	54.09%	78,053	28.51%	18.
19.	801-900	20	16,970	137	49.64%	79,511	26.14%	17	14,533	170	60.14%	92,585	33.82%	19.
20.	901-1000	21	19,861	158	57.19%	99,372	32.66%	18	16,962	188	66.55%	109,547	40.01%	20.
21.	1001-1100	9	9,501	167	60.43%	108,873	35.79%	3	3,159	191	67.62%	112,706	41.17%	21.
22.	1101-1200	14	16,312	181	65.47%	125,185	41.15%	9	10,107	200	70.82%	122,813	44.86%	22.
23.	1201-1300	6	7,520	187	67.63%	132,705	43.62%	5	6,354	205	72.60%	129,167	47.18%	23.
24.	1301-1400	7	9,470	194	70.14%	142,175	46.73%	13	17,508	218	77.22%	146,675	53.58%	24.
25.	1401-1500	10	14,432	204	73.74%	156,607	51.48%	5	7,274	223	79.00%	153,949	56.23%	25.
26.	1501-1600	21	32,772	224	81.29%	189,379	62.25%	8	12,396	231	81.85%	166,345	60.76%	26.
27.	1601-1700	5	8,290	229	83.09%	197,669	64.98%	15	24,574	246	87.19%	190,919	69.74%	27.
28.	1701-1800	8	14,213	237	85.97%	211,882	69.65%	7	12,185	253	89.68%	203,104	74.19%	28.
29.	1801-1900	5	9,308	242	87.77%	221,190	72.71%	4	7,380	257	91.10%	210,484	76.88%	29.
30.	1901-2000	2	3,833	244	88.49%	225,023	73.97%	1	1,939	258	91.46%	212,423	77.59%	30.
31.	2001-2100	5	10,111	249	90.29%	235,134	77.29%	4	8,236	262	92.88%	220,659	80.60%	31.
32.	2101-2200	4	8,528	253	91.73%	243,662	80.09%	8	17,227	270	95.73%	237,886	86.89%	32.
33.	2201-2300	3	6,688	256	92.81%	250,350	82.29%	2	4,560	272	96.44%	242,446	88.56%	33.
34.	2301-2400	8	18,847	264	95.68%	269,197	88.49%	-	-	272	96.44%	242,446	88.56%	34.
35.	2401-2500	2	4,923	266	96.40%	274,120	90.10%	-	-	272	96.44%	242,446	88.56%	35.
36.	2501-2600	1	2,553	267	96.76%	276,673	90.94%	-	-	272	96.44%	242,446	88.56%	36.
37.	2601-2700	1	2,649	268	97.12%	279,322	91.81%	-	-	272	96.44%	242,446	88.56%	37.
38.	2701-2800	-	-	268	97.12%	279,322	91.81%	2	5,510	274	97.15%	247,956	90.57%	38.
39.	2801-2900	-	-	268	97.12%	279,322	91.81%	1	2,880	275	97.51%	250,836	91.62%	39.
40.	2901-3000	2	5,926	270	97.84%	285,248	93.76%	2	5,868	277	98.22%	256,704	93.77%	40.
41.	Over 3000	6	18,975	276	100.00%	304,223	100.00%	5	17,064	282	100.00%	273,768	100.00%	41.
		Average Number of Customers:		46				Average Number of Customers:		47				
		Average Load:		1,102	kW per bill			Average Load:		971	kW per bill			
		Median Load:		580	kW per bill			Median Load:		490	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-32 TOU Large**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (June through October)						WINTER (November through May)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	1	-	1	0.36%	-	0.00%	4	-	4	1.42%	-	0.00%	1.
2.	1-100	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	2.
3.	101-200	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	3.
4.	201-300	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	4.
5.	301-400	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	5.
6.	401-500	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	6.
7.	501-750	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	7.
8.	751-1,000	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	8.
9.	1,001-1,500	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	9.
10.	1,501-2,000	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	10.
11.	2,001-3,000	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	11.
12.	3,001-4,000	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	12.
13.	4,001-5,000	-	-	1	0.36%	-	0.00%	-	-	4	1.42%	-	0.00%	13.
14.	5,001-7,500	-	-	1	0.36%	-	0.00%	1	6,242	5	1.78%	6,242	0.00%	14.
15.	7,501-10,000	-	-	1	0.36%	-	0.00%	-	-	5	1.78%	6,242	0.00%	15.
16.	10,001-15,000	-	-	1	0.36%	-	0.00%	-	-	5	1.78%	6,242	0.00%	16.
17.	15,001-20,000	-	-	1	0.36%	-	0.00%	-	-	5	1.78%	6,242	0.00%	17.
18.	20,001-25,000	-	-	1	0.36%	-	0.00%	-	-	5	1.78%	6,242	0.00%	18.
19.	25,001-30,000	-	-	1	0.36%	-	0.00%	-	-	5	1.78%	6,242	0.00%	19.
20.	30,001-35,000	1	31,182	2	0.72%	31,182	0.02%	1	32,337	6	2.14%	38,579	0.03%	20.
21.	35,001-40,000	1	36,320	3	1.08%	67,502	0.04%	1	39,312	7	2.49%	77,891	0.06%	21.
22.	40,001-50,000	1	47,245	4	1.45%	114,747	0.07%	-	-	7	2.49%	77,891	0.06%	22.
23.	50,001-75,000	2	106,144	6	2.17%	220,891	0.14%	-	-	7	2.49%	77,891	0.06%	23.
24.	75,001-100,000	-	-	6	2.17%	220,891	0.14%	7	647,418	14	4.98%	725,308	0.52%	24.
25.	100,001-125,000	-	-	6	2.17%	220,891	0.14%	1	99,865	15	5.34%	825,173	0.59%	25.
26.	125,001-150,000	3	392,136	9	3.24%	613,027	0.39%	7	966,549	22	7.83%	1,791,722	1.29%	26.
27.	150,001-200,000	13	2,379,391	22	7.92%	2,992,418	1.91%	27	4,665,711	49	17.44%	6,457,433	4.64%	27.
28.	200,001-300,000	54	12,949,184	75	27.34%	15,941,601	10.20%	47	11,536,929	96	34.16%	17,994,362	12.92%	28.
29.	300,001-400,000	48	16,494,765	123	44.61%	32,436,366	20.75%	51	17,641,605	148	52.31%	35,635,967	25.59%	29.
30.	400,001-500,000	29	12,702,839	152	55.04%	45,139,205	28.87%	38	16,913,206	186	65.84%	52,549,172	37.73%	30.
31.	500,001-750,000	55	32,957,147	207	74.82%	78,096,352	49.95%	44	26,725,920	230	81.49%	79,275,092	56.92%	31.
32.	750,001-1,000,000	30	25,986,480	236	85.61%	104,082,832	66.57%	19	16,463,536	249	88.26%	95,738,628	68.75%	32.
33.	Over 1,000,000	40	52,268,735	276	100.00%	156,351,567	100.00%	33	43,523,746	282	100.00%	139,262,374	100.00%	33.

Average Number of Customers:	46		Average Number of Customers:	47	
Average Consumption:	566,447	kWh per bill	Average Consumption:	493,838	kWh per bill
Median Consumption:	437,462	kWh per bill	Median Consumption:	379,994	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	6	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-1000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	1001-1500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	1501-2000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	2001-2250	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	2251-2500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	2500-2750	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	2751-3000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	3001-3250	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	3251-3500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	3501-3750	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	3751-4000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	4001-4250	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	4251-4500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	4501-4750	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	4751-5000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	5001-5500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	5501-6000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	6001-6500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	6501-7000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	7001-7500	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	7501-8000	-	-	6	2.60%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	8001-8500	-	-	6	2.60%	-	0.00%	2	2,560	2	1.05%	2,560	0.33%	23.
24.	8501-9000	-	-	6	2.60%	-	0.00%	-	-	2	1.05%	2,560	0.33%	24.
25.	9001-9500	1	1,470	7	3.13%	1,470	0.16%	-	-	2	1.05%	2,560	0.33%	25.
26.	9501-10000	-	-	7	3.13%	1,470	0.16%	-	-	2	1.05%	2,560	0.33%	26.
27.	10001-12500	-	-	7	3.13%	1,470	0.16%	-	-	2	1.05%	2,560	0.33%	27.
28.	12501-15000	-	-	7	3.13%	1,470	0.16%	-	-	2	1.05%	2,560	0.33%	28.
29.	15001-17500	-	-	7	3.13%	1,470	0.16%	-	-	2	1.05%	2,560	0.33%	29.
30.	17501-20000	-	-	7	3.13%	1,470	0.16%	1	2,000	3	1.58%	4,560	0.59%	30.
31.	20001-22500	1	2,030	8	3.65%	3,500	0.38%	-	-	3	1.58%	4,560	0.59%	31.
32.	22501-25000	-	-	8	3.65%	3,500	0.38%	1	2,169	4	2.11%	6,729	0.87%	32.
33.	25001-27500	-	-	8	3.65%	3,500	0.38%	4	8,992	9	4.21%	15,721	2.03%	33.
34.	27501-30000	1	2,380	9	4.17%	5,880	0.64%	2	4,790	11	5.26%	20,511	2.65%	34.
35.	30001-32500	-	-	9	4.17%	5,880	0.64%	9	19,794	20	9.47%	40,305	5.21%	35.
36.	32501-35000	3	7,720	12	5.73%	13,600	1.48%	11	25,453	31	14.74%	65,758	8.51%	36.
37.	35001-37500	2	5,347	14	6.77%	18,947	2.06%	11	26,538	43	20.00%	92,296	11.94%	37.
38.	37501-40000	6	13,767	20	9.38%	32,714	3.56%	6	13,811	48	22.63%	106,107	13.72%	38.
39.	40001-60000	3	8,502	23	10.94%	41,216	4.48%	13	34,203	62	28.95%	140,310	18.15%	39.
40.	60001-80000	4	11,844	28	13.02%	53,060	5.77%	10	26,746	72	33.68%	167,056	21.61%	40.
41.	Over 80000	186	866,518	214	100.00%	919,578	100.00%	141	606,105	213	100.00%	773,161	100.00%	41.
		Average Number of Customers:		18				Average Number of Customers:		18				
		Average Load:		4,297	kW per bill			Average Load:		3,630	kW per bill			
		Median Load:		4,070	kW per bill			Median Load:		3,500	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-34, E-34 Primary, E-34 Transmission**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	100.001-250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	250,001-500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	500,001-600,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	600,001-700,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	700,001-800,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	800,001-900,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	900,001-1,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	1,000,001-1,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	1,250,001-1,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	1,500,001-1,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	1,750,001-2,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	2,000,001-2,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	2,250,001-2,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	2,500,001-2,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	2,750,001-3,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	3,000,001-3,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	3,250,001-3,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	3,500,001-3,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	3,750,001-4,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	4,000,001-4,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	4,500,001-5,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	5,000,001-6,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	6,000,001-7,000,000	-	-	-	0.00%	-	0.00%	2	277,703	2	1.05%	277,703	0.06%	25.
26.	7,000,001-8,000,000	1	178,362	1	0.53%	178,362	0.03%	-	-	2	1.05%	277,703	0.06%	26.
27.	8,000,001-9,000,000	1	226,335	2	1.06%	404,697	0.07%	1	195,009	3	1.58%	472,713	0.09%	27.
28.	9,000,001-10,000,000	1	254,627	3	1.60%	659,324	0.11%	-	-	3	1.58%	472,713	0.09%	28.
29.	10,000,001-12,500,000	-	-	3	1.60%	659,324	0.11%	1	452,965	4	2.11%	925,678	0.19%	29.
30.	12,500,001-15,000,000	-	-	3	1.60%	659,324	0.11%	-	-	4	2.11%	925,678	0.19%	30.
31.	15,000,001-20,000,000	-	-	3	1.60%	659,324	0.11%	1	727,583	6	2.63%	1,653,261	0.33%	31.
32.	20,000,001-30,000,000	6	5,590,725	9	4.26%	6,250,050	1.07%	7	6,701,907	12	5.79%	8,355,168	1.67%	32.
33.	Over 30,000,000	205	580,016,543	214	100.00%	586,266,593	100.00%	201	491,425,450	213	100.00%	499,780,618	100.00%	33.
	Average Number of Customers:			18				Average Number of Customers:		18				
	Average Consumption:			2,739,564	kWh per bill			Average Consumption:		2,346,388	kWh per bill			
	Median Consumption:			2,740,255	kWh per bill			Median Consumption:		2,275,933	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		LOAD				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-1000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	1001-1500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	1501-2000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	2001-2250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	2251-2500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	2500-2750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	2751-3000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	3001-3250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	3251-3500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	3501-3750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	3751-4000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	4001-4250	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	4251-4500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	4501-4750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	4751-5000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	5001-5500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	5501-6000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	6001-6500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	6501-7000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	7001-7500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	7501-8000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	8001-8500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	8501-9000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	9001-9500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	25.
26.	9501-10000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	26.
27.	10001-12500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	27.
28.	12501-15000	-	-	-	0.00%	-	0.00%	1	1,776	1	0.56%	1,776	0.19%	28.
29.	15001-17500	1	1,824	1	0.56%	1,824	0.18%	1	1,879	2	1.12%	3,655	0.40%	29.
30.	17501-20000	-	-	1	0.56%	1,824	0.18%	2	3,923	4	2.23%	7,578	0.82%	30.
31.	20001-22500	2	2,099	3	1.68%	3,923	0.38%	4	8,162	9	4.47%	15,740	1.71%	31.
32.	22501-25000	-	-	3	1.68%	3,923	0.38%	4	8,612	13	6.70%	24,352	2.65%	32.
33.	25001-27500	-	-	3	1.68%	3,923	0.38%	2	4,459	16	7.82%	28,811	3.13%	33.
34.	27501-30000	-	-	3	1.68%	3,923	0.38%	2	2,319	18	8.94%	31,130	3.39%	34.
35.	30001-32500	-	-	3	1.68%	3,923	0.38%	2	2,410	20	10.06%	33,540	3.65%	35.
36.	32501-35000	2	5,189	6	2.79%	9,112	0.89%	6	12,868	26	12.85%	46,408	5.05%	36.
37.	35001-37500	1	2,687	7	3.35%	11,799	1.15%	2	5,313	28	13.97%	51,721	5.63%	37.
38.	37501-40000	1	2,760	8	3.91%	14,559	1.42%	9	22,062	37	18.44%	73,783	8.03%	38.
39.	40001-60000	4	11,246	12	6.15%	25,805	2.52%	3	8,587	40	20.11%	82,370	8.96%	39.
40.	60001-80000	1	2,903	13	6.70%	28,708	2.81%	6	14,818	46	22.91%	97,188	10.57%	40.
41.	Over 80000	186	994,195	199	100.00%	1,022,903	100.00%	153	822,211	199	100.00%	919,399	100.00%	41.
		Average Number of Customers:		17				Average Number of Customers:		17				
		Average Load:		5,140	kW per bill			Average Load:		4,620	kW per bill			
		Median Load:		4,723	kW per bill			Median Load:		4,291	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-35, E-35 Primary, E-35 Transmission**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	100.001-250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	250,001-500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	500,001-600,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	600,001-700,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	700,001-800,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	800,001-900,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	900,001-1,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	1,000,001-1,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	1,250,001-1,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	1,500,001-1,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	1,750,001-2,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	2,000,001-2,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	2,250,001-2,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	15.
16.	2,500,001-2,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	16.
17.	2,750,001-3,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	17.
18.	3,000,001-3,250,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	18.
19.	3,250,001-3,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	19.
20.	3,500,001-3,750,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	20.
21.	3,750,001-4,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	21.
22.	4,000,001-4,500,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	22.
23.	4,500,001-5,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	23.
24.	5,000,001-6,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	24.
25.	6,000,001-7,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	25.
26.	7,000,001-8,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	26.
27.	8,000,001-9,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	27.
28.	9,000,001-10,000,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	28.
29.	10,000,001-12,500,000	1	594,305	1	0.56%	594,305	0.07%	1	591,541	1	0.56%	591,541	0.08%	29.
30.	12,500,001-15,000,000	3	2,373,091	4	2.23%	2,967,396	0.34%	4	3,176,963	6	2.81%	3,768,504	0.48%	30.
31.	15,000,001-20,000,000	8	6,843,961	12	6.15%	9,811,357	1.11%	8	7,142,818	13	6.74%	10,911,321	1.38%	31.
32.	20,000,001-30,000,000	6	7,804,376	18	8.94%	17,615,733	1.99%	10	14,120,121	23	11.80%	25,031,442	3.17%	32.
33.	Over 30,000,000	181	867,102,854	199	100.00%	884,718,587	100.00%	176	763,618,598	199	100.00%	788,650,040	100.00%	33.
	Average Number of Customers:			17				Average Number of Customers:		17				
	Average Consumption:			4,445,822	kWh per bill			Average Consumption:		3,963,066	kWh per bill			
	Median Consumption:			2,740,255	kWh per bill			Median Consumption:		2,275,933	kWh per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1.								1.
2.		BILLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						2.
3.		IN REVENUE REQUIREMENT CALCULATIONS						3.
4.								4.
5.								5.
6.								6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.
34.								34.
35.								35.
36.								36.
37.								37.
38.								38.
39.								39.
40.								40.
41.								41.

Average Number of Customers:
Average Load: kW per bill
Median Load: kW per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-36 XL**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	Number (D)	% of Total (E)	Amount (kWh) (F)	% of Total (G)	Line No.
1.								1.
2.								2.
3.		BILLING DETERMINANTS FOR E-36 CUSTOMERS ARE NOT UTILIZED						3.
4.		IN REVENUE REQUIREMENT CALCULATIONS						4.
5.								5.
6.								6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-47**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

			ANNUAL					
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1.								1.
2.			24,613,368					2.
3.								3.
4.								4.
5.								5.
6.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-56**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1.	0	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	1.
2.	1-100	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	2.
3.	101-200	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	3.
4.	201-300	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	4.
5.	301-400	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	5.
6.	401-500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	6.
7.	501-750	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	7.
8.	751-1,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	8.
9.	1,001-1,500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	9.
10.	1,501-2,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	10.
11.	2,001-3,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	11.
12.	3,001-4,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	12.
13.	4,001-5,000	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	13.
14.	5,001-7,500	-	-	-	0.00%	-	0.00%	-	-	-	0.00%	-	0.00%	14.
15.	7,501-10,000	-	-	-	0.00%	-	0.00%	1	-	1	25.00%	-	0.00%	15.
16.	10,001-15,000	3	-	3	71.43%	-	0.00%	2	369,907	3	75.00%	369,907	22.29%	16.
17.	15,001-20,000	-	1,486,227	3	71.43%	1,486,227	81.87%	-	1,083,785	3	75.00%	1,453,692	87.60%	17.
18.	20,001-25,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	18.
19.	25,001-30,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	19.
20.	30,001-35,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	20.
21.	35,001-40,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	21.
22.	40,001-50,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	22.
23.	50,001-75,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	23.
24.	75,001-100,000	-	-	3	71.43%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	24.
25.	100,001-125,000	1	-	4	100.00%	1,486,227	81.87%	-	-	3	75.00%	1,453,692	87.60%	25.
26.	125,001-150,000	-	329,215	4	100.00%	1,815,442	100.00%	1	-	4	87.50%	1,453,692	87.60%	26.
27.	150,001-200,000	-	-	4	100.00%	1,815,442	100.00%	1	93,431	4	100.00%	1,547,123	93.23%	27.
28.	200,001-300,000	-	-	4	100.00%	1,815,442	100.00%	-	112,410	4	100.00%	1,659,533	100.00%	28.
29.	300,001-400,000	-	-	4	100.00%	1,815,442	100.00%	-	-	4	100.00%	1,659,533	100.00%	29.
30.	400,001-500,000	-	-	4	100.00%	1,815,442	100.00%	-	-	4	100.00%	1,659,533	100.00%	30.
31.	500,001-750,000	-	-	4	100.00%	1,815,442	100.00%	-	-	4	100.00%	1,659,533	100.00%	31.
32.	750,001-1,000,000	-	-	4	100.00%	1,815,442	100.00%	-	-	4	100.00%	1,659,533	100.00%	32.
33.	Over 1,000,000	-	-	4	100.00%	1,815,442	100.00%	-	-	4	100.00%	1,659,533	100.00%	33.

Average Number of Customers:	1		Average Number of Customers:	1	
Average Consumption:	453,861	kWh per bill	Average Consumption:	414,883	kWh per bill
Median Consumption:	65,550	kWh per bill	Median Consumption:	43,840	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-58**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

ANNUAL

Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	CUMULATIVE BILLS Number (D)	CUMULATIVE BILLS % of Total (E)	CUMULATIVE CONSUMPTION Amount (kWh) (F)	CUMULATIVE CONSUMPTION % of Total (G)	Line No.
1.								1.
2.			33,212,153					2.
3.								3.
4.								4.
5.								5.
6.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-59**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

			ANNUAL					
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) *(A)*	NUMBER OF BILLS BY BLOCK *(B)*	CONSUMPTION kWh BY BLOCK *(C)*	Number *(D)*	% of Total *(E)*	Amount (kWh) *(F)*	% of Total *(G)*	*Line No.*
1.								1.
2.			93,502,052					2.
3.								3.
4.								4.
5.								5.
6.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-67**
DESCRIPTION: Classified Electric Rate Applicable to Specific Territory Served by Company

ANNUAL

Line No.	BLOCK (kWh) (A)	NUMBER OF BILLS BY BLOCK (B)	CONSUMPTION kWh BY BLOCK (C)	CUMULATIVE BILLS Number (D)	CUMULATIVE BILLS % of Total (E)	CUMULATIVE CONSUMPTION Amount (kWh) (F)	CUMULATIVE CONSUMPTION % of Total (G)	Line No.
1.	0	66	-	66	2.90%	-	0.00%	1.
2.	1-100	29	524	95	4.19%	524	0.02%	2.
3.	101-200	49	9,192	144	6.36%	9,716	0.28%	3.
4.	201-300	113	22,821	257	11.34%	32,537	0.95%	4.
5.	301-400	138	41,264	395	17.42%	73,801	2.15%	5.
6.	401-500	283	113,314	678	29.91%	187,115	5.45%	6.
7.	501-750	654	338,262	1,331	58.76%	525,378	15.31%	7.
8.	751-1,000	229	183,839	1,560	68.85%	709,217	20.66%	8.
9.	1,001-1,500	288	322,045	1,848	81.57%	1,031,261	30.05%	9.
10.	1,501-2,000	101	161,685	1,950	86.04%	1,192,946	34.76%	10.
11.	2,001-3,000	89	200,120	2,038	89.95%	1,393,066	40.59%	11.
12.	3,001-4,000	37	121,120	2,075	91.57%	1,514,186	44.12%	12.
13.	4,001-5,000	27	91,298	2,102	92.76%	1,605,484	46.78%	13.
14.	5,001-7,500	51	289,194	2,153	95.02%	1,894,678	55.20%	14.
15.	7,501-10,000	43	307,554	2,196	96.91%	2,202,233	64.16%	15.
16.	10,001-15,000	33	424,847	2,229	98.39%	2,627,079	76.54%	16.
17.	15,001-20,000	20	273,430	2,249	99.26%	2,900,510	84.51%	17.
18.	20,001-25,000	10	282,432	2,260	99.72%	3,182,942	92.74%	18.
19.	25,001-30,000	5	192,909	2,265	99.95%	3,375,851	98.36%	19.
20.	30,001-35,000	1	56,413	2,266	100.00%	3,432,264	100.00%	20.
21.	35,001-40,000	-	-	2,266	100.00%	3,432,264	100.00%	21.
22.	40,001-50,000	-	-	2,266	100.00%	3,432,264	100.00%	22.
23.	50,001-75,000	-	-	2,266	100.00%	3,432,264	100.00%	23.
24.	75,001-100,000	-	-	2,266	100.00%	3,432,264	100.00%	24.
25.	100,001-125,000	-	-	2,266	100.00%	3,432,264	100.00%	25.
26.	125,001-150,000	-	-	2,266	100.00%	3,432,264	100.00%	26.
27.	150,001-200,000	-	-	2,266	100.00%	3,432,264	100.00%	27.
28.	200,001-300,000	-	-	2,266	100.00%	3,432,264	100.00%	28.
29.	300,001-400,000	-	-	2,266	100.00%	3,432,264	100.00%	29.
30.	400,001-500,000	-	-	2,266	100.00%	3,432,264	100.00%	30.
31.	500,001-750,000	-	-	2,266	100.00%	3,432,264	100.00%	31.
32.	750,001-1,000,000	-	-	2,266	100.00%	3,432,264	100.00%	32.
33.	Over 1,000,000	-	-	2,266	100.00%	3,432,264	100.00%	33.

Average Number of Customers:	189	
Average Consumption:	1,515	kWh per bill
Median Consumption:	1,163	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)							WINTER (November through April)						
				CUMULATIVE							CUMULATIVE				
				BILLS		LOAD					BILLS		LOAD		
Line No.	BLOCK (kW)	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.	NUMBER OF BILLS BY BLOCK	LOAD kW BY BLOCK	Number	% of Total	Amount (kW)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)		(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	897	-	897	10.28%	-	0.00%	1	1,370	-	1,370	15.81%	-	0.00%	1.
2.	1-10	1,500	7,145	2,397	27.47%	7,145	0.97%	2	1,721	6,960	3,092	35.67%	6,960	1.11%	2.
3.	11-20	945	14,456	3,342	38.30%	21,601	2.94%	3	824	12,479	3,916	45.18%	19,439	3.11%	3.
4.	21-30	852	21,499	4,195	48.06%	43,100	5.87%	4	723	18,023	4,639	53.52%	37,462	6.00%	4.
5.	31-40	523	18,411	4,718	54.06%	61,511	8.38%	5	446	15,499	5,085	58.67%	52,961	8.48%	5.
6.	41-50	371	16,756	5,088	58.31%	78,267	10.66%	6	323	14,597	5,408	62.40%	67,558	10.82%	6.
7.	51-60	333	18,475	5,421	62.12%	96,742	13.18%	7	271	15,031	5,680	65.53%	82,589	13.22%	7.
8.	61-70	279	18,409	5,701	65.32%	115,151	15.69%	8	241	15,735	5,921	68.31%	98,324	15.74%	8.
9.	71-80	236	17,829	5,937	68.03%	132,980	18.12%	9	226	17,015	6,146	70.92%	115,339	18.46%	9.
10.	81-90	175	15,102	6,112	70.04%	148,082	20.18%	10	191	16,366	6,337	73.12%	131,705	21.08%	10.
11.	91-100	244	23,384	6,356	72.83%	171,466	23.36%	11	206	19,650	6,543	75.49%	151,355	24.23%	11.
12.	101-200	1,469	215,166	7,824	89.66%	386,631	52.68%	12	1,348	195,843	7,891	91.05%	347,197	55.58%	12.
13.	201-300	472	116,240	8,296	95.06%	502,871	68.52%	13	420	102,840	8,311	95.89%	450,037	72.05%	13.
14.	301-400	176	59,989	8,472	97.08%	562,860	76.69%	14	160	54,188	8,471	97.74%	504,225	80.72%	14.
15.	401-500	109	49,587	8,581	98.33%	612,447	83.45%	15	84	37,631	8,555	98.70%	541,856	86.74%	15.
16.	501-600	60	33,239	8,642	99.02%	645,687	87.98%	16	48	25,650	8,602	99.25%	567,507	90.85%	16.
17.	601-700	31	20,073	8,672	99.38%	665,759	90.72%	17	22	14,249	8,624	99.51%	581,755	93.13%	17.
18.	701-800	21	15,669	8,693	99.61%	681,429	92.85%	18	19	14,147	8,643	99.72%	595,902	95.40%	18.
19.	801-900	7	5,918	8,700	99.69%	687,347	93.66%	19	4	3,342	8,647	99.77%	599,245	95.93%	19.
20.	901-1000	4	3,741	8,704	99.74%	691,088	94.17%	20	2	1,834	8,649	99.79%	601,078	96.23%	20.
21.	1001-1100	3	3,144	8,707	99.77%	694,232	94.59%	21	4	4,146	8,653	99.84%	605,225	96.89%	21.
22.	1101-1200	-	-	8,707	99.77%	694,232	94.59%	22	2	2,251	8,655	99.86%	607,476	97.25%	22.
23.	1201-1300	1	1,242	8,708	99.78%	695,474	94.76%	23	2	2,472	8,657	99.89%	609,948	97.65%	23.
24.	1301-1400	3	4,016	8,711	99.82%	699,490	95.31%	24	4	5,298	8,661	99.93%	615,246	98.49%	24.
25.	1401-1500	3	4,362	8,714	99.85%	703,852	95.91%	25	2	2,862	8,663	99.95%	618,108	98.95%	25.
26.	1501-1600	3	4,674	8,717	99.89%	708,526	96.54%	26	1	1,530	8,664	99.97%	619,638	99.20%	26.
27.	1601-1700	3	4,854	8,720	99.92%	713,380	97.20%	27	2	3,274	8,666	99.99%	622,912	99.72%	27.
28.	1701-1800	-	-	8,720	99.92%	713,380	97.20%	28	1	1,746	8,667	100.00%	624,658	100.00%	28.
29.	1801-1900	1	1,843	8,721	99.93%	715,223	97.46%	29	-	-	8,667	100.00%	624,658	100.00%	29.
30.	1901-2000	1	1,962	8,722	99.94%	717,185	97.72%	30	-	-	8,667	100.00%	624,658	100.00%	30.
31.	2001-2100	-	-	8,722	99.94%	717,185	97.72%	31	-	-	8,667	100.00%	624,658	100.00%	31.
32.	2101-2200	1	2,106	8,723	99.95%	719,291	98.01%	32	-	-	8,667	100.00%	624,658	100.00%	32.
33.	2201-2300	-	-	8,723	99.95%	719,291	98.01%	33	-	-	8,667	100.00%	624,658	100.00%	33.
34.	2301-2400	1	2,342	8,724	99.97%	721,633	98.33%	34	-	-	8,667	100.00%	624,658	100.00%	34.
35.	2401-2500	-	-	8,724	99.97%	721,633	98.33%	35	-	-	8,667	100.00%	624,658	100.00%	35.
36.	2501-2600	-	-	8,724	99.97%	721,633	98.33%	36	-	-	8,667	100.00%	624,658	100.00%	36.
37.	2601-2700	-	-	8,724	99.97%	721,633	98.33%	37	-	-	8,667	100.00%	624,658	100.00%	37.
38.	2701-2800	-	-	8,724	99.97%	721,633	98.33%	38	-	-	8,667	100.00%	624,658	100.00%	38.
39.	2801-2900	-	-	8,724	99.97%	721,633	98.33%	39	-	-	8,667	100.00%	624,658	100.00%	39.
40.	2901-3000	1	2,996	8,725	99.98%	724,629	98.74%	40	-	-	8,667	100.00%	624,658	100.00%	40.
41.	Over 3000	2	9,272	8,727	100.00%	733,901	100.00%	41	-	-	8,667	100.00%	624,658	100.00%	41.
		Average Number of Customers:		1,455					Average Number of Customers:		1,445				
		Average Load:		84	kW per bill				Average Load:		72	kW per bill			
		Median Load:		32	kW per bill				Median Load:		32	kW per bill			

Supporting Schedules:
N/A

Recap Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **E-221 and E-221-8T**
DESCRIPTION: Classified Electric Rate Applicable to All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	NUMBER OF BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(B)	(C)	(D)	(E)	(F)	(G)	
1.	0	606	-	606	6.95%	-	0.00%	981	-	981	11.32%	-	0.00%	1.
2.	1-100	497	20,517	1,104	12.65%	20,517	0.01%	743	30,016	1,723	19.88%	30,016	0.03%	2.
3.	101-200	200	31,111	1,304	14.94%	51,628	0.03%	361	52,894	2,084	24.05%	82,910	0.07%	3.
4.	201-300	175	45,656	1,479	16.95%	97,284	0.05%	190	46,441	2,274	26.24%	129,351	0.11%	4.
5.	301-400	114	42,608	1,593	18.25%	139,892	0.07%	191	67,503	2,466	28.45%	196,854	0.17%	5.
6.	401-500	77	37,170	1,670	19.14%	177,062	0.09%	149	67,676	2,614	30.16%	264,529	0.23%	6.
7.	501-750	220	144,888	1,891	21.66%	321,950	0.16%	246	151,819	2,860	33.00%	416,349	0.36%	7.
8.	751-1,000	240	222,999	2,131	24.42%	544,950	0.28%	281	246,748	3,141	36.25%	663,097	0.57%	8.
9.	1,001-1,500	365	476,629	2,496	28.60%	1,021,579	0.52%	406	506,055	3,547	40.93%	1,169,152	1.01%	9.
10.	1,501-2,000	294	541,904	2,790	31.97%	1,563,483	0.79%	330	575,602	3,877	44.73%	1,744,754	1.51%	10.
11.	2,001-3,000	453	1,197,513	3,242	37.15%	2,760,996	1.40%	535	1,327,022	4,412	50.91%	3,071,776	2.66%	11.
12.	3,001-4,000	398	1,472,075	3,640	41.72%	4,233,071	2.14%	390	1,357,669	4,802	55.40%	4,429,445	3.84%	12.
13.	4,001-5,000	317	1,499,815	3,957	45.34%	5,732,886	2.90%	308	1,378,603	5,110	58.96%	5,808,048	5.03%	13.
14.	5,001-7,500	638	4,161,766	4,595	52.66%	9,894,652	5.00%	654	4,125,998	5,764	66.50%	9,934,046	8.60%	14.
15.	7,501-10,000	463	484,277	5,059	57.97%	10,378,929	5.25%	465	4,153,653	6,229	71.87%	14,087,699	12.20%	15.
16.	10,001-15,000	711	9,279,168	5,769	66.11%	19,658,097	9.94%	610	7,486,447	6,839	78.91%	21,574,146	18.69%	16.
17.	15,001-20,000	463	908,033	6,232	71.41%	20,566,130	10.39%	366	6,377,959	7,205	83.13%	27,952,105	24.21%	17.
18.	20,001-25,000	378	8,984,686	6,610	75.74%	29,550,815	14.94%	250	5,548,352	7,455	86.02%	33,500,457	29.02%	18.
19.	25,001-30,000	313	9,066,958	6,923	79.32%	38,617,773	19.52%	207	5,659,020	7,662	88.41%	39,159,478	33.92%	19.
20.	30,001-35,000	265	9,083,155	7,188	82.36%	47,700,927	24.11%	173	5,590,279	7,836	90.41%	44,749,756	38.76%	20.
21.	35,001-40,000	193	7,597,990	7,380	84.57%	55,298,918	27.95%	122	4,520,066	7,957	91.81%	49,269,822	42.68%	21.
22.	40,001-50,000	326	15,283,883	7,706	88.30%	70,582,800	35.67%	151	6,771,169	8,109	93.56%	56,040,991	48.54%	22.
23.	50,001-75,000	423	27,422,295	8,129	93.14%	98,005,095	49.53%	230	14,101,973	8,339	96.22%	70,142,964	60.76%	23.
24.	75,001-100,000	230	21,214,068	8,359	95.78%	119,219,163	60.25%	110	9,440,513	8,449	97.48%	79,583,477	68.93%	24.
25.	100,001-125,000	123	14,449,692	8,482	97.19%	133,668,855	67.56%	66	7,227,959	8,515	98.24%	86,811,436	75.19%	25.
26.	125,001-150,000	52	7,525,232	8,533	97.78%	141,194,088	71.36%	40	5,476,217	8,554	98.70%	92,287,653	79.94%	26.
27.	150,001-200,000	87	16,055,960	8,621	98.78%	157,250,048	79.48%	59	10,053,661	8,613	99.38%	102,341,314	88.65%	27.
28.	200,001-300,000	65	16,614,050	8,685	99.52%	173,864,098	87.87%	38	8,904,601	8,651	99.82%	111,245,915	96.36%	28.
29.	300,001-400,000	14	5,215,941	8,699	99.68%	179,080,039	90.51%	9	329,217	8,660	99.92%	111,575,132	96.64%	29.
30.	400,001-500,000	12	5,480,178	8,711	99.82%	184,560,217	93.28%	3	1,270,509	8,663	99.95%	112,845,641	97.74%	30.
31.	500,001-750,000	12	7,512,426	8,723	99.95%	192,072,643	97.08%	3	1,822,450	8,666	99.99%	114,668,091	99.32%	31.
32.	750,001-1,000,000	2	1,668,325	8,725	99.98%	193,740,967	97.92%	1	781,362	8,667	100.00%	115,449,453	100.00%	32.
33.	Over 1,000,000	2	4,117,920	8,727	100.00%	197,858,887	100.00%	-	-	8,667	100.00%	115,449,453	100.00%	33.

Average Number of Customers:	1,455		Average Number of Customers:	1,445	
Average Consumption:	22,672	kWh per bill	Average Consumption:	13,321	kWh per bill
Median Consumption:	6,441	kWh per bill	Median Consumption:	1,790	kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE - CONSUMPTION
TEST YEAR ENDED DECEMBER 31, 2010 ADJUSTED

RATE SCHEDULE: **CONTRACT 12**
DESCRIPTION: General Service Electric Rate Applicable to All Territory Served by Company

		ANNUAL						
				CUMULATIVE				
				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh) *(A)*	NUMBER OF BILLS BY BLOCK *(B)*	CONSUMPTION kWh BY BLOCK *(C)*	Number *(D)*	% of Total *(E)*	Amount (kWh) *(F)*	% of Total *(G)*	*Line No.*
1.								1.
2.			11,495,572					2.
3.								3.
4.								4.
5.								5.
6.			LIGHTING CUSTOMERS ARE NOT BILLED BY KW OR KWH					6.
7.								7.
8.								8.
9.								9.
10.								10.
11.								11.
12.								12.
13.								13.
14.								14.
15.								15.
16.								16.
17.								17.
18.								18.
19.								19.
20.								20.
21.								21.
22.								22.
23.								23.
24.								24.
25.								25.
26.								26.
27.								27.
28.								28.
29.								29.
30.								30.
31.								31.
32.								32.
33.								33.

Average Number of Customers:
Average Consumption: kWh per bill
Median Consumption: kWh per bill

Supporting Schedules:
N/A

Recap Schedules:
N/A