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CAPITAL CORPORATION
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December 19, 2006

Arizona Corporation Commission
DOCKETED

DEC 20 2006

DOCKETED BY

Jeff Hatch-Miller, Chairman
William A. Mundell, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner
Barry Wong, Commissioner
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007-2996

Re: Docket Nos. E-01345A-05-0816; E-01345A-05-0826; and E-01345A-05-0827 (APS General Rate Case)

Dear Commissioners:

Pursuant to various requests from the bench for additional information during the course of the evidentiary hearing in the above matter, APS submits the following response. I have again divided our response by topic matter. It will include the areas of: (1) hook-up fees/line extensions; (2) Automated Metering Infrastructure ("AMI"); (3) bill impact of Staff's Power Supply Adjustor ("PSA") proposal; (4) level of unrecovered fixed distribution costs under Staff's modified recommendation regarding net metering; (5) updated PSA balances through November 30, 2006; (6) APS/electric industry "lobbying" efforts with regard to Section 118 of the Internal Revenue Code ("Section 118"), which addresses the taxation of customer contributions/advances (*see* APS Exhibit 14); (7) mercury control technology; (8) the time required to construct central station-sized solar generation; (9) a reconciliation of apparent discrepancies in the APS debt ratio in two November reports filed with the Commission; (10) the impact of customer/developer advances on FFO/Debt ratio; (11) the degree to which light rail and other reimbursable construction costs are included in APS Exhibit 27; (12) a seasonal breakdown of projected 2007 average fuel costs; (13) a summary of 2005 unplanned outage costs similar to that provided for the 2006 outages in my December 6, 2006 letter to Commissioner Mayes; (14) a comparison of actual versus budgeted generation from the Company's coal and nuclear plants in 2005 and 2006; and (15) the " back up" to Mayes Exhibit 3.

APS would ask that this letter and its attachments be marked as "APS Exhibit 105" and admitted under the procedure set forth in this proceeding by the Chief Administrative Law Judge. APS is also filing this letter in the emergency rate docket, E-01345A-06-0009.

I. HOOK-UP FEES/LINE EXTENSIONS

In Appendix A, APS has calculated the impact of variations to its proposed $5000 equipment allowance (which would be in lieu of its current 1000 foot "footage allowance") in increments of $500-$1000. *See* Tr. Vol. XXIII, pp.4349 - 4350. It has done so for both individual customer connections and new subdivisions. In the case of the latter, APS has assumed that all developers would pay for service extensions, less whatever level of equipment allowance is authorized by the Commission. This effectively removes any distinction between developers with or without established "track records" of successful development in the APS service area.

II. AMI

APS witness David Rumolo was asked if there were additional steps the Commission could take to facilitate the "roll-out" of AMI technology. Tr. Vol. XXIII, p. 4395. As was testified to at the hearing, APS will not achieve 100% penetration with this AMI technology because it uses cellular communications, which is not available in all areas of Arizona. Tr. Vol. XIV, p. 2859. Also, APS does not meter certain of its customers (e.g., street lighting) and thus will not be installing AMI for such customers.

The Commission could facilitate the AMI "roll-out" through four discreet actions. First, the Commission could take some of the steps suggested by APS witnesses to improve the Company's financial condition. Second, the Commission should both authorize accelerated depreciation rates/lives for meters (presently lasting some 30 years), thus minimizing the potential for stranded metering costs, and adopt a policy assuring the recovery of undepreciated meter costs for existing meters retired in

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favor of AMI. Third, consider authorization of an alternative funding mechanism such as a per meter surcharge or a pre-approval of recovery of investment of an AMI system. Lastly, the Commission's Electric Competition Rules, specifically A.A.C. R14-2-1615, prohibit APS from providing metering services to many non-residential customers selecting direct access. Although retail electric competition has not yet reappeared in Arizona and this specific regulation awaits Attorney General Certification per the *Phelps Dodge* decision to become effective, the above provision potentially discourages the use of sophisticated APS metering for this category of APS customer and should be modified to permit APS (at the customer's discretion) to continue to provide metering service to all direct access customers.

III. BILL IMPACT OF STAFF PSA

Appendix B sets forth our calculation of the bill impact on an E-12 residential customer using 800 kWh per month, consistent with my October 9, 2006 letter to Commissioner Mayes – Appendix A), under Staff's proposed rate design and Staff's proposed PSA. *See* Tr. Vol. XXIII, pp. 4379. This calculation is different from that set forth in Staff Exhibit 43 in that APS has assumed that the February 1, 2007 Annual Fuel Adjustor will be in place through January 31, 2008 even under the Staff PSA proposal. APS believes this assumption is consistent with Mr. Antonuk's testimony at hearing. Tr. Vol. XXI, pp. 3871-3872 and Vol. XXII, pp. 4122-4123.

IV. UNRECOVERED FIXED DISTRIBUTION COSTS ATTRIBUTABLE TO NET METERING

Appendix C is a recalculation of APS Exhibit 73 using Staff witness Keane's modified recommendation that only when a net metered customer is producing a surplus of energy (i.e., more energy than the customer uses) will there be unrecovered fixed distribution costs recovered through the Renewable Energy Standard ("RES"). Tr. Vol. XXIII, p.4412. Please note that the aggregate level of unrecovered fixed distribution costs remains unchanged from APS Exhibit 73. These unrecovered costs are an undeniable aspect of net metering and if not recovered through the RES, will impact base rates charged to non-participating customers.

V. UPDATED PSA BALANCES

The various PSA balances as of November 30, 2006 are provided below. *See* Special Open Meeting of December 8, 2006, Tr. Vol. I p.36. APS Exhibit 77 provided similar information through October 31, 2006.

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2006 Annual Adjustor (4 mills 2/06-1/07)	$ 20.2 million
Step 1 Surcharge (0.6 mills 5/06-4/07)	$ 5.7 million
2005 Paragraph 19(d) Balance	$ 46.6 million
2006 Tracking Account	$116.2 million
Total All Balances	$188.7 million

VI. SECTION 118

As requested at Tr. Vol. XXVI, pp. 4836 and 4874, APS contacted Pinnacle West Capital's Federal Affairs Department and determined that Edison Electric Institute ("EEI"), of which APS is a member, strongly lobbied against the initial enactment of Section 118 in 1986 and has since attempted to have it modified as regards electric utilities. The last attempt to deal with the issue legislatively failed in 2001 when provisions modifying Section 118 were believed to be too costly to the federal treasury. Since that time, EEI has continued to lobby the IRS for a more liberal interpretation of Section 118. I have attached as Appendix D a recent example of such efforts.

VII. MERCURY CONTROL TECHNOLOGY

APS witness Fox agreed to provide the Commission with instances in which the mercury control technology referenced in his testimony had been implemented. Tr. Vol. VII, p. 1482. APS understands that activated carbon injection has been installed in three coal plant to date: Presque Island (WE Energies – Wisconsin); Brayton Point (Dominion Energy – Massachusetts) and Mercer (PSE&E – New Jersey). Attached as Appendix E is a summary report from the Institute of Clean Air Companies indicating other instances of the use of mercury control technologies by electric utilities.

VIII. CONSTRUCTION TIME FOR LARGE-SCALE SOLAR GENERATION

APS Appendix F indicates the development schedule for APS Saguaro and Prescott Solar Facilities. This request was made at Tr. Vol. XXVI, p. 4837.

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IX. APS DEBT RATIO

As a result of Decision No. 65796 (April 4, 2003), APS filed a capital structure report with the Commission on November 15, 2006. On November 30, 2006, APS submitted financial ratio information pursuant to Decision No. 68685 (May 5, 2006). Attached as Appendix G is a reconciliation of the capital structures shown in these two filings. *See* Tr. Vol. XXIV, p. 4773. As can be seen, the former uses Generally Accepted Accounting Principles, as required by Decision No. 65796, to calculate the debt ratio. On the other hand, the calculation provided under the interim PSA adjustor order, Decision No. 68685, includes imputed debt per the S&P formula. The latter filing would also incorporate any short-term debt issued by APS, but no such debt was outstanding and thus did not affect the calculation.

X. IMPACT OF CUSTOMER/DEVELOPER ADVANCES ON FFO/DEBT RATIO

At Tr. Vol. XXIII, p. 4407, APS was asked to evaluate the impact of customer/developer advances on its FFO/ Debt ratio similar to that done on APS Exhibit 54. Neither customer advances nor contributions produce additional income that would increase FFO. If advances are taxable, their negative impact on FFO/Debt would be the same as contributions.

XI. REIMBURSABLE CONSTRUCTION COSTS

The figures shown on APS Exhibit 27 are net of any potential reimbursements. Thus, such reimbursements do not impact that Exhibit. *See* Tr. Vol. XXVI, pp. 4873 and 4875.

XII. SEASONAL BREAKDOWN OF 2007 AVERAGE FUEL COSTS

In response to Commissioner Gleason's request at Tr. Vol. XXIII pp. 4456 and 4457 for the projected 2007 fuel costs to be split on a seasonal basis, the following table indicates the average summer and winter fuel costs that correspond to the average annual base fuel rate of 3.2491¢ per kWh.

Summer (May-Oct)	3.6915¢
Winter (Nov-Apr)	2.6305¢

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XIII. 2005 UNPLANNED OUTAGE COSTS

Attached as Appendix H is a summary of April through December 2005 unplanned outage costs. It is in a similar format as that used for 2006 outages in APS Exhibit 97. *See* Tr. Vol. XXVIII, p. 5215

XIV. ACTUAL VS. BUDGETED COAL AND NUCLEAR GENERATION

Attached as Appendix I is a chart showing budgeted versus actual performance during 2005 and 2006 for the APS coal and nuclear plants. *See* Tr. Vol. XXIV, p. 4472. In the case of coal plants, both net capacity factors ("NCF") and equivalent availability factor ("EAF") are provided. Coal plants generally have lower NCF's than EAF's because coal plants are, at times, the most economic and technically appropriate resource to be used for system regulation and spinning reserves and therefore may be only partially loaded even though fully available. In both 2005 and 2006, the use of both the Cholla and Navajo plants for these purposes exceeded the amount expected in the budget.

XV. Mayes Exhibit

Attached as Appendix J is the breakdown of utility dividend growth rates used to prepare Mayes Exhibit 3. *See* Tr. Vol. XXIV, p. 4659.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

TLM/

cc: Original and 13 copies to Docket Control

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Arizona Public Service

Analysis of Impact of Impact of Alternative Equipment Allowances

1. Impact on extensions for individual customers, 2005 data

	Extension Length	No. of Work Orders	Estimated Extension Footage	Estimated Total "Free" Extension Footage	Estimated Total Extension Cost	Average Extension Cost	Customer Funding with elimination of $5,000 allowance	Customer Funding with elimination of 1,000 ft allowance	Customer Funding after $5,000 Allowance	Customer Funding after $4,000 Allowance	Customer Funding after $3,000 Allowance	Customer Funding after $2,000 Allowance	Customer Funding after $1,500 Allowance	Customer Funding after $1,000 Allowance	Customer Funding after $500 Allowance
Work orders less than 1,000 ft and less than $25,000 cost	Under 250 ft.	663	99,450	99,450	$902,012	$1,361	$902,012	$902,012	$0	$0	$0	$0	$0	$239,012	$570,512
	250 to 499 ft.	417	145,950	145,950	$1,323,767	$3,175	$1,323,767	$1,323,767	$0	$0	$72,767	$489,767	$698,267	$906,767	$1,115,267
	500 to 749 ft.	306	191,250	191,250	$1,734,638	$5,669	$1,734,638	$1,734,638	$204,638	$510,638	$816,638	$1,122,638	$1,275,638	$1,428,638	$1,581,638
	750 to 999 ft.	180	153,180	153,180	$1,389,343	$7,719	$1,389,343	$1,389,343	$489,343	$669,343	$849,343	$1,029,343	$1,119,343	$1,209,343	$1,299,343
	1000 ft	6	6,000	6,000	$54,420	$9,070	$54,420	$54,420	$24,420	$30,420	$36,420	$42,420	$45,420	$48,420	$51,420
	Total	1,572	595,830	595,830	$5,404,178	$3,438	$5,404,178	$5,404,178	$718,400	$1,210,400	$1,775,167	$2,684,167	$3,138,667	$3,832,178	$4,618,178
Work orders greater than 1,000 ft and less than $25,000 cost		239	388,052	239,000	$2,167,730	$9,070	$2,167,730	$2,167,730	$972,730	$1,211,730	$1,450,730	$1,689,730	$1,809,230	$1,928,730	$2,048,230
Total		1,811	983,882	834,830	$7,571,908	$4,181	$7,571,908	$7,571,908	$1,691,130	$2,422,130	$3,225,897	$4,373,897	$4,947,897	$5,760,908	$6,666,408

Notes:

1. Extension costs consists of local facilities and excludes meters and transformers

2. Completed Work Order Summary - Line Extensions and Services, Subdivision/Developer Projects, 2005 data

Work Order Type	No. Work Orders	No. Sites	Gross Cost	Cost per Site	Customer Funding with elimination of $5,000 allowance	Customer Funding with elimination of 1,000 ft allowance	Customer Funding after $5,000 Allowance	Customer Funding after $4,000 Allowance	Customer Funding after $3,000 Allowance	Customer Funding after $2,000 Allowance	Customer Funding after $1,500 Allowance	Customer Funding after $1,000 Allowance	Customer Funding after $500 Allowance
Residential Subdivision Extensions	265	23,513	$28,125,644	$1,196	$28,125,644	N/A	$0	$0	$0	$0	$0	$4,612,644	$16,369,144
Residential Multi-Family Developments	84	3,488	$2,733,881	$784	$2,733,881	N/A	$0	$0	$0	$0	$0	$0	$989,881
Total	349	27,001	$30,859,525	$1,143	$30,859,525	N/A	$0	$0	$0	$0	$0	$4,612,644	$17,359,025

Notes:

1. Extension costs consists of local facilities and excludes meters and transformers
2. 1000 foot allowance does not apply to subdivisions under current policy

Arizona Public Service Company
Analysis of Bill Impact of CWIP and Attrition Adjustor on Rate Schedule E-12 Residential Customer
Summer E-12 Customers' Monthly Bill with Increase and Adjustors
Revised with Staff's Proposed Forward PSA

		(a) July 2003 Summer E-12 Rates Pre-Decision No. 67744	(b) Feb. 2006 Summer E-12 Rates and 4 Mill PSA Post-Decision No. 67744	(c) Current (May 06) Summer E-12 Rates and PSA Adjustors Post-Decision No. 68685	(d) APS Proposed Rate Case Summer E-12 Rates and PSA Adjustors	(e) **STAFF** Proposed Rate Case Summer E-12 Rates and PSA Adjustors
1.	Customer kWh [1]	800	800	800	800	800
2.	Monthly Base Bill [2]	$ 78.12	$ 80.34	$ 80.34	$ 94.21	$ 86.78
3.	Plus EPS Charge [3]	$ 0.35	$ 0.35	$ 0.35	$ 0.56	$ 0.56
4.	Plus CRCC	$ -	$ 0.27	$ 0.27	$ 0.27	$ 0.27
5.	Plus PSA Adjustor Rate [4]	$ -	$ 3.20	$ 3.20	$ 2.96	$ 2.96
6.	**Plus Staff's PSA Adjustor Rate Forward Component [5]**	$ -	$ -	$ -	$ -	$ 3.61
7.	**Plus Staff's PSA Adjustor Rate Transistion Component [6]**	$ -	$ -	$ -	$ -	$ -
8.	Plus PSA Interim Adjustor [7]	$ -	$ -	$ 5.60	$ -	$ -
9.	Plus PSA Surcharge (May 06) [8]	$ -	$ -	$ 0.44	$ 0.44	$ 0.44
10.	Plus DSMAC	$ -	$ -	$ -	$ -	$ -
11.	Plus TCA	$ -	$ -	$ -	$ -	$ -
12.	Plus EIC [9]	$ -	$ -	$ -	$ -	$ -
13.	PSA 2nd Surcharge [10]	$ -	$ -	$ -	$ 0.13	$ -
14.	Plus Franchise Fee [11]	$ -	$ 1.21	$ 1.30	$ 1.42	$ 1.35
	Total Monthly Bill	**$ 78.47**	**$ 85.37**	**$ 91.50**	**$ 101.28**	**$ 96.80**
15	Overall Increase from July 2003 Rates [12]		$ 6.90	$ 13.03	$ 22.81	$ 18.33
16.	Overall Percent Increase from July 2003 Rates [12]		**8.8%**	**16.6%**	**29.1%**	**23.4%**
17.	Overall Increase from Feb. 2006 Rates [12]			$ 6.13	$ 15.91	$ 11.43
18.	Overall Percent Increase from Feb. 2006 Rates [12]			**7.2%**	**18.6%**	**13.4%**
19.	Overall Increase from Current (May 2006) Rates [12]				$ 9.78	$ 5.30
20.	Overall Percent Increase from Current (May 2006) Rates [12]				**10.7%**	**5.8%**

[1] 800 kWh/month consumption level consistent with assumption in previous response to request of Commission Mayes.
[2] Taxes and Reg. Assessment are not included.
[3] The APS Proposed column d uses the EPS charges proposed in APS Witness Delizio's Rebuttal Testimony.
[4] The PSA Adjustor rate used for columns a, b and c is $.004/kWh. The APS Proposed Rate column d uses a projected PSA Adjustor rate of $.0037/kWh (See APS' Dec. 4, 2006 response to Chairman Hatch-Miller's Nov. 30, 2006 letter in Docket No. E-01345A-06-0009.)
[5] The PSA Forward Component for column d under APS' proposed rates is zero for 2007 because the rates incorporate the base fuel rate of $.0325/kWh. The Staff's PSA Forward Component for column e uses $.004516 consistent with the testimony of Staff witness Antonuk.
[6] The Staff's PSA Transistion Component for column d and e is unknown at this time.
[7] The PSA Interim Adjustor rate is not included in the APS Proposed column d or e calculations.
[8] PSA Surcharge of $.000554/kWh that was effective on May 1, 2006 and is effective for approximately 12 months.
[9] The APS Proposed rate column d uses the EIC charge of $.00016/kWh proposed in APS Witness Delizio's Rebuttal Testimony.
[10] PSA Surcharge of $.001611/kWh as requested by APS in Docket No. E-01345A-06-0063 is used for APS Proposed column d. Column e utilized Staff's witness Keene's recommended $.001029/kWh. The actual rate will change slightly due to accumulated interest if it is approved.
[11] The Average Test Year Franchise Fee of 1.44% was used for all but the APS Proposed Column. The Avg. Franchise Fee for the Sep. 05 TY was 1.41% and this was used for the APS Proposed column.
[12] Actual impact will vary depending on factors such as gas and coal prices, transportation costs, customer growth, customer usage, fuel mix, off-system sales and other factors.

Arizona Public Service Company
Analysis of Bill Impact of CWIP and Attrition Adjustor on Rate Schedule E-12 Residential Customer
Winter E-12 Customers' Monthly Bill with Increase and Adjustors
Revised with Staff's Proposed Forward PSA

		(a) July 2003 Winter E-12 Rates Pre-Decision No. 67744	(b) Feb. 2006 Winter E-12 Rates and 4 Mill PSA Post-Decision No. 67744	(c) Current (May 06) Winter E-12 Rates and PSA Adjustors Post-Decision No. 68685	(d) APS Proposed Rate Case Winter E-12 Rates and PSA Adjustors	(e) **STAFF** Proposed Rate Case Winter E-12 Rates and PSA Adjustors
1.	Customer kWh [1]	800	800	800	800	800
2.	Monthly Base Bill [2]	$ 66.65	$ 66.73	$ 66.73	$ 77.21	$ 71.85
3.	Plus EPS Charge [3]	$ 0.35	$ 0.35	$ 0.35	$ 0.56	$ 0.56
4.	Plus CRCC	$ -	$ 0.27	$ 0.27	$ 0.27	$ 0.27
5.	Plus PSA Adjustor Rate [4]	$ -	$ 3.20	$ 3.20	$ 2.96	$ 2.96
6.	**Plus Staff's PSA Adjustor Rate Forward Component [5]**	$ -	$ -	$ -	$ -	$ 3.61
7.	**Plus Staff's PSA Adjustor Rate Transistion Component [6]**	$ -	$ -	$ -	$ -	$ -
8.	Plus PSA Interim Adjustor [7]	$ -	$ -	$ 5.60	$ -	$ -
9.	Plus PSA Surcharge (May 06) [8]	$ -	$ -	$ 0.44	$ 0.44	$ 0.44
10.	Plus DSMAC	$ -	$ -	$ -	$ -	$ -
11.	Plus TCA	$ -	$ -	$ -	$ -	$ -
12.	Plus EIC [9]	$ -	$ -	$ -	$ 0.13	$ -
13.	PSA 2nd Surcharge [10]	$ -	$ -	$ -	$ 1.29	$ 0.82
14.	Plus Franchise Fee [11]	$ -	$ 1.02	$ 1.11	$ 1.18	$ 1.14
	Total Monthly Bill	**$ 67.00**	**$ 71.57**	**$ 77.70**	**$ 84.04**	**$ 81.66**
15	Overall Increase from July 2003 Rates [12]		$ 4.57	$ 10.70	$ 17.04	$ 14.66
16.	Overall Percent Increase from July 2003 Rates [12]		**6.8%**	**16.0%**	**25.4%**	**21.9%**
17.	Overall Increase from Feb. 2006 Rates [12]			$ 6.13	$ 12.47	$ 10.09
18.	Overall Percent Increase from Feb. 2006 Rates [12]			**8.6%**	**17.4%**	**14.1%**
19.	Overall Increase from Current (May 2006) Rates [12]				$ 6.34	$ 3.96
20.	Overall Percent Increase from Current (May 2006) Rates [12]				**8.2%**	**5.1%**

[1] 800 kWh/month consumption level consistent with assumption in previous response to request of Commission Mayes.

[2] Taxes and Reg. Assessment are not included.

[3] The APS Proposed column d uses the EPS charges proposed in APS Witness Delizio's Rebuttal Testimony.

[4] The PSA Adjustor rate used for columns a, b and c is $.004/kWh. The APS Proposed Rate column d uses a projected PSA Adjustor rate of $.0037/kWh (See APS' Dec. 4, 2006 response to Chairman Hatch-Miller's Nov. 30, 2006 letter in Docket No. E-01345A-06-0009.)

[5] The PSA Forward Component for column d under APS' proposed rates is zero for 2007 because the rates incorporate the base fuel rate of $.0325/kWh. The Staff's PSA Forward Component for column e uses $.004516 consistent with the testimony of Staff witness Antonuk.

[6] The Staff's PSA Transistion Component for column d and e is unknown at this time.

[7] The PSA Interim Adjustor rate is not included in the APS Proposed column d or e calculations.

[8] PSA Surcharge of $.000554/kWh that was effective on May 1, 2006 and is effective for approximately 12 months.

[9] The APS Proposed rate column d uses the EIC charge of $.00016/kWh proposed in APS Witness Delizio's Rebuttal Testimony.

[10] PSA Surcharge of $.001611/kWh as requested by APS in Docket No. E-01345A-06-0063 is used for APS Proposed column d. Column e utilized Staff's witness Keene's recommended $.001029/kWh. The actual rate will change slightly due to accumulated interest if it is approved.

[11] The Average Test Year Franchise Fee of 1.44% was used for all but the APS Proposed Column. The Avg. Franchise Fee for the Sep. 05 TY was 1.41% and this was used for the APS Proposed column.

[12] Actual impact will vary depending on factors such as gas and coal prices, transportation costs, customer growth, customer usage, fuel mix, off-system sales and other factors.

STAFF NET METERING PROPOSAL
RES Surcharge Calculations for Impacts of Uncollected Fixed Costs under Net Metering
Prepared in Response to Commissioner Mayes request 11/30/06 Based on Staff Witness Keene Testimony
Excess Generation Only Example

Year	Retail Sales (GWh)	Estimated Distr. Gen. Requirement (GWh) [1,2]	Estimated Exess Sold Back to APS (kWh) [3]	Excess Generation Program Costs at $0.04/kWh [4]	Uncollected Fixed Costs Recovered From RES [5]	Uncollected Fixed Costs Recovered Through Base Rates	Estimated Total RES Revenue [6]	RES Funds Available After Excess Gen. Program Costs
2007	28,740	22	1,100,000	$ 44,000	$ 44,000	$ 836,000	$ 29,123,924	$ 29,079,924
2008	29,602	52	2,600,000	$ 104,000	$ 104,000	$ 1,976,000	$ 30,279,676	$ 30,175,676
2009	30,490	91	4,550,000	$ 182,000	$ 182,000	$ 3,458,000	$ 31,413,319	$ 31,231,319
2010	31,405	157	7,850,000	$ 314,000	$ 314,000	$ 5,966,000	$ 32,513,221	$ 32,199,221
2011	32,347	243	12,150,000	$ 486,000	$ 486,000	$ 9,234,000	$ 33,586,356	$ 33,100,356
2012	33,317	350	17,500,000	$ 700,000	$ 700,000	$ 13,300,000	$ 34,571,720	$ 33,871,720
2013	34,317	412	20,600,000	$ 824,000	$ 824,000	$ 15,656,000	$ 35,533,433	$ 34,709,433
2014	35,346	477	23,850,000	$ 954,000	$ 954,000	$ 18,126,000	$ 36,486,687	$ 35,532,687
2015	36,407	546	27,300,000	$ 1,092,000	$ 1,092,000	$ 20,748,000	$ 37,428,809	$ 36,336,809
2016	37,499	675	33,750,000	$ 1,350,000	$ 1,350,000	$ 25,650,000	$ 38,386,702	$ 37,036,702
2017	38,624	811	40,550,000	$ 1,622,000	$ 1,622,000	$ 30,818,000	$ 39,329,965	$ 37,707,965
2018	39,782	955	47,750,000	$ 1,910,000	$ 1,910,000	$ 36,290,000	$ 40,250,898	$ 38,340,898
2019	40,976	1,106	55,300,000	$ 2,212,000	$ 2,212,000	$ 42,028,000	$ 41,181,516	$ 38,969,516
2020	42,205	1,266	63,300,000	$ 2,532,000	$ 2,532,000	$ 48,108,000	$ 42,105,040	$ 39,573,040
2021	43,471	1,435	71,750,000	$ 2,870,000	$ 2,870,000	$ 54,530,000	$ 43,009,234	$ 40,139,234
2022	44,776	1,612	80,600,000	$ 3,224,000	$ 3,224,000	$ 61,256,000	$ 43,886,605	$ 40,662,605
2023	46,119	1,799	89,950,000	$ 3,598,000	$ 3,598,000	$ 68,362,000	$ 44,737,188	$ 41,139,188
2024	47,502	1,995	99,750,000	$ 3,990,000	$ 3,990,000	$ 75,810,000	$ 45,603,445	$ 41,613,445
2025	48,927	2,202	110,100,000	$ 4,404,000	$ 4,404,000	$ 83,676,000	$ 46,439,706	$ 42,035,706
Totals	721,852	16,206	810,300,000	$32,412,000	$32,412,000	$615,828,000	$725,867,444	$693,455,444

Notes:
1: Assumes RES Target DG requirement kWh attained entirely from net metered customers.
2: Assumes growth in sales as provided within the RES DG requirement.
3: Estimated at 5% of Distributed Generation annual requirement.
4: Average annual retail rate less average annual avoided cost for rates E-12, ET-1, ECT1R, E-32 (<20 kW)
5: Assumes Excess Generation uncollected fixed costs remain a cost of the Net Metering Program recovered through the RES Surcharge annually.
6: Assumes the following Caps and Charges based on APS version of the Sample Tariff:

	Cap	Rate per kWh
Residential	$ 1.33	$ 0.003325
C&I <3MW	$ 49.40	$ 0.003325
C&I >3MW	$ 148.20	$ 0.003325

ARIZONA PUBLIC SERVICE COMPANY
RES Surcharge Calculations for Impacts of Uncollected Fixed Costs under Net Metering
Prepared in Response to Commissioner Mayes request 11/30/06 Based on Staff Witness Keene Testimony
Excess Generation Only Example

2018 Incremental Increase to RES Caps and Surcharges for Uncollected Fixed Costs:

	APS Sample Rate Schedule		Projected Rate Schedule **		Increase	
	Cap	Rate per kWh	Cap	Rate per kWh	Cap	Rate per kWh
Residential	$ 1.33	$ 0.003325	$ 1.39	$ 0.003483	$ 0.06	$ 0.000158
C&I <3MW	$ 49.40	$ 0.003325	$ 51.75	$ 0.003483	$ 2.35	$ 0.000158
C&I >3MW	$ 148.20	$ 0.003325	$ 155.24	$ 0.003483	$ 7.04	$ 0.000158

** Designed to recover 2018 program costs of $1.910 million as seen on Page 1 of this Exhibit.

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EDISON ELECTRIC INSTITUTE

DAVID K. OWENS
Executive Vice President
Business Operations

September 15, 2006

The Honorable Eric Solomon
Acting Deputy Assistant Secretary (Tax Policy)
United States Department of the Treasury
1500 Pennsylvania Avenue, N.W.
Washington, D.C. 20220

Re: Utility Industry Concerns Regarding Section 118 of the Internal Revenue Code

Dear Mr. Secretary:

The Edison Electric Institute ("EEI") appreciates the opportunity to bring to your attention an important issue of tax policy affecting the electric utility industry. The issue relates to a change in administrative policies with respect to section 118 of the Internal Revenue Code of 1986, as amended (the "Code"), that hinders the expansion and improvement of our nation's electric transmission and distribution infrastructure, which is a key component of the Administration's energy policy. As discussed below, the current Internal Revenue Service ("IRS") administrative policy creates an impediment to investment which is needed to expand the nation's electric transmission and distribution systems and increases the cost to American citizens who seek to ensure the safety of their neighborhoods and businesses by asking their local utilities to relocate or bury transmission and distribution lines underground. Given the importance of robust, reliable, and cost-effective transmission and distribution systems for our nation, federal tax policy should be aimed at eliminating any federal income tax impediments to electric infrastructure investment.

EEI is the association of United States shareholder-owned electric companies, international affiliates, and industry associates worldwide. Our members serve 97 percent of the ultimate customers in the shareholder-owned segment of the industry, and 71 percent of all electric utility ultimate customers in the nation. In providing electricity to their customers, EEI members depend on and need well-integrated, well-developed transmission and distribution systems to ensure that electricity can be provided from a diverse portfolio of generation resources to customers reliably, efficiently, and economically.

I. Transfers to Utilities for Investments in Infrastructure

The nation's electric utilities are linked through system interconnections. Interconnected transmission networks improve reliability and lower costs by providing electric utilities with alternative power paths in emergencies and by allowing them to buy and sell power from one another and from other power suppliers. Conversely, limitations on the capacity of one utility can adversely impact the reliability and efficiency of a neighboring utility.

Last year Congress passed the Energy Policy Act of 2005 which contained provisions to encourage the development of transmission infrastructure and increase reliability of our nation's bulk power system. Additionally, the Federal Energy Regulatory Commission recently promulgated policies that seek to encourage expansion of the nation's transmission system and increase transmission capacity. It has become increasingly evident in recent years that substantial enhancements to the nation's transmission infrastructure are needed to maintain reliability and meet the growing demand for electricity. As the generation of electricity in many parts of our country has become unregulated, the sale of electricity has become more competitive. Greater competition in electricity markets is expanding the use of the nation's electric transmission and distribution grid and has required greater integration of the grid. As a result, EEI members are actively investing in the transmission system to meet the growing need for transmission service. From 2004 through 2008, preliminary data indicates that utilities have invested or are planning to invest $28 billion in transmission assets, a 60 percent increase over the amount spent from 1999 through 2003. *See* Edison Electric Institute, *EEI Survey of Transmission Investment, Historical and Planned Capital Expenditures (1999-2008)*, at 1 (May 2005)[1].

Federal energy policy is directed toward promoting development of a robust energy infrastructure and encouraging investment in energy infrastructure. *See* Federal Energy Regulatory Commission, *Top Priorities*, http://www.ferc.gov/whats-new/top-priorities.asp; Federal Energy Regulatory Commission, *Strategic Plan FY 2005-FY 2008*, http://www.ferc/gov/about/strat-docs/strat-plan.asp; Federal Energy Regulatory Commission, News Release: "Final Rule Promoting Transmission Investment Adopted; Rate Incentives For Two Transmission Proposals Accepted," July 20, 2006; White House Fact Sheet: Securing Our Nation's Energy Future, http://www.whitehouse.gov/news/releases/2005/03/20050309-4.html.

Yet EEI members confront various impediments in expanding and improving the nation's transmission and distribution systems. These impediments delay, increase the cost of, and in some cases even prevent electric infrastructure investment. Given the importance of robust, reliable, and cost-effective transmission and distribution systems for our nation,

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[1] From 2005 through 2009, preliminary data indicates that shareholder-owned utilities have invested or are planning to invest $37 billion in transmission assets, nearly a 45 percent increase over the amount spent from 1999 through 2004.

federal regulatory and legislative policies should be aimed at eliminating impediments to electric infrastructure investment.

One significant impediment to cost-effective investment in electric infrastructure arises from the narrow interpretation of section 118(a) of the Code that the IRS is currently applying. Section 118(a) provides an exclusion from income for non-shareholder contributions to capital. In considering the tax consequences of transfers to utilities for investments in transmission and distribution infrastructure, the IRS's current position appears to be that few transactions qualify as contributions to capital and that amounts received by utilities to expand, improve, or modify the nation's transmission and distribution systems frequently are taxable. Since the promulgation of Notice 2001-82, 2001-2 C.B. 619, in which the IRS provided a safe harbor for transfers of interconnection facilities by stand-alone generators to transmission utilities, the IRS has narrowed the definition of a non-shareholder contribution to capital under section 118(a) through private letter rulings and technical advice memoranda. At issue is whether the transferor's payment or transfer of property to an interconnected utility to benefit the transferor's operations should be appropriately characterized as taxable income to the recipient rather than a nontaxable contribution to capital. The IRS has taken the position that, where a transferor receives any modicum of benefit, whether direct or indirect, as a result of a transfer to a public utility, the transfer does not meet the definition of a contribution to capital for purposes of section 118(a). This position cannot be reconciled with Notice 2001-82 and Notice 88-129, 1988-2 C.B. 541 (regarding transfers by qualifying small power producers and qualifying cogenerators to utilities for interconnection facilities) in which the transferor-generators clearly receive a benefit (*i.e.*, the ability to sell the electricity that the transferor generates), yet the IRS nevertheless concludes that the transfers are nontaxable to the transferee-utility.

In helping to meet our country's serious need for enhanced transmission capacity, integrated utilities and independent transmission companies are building transmission lines around the country, and, where necessary, crossing state lines and regulatory jurisdictional boundaries. While a utility (or independent transmission company) may need to build transmission in a neighboring jurisdiction in order to alleviate a transmission "bottleneck," for regulatory compliance reasons, it likely will not make sense for the utility to own transmission property outside of its own service area. For this reason, utilities and independent transmission companies that build transmission lines outside of their own service areas are likely to want to contribute this property to the utility that serves that area to properly integrate the operations of the contributed transmission line into the utility's overall operational portfolio for reliability and practical purposes. There are direct parallels between this type of contribution and the generator-to-utility interconnection contribution considered in Notice 2001-82.

A typical transaction involves the payment by one transmission company (the "Transferor Utility") to a neighboring transmission company (the "Transferee Utility") to upgrade the Transferee Utility's transmission facilities so that more power can be transmitted by both utilities. Another variation of this transaction involves the immediate reimbursement of a portion of the construction costs and the repayment of the remainder over a period of time determined by the relevant regulatory commission. In either case, the Transferor Utility is not a customer or potential customer of the Transferee Utility, nor is the Transferor Utility related to the Transferee Utility in any way. The Transferor Utility is willing to make this payment to upgrade the Transferee Utility's system so that it (the Transferor Utility) will be able to provide a more reliable source of electricity to its customers. The utilities do not provide services to each other, and each utility is compensated for the transmission services which it provides to its customers by those customers. The Transferee Utility will not include the facilities or upgrades provided by the Transferor Utility in its rate base for ratemaking purposes.

If this transfer is treated as a contribution to capital under section 118(a), the Transferee Utility would be entitled to exclude the transfer from gross income. Whether a payment is a nontaxable non-shareholder contribution to capital under section 118(a) is governed by a five-factor test that was first articulated by the Supreme Court in *United States v. Chicago, Burlington, & Quincy Railroad Co.*, 412 U.S. 401 (1973) ("*CB&Q*"). Under the *CB&Q* test, a payment is a contribution to capital if the contribution (1) becomes part of the transferee's working capital; (2) is not compensation for services or goods; (3) is bargained for; (4) benefits the transferee; and (5) will contribute to the production of additional income. *See CB&Q,* 412 U.S. at 401. In the hypothetical posed above, the IRS likely would agree that the transfer satisfies the *CB&Q* test. Nonetheless, given recent private letter rulings (which are discussed below), the IRS is likely to assert that the transfer is not a contribution to capital under section 118(a), because the Transferor Utility is making the transfer to obtain a specific indirect benefit – the ability to sell more electricity to its customers. As noted above, this position is inconsistent with existing IRS guidance regarding transfers to utilities from unrelated generators. The Transferor Utility in this example obtains an indirect benefit identical to the benefit obtained by the transferor-generators in Notice 2001-82 and Notice 88-129. From a tax policy perspective, there is no basis for treating transfers from generators to utilities as nontaxable and transfers from one utility to another utility as taxable.

No government, company, or citizen is likely to make an entirely disinterested transfer to an unrelated party. Consequently, the standard that the IRS currently is applying in effect means that there can be no non-shareholder contributions to capital within the meaning of section 118(a). Simply put, we do not believe that the current administrative policy is serving the nation's best interests, because it effectively nullifies a section of the Code, overrides Supreme Court precedent, and discourages investment in needed assets. The better reading of section 118 is that the existence of a benefit to the transferor does not cause the transfer to become taxable where the transferor is not making the transfer to obtain new, additional, or different services from the utility. Where a transferor makes a transfer to a utility to receive a specific direct benefit, the transfer is compensation to the utility for providing such benefit and taxable under section 61. At the opposite end of the spectrum, a transfer resulting entirely from disinterested generosity is a gift and not taxable under section 102. The legislative history of section 118 indicates that somewhere between a gift and compensation for services is a nontaxable contribution to capital under section 118(a). *See* H.R. Rep. No. 83-1337, 17 (1954); S. Rep. No. 83-1622, 18-19 (1954); Staff of J. Comm. on Tax'n, 83d Cong., *Summary of the New Provisions of the Internal Revenue Code of 1954* (Comm. Print 1955). In other words, a transfer with respect to which the transferor receives some benefit is by definition a contribution to capital. Thus, the IRS's current section 118(a) policy appears to be inconsistent with Congressional intent in enacting section 118(a).

Moreover, the IRS's section 118(a) policy is contrary to the Administration's initiative to expand and improve the nation's electric infrastructure. As a result of this policy, for every dollar received by a utility for transmission or distribution system improvements, only about 77 cents can be used for the intended purposes. In other words, investments in electric infrastructure are 30 percent more expensive as a result of the IRS's policy. Consequently, some projects may not be cost effective, and may not be completed, due to the increased cost. The IRS's section 118(a) policy, therefore, has an adverse effect on the interests of all Americans. At a critical time in the development of the nation's electric infrastructure, investments in the nation's transmission and distribution system are more expensive than they need be due to the IRS's narrow definition of a contribution to capital for purposes of section 118(a). Federal income taxes, therefore, are creating an additional impediment to investment in the nation's transmission grid. Federal tax policy should be aimed at eliminating this impediment and encouraging such investment. Furthermore, given that increases in underlying fuel commodity prices have increased the cost of electricity dramatically in recent years, federal tax policy should not cause consumers, some of whom already are struggling to pay for electric service, to pay higher prices.

II. Relocation and Undergrounding of Lines

Similarly, federal income taxes are increasing the costs to relocate transmission and distribution lines and bury transmission and distribution lines underground. As discussed below, the primary motivating factor in relocating or burying electric lines is public safety. Undergrounding also improves community aesthetics and may improve system reliability by making the lines less susceptible to damage from storms, trees, and vehicles. Given the importance of these goals and the benefits that are shared by entire communities, federal tax policy should not discourage transfers to utilities to relocate or bury electric lines.

A typical utility transaction involves payments to a utility to relocate transmission or distributions lines. The principal reason for relocating transmission lines is to ensure public safety. It is simply unsafe to build close to high voltage transmission lines. In many states, it is illegal to build under, or in the right-of-way for, a transmission line, and states frequently require utilities to conduct surveys to ensure that no one has done so. The problem is that transmission lines that once were located in undeveloped or rural areas often now are in the middle of suburban or urban areas. These lines need to be moved to a safe distance away from development. Transmission lines running along highways and other roads also need to be moved to accommodate expansion of those thoroughfares.

A business or individual may own a vacant parcel of land that it would like to develop, but a utility's overhead transmission lines bisect the developable portion of the property. The utility agrees to relocate the transmission lines to the perimeter of the property (or to a location that cannot be developed for other reasons) if the property owner reimburses the utility for the costs incurred to do so. The property owner already receives electric service from the utility at an adjacent facility, and the undeveloped property already has access to electric service from another line. The utility consequently will not use the lines at issue to provide service to the customer requesting relocation. The relocated lines do not result in any increase in electric capacity or other operational improvement, and the capacity of each energized line remains unchanged. Relocation of the lines improves public safety and allows development of the land, thereby creating jobs and economic growth to the community at large. *See Brown Shoe Co. v. Comm'r*, 339 U.S. 583 (1950) (transfers to induce the taxpayer to construct a factory were contributions to capital because the transferors' expectation was that the contribution would prove advantageous to the community at large). Obtaining these benefits does not result in the transfers being treated as taxable contributions in aid of construction ("CIACs") under section 118(b). The legislative history of section 118 specifically provides that transfers are not taxable CIACs for federal income tax purposes where the primary motivating factor for the transfer was the benefit of the public as a whole. *See* H.R. Rep. No. 426, at 644-45 (1985). This is commonly referred to as the "public benefit exception" to section 118(b).

Initially, the IRS determined that a payment by a developer to a utility to relocate distribution lines was a contribution to capital under section 118, because the transfer satisfied the five-prong *CB&Q* test. *See* P.L.R. 200133036 (Aug. 20, 2001); *see also* P.L.R. 9448005 (Dec. 2, 1994) (a county's transfer to a utility to relocate a transmission line bisecting the county's landfill and preventing expansion of the landfill was a contribution to capital and not a CIAC); P.L.R. 9830023 (July 24, 1998) (same). Moreover, according to the IRS, the transfer was not a CIAC under section 118(b), because the "public benefit exception" was satisfied since the relocation was a condition to obtaining a building permit and necessary for enhancing public safety. The ruling does not consider the fact that the developer clearly benefited from the transfer by receiving the building permit and subsequently profiting from the development of the land.

In contrast, a few years later, the IRS concluded that a payment by a university to a utility to relocate transmission lines bisecting its property was not a contribution to capital under section 118(a), because notwithstanding the fact that the university was developing the campus in furtherance of its mission as an educational institution, the relocation payments resulted in a direct benefit to the university (*i.e.*, the ability to develop the property in an optimal manner). *See* T.A.M. 200450035 (Dec. 10, 2004). The IRS used the existence of a direct benefit to determine that the transfer was not a contribution to capital and thereby avoided having to address why the public benefit exception of section 118(b) was inapplicable. As discussed in detail above, the definition of a contribution to capital assumes that there is some benefit to the transferor obtained as a result of the payment. Indeed, the facts underlying the earlier relocation ruling indicate that the transferor's receipt of a benefit previously did not preclude the IRS from characterizing a payment as a contribution to capital. Given that the definition of a contribution to capital did not change in the intervening period, it is unclear what caused the IRS policy to change and what legal authority supports the current policy with respect to section 118(a).

Customers, developers, or municipalities also frequently transfer funds to utilities to bury distribution lines underground. The most significant reasons for undergrounding lines involve public safety, resistance to damage from trees, ice, wind, and heavy rain during storms, and elimination of the risk of vehicular accidents. Underground lines are less susceptible to damage from trees and weather conditions and thus reduce the number of injuries or fatalities from customers coming into contact with fallen overhead energized lines and, in some parts of the country, may result in fewer customer outages. Additionally, underground lines are not susceptible to damage from vehicular traffic (*i.e.*, poles being hit by cars, trucks getting caught on lines, etc.) which further improves public safety and reliability. *See, eg.*, P.L.R. 9622029 (May 31, 1996) (transfers by municipalities and developers to relocate electrical lines to improve the safety of pedestrians and drivers in connection with street widening efforts were nontaxable contributions to capital).

Many public utility commissions require utilities to offer customers the opportunity to have distribution lines proximate to their premises, including their connection lines, placed underground. This requirement often includes new connections to the distribution system. In those cases, the utilities will charge customers a fee ($X) to connect their properties to the utilities' distribution systems plus an additional fee ($Y) to bury the connections. Neighborhoods or subdivisions frequently will vote to underground the distribution lines in their communities. In other cases, pursuant to a municipal ordinance that requires undergrounding of electrical distribution and service drops in new developments for safety and aesthetic reasons, developers pay for the incremental cost of the undergrounding work ($Y in the prior example). In each of these examples, the utility is permitted to charge customers an amount which approximates its cost to bury the lines, but the utility does not earn a profit on the undergrounding service. The burial of the distribution lines does not result in any increase in electrical capacity or other operational improvement, and the capacity of each energized line remains unchanged. Amounts received to extend distribution lines ($X in the example above) constitute taxable CIACs, but amounts received to bury distribution lines underground should be nontaxable contributions to capital.

Like the change described above for transfers to relocate transmission and distribution lines, the IRS also has changed its position regarding the treatment of transfers to utilities for burial of distribution lines. Initially, the IRS ruled that transfers for undergrounding were contributions to capital under section 118(a) within the scope of the public benefit exception. *See* P.L.R. 200248014 (Nov. 29, 2002). The IRS later determined that, because a municipality required a developer to pay for undergrounding of distribution lines to obtain a building permit, the developer received a benefit from transfers to a utility for undergrounding (*i.e.*, the ability to develop a site), and as a result, the transfer to the utility was taxable. *See* P.L.R. 200542001 (Oct. 21, 2005). Interestingly, rather than concluding that the payments were not contributions to capital, as the IRS did in its ruling regarding relocation of the transmission line on a university's property, the IRS concluded that the transfers were taxable CIACs under section 118(b). Simply put, these transfers cannot be viewed as CIACs. While the transferors otherwise may purchase transmission services from the utility or may be developers, transfers for undergrounding are not made as a prerequisite to the receipt of electric service or to obtain additional or improved service. The transferors thus are not acting in their capacity as customers of the utilities. Instead, the transferors are motivated by a desire to ensure public safety, improve system reliability, and enhance their communities' aesthetics, all of which are benefits provided to the public as a whole, not just the transferors. The public benefit exception of section 118(b), therefore, applies. Consequently, payments for undergrounding should be treated as nontaxable contributions to capital under section 118(a).

Indeed, the IRS previously ruled that a developer's payments to a utility to relocate distribution lines, pursuant to a municipal ordinance requiring undergrounding to improve the municipality's aesthetics and public safety, were nontaxable contributions to capital. *See* T.A.M. 200248014 (Nov. 29, 2002); P.L.R. 9821024 (May 22, 1998). Furthermore, the IRS recently ruled that transfers from a municipality to a utility to underground distribution lines for public safety and aesthetic reasons are nontaxable contributions to capital, even though the municipality planned to issue tax-exempt bonds to fund the transfers and the bonds would be repaid through the imposition of special real estate taxes on property owners in the districts where undergrounding occurs (*i.e.*, the utility's customers ultimately pay for the undergrounding). *See* P.L.R. 200528022 (July 15, 2005); *see also* P.L.R. 199904029 (Feb. 1, 1999) (county's transfers to a utility to finance undergrounding were nontaxable contributions to capital notwithstanding that undergrounding was financed by assessment on property owners in a special improvement district). Whether an individual transfers funds to a utility for undergrounding directly or indirectly through a municipality should not affect the tax treatment of the transfer. The IRS's section 118 policy, however, has the effect of treating a direct payment for undergrounding as taxable and an indirect payment as nontaxable.

III. Conclusion

As you can see, in administering section 118, the IRS has adopted a policy that conflicts with Congressional intent, overrides Supreme Court precedent, and hinders the Administration's efforts to promote electric infrastructure investment. This policy is not well-articulated and often is confusing to our members. Moreover, the policy creates an impediment to investment in the nation's electric transmission and distribution systems and increases the cost to American citizens who seek to improve the safety of, and ensure reliable provision of electricity to, their homes, businesses, and communities by asking their local utilities to relocate electric transmission or distribution lines or bury distribution lines underground.

EEI appreciates the opportunity to bring to your attention this important issue of tax policy which adversely affects our members' efforts to expand and improve our nation's electric transmission and distribution infrastructure and reliably serve our customers. EEI respectfully requests a meeting with you at your earliest convenience to discuss how we can work together to resolve this issue in the best interests of the government, EEI members, and the public. We appreciate your consideration of this request and look forward to hearing from you. Should you have any questions on this matter, please contact me directly or Roger Kranenburg, EEI's Taxation Committee Representative, at 202/508-5183 or rkranenburg@eei.org.

Sincerely yours,

David K. Owens

David K. Owens

DKO:rky

Commercial Electric Utility Mercury Control Technology Bookings

Air pollution control vendors are reporting booking new contracts for mercury control equipment for more than two dozen power plant boilers. The contracts for commercial systems are attributed to federal and state regulations, including new source permit requirements and consent decrees, which specify high levels of mercury capture. Below is a summary of the mercury control equipment that has been procured to date:

	Plant Size (MW)	Location	Prime OEM Contractor	Coal	APC Configuration	Hg Control	New Plant or Retrofit	Regulatory Driver
Unit 1	270	Midwest	Wheelabrator (Norit/ADA-ES)	PRB	TOXECON	ACI	Retrofit	Consent Decree
Unit 2	250	East	Wheelabrator	Bituminous	SDA/FF	ACI	Retrofit	State Regulatory
Unit 3	250	East	Wheelabrator	Bituminous	SDA/FF	ACI	Retrofit	State Regulatory
Unit 4	650	East	Wheelabrator	Bituminous	ESP	ACI	Retrofit	State Regulatory
Unit 5	740	Midwest	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	New Plant	New Construction Permit
Unit 6	550	Midwest	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	New Plant	New Construction Permit
Unit 7	350	West	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	Retrofit	Consent Decree
Unit 8	350	West	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	Retrofit	Consent Decree
Unit 9	800	West	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	New Plant	New Construction Permit
Unit 10	350	East	ADA-ES	Bituminous	ESP	ACI	Retrofit	Consent Decree
Unit 11	350	East	ADA-ES	Bituminous	ESP	ACI	Retrofit	Consent Decree
Unit 12	204	Midwest	Dustex	PRB	TOXECON	ACI	Retrofit	Consent Decree
Unit 13	375	East	Wheelabrator	Bituminous		ACI	Retrofit	Consent Decree
Unit 14	650	Midwest	Alstom (ADA-ES)	PRB	SDA/FF	Br-ACI	New Plant	New Construction Permit
Unit 15	215	Midwest	Powerspan	Bituminous	Multipollutant	ECO	Retrofit	Construction Permit
Unit 16	75	Midwest	Mobotec	PRB	Cold-Side ESP	MinPlus Furnace Injection, Non-Carbon Sorbents	Retrofit	Voluntary Regional Emission Abatement Plan
Unit 17	750	Midwest	Wheelabrator	High Sul. Bit	ESP/WFGD/WESP	ACI	New Plant	Construction Permit
Unit 18	680	South	Alstom (ADA-ES)	PRB	SDA/FF	Br-ACI	New Plant	Construction Permit
Unit 19	107	East	BPI	Bit./Bio-Mass	FT-SNCR/CDS/FF	ACI	Retrofit	DOE Demo.
Unit 20	860	South	BPI	Lignite	SCR/FF/WFGD	Undefined Sorbent	New Plant	Construction Permit
Unit 21	860	South	BPI	Lignite	SCR/FF/WFGD	Undefined Sorbent	New Plant	Construction Permit

	Plant Size (MW)	Location	Prime OEM Contractor	Coal	APC Configuration	Hg Control	New Plant or Retrofit	Regulatory Driver
Unit 22	220	West	B&W (ADA-ES)	PRB	SDA/FF	Br-ACI	New	Construction Permit
Unit 23	75	Midwest	Mobotec	PRB	Cold-Side ESP	MinPlus Furnace Injection, Non-Carbon Sorbents	Retrofit	Voluntary Regional Emission Abatement Plan
Unit 24	75	Midwest	Mobotec	PRB	Cold-Side ESP	MinPlus Furnace Injection, Non-Carbon Sorbents	Retrofit	Voluntary Regional Emission Abatement Plan
Unit 25	575	Southwest	B&W (STC)	West.Bit/Sub. Bit. Blend	HS-ESP/FF/WFGD	ACI	Retrofit	Construction Permit
Unit 26	575	Southwest	B&W (STC)	West.Bit/Sub. Bit. Blend	HS-ESP/FF/WFGD	ACI	Retrofit	Construction Permit
Unit 27	335	Northeast	ADA-ES	Bituminous	Cold-Side ESP	ACI	Retrofit	Voluntary Regional Emission Abatement Plan

Renewable Development Schedule:

APS Saguaro Solar @ 1MW – 4 to 5 years
Initial Planning 2001, Announced April 2002, Operational October 2006

APS Prescott Solar @ 3.5MW – 2 to 6 years
Initial Planning 2000, Announced October 2002, Operational Phase 1 December 2002, Final Phase March 2006

Prescott Notes: Site selection - 2 years, procurement - 1.5 years, construction 15 months for each phase w/parallel path on procurement/construction. Critical element of solar development - module availability.

Reconciliation of APS September 30, 2006 Capitalization Ratios ($m)

	Nov 15th Filing (1)	Nov 30th Filing (2)
Long-term debt excluding current maturities	$ 2,877.3	$ 2,877.3
Current maturities	84.8	84.8
Total long-term debt on balance sheet	2,962.1	2,962.1
Imputed debt for leases and purchased power agreements		697.8
Short-term debt		-
Total adjusted debt		3,659.9
Common equity	3,156.6	3,156.6
Total capitalization	$ 6,118.7	$ 6,816.5
Debt ratio without imputed debt	48.4%	
Debt ratio with imputed debt		53.7%
Equity ratio without imputed debt	51.6%	
Equity ratio with imputed debt		46.3%
Total	100.0%	100.0%

(1) from capital structure report (which does not include rating agency imputed debt)

(2) from monthly cash position and financial ratio report

Arizona Public Service Company
Summary of Unplanned Actual Outage Fuel Cost versus Base Rate Fuel Cost
April - December 2005

Line No.		Resource Type: Nuclear	Coal	Gas Combined Cycle	Total
	Actual Replacement Energy [MWh]				
1	Replaced	765,220	465,237	753,819	1,984,277
	Actual Net Replacement Cost [$000]				
2	Replacement	60,790	39,754	66,383	166,928
3	Avoided	3,867	6,675	49,107	59,649
4	**Actual Net Replacement Cost**	56,923	33,079	17,277	107,278
	Base Rate Replacement Energy [MWh]				
5	Replaced	168,201	766,543	548,222	1,482,966
	Base Rate Net Replacement Cost [$000]				
6	Replacement	8,230	37,483	34,041	79,754
7	Avoided	823	10,505	25,871	37,199
8	**Base Rate Net Replacement Cost**	7,407	26,978	8,170	42,555
9	**Actual Greater/(Less) Base Rate Replacement Energy (Ln. 1 - Ln. 5)**	597,019	(301,306)	205,597	501,310
10	**Actual Greater/(Less) Base Rate Net Replacement Cost (Ln. 4 - Ln. 8)**	49,516	6,101	9,106	64,723
11	**Amount Deferred (90%* Ln. 10)**	44,564	5,491	8,196	58,251
12	**Variance Due to Outage Time [$000]**	23,947	(11,079)	2,723	15,591
13	**Variance Due to Outage Replacement Prices [$000]**	25,568	17,180	6,383	49,132

APS COAL STATISTICS - 2005 & 2006

2005	EAF Actual	EAF Budget	EAF Variance	NCF Actual	NCF Budget	NCF Variance
Cholla	91.7	89.8	1.9	85.5	84.9	0.6
Four Corners	89.9	88.2	1.7	89.5	88.2	1.3
Navajo	88.5	90.0	(1.5)	84.2	89.5	(5.3)
Total Coal	90.3	89.1	1.2	87.1	87.3	(0.2)

2006 - YTD NOV	EAF Actual	EAF Budget	EAF Variance	NCF Actual	NCF Budget	NCF Variance
Cholla	89.4	89.3	0.1	85.8	88.1	(2.3)
Four Corners	88.0	86.9	1.1	87.4	86.8	0.6
Navajo	93.0	91.8	1.2	88.9	85.5	3.4
Total Coal	89.4	88.7	0.7	87.1	87.1	-

APS NUCLEAR STATISTICS - 2005 & 2006

2005	NCF Actual	NCF Budget	NCF Variance
Palo Verde	77.4	86.1	(8.7)

2006 - YTD NOV	NCF Actual	NCF Budget	NCF Variance
Palo Verde	67.9	89.8	(21.9)

Definitions:

EAF = Equivalent Availability Factor — Represents the portion of time the units were available to generate electricity over a specified time period.

NCF = Net Capacity Factor — Represents the actual net generation divided by total possible generation at a stated capacity over a specified time period.

U.S Electric Utilities
5-Year Dividend Growth
2000 - 2005 Compound Annual Growth Rate [a]

Ranking	Company	5-Year Dividend Growth
1	UniSource Energy	18.9%
2	Exelon	13.6%
3	PPL Corp	13.5%
4	Northeast Utilities	11.8%
5	Entergy	11.4%
6	PNM Resources	8.4%
7	TXU	6.6%
8	Scana Corp	6.3%
9	Pinnacle West	5.9%
10	Energy East	5.7%
11	FPL	5.6%
12	FirstEnergy	3.7%
13	Vectren Corp	3.6%
14	Sempra Energy	3.0%
15	Progress Energy	2.7%
16	Avista Corp	2.4%
16	NSTAR	2.4%
18	Southern Company	2.1%
19	Duke Energy	2.0%
19	PG&E Corp	2.0%
21	Wisconsin Energy	1.9%
21	WPS Resources	1.9%
23	Cinergy Corp	1.3%
24	Cleco Corp	1.1%
25	Consolidated Edison	0.9%
25	KeySpan	0.9%
27	Dominion Resources	0.8%
28	Public Service Enterprises	0.7%
29	DPL	0.4%
30	Ameren Corp	0.0%
30	CH Energy	0.0%
30	DTE Energy	0.0%
30	Great Plains Energy	0.0%
30	Hawaiian Electric	0.0%
30	OGE Energy	0.0%
30	UIL Holdings	0.0%
37	NiSource	(3.2)%
38	Constellation Energy	(4.4)%
39	Westar Energy	(5.2)%
40	IDACORP	(8.4)%
41	American Electric Power	(9.2)%
42	Pepco Holdings	(9.6)%
43	Duquesne Light	(9.9)%
44	Xcel Energy	(10.2)%
45	TECO Energy	(10.7)%
46	Puget Energy	(11.5)%
47	Alliant Energy	(12.1)%
48	Allete	(17.1)%
49	Centerpoint Energy	(23.2)%
50	Allegheny Energy	(100.0)% [b]
50	CMS Energy	(100.0)% [b]
50	Sierra Pacific	(100.0)% [b]
	Industry Average	(1.4)%

[a] Bars are graphed in same order as ranking listed above. Ties are noted in brackets.

[b] Not shown on graph due to distortion effect on graph.