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October 2, 2009

Arizona Corporation Commission
DOCKETED
OCT - 2 2009
DOCKETED BY

Hon. Lyn Farmer
Chief Administrative Law Judge
Hearing Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Late-Filed APS Exhibit 39; Docket No. E-01345A-08-0172

Dear Judge Farmer:

Please consider this letter and its attachments as Late-Filed APS Exhibit 39. It includes Arizona Public Service Company's ("APS" or "Company") response to the letter from Commissioner Newman dated September 17, 2009, as well as responses to various questions posed during the hearing and/or documents requested during the hearing. APS has presented the latter in the format customarily used for discovery requests so that both the request and the requester will be clearly identified. A table of contents has been provided for your convenience and that of the parties.

There are also some additional inquiries outstanding that were directed to APS witness Daniel Froetscher. They will be responded to in a separate letter to the Chairman and docketed in this proceeding. Subject to the aforementioned caveat, please let me know if this Late-Filed APS Exhibit 39 is incomplete in any manner.

Sincerely,

Thomas L. Mumaw

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Attorney for Arizona Public Service Company

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Response to Commissioner Newman Letter of September 17, 2009

**APS RESPONSE TO LETTER DATED SEPTEMBER 17, 2009
FROM COMMISSIONER NEWMAN**

Q1. Mr. Rumolo testified on Wednesday, September 16th in the a.m. that in this case APS would like to put "some" of its fuel costs into rate base.

a) Does APS want to put "some" fuel costs that are currently in the Power Supply Adjustor (PSA) into rate base? In other words, will fuel costs that were formerly in the PSA now be put into rate base?

A. APS does not wish nor does the Settlement provide that any fuel costs be placed into rate base. Rate base is the capitalized amount upon which the Company is allowed to earn a reasonable rate of return. No party is suggesting that any portion of fuel expenses be capitalized and earn a return. Therefore, APS will assume that wherever the term "rate base" was used, it was intended to mean "base rate" or "base rates."

The Company did request in its Application and the Settlement provides for a certain level of fuel costs to be recovered in base rates through establishment of a new base fuel cost. *See* Paragraph 6.2. The base fuel cost proposed in the settlement is less than that requested by APS and slightly less than that recommended by Commission Staff. *See* Paragraph 3.8. Such a re-establishment of a new base fuel cost is consistent with the Commission's decisions in 2005 and 2007, which constitute all the rate case decisions since establishment of the PSA. *See* Decision No. 67744 (April 5, 2005) at 14 and Decision No. 69663 (June 28, 2007) at 33. It is also required by the PSA Plan of Administration as approved by the Commission. Because a greater amount of fuel costs would be recovered through base rates, less will need to be reflected in the PSA adjustor.

In fact, APS currently anticipates that if the Settlement's level of base fuel cost is accepted by the Commission, the PSA adjustor for 2010 will be negative, thus providing APS customers a credit against their bills. And in response to a question from Chairman Mayes and also a later portion of the September 17th letter, APS has looked at 2011 and believes that the so-called forward element of the PSA could well remain negative for that year as well should current market and operational conditions continue. But should a lower base fuel cost be adopted, the PSA credit alluded to above would be reduced by an equal amount for both 2010 and 2011, as well as future years.

b) Am I correct in understanding that APS will replace the current PSA with a NEW surcharge that would collect $115 million in base rates?

A. No. The $115 million apparently refers to the Company's original request for interim rate relief in June of 2008. The Commission thereafter granted APS interim rate relief in the amount of $65.2 million in Decision No. 70667

(December 24, 2008). Neither amount was related to fuel costs nor were they intended to in any way replace the PSA.

c) Please explain the relationship between the PSA and the requested $115 million. Does the $115 million include fossil fuel costs.

A. As noted above, the $115 million originally requested by APS in the interim rate motion of June 2008 was unrelated to the PSA.

d) If so, how much of APS' fuel costs will be in rate base v. in the PSA? Please give as an absolute number and as a percentage of total fuel costs.

A. If the question is how much of APS's total fuel expenses would now be in base rates in the form of the base fuel cost established by Paragraph 6.2 of the Settlement, the answer is approximately $1.10 billion. As noted above, APS anticipates that the PSA adjustor will be negative for 2010, thus suggesting that slightly more than 100% of projected 2010 fuel and purchased power expenses will be recovered through base rates. It is this negative PSA adjustor that allows the rate increase to be held to a net of less than 1% for a typical residential customer of APS. For 2011 and 2012, the base fuel cost recommended in the settlement is in the middle of the range of anticipated fuel costs as shown in Attachment A.

e) Please break out these numbers in terms of coal costs, natural gas costs, and uranium fuel costs.

A. Attached is a table displaying the components of the proposed base fuel rate.

Proposed Base Fuel Rate by Fuel Type	Fuel Expense (¢/kWh)*	Fuel Expense ($000,000)**	Share of Production (%)	Production Cost ($/MWh)***
Nuclear	0.18	53	27%	6.04
Coal	0.85	253	39%	19.72
Natural Gas (w/ sales margin as offset)	1.57	436	21%	62.82
Purchased Power	0.43	148	11%	42.76
Renewables (w/o above-market premiums)	0.12	35	2%	52.56
Fixed Costs	0.60	178	0%	NA
Total	3.76	1,103	100%	33.71

*The ¢/kwh charge is reflective of costs spread over sales mega-watt hours.
**Reflects expenses at 2009 sales levels.
***Reflects average production costs at generator bus.

Q2. Mr. Higgins says that this increase is NOT for fuel costs, (p.14 of Decision 70667), yet the increase is related to ending the current PSA. Please explain.

A. The cited reference to Mr. Higgins' testimony in Decision No. 70667 related to the interim request, which was not for fuel costs. Neither is that interim increase nor the permanent increase proposed by the Settlement related to ending the PSA,

which has not been proposed by any party. That being said, a portion of the increase in base rates proposed by the Settlement is related to reflecting higher fuel and purchased power expenses in base rates, as is set forth in Paragraph 3.8 of the Settlement.

Q3. Why does APS want to put a fuel supply adjustor in rate base?

A. Placing a portion of fuel and purchased power expenses in base rates through the base fuel cost is an established way of addressing the recovery in rates of this expense and has been ordered by the Commission for all electric utilities and in all instances of which APS is aware, including the Company's last two general rate decisions, and is called for in the PSA Plan of Administration.

Q4. How much does APS anticipate fuel costs will increase over the next 20-30 years, both as percentage and in absolute dollars? (Please explain if the percentage increase accounts for inflation.) For example, has APS modeled coal costs increasing by 2% per year, 3% per year, 4% per year, etc.; while the Energy Information Administration increased 14% from 2007 to 2008?

A. APS anticipates that fuel expenses will increase to $1.96B by the year 2025, which is a 78% increase over the $1.10B in costs to be collected through the proposed base fuel rate, which is primarily driven by growth in energy demand and overall rate of inflation. Over this same time period, the Company expects the number of retail customers it serves to increase by 53% and the number of kWh sold to these customers to increase by 38%. Additionally, the inflation rate is expected to increase costs at a 3% average annual rate which raises costs by 60%.

APS has long-term agreements for our coal supplies that provide significant price stability. These coal contracts have established base prices with standard price escalation provisions that will generally lead to price increases around the general rate of inflation, although in any given year, prices may deviate from the expected inflation rate. For example, delivered coal prices in 2009 are expected to be approximately 2% below the 2008 levels. In the forecast described above, delivered coal prices increase approximately 30% from 2009 to 2025, or at less than a 2% annual average growth rate.

Furthermore, the Company believes that a policy of maintaining diversity among its various fuel types is one of the best potential mitigators of future pricing pressures from any one commodity. In its Resource Plan Report submitted to the Commission January 29, 2009, APS explained the need for fuel diversity as follows:

> The diversity of energy sources is one of the most important planning considerations. Despite the best efforts of utility

> resource planners and other stakeholders involved in resource planning, it is impossible to anticipate all future risks. For example, when the current fleet of coal-fired power plants was constructed in the 1960s and 1970s, the planners of that era could not have anticipated the potentially significant cost impacts related to today's debate on climate change policy. Additionally, even though natural gas resources offer many advantages as compared to other generation choices, it is difficult to accurately forecast natural gas prices, and, as a result, there is a wide range of potential outcomes associated with natural gas generation. . . . It is difficult to anticipate all of the issues that may emerge in the future that could present challenges to one or more elements of the Company's portfolio. (Arizona Public Service Company Resource Plan Report, submitted January 29, 2009, pp. 5-6).

Q5. Please fill out the following tables re APS' estimated v. actual costs for coal and natural gas and PSA overage/underage:

A. Because of the extensive data provided, Table A is attached as a stand-alone designated as Attachment A.

TABLE B*

APS's Underage/Overage for the Power Supply Adjustor (PSA)	Retail Fuel Costs Deferred for Recovery Through PSA** ($000,000)	Retail PSA Balance at Year-end ($000,000)	Fuel Costs Not Recovered ($000,000)	Total Estimated Retail Fuel Costs*** ($000,000)	Retail Fuel Cost Deferrals as a % of Estimated Costs
2005	166	166	18	N/A	N/A
2006	244	173	27	N/A	N/A
2007	185	116	20	958	19%
2008	77	13	6	1,059	7%
2009	62	(71)	3	1,103	6%

** We have omitted the Coal and Natural Gas columns requested because we do not calculate the PSA Underage/Overage by fuel type.*

*** 2009 deferrals are projected.*

**** Represents the fuel expense forecast used to set the PSA forward component rate element in each year. The PSA forward component did not exist prior to its authorization by the Commission in Decision No. 69663 in June 2007 and thus there was no estimation of fuel costs for purposes of the PSA.*

Q6. Has APS accounted for a possible rapid increase in the cost of coal and natural gas?

A. Yes, APS does scenario analysis that evaluates the impacts of significant changes in our fossil fuel costs as well as other major uncertainties that could affect the cost and reliability of power deliveries. An example of this analysis can be seen in Appendix 2, Tables 73-86, of the Company's Resource Plan Report submitted to the Commission in January of 2009. See also the response to Question 4 above.

a) What if natural gas costs increase to the high natural gas prices from September 2005 (post-Katrina) and July 2008?

A. APS manages a three-year ahead natural gas and purchased power hedging program which substantially mitigates near term price volatility. This hedging program has been reviewed by the Commission and found to be reasonable in Decision No. 69663. Despite historic high natural gas prices in both 2005 and 2008 of over $10.50/mmbtu over various periods, our delivered (hedged) natural gas prices for 2005 and 2008 were $5.29/mmbtu and $7.98/mmbtu, respectively.

b) When does APS believe that natural gas prices will again be that high?

A. The Company does not know if or when prices will again be that high.

Q7. Staff Regulatory Consultant Ralph Smith submitted testimony that APS' cash flow problems are from low customer growth (p. 17 of Decision 70667).

a) Please provide APS' growth, in terms of both customers and retail sales, as both a percentage and an absolute dollar amount per year for the years 2008-2001; and projections up to 2020.

A. Please see Attachment B.

b) Has APS modeled what its cash flow would look like in a no-growth or declining sales scenario?

A. Yes. Please see Attachment C.

Q8. On page 5 of the Settlement Agreement dated May 4, 2009, there is a table showing a comparison of APS, Staff, RUCO and the Settlement agreement.

a) The table is very hard to read; can you please provide a table in at least 10 point font, perhaps as a landscape-oriented page to allow larger font in all filings from now on?

A. Attachment D is the "Comparison of APS, Staff, RUCO, and Settlement Summary of Base Rate Increase" table from the Settlement Agreement in a more readable format.

b) On line 6 of the table, titled "Fuel Related Increase in Base Rates," the Settlement amount is listed as $11.2 million. Is this the amount of fuel cost included in base rates?

A. See answer to 8 (c) below.

c) How does the $11.2 million above relate to the $137.2 million listed in line 8 of the table, titled "Adjusted Base Cost of Fuel Related Increase"?

A. The Settlement Agreement provided for an increase in base fuel from 3.2491 ¢/kWh (authorized by the Commission in Decision No. 69663) to 3.7571 ¢/kWh, resulting in reclassifying $137.2 million of fuel and purchased power costs currently collected in the PSA as base rates. The impact of moving additional fuel and purchased power costs into base rates means that an additional $11.2 million of legitimate and prudent power costs that heretofore have been absorbed by the Company as a result of the 90/10 sharing agreement, which as was previously stated is not being eliminated as part of the Settlement Agreement, will henceforth be recovered by APS.

d) Under the section in the table "Percentage Increase Over Current Rates," please explain the difference between "Percentage Increase – Net of PSA" and "Percentage Increase – Total."

A. The line titled "Percentage Increase – Net of PSA" is referring to the non-fuel portion of the settlement base rate revenue requirement, whereas the line "Percentage Increase – Total" is referencing the entire base rate revenue requirement inclusive of both non-fuel and fuel components.

e) The table includes a note that states "the Parties are looking at transitioning DSM [Demand Side Management] costs currently recovered in base rates into the DSM Adjustor Mechanism that all DSM costs would be recovered via that Adjustor (similar to the TEP mechanism) as discussed in Section II-G." Can you please explain what this means? Do the parties want to roll DSM costs into rate base as well?

A. Section 3.11 actually states that the signatories *were* looking at the issue of transitioning the $10 million of DSM costs currently recovered in base rates into the DSMAC. This section was intended to clarify an issue that was unresolved at the time when the Settling parties filed the Term Sheet. The reference to TEP was to indicate that in the case of TEP, the utility had no significant amount of DSM expense in base rates and thus DSM costs on a going forward basis would essentially be recovered solely through an adjustment mechanism.

In contrast, APS already had an approved procedure for DSM cost recovery prior to the instant Settlement. The Settlement does not propose to change the treatment of DSM cost recovery provided for by Decision No. 67744 and continued in Decision No 69663. Instead, the Settlement maintains the current DSM recovery in base rates of $10 million, with any additional costs above that amount recovered through the DSMAC.

f) If so, do you believe that including DSM costs into rate base serves ratepayers? Shouldn't DSM costs be broken out to more accurately track them? Why or why not?

A. The Settlement maintains the current treatment of DSM costs and as Section 3.11 states, the parties agreed to address the appropriateness of DSM cost recovery of either maintaining some or all of the current $10 million in base rates, moving all DSM costs to the DSMAC, or determining another appropriated treatment in APS's *next* general rate case to be filed no earlier than June 1, 2011.

Presently, APS submits thorough DSM compliance reports which provides a description of the programs for residential, non-residential and low-income customers, including the goals and savings targets, the level of program participation, a description of how APS evaluates and monitors the results of DSM programs, kW and kWh savings, the benefits incurred due to DSM, including environmental benefits, and incentives paid to customers. In addition, APS submits an annual Implementation Plan which provides a forecast of future DSM costs. Thus, it is easy to track actual and anticipated DSM costs irrespective of how they are portrayed on customer bills.

Those favoring including all DSM costs in a single charge argue this provides greater transparency. Those opposed note that no other resource costs are billed in such a fashion and that simply providing the costs of DSM without similarly informing customers of the benefits might lead consumers to undervalue DSM relative to other resource options. In light of these conflicting arguments, the Settling Parties decided to maintain the *status quo* as determined in Decision Nos. 67744 and 69663.

Table C

% Supply Under Contract by Year	*Coal*	*% Coal Transportation Under Contract*	*Natural Gas*
2009	100%	100%	85%
2010	100%	100%	85%
2011	91%	85%	55%
2012	86%	77%	35%
2013	86%	77%	0%

% Supply Under Contract by Year	*Coal*	*% Coal Transportation Under Contract*	*Natural Gas*
2014	86%	77%	0%
2015	86%	77%	0%
2016	70%	77%	0%
2017	46%	77%	0%
2018	46%	0%	0%
2019	46%	0%	0%
2020	46%	0%	0%

APS' Cost of Power per MWH

	Top 10 Hours	*Top 100 Hours*	*Top 200 Hours*
April	36.06	33.15	31.81
May	45.70	43.01	41.15
June	46.39	43.72	41.88
July	55.82	49.87	47.46
August	53.78	47.85	45.20
September	49.20	45.15	42.95
October	41.78	39.51	37.51

The table above shows the average variable fuel cost consistent with the Company's cost of service study filed in the current case. Fixed fuel costs – those items whose costs do not vary directly with changes in generation levels – are excluded from this table. Such costs include natural gas capacity reservation costs, purchased power capacity purchases, third-party wheeling, fixed coal reclamation amortization, etc.

Q9. The EPA has listed a number of coal ash ponds as "high" or "hazardous" recently. Can you please answer the following questions re: APS' coal ash ponds at:

a) Cholla bottom ash pond in Joseph City
b) Cholla fly ash pond in Joseph City
c) Four Corners Lined Water Impoundment
d) Found Corners Lined Ash Impoundment

A. It is important to note that the classification of APS's coal ash ponds/impoundments relates only to dam safety under the assumption that the dam has already failed (*e.g.*, economic loss, environmental damage, disruption of lifeline facilities or loss of life). It has no relation to the integrity of the dams themselves or to any environmental hazard that might be posed by the contents of the ash ponds. These latter classifications are not designated by EPA. Rather EPA reported how the state agencies responsible for dam safety rate the dams (which are the New Mexico Office of the State Engineer, Dam Safety Bureau, for Four Corners; and the Arizona Department of Water Resources for Cholla).

Q10. Please provide answers to the letter recently sent to APS by the EPA regarding its ash ponds. Please provide copies of these letters to the Commission on an ongoing basis.

A. In early 2009, APS, along with all other utilities in the United States with wet coal ash ponds or impoundments, received from the EPA a request for information regarding the safety and structural integrity of its ash ponds. APS responded to the EPA's request on March 26, 2009. In addition, a supplement to the Cholla response was submitted to EPA on June 18, 2009. Finally, on September 23, at EPA's request, APS responded to the EPA's report on the ash impoundment inspection of the Four Corners plant (see below). Copies of these submittals are being provided to the Commission as Attachment E.

Following receipt of APS's information, EPA inspected both plants' ash impoundments. EPA rated the Four Corners plant with the highest rating of "satisfactory." While APS does not have EPA's final report on the Cholla impoundments, the inspectors verbally indicated the rating was also "satisfactory."

Q11. Does APS have money set aside to safely dispose of its coal ash?

A. APS does not have a discrete segregated fund for this purpose similar to the funds included in its decommissioning trusts for spent nuclear fuel disposal. The Company does include the ongoing costs of safe coal ash disposal in its cost-of-service, recovers those costs through rates, and uses part of its resultant operating funds for continuing safe coal ash disposal. In the longer term, APS maintains accounting reserves for what are referred to as "Asset Retirement Obligations" or "AROs." To the extent coal ash disposal is or becomes at some future date a retirement obligation, it would be funded through such ARO accounting reserves.

Q12. What kind of groundwater monitoring does APS do at all its coal ash sites?

A. As discussed above, the EPA's rating of APS's Cholla and Four Corners ash impounds are not related to issues concerning groundwater quality.

The Cholla Power Plant Fly Ash Pond (FAP) and Bottom Ash Pond (BAP) are permitted under the Aquifer Protection Permit (APP) program by the Arizona Department of Environmental Quality. The APP requires groundwater monitoring for both water quality and water levels in the aquifers beneath and down-gradient of the ponds. The focus of the APP monitoring program is the prevention of contamination to local aquifers. Monitoring includes wells in three different aquifers. These include, from shallow to deep, the local shallow alluvium, the Moenkopi Formation and the Coconino Sandstone.

The APP requires annual groundwater quality sampling for 24 groundwater monitoring wells. Eight of the wells are defined as "Point of Compliance" wells that monitor for specific compliance conditions, while the other 16 wells monitor the background water quality in the nearby aquifers. Two new Point of Compliance monitor wells were drilled northwest of the FAP. A permit amendment was filed with ADEQ to add these wells to the monitoring system. All groundwater monitoring data is submitted to ADEQ as required by the permit. The Plant is in compliance with all terms of the permit.

The Four Corners ash sites are located in New Mexico on the Navajo Nation Reservation and are, therefore, not subject to regulation by the New Mexico Environmental Department. The dam structures, however, are permitted and inspected annually by the New Mexico Office of the State Engineer, Dam Safety Bureau.

The plant's active ash disposal area includes the Dry Fly Ash Disposal Unit (does not receive liquid-born material), the Lined Ash Impoundment and a Lined Decant Water Pond . There are also six old ash impoundments that are no longer in service. The old ash impoundments are dry and contain no free liquid.

With respect to groundwater quality, the plant has voluntarily installed a groundwater monitoring system consisting of 25 monitor wells in the ash disposal area. This monitoring system was installed to monitor the impact on the area and to allow the Plant to respond to any issues as they occur. The groundwater monitoring program follows the guidance in the EPA Guide for Industrial Solid Waste Management (Industrial D) for industrial waste disposal facilities. Groundwater quality samples are collected and analyzed on an annual basis from 20 of these wells. Five of the wells are currently dry. Groundwater levels at all 25 wells are monitored on an annual basis.

Attachment A

To Commissioner Newman Response

ARIZONA PUBLIC SERVICE
TABLE A

	Actuals 2005	Actuals 2006	Actuals 2007	Actuals 2008	Actual plus Forecast 2009	Forecast 2010	Forecast Range [1] 2011	Forecast Range [1] 2012	Forecast 2013-2020
Nuclear									
Fuel (000,000 mmbtu)	80	74	82	88	92	90	95 - 96	96 - 96	764
Fuel Price ($/mmbtu)	0.46	0.50	0.50	0.51	0.57	0.80	0.89 - 0.89	0.97 - 0.97	1.03
Fuel Expense ($000,000)	37	37	41	45	52	72	85 - 86	92 - 93	790
Coal									
Fuel (000,000 mmbtu)	134	136	137	131	125	135	134 - 132	136 - 133	1,087
Fuel Price ($/mmbtu)	1.44	1.50	1.58	1.78	1.75	1.83	1.85 - 1.97	1.89 - 2.02	2.16
Variable Fuel Expense ($000,000)	194	204	216	234	217	248	247 - 260	257 - 269	2,352
Fixed Fuel Expense ($000,000)	6	6	6	7	8	7	7 - 6	7 - 6	75
Natural Gas									
Fuel (000,000 mmbtu)	46	55	64	64	57	54	52 - 56	52 - 55	463
Fuel Price ($/mmbtu)	5.41	5.73	6.65	6.82	7.25	6.84	7.16 - 7.41	6.46 - 6.79	7.34
Variable Fuel Expense [2] ($000,000)	250	315	428	434	411	370	376 - 417	339 - 374	3,397
Fixed Fuel Expense ($000,000)	6	34	38	34	52	66	66 - 65	66 - 65	653
Purchased Power									
Purchases (GWH)	3,474	4,191	3,469	2,021	2,879	2,494	2,264 - 3,412	1,914 - 2,925	22,727
Average Cost ($/mwh)	53.24	55.84	55.09	76.05	45.42	44.49	41.90 - 40.37	40.87 - 36.25	48.39
Variable Expense ($000,000)	185	234	191	154	131	111	95 - 138	78 - 106	1,100
Fixed Expense ($000,000)	48	48	97	99	101	127	116 - 121	138 - 144	957
Renewable									
Energy [3] (GWH)	21	76	176	594	637	768	893 - 826	1,075 - 1,648	23,400
Average Cost ($/mwh)	NA	58.99	55.55	56.41	45.77	53.70	55.97 - 55.51	57.63 - 70.71	87.38
At-Market Expense [4] ($000,000)	NA	4	10	34	29	41	50 - 46	62 - 117	2,045
Net System Cost ($000,000) [5]	725	882	1,028	1,040	1,001	1,042	1,041 - 1,137	1,039 - 1,174	11,368
Retail Sales Covered by PSA [5] (GWH)	21,031	27,923	29,104	29,871	28,362	28,881	28,871 - 29,334	28,922 - 29,654	257,451
Average Cost for the PSA [6] (¢/kWh)	2.96	3.05	3.42	3.53	3.54	3.61	3.60 - 3.88	3.59 - 3.96	4.47
Total Retail Fuel Expense [6] ($000,000)									
Recovered through Base Fuel Rate	436	579	790	933	922	1,085	1,085 - 1,102	1,087 - 1,114	9,673
Recovered through PSA	166	244	185	77	62	(51)	(53) - 20	(53) - 51	1,544
Total Recovery	602	823	975	1,011	984	1,034	1,032 - 1,122	1,034 - 1,165	11,217
Items not Recovered through the PSA ($000,000)									
Independent Spent Fuel Storage Installation	6	8	10	11	11	5	3 - 3	2 - 2	5
Coal Reclamation	-	-	1	1	1	1	1 - 1	1 - 1	5
E-36 incremental costs	4	4	3	4	4	4	4 - 4	5 - 5	37
Renewable above-market premiums	-	-	1	6	7	9	17 - 9	30 - 37	689
Other items not recovered through the PSA [7]	47	(6)	2	-	(3)	-	- - -	- - -	-
Total Items not Recovered through the PSA	57	6	17	22	21	20	26 - 18	37 - 45	736
Items not Recovered through the PSA as a % of Total Fuel Costs	7.3%	0.7%	1.6%	2.1%	2.0%	1.9%	2.4% - 1.5%	3.5% - 3.7%	6.1%

1/ Because costs in outer years can be very volatile, we are showing a range around costs for 2011 and 2012. Both sets of cost estimates are from forecasts over the last 12-months.
2/ Natural gas variable fuel expense includes the impact of the gas hedges and the off-system sales margin.
3/ Renewable purchase GWHs include the Company-owned solar generation and purchased renewables.
4/ Renewable expense excludes the above-market premiums recovered through the Renewable Energy Surcharge.
5/ Net System Costs include total APS fuel costs net of off-system sales margins and items excluded from the PSA.
6/ Retail fuel expenses for 2005 only reflect costs for the time period that the PSA existed, April 2005 - December 2005.
7/ Includes costs that pertain to time periods prior to April 2005 recorded in actuals, capacity cost payments to Pinnacle West Energy in 2005, and savings from the Sundance units prior to their inclusion in rate base.

Attachment **B**

To Commissioner Newman Response

APS Retail Customers and Sales

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Sales (MWh):									
Residential	9,780,680	10,334,860	10,443,820	11,147,195	11,527,402	12,223,576	12,993,961	13,771,481	13,368,015
Total retail	22,534,524	23,399,012	23,361,755	24,562,305	25,353,323	26,477,551	27,970,397	29,171,321	28,793,588
Year over Year Change in Sales									
Residential		5.7%	1.1%	6.7%	3.4%	6.0%	6.3%	6.0%	-2.9%
Total retail		3.8%	-0.2%	5.1%	3.2%	4.4%	5.6%	4.3%	-1.3%
Average customers									
Residential	749,285	776,339	801,801	828,366	859,069	896,472	936,464	966,013	977,944
Total retail	843,413	874,537	902,029	931,462	966,185	1,007,640	1,051,895	1,086,328	1,101,905
Year over Year Change in Customers									
Residential		3.6%	3.3%	3.3%	3.7%	4.4%	4.5%	3.2%	1.2%
Total retail		3.7%	3.1%	3.3%	3.7%	4.3%	4.4%	3.3%	1.4%
Retail Revenues (thousands):									
Residential	880,468	914,711	912,245	960,303	983,525	1,079,223	1,270,521	1,418,315	1,454,458
Total retail	1,815,682	1,867,338	1,845,563	1,917,807	1,964,264	2,121,093	2,510,180	2,772,955	2,898,549
Year over Year Change in Revenue									
Residential		3.9%	-0.3%	5.3%	2.4%	9.7%	17.7%	11.6%	2.5%
Total retail		2.8%	-1.2%	3.9%	2.4%	8.0%	18.3%	10.5%	4.5%

Revenue changes largely the result of changes in sales volume net of rate reductions in 2001, 2002, 2003, and 2004.

Revenue changes largely the result of changes in sales volume and higher fuel costs.

*The information on this page is the same as APS Exhibit 38

APS Retail Customers and Sales

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Electric Sales (MWH):												
Total retail	22,534,524	23,399,012	23,361,755	24,562,305	25,353,323	26,477,551	27,970,397	29,171,321	28,793,588	28,537,168	28,971,908	28,962,111
Year over Year Change in Sales												
Total retail		3.8%	-0.2%	5.1%	3.2%	4.4%	5.6%	4.3%	-1.3%	-0.9%	1.5%	0.0%
Average customers												
Total retail	843,413	874,537	902,029	931,462	966,185	1,007,640	1,051,895	1,086,328	1,101,905	1,109,797	1,124,530	1,138,529
Year over Year Change in Customers												
Total retail		3.7%	3.1%	3.3%	3.7%	4.3%	4.4%	3.3%	1.4%	0.7%	1.3%	1.2%
Operating Revenues[1] (thousands):												
Total retail	1,815,682	1,867,338	1,845,563	1,917,807	1,964,264	2,121,093	2,510,180	2,772,955	2,898,549			
Year over Year Change in Revenue												
Total retail		2.8%	-1.2%	3.9%	2.4%	8.0%	18.3%	10.5%	4.5%			

APS previously provided revenue estimates for 2009 in Schedule A-2 of its original fling and for 2010-2012 in Schedule JRH-2-S to APS Exhibit 31. No other revenue projections have been publically announced and would, as a practical matter, largely depend on future Commission actions that cannot be accurately forecasted.

APS Retail Customers and Sales

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Electric Sales (MWH):									
Total retail	28,993,628	29,360,570	30,134,789	30,988,361	31,884,569	32,730,902	33,548,521	34,335,234	35,108,904
Year over Year Change in Sales									
Total retail	0.1%	1.3%	2.6%	2.8%	2.9%	2.7%	2.5%	2.3%	2.3%
Average customers									
Total retail	1,158,777	1,188,102	1,228,751	1,273,698	1,321,103	1,367,672	1,411,907	1,454,447	1,494,977
Year over Year Change in Customers									
Total retail	1.8%	2.5%	3.4%	3.7%	3.7%	3.5%	3.2%	3.0%	2.8%
Operating Revenues[1] (thousands):									
Total retail									
Year over Year Change in Revenue									
Total retail									

[1] Revenues for the current and future years are not disclosed to avoid violating SEC rules on financial disclosure.

Attachment C

To Commissioner Newman Response

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED FUNDS FROM OPERATIONS
WITH PROPOSED SETTLEMENT RATE INCREASE UNDER VARIOUS SALES GROWTH ASSUMPTIONS FOR 2010-2012
(Dollars in Millions)

Line No.	Description	Projected Year - Total Company		
		Year Ending 12/31/2010	Year Ending 12/31/2011	Year Ending 12/31/2012
1	Net Income	$ 325	$ 314	$ 325
2	Book depreciation and amortization	417	438	432
3	Nuclear fuel amortization	59	72	78
4	Deferred income taxes	52	75	107
5	AFUDC debt	(17)	(17)	(20)
6	AFUDC equity	(28)	(28)	(33)
7	Other	52	28	32
8	Funds from operations (a)	$ 860	$ 882	$ 921
9	Change in funds from operations from a flat sales growth to a declining sales growth environment for 2010 through 2012 (b)	(13)	(27)	(43)
10	Funds from operations under a declining sales growth environment for 2010 through 2012	$ 847	$ 855	$ 878

(a) As used in the Company's July 1, 2009 settlement testimony ffo to debt ratios. After layering on the impacts of DSM and energy efficiency as proposed in the settlement agreement, sales growth from the 2009 budget through 2012 was effectively flat.

(b) For demonstration purposes, assumes sales growth after layering on impacts of DSM and energy efficiency, declines 2% per year from the 2009 budget through 2012.

These numbers are being provided solely for purposes of the proposed rate case settlement and are not to be used or relied upon for purposes of trading any security

Attachment **D**

To Commissioner Newman Response

Comparison of APS, Staff, RUCO and Settlement
Summary of Base Rate Increase
(Thousands of Dollars)

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

These numbers are being provided solely for purposes of the proposed rate case settlement and are not to be used or relied upon for purposes of trading any security

Attachment E

To Commissioner Newman Response

APS
A subsidiary of Pinnacle West Capital Corporation

Mark Schiavoni
Senior Vice President
Fossil

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Phoenix, AZ 85072-3999

September 23, 2009

VIA FEDERAL EXPRESS

Mr. Stephen Hoffman
U.S. Environmental Protection Agency
Two Potomac Yard
2733 S. Crystal Drive
5th Floor, N-237
Arlington, Virginia 22202-2733

Re: Arizona Public Service Company's Response to Site Assessment for the Four Corners Generating Station.

Dear Mr. Hoffman:

Arizona Public Service Company ("APS") is responding to Matt Hale's letter to Mr. John Denman, requesting that APS respond to GEI's September 2009 Specific Site Assessment Report regarding coal ash impoundments at APS's Four Corners Generating Station. APS's response to Section 12.0 GEI's report is set forth below. The relevant text of the report (requiring a response) has also been reproduced for your reference.

APS's Response

12.0 Recommendations
12.1 Corrective Measures for the Structures
12.1.1 Lined Decant Water Impoundment

1. The 2003 calculated factor of safety for static steady-seepage of 1.4 is somewhat below the current state and federal guidance of 1.5. Re-evaluation of this loading condition should be documented and may need to consider less conservative assumptions regarding saturation levels in the underlying fly ash. While the 2003 factors of safety for the LDWI are somewhat below the required minimum, they are not considered deficient with respect to current guidance because the 2003 analysis was based on conservative assumptions and did not reflect the existing unsaturated condition of the underlying fly ash layer.

Response: APS will re-evaluate the west embankment load condition factors of safety. We have retained a consultant, URS Corporation, to perform the engineering analysis. Our re-evaluation will be completed by February 26, 2010.

2. *The uneven dam crest on the west embankment should be restored to full height with compacted fill. This maintenance should be performed within the next six months.*

Response: APS had previously identified the need for dam crest restoration; and our engineers are working with the New Mexico Office of the State Engineer ("OSE") to obtain approval of our maintenance work plan (with URS Corporation preparing the necessary installation drawings). Pending OSE approval, the work will be completed by November 20, 2009.

3. *Tamarisk trees should be removed from the downstream toe of the west embankment (Pond #3 toe) and an evaluation for any potential seepage should be performed in that area. However, instrumentation indicates the embankment is essentially dry and the trees may be supported primarily by water in the nearby Pond #6 seepage ditch.*

Response: APS has begun the process of removing the tamarisk trees, and the work is 75% complete. Examination of the area along the toe of the embankment, where the trees existed, indicates that the area is completely dry, and there is no evidence of any seepage or wet areas. The old Pond #6 seepage trench has been cleaned of the trees and is also completely dry. Tree removal efforts will be completed by October 16, 2009.

12.1.2 Decant Drop Inlet Structure.

1. *Perform a structural analysis that includes a sensitivity analysis of the HDPE decant drop inlet structure to varying water depth and the influence of multiple penetrations of the manhole sides. Evaluate the decant structure for potential for differential movement between the manhole riser and the foundation slab. Provide protection for the exposed part of the manhole from impacts from vehicles or large equipment.*

Response: APS structural engineers have started the recommended analysis. The analysis of the drop inlet structure and the potential for differential movement will be completed by October 30, 2009.

Vehicle barriers will be installed near the manhole to ensure it cannot be impacted by vehicles or equipment in the area. The vehicle barriers will be installed immediately following completion of construction of the current embankment. Installation will be complete before October 30, 2009.

12.4 Any New or Additional Monitoring Instruments, Periodic Observations, or Other Methods of Monitoring Project Works or Conditions That May Be Required.

Continue monitoring seepage at the downstream toe of the south embankment (Pond #4 toe) for any changes in seepage quantity and flow rate or evidence that the flow is carrying soil/ash particles from the embankment.

Response: APS believes that the water at the toe of the south embankment identified during the inspection was the result of compaction water run-off from bottom ash construction placement. Since bottom ash construction on the embankment is now complete, the ponded water at the toe has dried up and is no longer visible. APS engineers, however, will continue to monitor the toe of the south embankment (via weekly and monthly inspections) to ensure that there is no seepage from the embankment. Any new evidence of seepage will be promptly reported to the OSE.

12.4 Continued: *Expand program to include additional monitoring of potential seepage under the dam at the northwest corner of the LAI, where the LAI embankment was not tied in to the underlying Pond 3-4 embankment to provide continuity of seepage control, and where a potential seepage pathway exists if the HDPE lining fails. Install additional piezometers to address this potential seepage pathway and expand documentation in APS dam safety inspections to note any evidence of seepage near the downstream toe of the dam in this area.*

Response: APS will install additional piezometers and begin monitoring of the NW corner of the LAI as recommended above. Piezometer readings and monitoring results will be reported to the OSE. The installation of new piezometers will be completed by December 31, 2009 (pending OSE approval). This area will be specifically monitored and addressed in future dam safety inspections.

12.4 Continued: *Repair or replace the two settlement plates that do not appear to be providing useful information and that may have been damaged during construction or maintenance activities.*

Response: The settlement plates have been inspected by APS and URS Corporation engineers and were found to be in proper operating condition. Specifically, we determined that the piezometers were not reading properly because they had not yet been buried in embankment material. The plates are now being buried under construction material, as a part of the current embankment lift, taking place at the pond. APS will continue to monitor the piezometer plates over the next few months, to ensure they are performing properly. Final validation of the plates' operation will be complete by November 30, 2009. If they are not operating properly, appropriate corrective action will be taken.

APS appreciates the opportunity to respond to GEI's recommendations. Please feel free to contact me if the EPA or GEI has any additional questions or concerns.

Sincerely,

Mark A. Schiavoni

APS

A subsidiary of Pinnacle West Capital Corporation

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June 18, 2009

VIA FEDEX

Mr. Richard Kinch
U.S. Environmental Protection Agency
5th Floor N-5783
Two Potomac Yard
2733 S. Crystal Drive
Arlington, Virginia 22202-2733

Re: Arizona Public Service Company – Cholla Generating Station
Supplement to Response for Request for Information Under 104(e) of the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. 9604(e) ("104(e) Request").

Dear Mr. Kinch:

On March 26, 2009, Arizona Public Service Company ("APS") responded to the above referenced 104(e) Request for each surface impoundment or similar diked or bermed management unit(s) or management units designated as landfills at the Cholla Generating Station which receive liquid-borne material for the storage or disposal of residuals or by-products from the combustion of coal, including, but not limited to, fly ash, bottom ash, boiler slag, or flue gas emission control residuals.

By this letter, APS is supplementing its original response to question number 3 to add certain "other" materials that are temporarily or permanently contained in the Bottom Ash Pond and the Fly Ash Pond at the Cholla plant as follows:

3. *What materials are temporarily or permanently contained in the unit? Use the following categories to respond to this question: (1) fly ash; (2) bottom ash: (3) boiler slag; (4) flue gas emission control residuals; (5) other. If the management unit contains more than one type of material, please identify all that apply. Also, if you identify "other," please specify the other types of materials that are temporarily or permanently contained in the unit(s).*

Bottom Ash Pond

(5) Other: cooling tower basin sludge, general water sump sediment, West Area Retention Pond sediment, area-wide drainage sump sediment, and seepage intercept system sump sediment. These are in addition to those materials listed in APS's March 26, 2009 response.

Fly Ash Pond

(5) Other: cooling tower basin sludge, general water sump sediment, West Area Retention Pond sediment, area-wide drainage sump sediment, and seepage intercept system sump sediment. These are in addition to those materials listed in APS's March 26, 2009 response.

Sincerely,

Mark A. Schiavoni

MAS/na

APS

THE POWER TO MAKE IT HAPPEN™

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VIA FEDERAL EXPRESS

March 26, 2009

Mr. Richard Kinch
U.S. Environmental Protection Agency
5th Floor N-5783
Two Potomac Yard
2733 S. Crystal Drive
Arlington, Virginia 22202-2733

Re: Arizona Public Service Company – Four Corners Generating Station: Request for Information Under 104(e) of the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. 9604(e) ("104(e) Request").

Dear Mr. Kinch:

On March 16, 2009, Arizona Public Service Company ("APS") received the above referenced 104(e) Request for each surface impoundment or similar diked or bermed management unit(s) or management units designated as landfills at the Four Corners Generating Station which receive liquid-borne material for the storage or disposal of residuals or by-products from the combustion of coal, including, but not limited to, fly ash, bottom ash, boiler slag, or flue gas emission control residuals. APS's response for the Four Corners Generating Station is attached.

I certify that the information contained in this response to EPA's request for information and the accompanying documents is true, accurate, and complete. As to the identified portions of this response for which I cannot personally verify their accuracy, I certify under penalty of law that this response and all attachments were prepared in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations.

Signature: John R. Denman
Name: John R. Denman
Title: Sr. V.P., Fossil Generation

Arizona Public Service Company's 104(e) Response for the Four Corners Generating Station

Plant Description

The Four Corners Generating Station is a five unit, coal fired, 2060 megawatt steam electric power plant. All five generating units have operating particulate control devices and SO_2 scrubbers. As part of its operations, the plant generates residuals and by-products from the combustion of coal.

The plant's ash disposal area consists of an existing Dry Fly Ash Disposal Unit (which does not receive liquid-borne material), a Lined Ash Impoundment, a Lined Water Impoundment, and six old ash impoundments that are no longer in service. The old ash impoundments are dry and contain no free liquid. The old ash impoundments that the plant identifies as #3 and #6 are still inspected by the New Mexico Office of the State Engineer, Dam Safety Bureau, because APS has not yet submitted closure plans for those facilities.

Up to 20% of the fly ash generated at the plant is sold for beneficial reuse.

Bottom Ash Disposal

Wet bottom ash is removed from all five generating unit boilers and is slurried to collection bins for dewatering. The bottom ash is completely dewatered and then hauled by truck to the plant's ash disposal area.

All bottom ash is used by the plant in the construction of embankments for future Lined Ash Impoundment expansions. The embankments are constructed of a 15 foot layer of compacted clay material (water side portion of the embankment) and then ballasted with compacted bottom ash (on the dry side of the embankment).

Fly Ash and Flue Gas Desulphurization ("FGD") Disposal

The fly ash from generating units 1, 2, and 3 is collected by venturi scrubbers (a wet particulate/ SO_2 removal system), slurried to thickener equipment for fly ash and FGD material concentration (water reduction), and then pumped to the plant's Lined Ash Impoundment for dewatering. The decanted water flows by gravity through a filter built into the Lined Ash Impoundment, and then into the Lined Water Impoundment.

The fly ash from generating units 4 and 5 is collected by fabric filters (dry collection) and is disposed of dry at a lined, dry fly ash accumulation area (that that does not receive liquid-borne material).

The SO_2 from generating units 4 and 5 is removed from the flue gas by a wet spray tower scrubber system. The resulting FGD material is then pumped to thickener equipment, where it is concentrated before being pumped to the plant's Lined Ash Impoundment, where it is commingled with fly ash and FGD material from generating units 1, 2, and 3.

Low Volume Waste Water System

Water from the plant's low volume waste water system is pumped into a collection system sump from several sources within the plant. The water then flows out of the collection sump by gravity and flows through the Low Volume Waste Water Decant Cells before flowing into the plant's Low Volume Waste Water Pond.

Impoundment Descriptions

Lined Ash Impoundment

The Lined Ash Impoundment is constructed on top of the old ash impoundments identified by the plant as #3 and #4. The Lined Ash Impoundment's dikes are constructed of compacted clay material, in accordance with dam construction specifications approved by the New Mexico Office of the State Engineer, Dam Safety Bureau. The dikes are built on top of the clay dikes used for old ash impoundments #3 and #4. The Lined Ash Impoundment is constructed with a 60 Mil HDPE liner that lines the entire impoundment area, including the dikes.

Lined Water Impoundment

The Lined Water Impoundment is constructed on top of the old ash impoundment identified by the plant as #3. The Lined Water Impoundment's dikes are constructed of compacted clay material in accordance with dam construction specifications approved by the New Mexico Office of the State Engineer, Dam Safety Bureau. The dikes are built on top of the clay dikes used for old ash impoundment #3. The Lined Water Impoundment is constructed with two 60 Mil HDPE liner layers that lines the entire impoundment area, including the dikes. The second HDPE liner barrier also includes a leak detection system. The Lined Water Impoundment contains no solid ash material and is not an ash management unit. But due to the breadth of the impoundment definition and subsequent EPA guidance on chemicals of concern, APS is reporting on this unit.

Upper Retention Sump

The Upper Retention Sump is a below grade compacted soil cement basin that is part of the generating unit 4 and 5 SO_2 scrubber system. It is used for temporary surge capacity of coal combustion products and FGD materials from the normal waste disposal processes of the scrubbers. The material in the basin is returned to the generating unit 4 and 5 thickener equipment, and then sent to the Lined Ash Impoundment.

Low Volume Waste Water System Decant Cells

The Low Volume Waste Water System Decant Cells are below grade cells constructed with engineered fill (bottom ash placed on top of clay material). Each of the three cells contains floor drains (French type drains) to decant water from the solids contained in the plant's low volume waste water system. The decant cells help remove solids from the low volume waste water, prior to the water entering the Low Volume Waste Water Pond.

Low Volume Waste Water Pond

The Low Volume Waste Water Pond is a below grade water treatment pond. The pond allows solids in the water to settle, for later dredging (prior to the water flowing back into the plant's cooling lake).

104(e) Questions

Please provide the information requested below for each surface impoundment or similar diked or bermed management unit(s) or management units designated as landfills which receive liquid-borne material for the storage or disposal of residuals or by-products from the combustion of coal, including, but not limited to, fly ash, bottom ash, boiler slag, or flue gas emission control residuals. This includes units that no longer receive coal combustion residues or by-products, but still contain free liquids.

1. Relative to the National Inventory of Dams criteria for High, Significant, Low, or Less-than-Low, please provide the potential hazard rating for each management unit and indicate who established the rating, what the basis of the rating is, and what federal or state agency regulates the unit(s). If the unit(s) does not have a rating, please note that fact.

Lined Ash Impoundment

The rating, which is designated by the New Mexico Office of the State Engineer, Dam Safety Bureau, which regulates the unit, is "Significant Hazard Potential." The basis for the rating is set forth in the New Mexico Administrative Code ("N.M.A.C."), Title 19, Chapter 25, Part 12, Section 19.25.12.10 attached to this response as Exhibit A.

Lined Water Impoundment

The rating, which is designated by the New Mexico Office of the State Engineer, Dam Safety Bureau, which regulates the unit, is "Significant Hazard Potential." The basis for the rating is set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.12.10 attached to this response as Exhibit A.

Upper Retention Sump

Because the Upper Retention Sump does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., the unit is not regulated as a dam.

Low Volume Waste Water System Decant Cells

Because none of the Low Volume Waste Water Decant Cells meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., the units are not regulated as dams.

Low Volume Waste Water Pond

Because the Low Volume Waste Water Pond does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., the unit is not regulated as a dam.

2. What year was each management unit commissioned and expanded?

Lined Ash Impoundment

Commissioned (in-service) in 2003. Expanded in 2007.

Lined Water Impoundment

Commissioned (in-service) in 2003.

Upper Retention Sump

Commissioned (in-service) in 1984.

Low Volume Waste Water System Decant Cells

Commissioned (in-service) in 2004.

Low Volume Waste Water Pond

Commissioned (in-service) in 1979.

3. What materials are temporarily or permanently contained in the unit? Use the following categories to respond to this question: (1) fly ash; (2) bottom ash: (3) boiler slag; (4) flue gas emission control residuals; (5) other. If the management unit contains more than one type of material, please identify all that apply. Also, if you identify "other," please specify the other types of materials that are temporarily or permanently contained in the unit(s).

Lined Ash Impoundment

(1) Fly ash; (2) bottom ash: (3) boiler slag; (4) flue gas emission control residuals; and (5) other. Other types include: boiler acid cleaning waste, treated sewage, chemical metal cleaning wastes, air preheater wash, co-disposal waste (permitted by 40 C.F.R. § 261.4(b)(4)), turbine foam cleaning waste, and stack flue gas residues.

Lined Water Impoundment

(4) Flue gas emission control residuals and (5) other. Other types include blow dust/dirt.

Upper Retention Sump

(4) Flue gas emission control residuals and (5) other. Other types include scrubber area wash down, dirt, and coal dust.

Low Volume Waste Water System Decant Cells

(1) Fly ash; (2) bottom ash: (4) flue gas emission control residuals; and (5) other. Other types include: boiler blow down, back pass boiler wash down, metal cleaning waste, coal dust, dirt, de minimus lubricants, demineralizer regeneration wastes, storm water, corrosion and flocculation chemicals, and potable water flushings.

Low Volume Waste Water Pond

(1) Fly ash; (2) bottom ash: (4) flue gas emission control residuals; and (5) other. Other types include: boiler blow down, back pass boiler wash down, metal cleaning waste, coal dust, dirt, de minimus lubricants, demineralizer regeneration wastes, storm water, corrosion and flocculation chemicals, and potable water flushings.

4. Was the management unit(s) designed by a Professional Engineer? Is or was the construction of the waste management unit(s) under the supervision of a Professional Engineer? Is inspection and monitoring of the safety of the waste management unit(s) under the supervision of a Professional Engineer?

Lined Ash Impoundment

The Lined Ash Impoundment was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Lined Ash Impoundment is under the supervision of a Professional Engineer.

Lined Water Impoundment

The Lined Water Impoundment was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Lined Water Impoundment is under the supervision of a Professional Engineer.

Upper Retention Sump

The Upper Retention Sump was not designed by a Professional Engineer. Its construction was not under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Upper Retention Sump is not under the supervision of a Professional Engineer.

Low Volume Waste Water System Decant Cells

The Low Volume Waste Water System Decant Cells were designed by a Professional Engineer. Their construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Low Volume Waste Water System Decant Cells is under the supervision of a Professional Engineer.

Low Volume Waste Water Pond

The Low Volume Waste Water Pond was not designed by a Professional Engineer. Its construction was not under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Low Volume Waste Water Pond is under the supervision of a Professional Engineer.

5. When did the company last assess or evaluate the safety (i.e., structural integrity) of the management unit(s)? Briefly describe the credentials of those conducting the structural integrity assessments/evaluations. Identify actions taken or planned by facility personnel as a result of these assessments or evaluations. If corrective actions were taken, briefly describe the credentials of those performing the corrective actions, whether they were company employees or contractors. If the company plans an assessment or evaluation in the future, when is it expected to occur?

APS Engineers who conducted the evaluations/assessments below are registered with the State of New Mexico as Professional Engineers, in accordance with the requirements of the New Mexico Board of Technical Registration. Also, in accordance with its dam safety regulations (N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.12.13 A), the New Mexico Office of State Engineer, Dam Safety Bureau, has accepted each engineer as qualified for design, construction, maintenance, and operational oversight of the dam structures.

Lined Ash Impoundment

APS last assessed or evaluated the safety of the Lined Ash Impoundment in January 2009. The individual who conducted the assessment/evaluation was a Four Corners plant Professional Engineer. No safety deficiencies were identified. The next assessment/evaluation is scheduled for July 2009.

Lined Water Impoundment

APS last assessed or evaluated the safety of the Lined Water Impoundment in January 2009. The individual who conducted the assessment/evaluation was a Four Corners plant Professional Engineer. No safety deficiencies were identified. The next assessment/evaluation is scheduled for July 2009.

Upper Retention Sump

Because the Upper Retention Sump does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety assessments/evaluations are not necessary for this sort of structure.

Low Volume Waste Water System Decant Cells

Because the Low Volume Waste Water System Decant Cells do not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety assessments/evaluations are not necessary for these sorts of structures.

Low Volume Waste Water Pond

Because the Low Volume Waste Water Pond does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety assessments/evaluations are not necessary for this sort of structure.

6. When did a State or a Federal regulatory official last inspect or evaluate the safety (structural integrity) of the management unit(s)? If you are aware of a planned state or federal inspection or evaluation in the future, when is it expected to occur? Please identify the Federal or State regulatory agency or department which conducted or is planning the inspection or evaluation. Please provide a copy of the most recent official inspection report or evaluation.

Lined Ash Impoundment

The New Mexico Office of State Engineer, Dam Safety Bureau, last inspected the Lined Ash Impoundment on October 4, 2007. Inspections by this agency are not planned and are unannounced. A copy of the most recent official inspection report is attached as Exhibit B. All recommended actions indicated on the report have been completed.

Lined Water Impoundment

The New Mexico Office of State Engineer, Dam Safety Bureau, last inspected the Lined Water Impoundment on October 4, 2007. Inspections by this agency are not planned and are unannounced. A copy of the most recent official inspection report is attached as Exhibit C. All recommended actions indicated on the report have been completed.

Upper Retention Sump

Because the Upper Retention Sump does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety inspections are not conducted.

Low Volume Waste Water System Decant Cells

Because the Low Volume Waste Water System Decant Cells do not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety inspections are not conducted.

Low Volume Waste Water Pond

Because the Low Volume Waste Water Pond does not meet the definition of a dam, as set forth in the N.M.A.C., Title 19, Chapter 25, Part 12, Section 19.25.7 H., safety inspections are not conducted.

7. Have assessments or evaluations, or inspections conducted by State or Federal regulatory officials conducted within the past year uncovered a safety issue(s) with the management unit(s), and, if so describe the actions that have been or are being taken to deal with the issue or issues. Please provide any documentation that you have for these actions.

Lined Ash Impoundment

No.

Lined Water Impoundment

No.

Upper Retention Sump

Not applicable. See response to Question #6.

Low Volume Waste Water System Decant Cells

Not applicable. See response to Question #6.

Low Volume Waste Water Pond

Not applicable. See response to Question #6.

8. What is the surface area (acres) and total storage capacity of each of the management units? What is the volume of materials currently stored in each of the management unit(s)? Please provide the date that the volume measurement(s) was taken. Please provide the maximum height of the management unit(s). The basis for determining maximum height is explained later in this Enclosure.

Lined Ash Impoundment

Surface area: 75 Acres.

Total storage capacity: 3,870,000 cubic yards.

Volume of materials currently stored: 3,406,600 cubic yards.

Date volume measurement was taken: December 31, 2008.

Maximum height: 83 feet (note, however, that the Lined Ash Impoundment is constructed on top of old ash impoundment #3, which comprises the first 43 feet of the dam height).

Lined Water Impoundment

Surface area: 45.1 Acres.

Total storage capacity: 435 acre-feet.

Volume of materials currently stored: 284 acre-feet.

Date volume measurement was taken: March 17, 2009.

Maximum height: 90 feet (note, however, that the Lined Water Impoundment is constructed on top of old ash impoundment #3, which comprises the first 80 feet of the dam height).

Upper Retention Sump

Surface area: 1.07 acres.

Total storage capacity: 17,265 cubic yards.

Volume of materials currently stored: 6,900 cubic yards.

Date volume measurement was taken: March 12, 2009.

Maximum height: Below grade, 0 feet.

Low Volume Waste Water System Decant Cells

Surface area: 0.63 acres.

Total storage capacity: 6,419 cubic yards.

Volume of materials currently stored: 1,100 cubic yards.

Date volume measurement was taken: March 12, 2009.

Maximum height: 6 feet.

Low Volume Waste Water Pond

Surface area: 13.7 acres.

Total storage capacity: 221,000 cubic yards.

Volume of materials currently stored: 88,400 cubic yards.

Date volume measurement was taken: March 17, 2009.

Maximum height: Below grade, 0 feet.

9. Please provide a brief history of known spills or unpermitted releases from the unit within the last ten years, whether or not these were reported to State or federal regulatory agencies. For purposes of this question, please include only releases to surface water or to the land (do not include releases to groundwater).

Lined Ash Impoundment

There have been no known spills or unpermitted releases within the last ten years.

Lined Water Impoundment

There have been no known spills or unpermitted releases within the last ten years.

Upper Retention Sump

There have been no known spills or unpermitted releases within the last ten years.

Low Volume Waste Water System Decant Cells

There have been no known spills or unpermitted releases within the last ten years.

Low Volume Waste Water Pond

There have been no known spills or unpermitted releases within the last ten years.

10. Please identify all current legal owner(s) and operator(s) at the facility.

Owner/Operator	Arizona Public Service Company.
Owner	Public Service Company of New Mexico
Owner	El Paso Electric
Owner	Tucson Electric Power
Owner	Salt River Project
Owner	Southern California Edison

D. For inspecting construction of a dam the fee shall be $100/8-hour day and actual and necessary traveling expenses.

E. For filing a proof of completion of works for a dam the fee shall be $25.

F. For filing a change of ownership for a dam the fee shall be $5.

G. For copies of dam safety records up to 11 inches by 17 inches the fee shall be $0.20 per copy.

H. For copies of dam safety records greater than 11 inches by 17 inches the fee shall be $3.00 per copy.

[19.25.12.8 NMAC - N, 3/31/2005]

19.25.12.9 SIZE CLASSIFICATION: A dam shall be less than or equal to the maximum height and storage to qualify for the size classification.

A. Small: A small dam is greater than 10 feet but less than or equal to 40 feet in height, or greater than 10 acre-feet but less than or equal to 1000 acre-feet of storage.

B. Intermediate: An intermediate dam is greater than 40 feet but less than or equal to 100 feet in height, or greater than 1000 acre-feet but less than or equal to 50,000 acre-feet of storage.

C. Large: A large dam is greater than 100 feet in height, or greater than 50,000 acre-feet of storage.

[19.25.12.9 NMAC - N, 3/31/2005]

19.25.12.10 HAZARD POTENTIAL CLASSIFICATION: The hazard potential classification is a rating for a dam based on the potential consequences of failure. The rating is based on loss of life, damage to property and environmental damage that is likely to occur in the event of dam failure. No allowances for evacuation or other emergency actions by the population should be considered. The hazard potential classification is not a reflection of the condition of the dam.

A. Low hazard potential: Dams assigned the low hazard potential classification are those dams where failure or misoperation results in no probable loss of life and low economic and/or environmental losses. Losses are principally limited to the dam owner's property.

B. Significant hazard potential: Dams assigned the significant hazard potential classification are those dams where failure or misoperation results in no probable loss of human life but can cause economic loss, environmental damage, disruption of lifeline facilities, or can impact other concerns. Significant hazard potential classification dams are often located in predominantly rural or agricultural areas but could be located in populated areas with significant infrastructure.

C. High hazard potential: Dams assigned the high hazard potential classification are those dams where failure or misoperation will probably cause loss of human life.

[19.25.12.10 NMAC - N, 3/31/2005]

19.25.12.11 DESIGN OF A DAM: Any person, association or corporation, public or private, the state, or the United States that is intending to construct a dam shall submit an application to construct and operate a dam and supporting documentation acceptable to the state engineer. This section primarily addresses the design and construction of embankment dams. Other types of dams shall conform to sound engineering principles and current state of the practice. Because each site, design and operating practice is unique, waivers of specific requirements in this section will be considered on a case-by-case basis. Request for waiver shall be in writing accompanied with documentation justifying the request. If the request is not justified to the satisfaction of the state engineer the request will be denied. Construction shall not begin until the state engineer has accepted the supporting documentation and approved the application with construction and operation conditions. The application and supporting documentation shall include:

A. Application: An application form shall be completed with original signature of the dam owner and accompanied with a filing fee in accordance with Subsection A of 19.25.12.8 NMAC. The form will be the only information available to the public before the project is approved for construction. All other supporting documentation is considered draft until accepted by the state engineer. A plan review fee in accordance with Subsection B of 19.25.12.8 NMAC shall accompany the submittal of the design report, construction drawings and specifications. A detailed estimate of the construction cost for the proposed dam and appurtenant structures shall be submitted in support of the plan review fee.

B. Water right: A water right is required for water impounded by the dam. If the dam owner has a permit for the diversion of water, documentation addressing the necessity for storage, diversion periods and release conditions for the reservoir may be required. This requirement is waived for flood control dams that do not detain

MEMORANDUM
OFFICE OF THE STATE ENGINEER
Dam Safety Bureau

DATE: October 30, 2007

TO: Elaine C. Pacheco, P.E., Chief, Dam Safety Bureau

FROM: Sushil K. Chaudhary, D.Eng., P.E., Dam Safety Engineer

SUBJECT: Inspection of Lined Ash Impoundment (a.k.a. Lined Ash Pond), San Juan County, OSE File No. D-634

On October 4, 2007, I inspected Lined Ash Impoundment (LAI) dam. The purpose of the dam is to store tailings from the coal fired power plant that is rich in fly ash. The liquid is decanted into the downstream pond. Characteristics of the dam, verified from visual inspection and research of available documents, are shown on a Dam Inventory Form. Observations made during the inspection are shown on the attached Inspection Checklist.

Recommended Actions

1. Please submit Construction Completion Report for 5248-Lift Elevation, which shall include a summary of construction activities, descriptions of problems and their solutions, summary of materials test data, captioned and dated construction photographs, and a certificate that the dam as constructed is safe for the intended use per conditions of construction permit approval dated February 25, 2003.
2. Please submit as-built drawings reflecting present cross-sections of dam embankments per conditions of construction permit approval dated February 25, 2003.
3. Please submit "Proof of Completion of Works – Dam" form with original signatures for 5248-Lift Elevation.
4. Please submit details of instrumentation, including installation of new vibrating wire piezometers.
5. Please prepare and submit "Operation and Maintenance Manual" and "Emergency Action Plan" prior to June 30, 2008 per conditions of construction permit approval dated February 25, 2003.

Operation and Maintenance Manual and Emergency Action Plan

There is currently no Operation and Maintenance Manual (O&M) or Emergency Action Plan (EAP) on file with OSE Dam Safety Bureau. The OSE adopted new rules and regulations for dams, effective March 31, 2005. The rules and regulations are part 12 of 19.25 NMAC and are titled Dam Design, Construction and Dam Safety. Section 19.25.12.21 NMAC establishes O&M and EAP requirements for existing dams. Conditions of construction permit approval dated February 25, 2003 require this structure to have an approved Operation and Maintenance Manual and an Emergency Action Plan in place by June 30, 2008.

Spillway
The dam is designed to contain spillway design flood (half-PMP event based on HMR 49).

Inspection Findings

Overall Dam Condition
Based on the inspection, Lined Ash Impoundment Dam is in "Satisfactory" condition.

Hazard Potential Classification
The Hazard Class for this structure is listed as SIGNIFICANT. The hazard class is appropriate.

Monitoring Data
Monitoring data is submitted on monthly basis with construction progress report. Please continue reporting the data. Include data from new piezometers as they become available.

Sushil Chaudhary
Sushil K. Chaudhary, D.Eng., P.E.
Dam Safety Bureau

SKC

New Mexico Office Of The State Engineer
Dam Safety Bureau
Tailings Dam Inspection Checklist

County: San Juan	Dam Name: Lined Ash Impoundment	OSE No.: D-634	Fed ID No.: NM00614
Inspection Performed By: Sushil K. Chaudhary	Inspection Date: 10/4/07	Last Inspection Date: 3/28/06	
Owner Name: APS Four Corners Power Plant	Owner Address: P.O. Box 355, Mail Station 4913 Fruitland, NM 87416	Owner Contact: David Bloomfield Owner Phone No.: 505-598-8405	
Method of Construction: Compacted bottom ash embankment in stages	Hazard Class: Significant	Hazard Class Appropriate: Yes ☒ No ☐	
Dam Location: APS Four Corners Power Plant		Latitude: 36.6849	Longitude: -108.3066
Weather: Partly cloudy	Attendees: David Bloomfield, Bruce Salisbury		

1. General Conditions	Satisfactory	Needs Attention	N/A	Remarks:
a. Access for O & M	☒	☐	☐	
b. Unauthorized access restricted	☒	☐	☐	
c. No unauthorized alterations	☒	☐	☐	

2. Interior Slope	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Distortion or cracking	☒	☐	☐	
d. Adequate freeboard	☒	☐	☐	

3. Dam Crest	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Adequate width maintained	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	

4. Downstream Slope	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Rodent control	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	
e. Seepage control	☒	☐	☐	

5. Downstream Area	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Rodent control	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	
e. Seepage or boils	☒	☐	☐	
f. Drains or Wells	☐	☐	☒	Est. gpm

Dam Name: Lined Ash Impoundment **Inspection Date:** 10/4/07 **File No.** D-634

6. Abutment Contacts	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion, cracks, or slides	☒	☐	☐	
b. Woody vegetation	☒	☐	☐	
c. Distortion or cracking	☒	☐	☐	
d. Seepage	☒	☐	☐	
e. Drains or Wells	☐	☐	☒	Est. gpm

7. Tailings Storage Area	Satisfactory	Needs Attention	N/A	Remarks:
a. Adequate beach maintained	☐	☐	☒	Embankment is lined, beach not required
b. Tailing placement method	☒	☐	☐	
c. Tailing placement rate	☒	☐	☐	
d. Sediment level	=			
e. Water level	=			

8. Intake Structure	Type of Structure: Decant structure (CMP drop inlet with ports filtered by bottom ash)			
	Satisfactory	Needs Attention	N/A	Remarks:
a. Concrete condition	☐	☐	☒	
b. Reinforcement encasement	☐	☐	☒	
c. Coating adequacy	☐	☐	☒	
d. Leakage	☐	☐	☒	
e. Trash rack condition	☐	☐	☒	
f. Inlet unobstructed	☒	☐	☐	Inlet ports are covered with bottom ash filter
g. Gates operative	☐	☐	☒	
h. Woody vegetation	☒	☐	☐	
Number of intake ports		Number of ports open		

9. Outlet Conduit	Type of Conduit: 18-in, 8-in, 8-in HDPE pipes			Estimated Discharge:
	Interior Inspection: Yes ☐ Date		No ☒	
	Satisfactory	Needs Attention	N/A	Remarks:
a. Overall Condition	☐	☐	☐	Conduits were discharging liquid into the downstream decant pond.
b. Condition of surfaces	☐	☐	☐	
c. Reinforcement encasement	☐	☐	☐	
d. Clear of obstructions	☐	☐	☐	
e. Joint Condition	☐	☐	☐	
f. Leakage	☐	☐	☐	
g. Alignment	☐	☐	☐	

10. Instrumentation	Satisfactory	Needs Attention	N/A	Remarks:
a. Structure instrumented	☒	☐	☐	
b. Monitoring performed	☒	☐	☐	
c. Piezometers	☐	☒	☐	Details of the installation of new vibrating wire piezometers must be submitted for review
d. Settlement monuments	☐	☐	☒	
e. Other	☐	☐	☐	

Overall Remarks:	Lined Ash Impoundment embankments are in satisfactory condition. However, the as-built drawings reflecting present cross-sections must be submitted. Details of new vibrating wire piezometers must be submitted for OSE review and approval. Construction Completion Report for the 5248-Lift elevation must be submitted.

Signature: Sushil Chaudhary Date: 10/30/07

MEMORANDUM
OFFICE OF THE STATE ENGINEER
Dam Safety Bureau

DATE: October 31, 2007

TO: Elaine C. Pacheco, P.E., Chief, Dam Safety Bureau

FROM: Sushil K. Chaudhary, D.Eng., P.E., Dam Safety Engineer

SUBJECT: Inspection of Lined Decant Water Pond, San Juan County, OSE File No. D-635

On October 4, 2007, I inspected Lined Decant Water Pond Dam. The purpose of the dam is to store decant water from the coal fired power plant tailings rich in fly ash. Characteristics of the dam, verified from visual inspection and research of available documents, are shown on a Dam Inventory Form. Observations made during the inspection are shown on the attached Inspection Checklist.

Recommended Actions

1. Please submit "Proof of Completion of Works – Dam" form with original signatures and a filing fee of $25.00 per conditions of construction permit approval dated February 25, 2003 by December 31, 2007. The Office of the State Engineer (OSE) has notified Mr. David Bloomfield of Arizona Public Service Company (APS) of this deficiency with the letter dated July 1, 2004. No response from APS is on file with the OSE. The OSE has not issued the Certificate of Construction and the Operating License for Lined Decant Water Pond. The pond is already in full operation.
2. Please prepare and submit "Operation and Maintenance Manual" and "Emergency Action Plan" prior to June 30, 2008 per conditions of construction permit approval dated February 25, 2003.

Operation and Maintenance Manual and Emergency Action Plan

There is currently no Operation and Maintenance Manual (O&M) or Emergency Action Plan (EAP) on file with OSE Dam Safety Bureau. The OSE adopted new rules and regulations for dams, effective March 31, 2005. The rules and regulations are part 12 of 19.25 NMAC and are titled Dam Design, Construction and Dam Safety. Section 19.25.12.21 NMAC establishes O&M and EAP requirements for existing dams. Conditions of construction permit approval dated February 25, 2003 require this structure to have an approved Operation and Maintenance Manual and an Emergency Action Plan in place by June 30, 2008.

Spillway

This structure does not have a spillway. The dam is designed to contain spillway design flood (half-PMP event based on HMR 49).

Inspection Findings

Overall Dam Condition
Based on the inspection, Lined Decant Water Pond Dam is in "Satisfactory" condition.

Hazard Potential Classification
The Hazard Class for this structure is listed as SIGNIFICANT. The hazard class is appropriate.

Monitoring Data
The west embankment has a number of standpipe type piezometers which were likely installed to monitor pore pressure during embankment construction. The Lined Decant Water Pond has HDPE liner with leak detection system. The piezometers, therefore, may not record any water level. However, the piezometers should still be read occasionally as they represent one more layer of tools to indicate liner leak. Details of piezometer installation are not available on file with the OSE.

Sushil Chaudhary
Sushil K. Chaudhary, D.Eng., P.E.
Dam Safety Bureau

SKC

New Mexico Office Of The State Engineer
Dam Safety Bureau
Inspection Checklist

County: San Juan	Dam Name: Lined Decant Water Pond	OSE No.: D-635	Fed ID No.: NM00634
Inspection Performed By: Sushil K. Chaudhary	Inspection Date: 10/4/07	Last Inspection Date: 3/28/06	
Owner Name: APS Four Corners Power Plant	Owner Address: P.O. Box 355, Mail Station 4913 Fruitland, NM 87416	Owner Contact: David Bloomfield Owner Phone No.: 505-598-8405	
Purpose of Dam: Decant water storage	Hazard Class: Significant	Hazard Class Appropriate: Yes ☒ No ☐	
Dam Location: APS Four Corners Power Plant		Latitude: 36.6831	Longitude: -108.5124
Weather: Partly cloudy	Attendees: David Bloomfield, Bruce Salisbury		

1. General Conditions	Satisfactory	Needs Attention	N/A	Remarks:
a. Access for O & M	☒	☐	☐	
b. Unauthorized access restricted	☒	☐	☐	
c. No unauthorized alterations	☒	☐	☐	

2. Interior Slope	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	Interior is lined with liner
b. Woody vegetation control	☒	☐	☐	
c. Distortion or cracking	☒	☐	☐	
d. Adequate freeboard	☒	☐	☐	

3. Dam Crest	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Adequate width maintained	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	

4. Downstream Slope	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Rodent control	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	
e. Seepage control	☒	☐	☐	

5. Downstream Area	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion control	☒	☐	☐	
b. Woody vegetation control	☒	☐	☐	
c. Rodent control	☒	☐	☐	
d. Distortion or cracking	☒	☐	☐	
e. Seepage or boils	☒	☐	☐	
f. Drains or Wells	☐	☐	☒	Est. upon

Dam Name: Lined Decant Water Pond **Inspection Date:** 10/4/07 **File No.** D-635

6. Abutment Contacts	Satisfactory	Needs Attention	N/A	Remarks:
a. Erosion, cracks, or slides	☒	☐	☐	
b. Woody vegetation	☒	☐	☐	
c. Distortion or Sloughing	☒	☐	☐	
d. Seepage	☒	☐	☐	
e. Drains or Wells	☐	☐	☒	Est. gpm

7. Reservoir	Satisfactory	Needs Attention	N/A	Remarks:
a. Developed/Encroachment	☐	☐	☐	It is a perimeter pond.
b. Banks and slopes stable	☐	☐	☐	
c. Obstruction or debris	☐	☐	☐	
d. Sediment level	-			
e. Water level	-			

8. Instrumentation	Satisfactory	Needs Attention	N/A	Remarks:
a. Structure instrumented	☒	☐	☐	
b. Monitoring performed	☒	☐	☐	
c. Piezometers	☒	☐	☐	
d. Settlement monuments	☐	☐	☒	
e. Other	☒	☐	☐	Leak detection system for liner system

Overall Remarks:	Lined Decant Water Pond embankments are in satisfactory condition.

Signature: Sushil Chaudhary

Date: 10/31/07

APS

THE POWER TO MAKE IT HAPPEN™

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VIA FEDERAL EXPRESS

March 26, 2009

Mr. Richard Kinch
U.S. Environmental Protection Agency
5th Floor N-5783
Two Potomac Yard
2733 S. Crystal Drive
Arlington, Virginia 22202-2733

Re: Arizona Public Service Company – Cholla Generating Station: Request for Information Under 104(e) of the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. 9604(e) ("104(e) Request").

Dear Mr. Kinch:

On March 13, 2009, Arizona Public Service Company ("APS") received the above referenced 104(e) Request for each surface impoundment or similar diked or bermed management unit(s) or management units designated as landfills at the Cholla Generating Station which receive liquid-borne material for the storage or disposal of residuals or by-products from the combustion of coal, including, but not limited to, fly ash, bottom ash, boiler slag, or flue gas emission control residuals. APS's response for the Cholla Generating Station is attached.

I certify that the information contained in this response to EPA's request for information and the accompanying documents is true, accurate, and complete. As to the identified portions of this response for which I cannot personally verify their accuracy, I certify under penalty of law that this response and all attachments were prepared in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations.

Signature: John R Denman
Name: John R. Denman
Title: Sr. V.P., Fossil Generation

Arizona Public Service Company's 104(e) Response for the Cholla Generating Station

Plant Description

The Cholla Generating Station is a four unit, coal fired, 1160 megawatt steam electric power plant. As part of its operations, the plant generates residuals and by-products from the combustion of coal. The residuals and by-products are conveyed to four surface impoundments for storage and disposal: a Bottom Ash Pond, a Fly Ash Pond, a Sedimentation Pond, and a retention pond named the West Area Retention Pond. Approximately 70% of the fly ash generated at the plant is sold for beneficial reuse.

Impoundment Descriptions

Bottom Ash Pond

The Bottom Ash Pond is a zoned clay core earthen embankment, which receives bottom ash (slurried with process water) from all four of the plant's generating units. The bottom ash settles to the bottom of the Bottom Ash Pond, and the process water is siphoned back to the general water sump and re-used.

Fly Ash Pond

The Fly Ash Pond is a zoned clay core earthen embankment (with a ten foot by 650 foot saddle dike), which receives fly ash from all four of the plant's generating units.

Fabric filters remove dry fly ash from generating units 1, 3, and 4. Generating unit 2 uses a mechanical dust collector to remove some fly ash on a dry basis, and a venturi scrubber system (a wet particulate/ SO_2 removal system) removes additional fly ash. The dry fly ash that is not sold for beneficial re-use and all of the wet fly ash are slurried with flue gas desulfurization residuals and pumped to the fly ash pond.

Sedimentation Pond

The Sedimentation Pond is a sub-grade impoundment, with a two foot thick compacted clay liner, which receives *de minimis* amounts of coal combustion by-products in storm water, process water, plant wash down water, and slurry from system leaks, from drains located on the plant site.

West Area Retention Pond

The West Area Retention Pond is a sub-grade impoundment, with an earthen liner, which receives *de minimis* amounts of coal combustion by-products in storm water, process water, and plant wash down water, from the west side of the plant.

104(e) Questions

Please provide the information requested below for each surface impoundment or similar diked or bermed management unit(s) or management units designated as landfills which receive liquid-borne material for the storage or disposal of residuals or by-products from the combustion of coal, including, but not limited to, fly ash, bottom ash, boiler slag, or flue gas emission control residuals. This includes units that no longer receive coal combustion residues or by-products, but still contain free liquids.

1. Relative to the National Inventory of Dams criteria for High, Significant, Low, or Less than Low Hazard Potential, please provide the potential hazard rating for each management unit and indicate who established the rating, what the basis for the rating is, and what federal or state agency regulates the unit(s). If the unit(s) does not have a rating, please note that fact.

Bottom Ash Pond

The rating, which is designated by the Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, which regulates the unit, is "High Hazard Potential." The basis for the rating is set forth in the Arizona Administrative Code ("A.A.C."), Article 12. Dam Safety Procedures, Section R12-15-1206 B, attached to this response as Exhibit A (Section R12-15-1202, which contains the definitions of the terms "Hazard potential" and Hazard potential classification," is also attached as part of Exhibit A).

Fly Ash Pond

The rating, which is designated by the Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, which regulates the unit, is "High Hazard Potential." The basis for the rating is set forth in the A.A.C., Article 12. Dam Safety Procedures, Section R12-15-1206 B, attached to this response as Exhibit A (Section R12-15-1202, which contains the definitions of the terms "Hazard potential" and Hazard potential classification," is also attached as part of Exhibit A).

Sedimentation Pond

Because the Sedimentation Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), the unit is not regulated as a dam.

West Area Retention Pond

Because the West Area Retention Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), the unit is not regulated as a dam.

2. What year was each management unit commissioned and expanded?

Bottom Ash Pond

Commissioned (in-service) in 1978. Expanded in 1991.

Fly Ash Pond

Commissioned (in-service) in 1978.

Sedimentation Pond

Commissioned (in-service) in 1976

West Area Retention Pond

Commissioned (in-service) in 2002.

3. What materials are temporarily or permanently contained in the unit? Use the following categories to respond to this question: (1) fly ash; (2) bottom ash: (3) boiler slag; (4) flue gas emission control residuals; (5) other. If the management unit contains more than one type of material, please identify all that apply. Also, if you identify "other," please specify the other types of materials that are temporarily or permanently contained in the unit(s).

Bottom Ash Pond

(1) Fly ash ; (2) bottom ash; (3) boiler slag; (4) flue gas emission control residuals; and (5) other. Other types include: sedimentation pond effluent, sedimentation pond solids, cooling tower blowdown, oil/water separators effluent, oil/water separator solids, boiler cleaning wastes, and storm water.

Fly Ash Pond

(1) Fly ash; (2) bottom ash; (3) boiler slag; (4) flue gas emission control residuals; and (5) other. Other types include: storm water, sedimentation pond solids, boiler cleaning wastes, and oil/water separator solids.

Sedimentation Pond

(1) Fly ash (*de minimis* amounts); (2) bottom ash (*de minimis* amounts); (3) boiler slag (*de minimis* amounts); (4) flue gas emission control residuals (*de minimis* amounts); and (5) other. Other types include: discharges of domestic wastewater from the secondary wastewater treatment plant, effluent from the oil/water separator, storm water, and vehicle wash water from the spray wash station.

West Area Retention Pond

(1) Fly ash (*de minimis* amounts); (2) bottom ash (*de minimis* amounts); (3) boiler slag (*de minimis* amounts); (4) flue gas emission control residuals (*de minimis* amounts); and (5) other (storm water).

4. Was the management unit(s) designed by a Professional Engineer? Is or was the construction of the waste management unit(s) under the supervision of a Professional Engineer? Is inspection and monitoring of the safety of the waste management unit(s) under the supervision of a Professional Engineer?

Bottom Ash Pond

The Bottom Ash Pond was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Bottom Ash Pond is under the supervision of a Professional Engineer.

Fly Ash Pond

The Fly Ash Pond was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Fly Ash Pond is under the supervision of a Professional Engineer.

Sedimentation Pond

The Sedimentation Pond was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the Sedimentation Pond is not under the supervision of a Professional Engineer.

West Area Retention Pond

The West Area Retention Pond was designed by a Professional Engineer. Its construction was under the supervision of a Professional Engineer. Inspection and monitoring of the safety of the West Area Retention Pond is not under the supervision of a Professional Engineer.

5. When did the company last assess or evaluate the safety (i.e., structural integrity) of the management unit(s)? Briefly describe the credentials of those conducting the structural integrity assessments/evaluations. Identify actions taken or planned by facility personnel as a result of these assessments or evaluations. If corrective actions were taken, briefly describe the credentials of those performing the corrective actions, whether they were company employees or contractors. If the company plans an assessment or evaluation in the future, when is it expected to occur?

Bottom Ash Pond

APS last assessed or evaluated the safety of the Bottom Ash Pond on May 8-9, 2008. The individual who conducted the assessment/evaluation was an APS Generation Engineering, Civil and Structural Engineer (P.E.). No safety deficiencies were identified. The next assessment/evaluation is scheduled for May 2009.

Note that APS's assessment/evaluation included an examination of dessication cracks in the crest of the embankment of the Bottom Ash Pond (above the water line). These cracks were observed during the Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division's ("ADWR") 2007 inspection, at which time, ADWR did not designate the cracks as a safety deficiency. The cracks were also noted in ADWR's 2008 inspection report, which also indicated that there were no safety deficiencies found during the inspection.

APS has determined that the cracks are shallow and do not represent a safety issue, and APS is working with ADWR to close out the evaluation.

Fly Ash Pond

APS last assessed or evaluated the safety of the Fly Ash Pond on May 8-9, 2008. The individual who conducted the assessment/evaluation was an APS Generation Engineering, Civil and Structural Engineer (P.E.). No safety deficiencies were identified. The next assessment/evaluation is scheduled for May 2009.

Sedimentation Pond

Because the Sedimentation Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), safety assessments/evaluations are not necessary for this sort of structure.

West Area Retention Pond

Because the West Area Retention Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), safety assessments/evaluations are not necessary for this sort of structure.

6. When did a State or a Federal regulatory official last inspect or evaluate the safety (structural integrity) of the management unit(s)? If you are aware of a planned state or federal inspection or evaluation in the future, when is it expected to occur? Please identify the Federal or State regulatory agency or department which conducted or is planning the inspection or evaluation. Please provide a copy of the most recent official inspection report or evaluation.

Bottom Ash Pond

The Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, last inspected the Bottom Ash Pond on September 24-25, 2008. The next planned inspection is scheduled for September 2009. A copy of the most recent official inspection report is attached as Exhibit B.

Fly Ash Pond

The Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, last inspected the Fly Ash Pond on September 24-25, 2008. The next planned inspection is scheduled for September 2009. A copy of the most recent official inspection report is attached as Exhibit C.

Sedimentation Pond

Because the Sedimentation Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), safety inspections are not conducted.

West Area Retention Pond

Because the West Area Retention Pond does not meet the definition of a dam, as set forth in the Arizona Revised Statutes § 45-1201(1), safety inspections are not conducted.

7. Have assessments or evaluations, or inspections conducted by State or Federal regulatory officials conducted within the past year uncovered a safety issue(s) with the management unit(s), and, if so, describe the actions that have been or are being taken to deal with the issue or issues. Please provide any documentation that you have for these actions.

Bottom Ash Pond

No.

Fly Ash Pond

No.

Sedimentation Pond

Not applicable. See response to Question #6.

West Area Retention Pond

Not applicable. See response to Question #6.

8. What is the surface area (acres) and total storage capacity of each of the management units? What is the volume of material currently stored in each of the management unit(s). Please provide the date that the volume measurement(s) was taken. Please provide the maximum height of the management units(s). The basis for determining maximum height is explained later in this Enclosure.

Bottom Ash Pond

Surface area: 80 surface acres.

Total storage capacity: 2,300 acre feet.

Volume of materials currently stored: APS estimates that the Bottom Ash Pond currently holds 1,440 acre feet of bottom ash. This number is based on annual calculations of ash disposed of, which are performed as part of the annual Toxic Release Inventory Reporting submissions. The plant does not take physical measurements of volume.

Date volume measurement was taken: N/A (see explanation above).

The statutory dam height, established by the Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, is 73 feet.

Fly Ash Pond

Surface area: 420 surface acres.

Total storage capacity: 18,000 acre feet.

Volume of materials currently stored: APS estimates that the Fly Ash Pond currently holds 4,415 acre feet of material. This number is based on annual calculations of ash disposed of, which are performed as part of the annual Toxic Release Inventory Reporting submissions. The plant does not take physical measurements of volume.

Date volume measurement was taken: N/A (see explanation above).

The statutory dam height, established by the Arizona Department of Water Resources, Dam Safety and Flood Mitigation Division, is 80 feet.

Sedimentation Pond

Surface area: 1/2 surface acre.

Total storage capacity: 10.7 acre feet.

Volume of materials currently stored: 0.5 acre feet.

Date volume measurement was taken: March 19, 2009 (visual observation of sedimentation).

Dam height: N/A

West Area Retention Pond

Surface area: 1/4 surface acres.

Total storage capacity: 4.6 acre feet.

Volume of materials currently stored: Negligible.

Date volume measurement was taken: 03/19/09 (visual observation of sedimentation).

Dam height: N/A

9. Please provide a brief history of known spills or unpermitted releases from the unit within the last ten years, whether or not these were reported to State or federal regulatory agencies. For purposes of this question, please include only releases to surface water or to the land (do not include releases to groundwater).

APS's responses below do not include permitted releases.

Bottom Ash Pond

There have been no known spills or unpermitted releases within the last ten years.

Fly Ash Pond

There have been no known spills or unpermitted releases within the last ten years.

Sedimentation Pond

There have been no known spills or unpermitted releases within the last ten years.

West Area Retention Pond

There have been no known spills or unpermitted releases within the last ten years.

10. Please identify all current legal owner(s) and operator(s) at the facility.

For all four facilities, APS and PacifCorp are the owners, and APS is the operator.

subject of the audit. The notice shall state the date, time and place of the audit. The notice shall specify the records or information which the person must produce. The notice shall also include the statutory authorization and purpose for the audit and the name and telephone number of a Department employee who may be contacted for further information. The audit shall be held at the Department's offices, unless the Director grants a request to have the audit conducted at a different location.

D. The person subject to the audit or a representative shall appear at the scheduled time and shall produce the records and information specified in the notice. The person subject to the audit or a representative may make one request to reschedule the audit, which the Department shall grant if practicable.

E. The Director shall mail a copy of the report of the audit to the person subject to the audit. An aggrieved person may file with the Director written comments on the report within 30 days after the report is mailed.

F. The person subject to the audit may waive the provisions for notice contained in this rule.

Historical Note

Adopted effective August 31, 1992 (Supp. 92-3).
Amended effective July 22, 1994 (Supp. 94-3).

ARTICLE 12. DAM SAFETY PROCEDURES

R12-15-1201. Applicability

A. This Article applies to any artificial barrier meeting the specifications of A.R.S. § 45-1201(1) as interpreted by R12-15-1204. This Article applies to an application for the construction of a dam and reservoir; an application to reconstruct, repair, alter, enlarge, breach, or remove an existing dam and reservoir, including a breached or damaged dam; operation and maintenance of an existing dam and reservoir; and enforcement. A structure identified in R12-15-1203 is exempt from this Article.

B. This Article is applicable to any dam regardless of hazard potential classification, with the following exceptions:
   1. R12-15-1208, R12-15-1209, R12-15-1213, R12-15-1221, R12-15-1225, and R12-15-1226 apply only to a dam classified as a high or significant hazard potential dam.
   2. R12-15-1210 applies only to a dam classified as a low hazard potential dam. A low hazard potential dam is exempt from R12-15-1208, R12-15-1209, R12-15-1211, R12-15-1213, R12-15-1221, R12-15-1225, and R12-15-1226.
   3. R12-15-1211 applies only to a dam classified as a very low hazard potential dam. A very low hazard potential dam is exempt from R12-15-1208, R12-15-1209, R12-15-1210, R12-15-1212, R12-15-1213, R12-15-1215, R12-15-1216, R12-15-1221, R12-15-1225, and R12-15-1226.
   4. R12-15-1216(B) applies only to an embankment dam.

Historical Note

Adopted effective November 2, 1978 (Supp. 78-6). Former Section R12-15-01 renumbered without change as Section R12-15-1201 effective October 8, 1982 (Supp. 82-5). Section repealed; new Section adopted by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000 (Supp. 00-2).

R12-15-1202. Definitions

In addition to the definitions provided in A.R.S. § 45-1201, the following definitions are applicable to this Article:

1. "Alteration or repair of an existing dam or appurtenant structure" means to make different from the originally approved construction drawings and specifications or current condition without changing the height or storage capacity of the dam or reservoir, except for ordinary repairs and general maintenance as prescribed in R12-15-1217.
2. "Appurtenant structure" means any structure that is contiguous and essential to the safe operation of the dam including embankments, saddle dikes, outlet works and controls, diversion ditches, spillway and controls, access structures, bridges, and related housing at a dam.
3. "Classification of dams" means the placement of dams into categories based upon an evaluation of the size and hazard potential, regardless of the condition of the dam.
4. "Concrete dam" means any dam constructed of concrete, including arch, gravity, arch-gravity, slab and buttress, and multiple arch dams. A dam that only has a concrete facing is not a concrete dam.
5. "Construction" means any activity performed by the owner or someone employed by the owner that is related to the construction, reconstruction, repair, enlargement, removal, or alteration of any dam, unless the context indicates otherwise. Construction is performed after approval of an application and before issuance of a license.
6. "Dam failure inundation map" means a map depicting the maximum area downstream from a dam that would be flooded in the event of the worst condition failure of the dam.
7. "Department" means the Arizona Department of Water Resources.
8. "Director" means the Director of the Arizona Department of Water Resources or the Director's designee.
9. "Embankment dam" means a dam that is constructed of earth or rock material.
10. "Emergency spillway" means a spillway designed to safely pass the inflow design flood routed though the reservoir. If the flow is controlled by gates, it is a controlled spillway. If the flow is not controlled by gates, it is an uncontrolled spillway.
11. "Engineer" means a Professional Engineer registered and licensed in accordance with A.R.S. Title 32, Chapter 1, with proficiency in engineering and knowledge of dam technology.
12. "Enlargement to an existing dam or appurtenant structure" means any alteration, modification, or repair that increases the vertical height of a dam or the storage capacity of the reservoir.
13. "Flashboards" mean timber, concrete, or steel sections placed on the crest of a spillway to raise the retention water level that may be quickly removed at time of flood either by a tripping device or by designed failure of the flashboards or their supports.
14. "Flood control dam" means a dam that uses all of its reservoir storage capacity for temporary impoundment of flood waters and collection of sediment or debris.
15. "Hazard potential" means the probable incremental adverse consequences that result from the release of water or stored contents due to failure or improper operation of a dam or appurtenances.
16. "Hazard potential classification" means a system that categorizes dams according to the degree of probable incremental adverse consequences of failure or improper operation of a dam or appurtenances. The hazard potential classification does not reflect the current condition of the dam with regard to safety, structural integrity, or flood routing capacity.
17. "Height" means the vertical distance from the lowest elevation of the outside limit of the barrier at its intersection

1. The owner shall increase the frequency of observation when the reservoir is full, during heavy rains or flooding, and following an earthquake.
2. The owner shall report to the Director any condition that threatens the safety of the dam as prescribed in R12-15-1224(A). The owner shall make the report as soon as possible, but not later than 12 hours after discovery of the conditions.
3. If dam failure appears imminent, the owner shall notify the county sheriff or other emergency official immediately.
4. The owner is responsible for the safety of the dam and shall take action to lower the reservoir if it appears that the dam has weakened or is in danger of failing.

C. The owner of a dam shall install, maintain, and monitor instrumentation to evaluate the performance of the dam. The Director shall require site-specific instrumentation that the Director deems necessary for monitoring the safety of the dam when failure may endanger human life and property. Conditions that may require monitoring include land subsidence, earth fissures, embankment cracking, phreatic surface, seepage, and embankment movements.

D. The owner shall perform timely maintenance and ordinary repair of a dam. The owner shall implement an annual plan to inspect the dam and accomplish the maintenance and ordinary repairs necessary to protect human life and property.

E. If a change of ownership of a dam occurs, the new owner shall notify the Department within 15 days after the date of the transaction and provide the mailing address and telephone number where the new owner can be contacted. Within 90 days after the date of the transaction, the new owner shall provide the name and telephone number of the individual or individuals who are responsible for operating and maintaining the dam.

Historical Note

Adopted effective November 2, 1978 (Supp. 78-6). Former Section R12-15-05 renumbered without change as Section R12-15-1205 effective October 8, 1982 (Supp. 82-5). Section repealed; new Section adopted by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000 (Supp. 00-2).

R12-15-1206. Classification of Dams

A. Size Classification. Dams are classified by size as small, intermediate, or large. Size is determined with reference to Table 2. An owner or engineer shall determine size by storage capacity or height, whichever results in the larger size.

B. Hazard Potential Classification

1. The Department shall base hazard potential classification on an evaluation of the probable present and future incremental adverse consequences that would result from the release of water or stored contents due to failure or improper operation of the dam or appurtenances, regardless of the condition of the dam. The evaluation shall include land use zoning and development projected for the affected area over the 10 year period following classification of the dam. The Department considers all of the following factors in hazard potential classification: probable loss of human life, economic and lifeline losses, and intangible losses identified and evaluated by a public resource management or protection agency.
   a. The Department bases the probable incremental loss of human life determination primarily on the number of permanent structures for human habitation that would be impacted in the event of failure or improper operation of a dam. The Department considers loss of human life unlikely if:
      i. Persons are only temporarily in the potential inundation area;
      ii. There are no residences or overnight campsites; and
      iii. The owner has control of access to the potential inundation area and provides an emergency action plan with a process for warning in the event of a dam failure or improper operation of a dam.
   b. The Department bases the probable economic, lifeline, and intangible loss determinations on the property losses, interruptions of services, and intangible losses that would be likely to result from failure or improper operation of a dam.
2. The 4 hazard potential classification levels are very low, low, significant, and high, listed in order of increasing probable adverse incremental consequences, as prescribed in Table 3. The Director shall classify intangible losses by considering the common or unique nature of features or habitats and temporary or permanent nature of changes.
   a. Very Low Hazard Potential. Failure or improper operation of a dam would be unlikely to result in loss of human life and would produce no lifeline losses and very low economic and intangible losses. Losses would be limited to the 100 year floodplain or property owned or controlled by the dam owner under long-term lease. The Department considers loss of life unlikely because there are no residences or overnight camp sites.
   b. Low Hazard Potential. Failure or improper operation of a dam would be unlikely to result in loss of human life, but would produce low economic and intangible losses, and result in no disruption of lifeline services that require more than cosmetic repair. Property losses would be limited to rural or agricultural property, including equipment, and isolated buildings.
   c. Significant Hazard Potential. Failure or improper operation of a dam would be unlikely to result in loss of human life but may cause significant or high economic loss, intangible damage requiring major mitigation, and disruption or impact on lifeline facilities. Property losses would occur in a predominantly rural or agricultural area with a transient population but significant infrastructure.
   d. High Hazard Potential. Failure or improper operation of a dam would be likely to cause loss of human life because of residential, commercial, or industrial development. Intangible losses may be major and potentially impossible to mitigate, critical lifeline services may be significantly disrupted, and property losses may be extensive.
3. An applicant shall demonstrate the hazard potential classification of a dam before filing an application to construct. The Department shall review the applicant's demonstration early in the design process at pre-application meetings prescribed in R12-15-1207(D).
4. The Department shall review the hazard potential classification of each dam during each subsequent dam safety inspection and revise the classification in accordance with current conditions.

Historical Note

Adopted effective November 2, 1978 (Supp. 78-6).

Former Section R12-15-06 renumbered without change as Section R12-15-1206 effective October 8, 1982 (Supp. 82-5). Section repealed; new Section adopted by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000 (Supp. 00-2).

Exhibit A. Repealed

Historical Note
Exhibit repealed by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000; a Historical Note for Exhibit A did not exist before this date (Supp. 00-2).

Table 2. Size Classification

Category	Storage Capacity (acre-feet)	Height (feet)
Small	50 to 1,000	25 to 40
Intermediate	greater than 1,000 and not exceeding 50,000	higher than 40 and not exceeding 100
Large	greater than 50,000	higher than 100

Historical Note
New Table adopted by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000 (Supp. 00-2).

Table 3. Downstream Hazard Potential Classification

Hazard Potential Classification	Probable Loss of Human Life	Probable Economic, Lifeline, and Intangible Losses
Very Low	None expected	Economic and lifeline losses limited to owner's property or 100-year floodplain. Very low intangible losses identified.
Low	None expected	Low
Significant	None expected	Low to high
High	Probable - One or more expected	Low to high (not necessary for this classification)

Historical Note
New Table adopted by final rulemaking at 6 A.A.R. 2558, effective June 12, 2000 (Supp. 00-2).

R12-15-1207. Application Process

A. An applicant shall obtain written approval from the Director before constructing, reconstructing, repairing, enlarging, removing, altering, or breaching a dam. Application requirements differ according to the hazard potential of the dam.
   1. To construct, reconstruct, repair, enlarge, or alter a high or significant hazard potential dam, the applicant shall comply with R12-15-1208.
   2. To breach or remove a high or significant hazard potential dam, the applicant shall comply with R12-15-1209.
   3. To construct, reconstruct, repair, enlarge, alter, breach, or remove a low hazard potential dam, the applicant shall comply with R12-15-1210.
   4. To construct, reconstruct, repair, enlarge, alter, breach, or remove a very low hazard potential dam, the applicant shall comply with R12-15-1211.

B. An application shall not be filed with the Director under the following circumstances:
   1. The dam is exempt under R12-15-1203;
   2. A dam owner starts repairs to an existing dam that are necessary to safeguard human life or property and the Director is notified without delay;
   3. The owner performs general maintenance or ordinary repairs as prescribed in R12-15-1217(A) or (B); or
   4. Breach, removal, or reduction of a very low hazard dam as prescribed in R12-15-1211(C).

C. An applicant is not required to comply with a requirement in this Article if the Director finds that, considering the site characteristics and the proposed design, the requirement is unduly burdensome or expensive and is not necessary to protect human life or property. The Director shall consider the size, hazard potential classification, physical site conditions, and applicability of a requirement to a proposed dam. The Director shall state in writing the reason or reasons the applicant is not required to comply with a requirement.

D. An applicant shall schedule pre-application conferences with the Department to discuss the requirements of this Article and to resolve issues essential to the design of a dam while the design is in preliminary stages. The Director shall view the dam site during the pre-application process. The following are examples of issues for pre-application conferences: the hazard potential classification, the approximate inflow design flood, the basic design concepts, and any requirements that may be found by the Director to be unduly burdensome or expensive and not necessary to protect human life or safety. In addition, the applicant may submit preliminary design calculations to the Department for review and comment. The Department shall comment as soon as practicable, depending on the size of the submittal and the current workload.

E. The Department shall review applications as follows:
   1. Applications will be received by appointment. During this meeting the Department shall make a brief review of the application to determine that the application contains each of the items required by R12-15-1208, R12-15-1209, R12-15-1210, or R12-15-1211.
   2. Following receipt of an application submitted under R12-15-1208, R12-15-1209, R12-15-1210, or R12-15-1211, the Director shall complete an administrative review as prescribed in R12-15-401(1) and notify the applicant in writing whether the application is administratively complete. If the application is not administratively complete, the notification shall include a list of additional information that is required to complete the application.
   3. After finding the application submitted under R12-15-1208, R12-15-1209, R12-15-1210, or R12-15-1211 administratively complete, the Director shall complete a substantive review as prescribed in R12-15-401(3) and

JANICE K. BREWER
Governor

HERBERT R. GUENTHER
Director

ARIZONA DEPARTMENT OF WATER RESOURCES

3550 North Central Avenue, Second Floor
PHOENIX, ARIZONA 85012-2105
(602) 771-8500

RECEIVED
MAR 09 2009
CHOLLA POWER PLANT

February 18, 2009

Mr. Douglas Lavarnway
Environmental Manager
Arizona Public Services Company
Cholla Power Plant
P.O. Box 188
Joseph City, Arizona 86032

Subject: **Cholla Bottom Ash Pond (09.27)**
September 2008 Dam Safety Inspection Report
Finding of No Safety Deficiency

Dear Mr. Lavarnway

Enclosed for your information and action is a copy of the Arizona Department of Water Resources (Department) report of the most recent inspection conducted by Ravi Murthy, P.E. on September 24, 2008 on the above listed dam. Along with the enclosed invoice, please remit payment in the amount of $ 246.00 to:

Peggy Beckett
Arizona Department of Water Resources
Surface Water Division
3550 North Central Avenue
Phoenix, Arizona 85012

In compliance with Arizona Revised Statutes (A.R.S.) § 41-1009, this letter notifies you that the inspection found no safety deficiencies that must be corrected. The dam safety inspection report identifies maintenance and repair action items that need to be addressed at the dam before the next scheduled inspection. Please provide the Department a schedule of when you intend to do this work and also notify us in writing when you complete the items listed below. For additional information on how to conduct these repairs, please refer to the inspection report and/or contact the Department.

The Department has reviewed the size and hazard potential classifications for the dam. The classifications have not changed from intermediate size and high hazard potential.

Printed on recycled paper. Each ton of recycled paper saves 7,000 gallons of water.

It is Department policy to review the License of Approval of each operating dam within state jurisdiction following its dam safety inspection. Based on the findings of the inspection and a review of our files, the License, issued December 11, 1998, requires no changes and remains in full force and effect.

The next inspection by the Department is tentatively scheduled for September 2009. We will contact you in advance to arrange a mutually convenient inspection date and time. Please notify the Department promptly of any unusual or alarming condition, which may occur at the dam

If you or anyone connected this dam have any questions regarding this letter, please contact Ravi Murthy, P.E. at (602) 771 8656.

Sincerely,

Michael Johnson, Ph.D., P.E.
Assistant Director
Surface Water Division

Enclosures:
1. Inspection Report & Photos
2. Invoice
3. Notification of Inspection and Due Process Rights

cc: Mr. John Mitchell, P.E. – APS Generation Engineering, Phoenix, Arizona.

ARIZONA DEPARTMENT OF WATER RESOURCES
SURFACE WATER DIVISION, DAM SAFETY SECTION
DAM SAFETY INSPECTION REPORT

Each item of the checklist should be completed. Repair is required when obvious problems are observed. Monitoring is recommended if there is a potential for a problem to occur in the future. Investigation is necessary if the reason for the observed problem is not obvious.

SID: (09.27)	DAM NAME: Bottom Ash Pond	TYPE: Earth	PURPOSE: Bottom Ash Containment
CONTACT(S): Douglas Lavarnway & John Roznovak (accompanied)		REPORT DATE: February 18, 2009	
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 24, 2008	
REVIEWED BY: Michael J. Johnson, PhD, P.E. MJJ		DATE: 2-24-09	
DESIGN DAM CREST ELEVATION: 5123.3 ft		DESIGN SPILLWAY CREST ELEVATION: None	
DESIGN TOTAL FREEBOARD (FT): 4.7		*MEASURED TOTAL FREEBOARD (FT)*: 11.8 ±	
STATUTORY DAM HEIGHT (FT): 73		STRUCTURAL HEIGHT (FT): 73	
DAM CREST LENGTH (FT): 4,200	UPSTREAM SLOPE: 3:1	DOWNSTREAM SLOPE: 2:1	
DAM CREST WIDTH (FT): 12	GPS Lat.: N34°57'07" Long.: W110°17'22.7"	WATER RIGHTS: N/A	
RSRVR. AREA (AC): 80	RSRVR. STORAGE (AC-FT): 2190	MAX. STORAGE (AC-FT): 2300	
INFLOW DESIGN FLOOD / SAFE FLOOD-PASSING CAPACITY: PMF/Not Applicable (no spillway)			
RESERVOIR LEVEL DURING INSPECTION: 5111.5±		PHOTOS: Yes	Page 1 of 6

COMPLIANCE CHECKLIST

1. CONDITION SUMMARY / LICENSE / EAP / NEXT INSPECTION	NOT APPLICABLE	NO	YES	MONITOR	REPAIR	INVESTIGATE
a. Recorded downstream hazard: **High** Should hazard be revised? **No**		X				
b. If High Hazard, estimate downstream persons-at-risk (PAR): **<30** Is there a significant increase since the last inspection? **No**		X				
c. Recorded size: **Intermediate** Should size be revised? **No**		X				
d. Any safety deficiencies? Describe: **None**		X				
e. Any Statute or Rule violations? Describe and list required action: **AAC R12-15-1205. See Recommendations**			X	X	X	
f. Safe storage level on License: **5117.8** Should level be revised? **No**		X				
g. Any License violations? Describe and list required action:		X				
h. Date of current License: **December 11, 1998** Should new License be issued? **No**		X				
i. Date of last Emergency Action Plan revision: **November 2006** Should EAP be revised? **Should be updated**			X			
j. Any Agency Actions? **None** Describe and list required action:		X				
k. Normal inspection frequency: **Annual** Should inspection frequency be revised? **No**		X				
l. Recommended date for next inspection: **September 2008**						

MONITORING CHECKLIST

2. INSTRUMENTATION AND MONITORING						
a. Describe: **Piezometers in embankment and foundation. Settlement monuments on crest.**						
b. Any repair or replacement required? Describe:		X				
c. Date of last monitoring report: **June 2006** Should new readings be taken and new report provided?						

DAM INSPECTION REPORT	Page 2 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						

DAM EMBANKMENT CHECKLIST

	N/A	NO	YES	MON.	REP.	INV.
3. DAM CREST						
a. Settlements, slides, depressions?		X				
b. Misalignment?		X				
c. Longitudinal/Transverse cracking? **Longitudinal and transverse cracking; under investigation See photos 8,9,10**			X			X
d. Animal burrows? **Minor**			X	X	X	
e. Adverse Vegetation? **Minor. Should be cleared during routine maintenance**			X	X	X	
f. Erosion?		X				
4. UPSTREAM SLOPE						
a. Erosion?		X				
b. Inadequate ground cover?		X				
c. Adverse vegetation? **Small salt cedars and other vegetation. Should be removed during routine maintenance**			X	X	X	
d. Longitudinal/Transverse cracking? **Unable to observe because of riprap cover**	X					
e. Inadequate riprap?		X				
f. Stone deterioration? **Generally in good condition, but occasional stones have deteriorated.**			X	X		
g. Settlements, slides, depressions, bulges?		X				
h. Animal burrows?		X				
5. DOWNSTREAM SLOPE						
a. Erosion? **Raised section has no riprap and shows minor erosion rills. Remainder of slope has riprap**			X	X		
b. Inadequate ground cover?		X				
c. Adverse vegetation? **Moderate vegetation at several locations. Should be cleared during maintenance**			X		X	
d. Longitudinal/Transverse cracking? **Unable to observe due to riprap**	X					
e. Inadequate riprap?		X				
f. Stone deterioration?		X				
g. Settlements, slides, depressions, bulges?		X				
h. Soft spots or boggy areas? **Right groin area near seepage weir**			X	X		
i. Movement at or beyond toe?		X				
j. Animal burrows? **Minor**			X	X		
6. ABUTMENT CONTACTS						
a. Erosion?		X				
b. Differential movement?		X				
c. Cracks?		X				
d. Settlements, slides, depressions, bulges?		X				
e. Seepage? Est. Left ___ gpm; Est. Right ___ gpm **Weir near downstream (See Photo 14), right groin showed a flow. Seepage conditions difficult to observe due to thick vegetation (See Photo 13). Vegetation should be cleared, and a formal measurement weir/system should be installed.**			X	X	X	
f. Animal burrows?		X				
7. SEEPAGE/PIPING CONTROL DESIGN FEATURE(S)						
a. Describe: **None**						
b. Internal drains flowing? Est. Left ___ gpm; Est. Right ___ gpm						
c. Seepage at or beyond toe? Estimated ___ gpm **Seepage beyond downstream toe collected in drain and pumped back to impoundment**						
e. If so, does seepage contain fines?						

DAM INSPECTION REPORT	Page 3 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						

d. Evidence of sand boils at or beyond toe?		X				

OUTLET WORKS CHECKLIST

8. APPROACH CHANNEL						
a. Describe: None						
b. Eroding or backcutting?	X					
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
9. INLET STRUCTURE						
a. Describe: None						
b. Seepage into structure?	X					
c. Debris or obstructions?	X					
d. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
e. *If metal*, do surfaces show:						
1. Corrosion?	X					
2. Protective coating deficient?	X					
3. Misalignment or split seams?	X					
f. Do the joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
g. Are the trash racks:						
1. Broken or bent?.	X					
2. Corroded or rusted?	X					
3. Obstructed?	X					
h. Operator, gates and valves:						
1. Describe:						
2. Date(s) last operated:						
3. Broken or bent?	X					
4. Corroded or rusted?	X					
5. Leaking?	X					
6. Not seated properly?	X					
7. Not operational?	X					
8. Not periodically maintained?	X					
10. CONDUIT						

DAM INSPECTION REPORT	Page 4 of 6	SID: 09:27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						
a. Describe: None								
b. Seepage into conduit?			X					
c. Debris present?			X					
d. *If concrete*, do surfaces show:								
1. Spalling or scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
e. *If metal*, do surfaces show:								
1. Corrosion?			X					
2. Protective coating deficient?			X					
3. Misalignment or split seams?			X					
f. Do the joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
11. STILLING BASIN / ENERGY DISSIPATOR								
a. Describe: None								
b. Do surfaces show:								
1. Spalling or Scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
12. OUTLET CHANNEL								
a. Describe: None								
b. Eroding or backcutting?			X					
c. Sloughing?			X					
d. Obstructions or restrictions?			X					
e. Poorly riprapped?			X					
f. Tailwater elevation and flow condition:								

EMERGENCY SPILLWAY CHECKLIST

13. ENTRANCE CHANNEL

DAM INSPECTION REPORT	Page 5 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						

	N/A	NO	YES	MON.	REP.	INV.
a. Describe None						
b. Eroding or backcutting?	X					
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
14. CONTROL SECTION						
a. Describe: None						
b. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
c. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
f. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Is crest eroding?	X					
g. Is the control structure (i.e. weir, sill, etc.) in poor condition?	X					
15. DISCHARGE CHANNEL						
a. Describe: None						
b. Obstructions or restrictions?	X					
c. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
d. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
e. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Poorly protected w/ vegetation/riprap?	X					
16. STILLING BASIN / ENERGY DISSIPATOR						
a. Describe: None						
b. Do surfaces show:						

DAM INSPECTION REPORT	Page 6 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept.24, 2008						
1. Spalling or Scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
17. OUTLET CHANNEL								
a. Eroding or backcutting?			X					
b. Sloughing?			X					
c. Obstructions or restrictions?			X					

RESERVOIR CHECKLIST

18. RESERVOIR						
a. High water marks?		X				
b. Erosion/Slides into pool area?		X				
c. Sediment accumulation? Bottom Ash			X			
d. Floating debris present?		X				
e. Depressions, sinkholes or vortices?		X				
f. Low ridges/saddles allowing overflow?		X				
g. Structures below dam crest elevation? Discharge pipes. See Photo 6			X			

ADDITIONAL COMMENTS AND RECOMMENDATIONS:

1. The Department has received your report documenting the investigation of the transverse cracking on the dam crest. We will contact you with questions and comments once we complete our review.
2. Vegetation on the downstream face, at the downstream toe, and in the area of the right, downstream groin should be cleared.
3. The seepage measurement weir near the right downstream groin of the dam is not useable and should be replaced with a standard weir box and weir plate, or an approved alternate system for measurement of rates of seepage.
4. The Emergency Action Plan should be updated to meet current ADWR requirements.

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

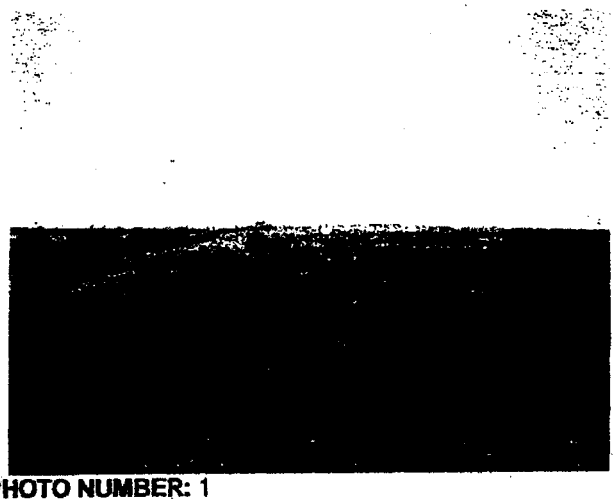

PHOTO NUMBER: 1
DESCRIPTION: Partial view of crest and downstream slope from the right abutment.

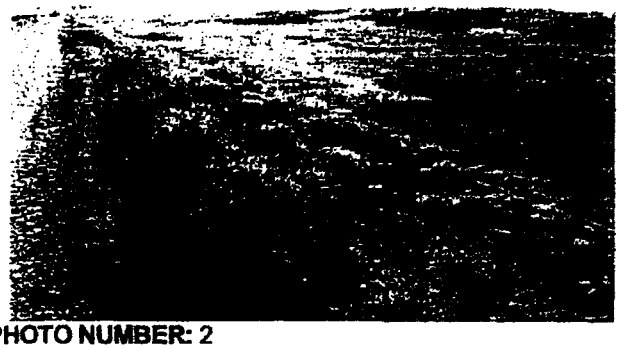

PHOTO NUMBER: 2
DESCRIPTION: Partial view of the downstream slope from the right abutment.

PHOTO NUMBER: 3
DESCRIPTION: Downstream view from the crest of the dam

PHOTO NUMBER: 4
DESCRIPTION: Partial view of the crest and the upstream impoundment from the crest of the dam

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

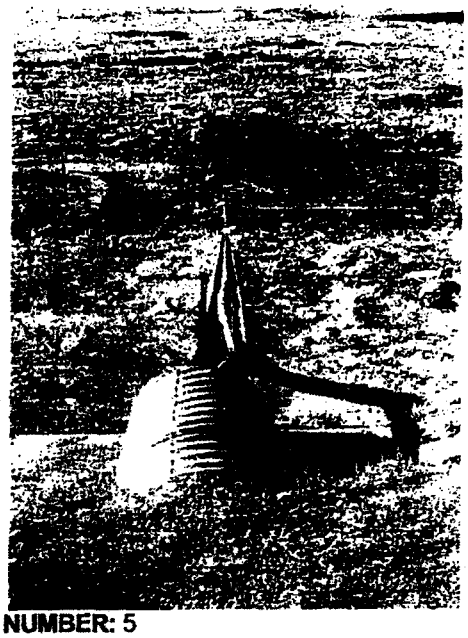

PHOTO NUMBER: 5
DESCRIPTION: Intake line, downstream segment.

PHOTO NUMBER: 6
DESCRIPTION: Intake line, upstream segment

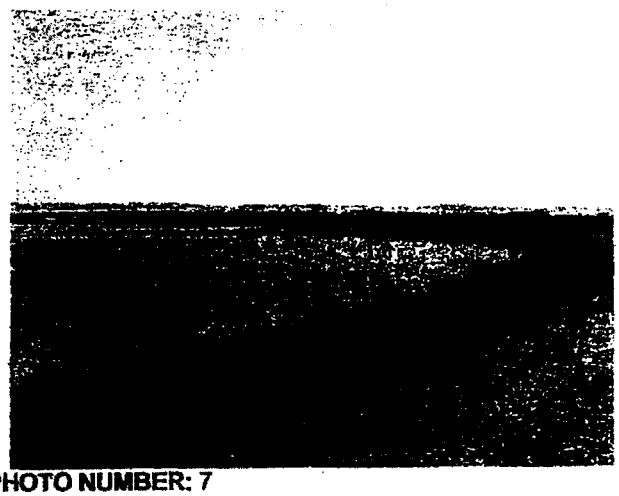

PHOTO NUMBER: 7
DESCRIPTION: View of the impoundment

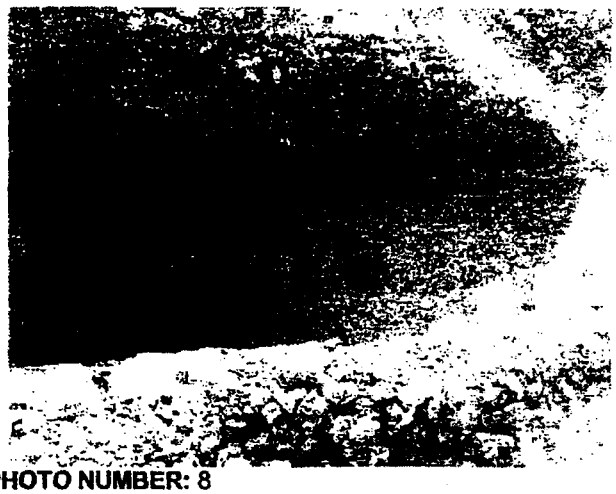

PHOTO NUMBER: 8
DESCRIPTION: Longitudinal crack in trench on dam crest

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

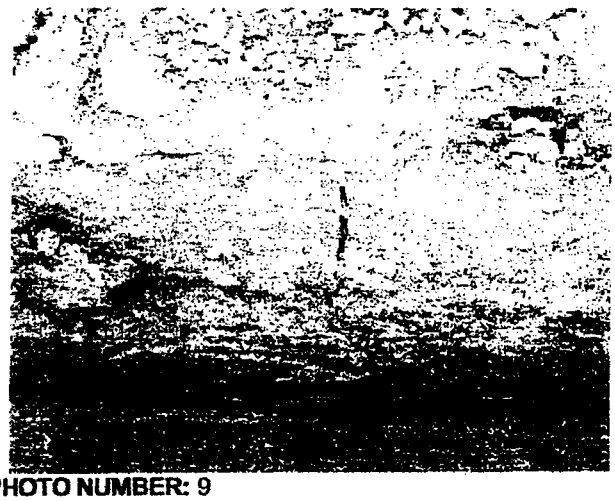

PHOTO NUMBER: 9
DESCRIPTION: Transverse crack in wall of trench excavated in dam crest.

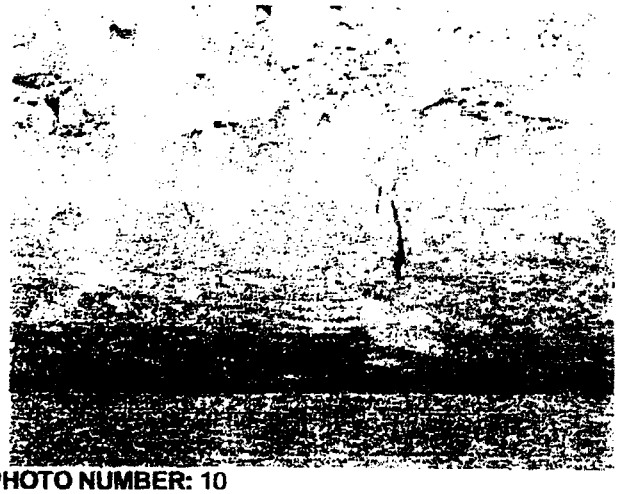

PHOTO NUMBER: 10
DESCRIPTION: Transverse crack in wall of trench excavated in dam crest.

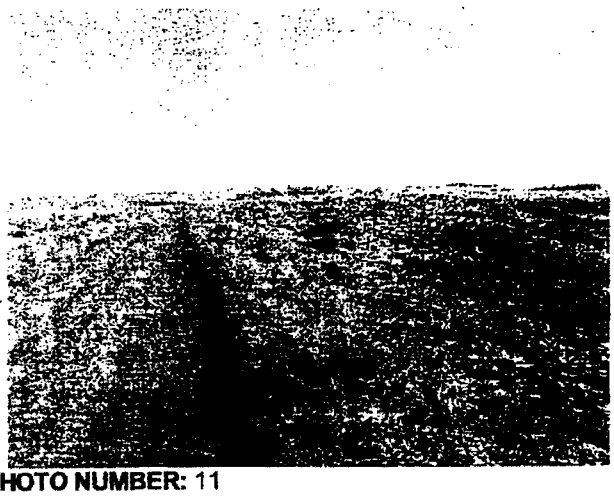

PHOTO NUMBER: 11
DESCRIPTION: View of the dam crest

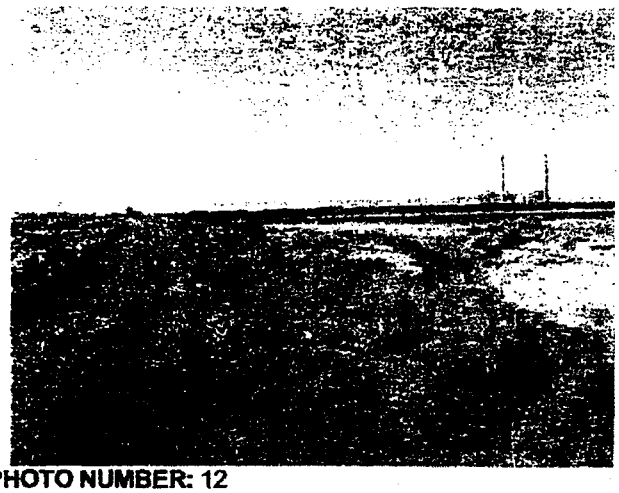

PHOTO NUMBER: 12
DESCRIPTION: Partial view of the dam crest and impoundment

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

PHOTO NUMBER: 13
DESCRIPTION: Thick vegetation in the right downstream groin and downstream toe

PHOTO NUMBER: 14
DESCRIPTION: Wooden tie used as seepage flow measurement weir

Well Registration No. _____ Application/Right No. _____ Permit/License No. _____
Regulated Person: _____ Address: _____
_____ Phone: _____

ARIZONA DEPARTMENT OF WATER RESOURCES
500 North Third Street, Phoenix, Arizona 85004
NOTIFICATION OF INSPECTION AND DUE PROCESS RIGHTS

In compliance with A.R.S. § 41-1009, this document is being provided to you by the Arizona Department of Water Resources (ADWR) to inform you of your rights concerning this inspection of the following described property:
CHOLLA COTTON ASH + CHOLLA FLYAWAY DAMS
on the following date(s): SEPT 24, 25 2008
ADWR must present this document for your signature, or the signature of an authorized representative, indicating that you have been informed of your rights concerning this inspection and have read both sides of this document. If you decline to sign, or signature is unavailable, ADWR must note that fact on this document and the inspection will proceed.

1. **ADWR Inspector.** This inspection is being conducted by an inspector for ADWR who must present photo identification upon entry of the inspected property, and whose name and phone number are indicated below. The ADWR inspector will be available to answer questions regarding this inspection.
   Name: KAVI MURTHY Phone: [illegible]
2. **Purpose of Inspection.** This inspection is being conducted by an ADWR inspector either for the purpose of ☐ issuing a permit/license, or ☑ determining compliance with permit/license requirements.
3. **Legal Authority.** This inspection is being conducted under the following legal authority: [illegible]
4. **Fees.** The following inspection fees apply and will be billed separately: [illegible]
5. **Ombudsmen.** Questions regarding due process rights described in paragraph 10 on the reverse should be directed to one of the following Ombudsmen:

Name (ADWR): FRED [illegible] Phone: [illegible]
Name (Arizona): PATRICK SHANNAHAN Phone: [illegible]

(continued on reverse)

Signature. This signature below is made by either the regulated person or the regulated person's authorized representative who has been informed of inspection and due process rights relating to this inspection and who has read both sides of this Notification.

Name (please print): John Rossman
Signature: [signature] Title: [illegible]

Signature Declined. The regulated person or the regulated person's authorized representative indicated below was present during the inspection but declined to sign this Notification.

Name: Title:

Signature Unavailable. Neither the regulated person nor the regulated person's authorized representative was present during this inspection. The ADWR inspector contacted or attempted to contact the regulated person by the following method:

ARIZONA DEPARTMENT OF WATER RESOURCES

Agency Inspector: [signature] (SIGNATURE) Date: [illegible]
☐ Photo identification presented.
☐ Copy provided prior to inspection to: _____ Time: [illegible]

Well Registration No. _____ Application/Right No. _____ Permit/License No. _____
Regulated Person: _____ Address: _____
_____ Phone: _____

ARIZONA DEPARTMENT OF WATER RESOURCES
500 North Third Street, Phoenix, Arizona 85004
NOTIFICATION OF INSPECTION AND DUE PROCESS RIGHTS

In compliance with A.R.S. § 41-1009, this document is being provided to you by the Arizona Department of Water Resources (ADWR) to inform you of your rights concerning this inspection of the following described property:
CHOLLA BOTTOM ASH + CHOLLA FLYASH DAMS
on the following date(s): SEPT 24, 25 2008
ADWR must present this document for your signature, or the signature of an authorized representative, indicating that you have been informed of your rights concerning this inspection and have read both sides of this document. If you decline to sign, or signature is unavailable, ADWR must note that fact on this document and the inspection will proceed.

1. **ADWR Inspector.** This inspection is being conducted by an inspector for ADWR who must present photo identification upon entry of the inspected property, and whose name and phone number are indicated below. The ADWR inspector will be available to answer questions regarding this inspection.
   Name: NAVI MURTHY Phone: 602 771 8656
2. **Purpose of Inspection.** This inspection is being conducted by an ADWR inspector either for the purpose of ☐ issuing a permit/license, or ☒ determining compliance with permit/license requirements.
3. **Legal Authority.** This inspection is being conducted under the following legal authority: ARS 45-1212
4. **Fees.** The following inspection fees apply and will be billed separately: $260 + $246 = $506
5. **Ombudsmen.** Questions regarding due process rights described in paragraph 10 on the reverse should be directed to one of the following Ombudsmen:
   Name (ADWR): FRED BREEDLOVE Phone: 602 771 8429
   Name (Arizona): PATRICK SHANAHAN Phone: 800 872 2879

(continued on reverse)

Signature. This signature below is made by either the regulated person or the regulated person's authorized representative who has been informed of inspection and due process rights relating to this inspection and who has read both sides of this Notification.

Name (please print): John Rozanovich
Signature: [signature] Title: Environmental Consultant

Signature Declined. The regulated person or the regulated person's authorized representative indicated below was present during the inspection but declined to sign this Notification.

Name: Title:

Signature Unavailable. Neither the regulated person nor the regulated person's authorized representative was present during this inspection. The ADWR inspector contacted or attempted to contact the regulated person by the following method:

ARIZONA DEPARTMENT OF WATER RESOURCES
Agency Inspector: [signature] (SIGNATURE) Date: 9/25/08
☒ Photo identification presented.
☐ Copy provided prior to inspection to: _____ Time: _____

JANICE K. BREWER
Governor

HERBERT R. GUENTHER
Director

ARIZONA DEPARTMENT OF WATER RESOURCES

3550 North Central Avenue, Second Floor
PHOENIX, ARIZONA 85012-2105
(602) 771-8500

RECEIVED
MAR 09 2009
CHOLLA POWER PLANT

February 18, 2009

Mr. Douglas Lavarnway
Environmental Manager
Arizona Public Services Company
Cholla Power Plant
P.O. Box 188
Joseph City, Arizona 86032

Subject: **Cholla Bottom Ash Pond (09.27)**
September 2008 Dam Safety Inspection Report
Finding of No Safety Deficiency

Dear Mr. Lavarnway

Enclosed for your information and action is a copy of the Arizona Department of Water Resources (Department) report of the most recent inspection conducted by Ravi Murthy, P.E. on September 24, 2008 on the above listed dam. Along with the enclosed invoice, please remit payment in the amount of $ 246.00 to:

Peggy Beckett
Arizona Department of Water Resources
Surface Water Division
3550 North Central Avenue
Phoenix, Arizona 85012

In compliance with Arizona Revised Statutes (A.R.S.) § 41-1009, this letter notifies you that the inspection found no safety deficiencies that must be corrected. The dam safety inspection report identifies maintenance and repair action items that need to be addressed at the dam before the next scheduled inspection. Please provide the Department a schedule of when you intend to do this work and also notify us in writing when you complete the items listed below. For additional information on how to conduct these repairs, please refer to the inspection report and/or contact the Department.

The Department has reviewed the size and hazard potential classifications for the dam. The classifications have not changed from intermediate size and high hazard potential.

Printed on recycled paper. Each ton of recycled paper saves 7,000 gallons of water.

It is Department policy to review the License of Approval of each operating dam within state jurisdiction following its dam safety inspection. Based on the findings of the inspection and a review of our files, the License, issued December 11, 1998, requires no changes and remains in full force and effect.

The next inspection by the Department is tentatively scheduled for September 2009. We will contact you in advance to arrange a mutually convenient inspection date and time. Please notify the Department promptly of any unusual or alarming condition, which may occur at the dam

If you or anyone connected this dam have any questions regarding this letter, please contact Ravi Murthy, P.E. at (602) 771 8656.

Sincerely,

Michael Johnson, Ph.D., P.E.
Assistant Director
Surface Water Division

Enclosures:
1. Inspection Report & Photos
2. Invoice
3. Notification of Inspection and Due Process Rights

cc: Mr. John Mitchell, P.E. – APS Generation Engineering, Phoenix, Arizona.

ARIZONA DEPARTMENT OF WATER RESOURCES
SURFACE WATER DIVISION, DAM SAFETY SECTION
DAM SAFETY INSPECTION REPORT

Each item of the checklist should be completed. Repair is required when obvious problems are observed. Monitoring is recommended if there is a potential for a problem to occur in the future. Investigation is necessary if the reason for the observed problem is not obvious.

SID: (09.27)	DAM NAME: Bottom Ash Pond	TYPE: Earth	PURPOSE: Bottom Ash Containment
CONTACT(S): Douglas Lavarnway & John Roznovak (accompanied)		REPORT DATE: February 18, 2009	
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 24, 2008	
REVIEWED BY: Michael J. Johnson, PhD, P.E. MJJ		DATE: 2-24-09	
DESIGN DAM CREST ELEVATION: 5123.3 ft.		DESIGN SPILLWAY CREST ELEVATION: None	
DESIGN TOTAL FREEBOARD (FT): 4.7		*MEASURED TOTAL FREEBOARD (FT):* 11.8 ±	
STATUTORY DAM HEIGHT (FT): 73		STRUCTURAL HEIGHT (FT): 73	
DAM CREST LENGTH (FT): 4,200	UPSTREAM SLOPE: 3:1	DOWNSTREAM SLOPE: 2:1	
DAM CREST WIDTH (FT): 12	GPS: Lat: N34°57'07" Long: W110°17'22.7"	WATER RIGHTS: N/A	
RSRVR. AREA (AC): 80	RSRVR. STORAGE (AC-FT): 2190	MAX. STORAGE (AC-FT): 2300	
INFLOW DESIGN FLOOD / SAFE FLOOD-PASSING CAPACITY: PMF/Not Applicable (no spillway)			
RESERVOIR LEVEL DURING INSPECTION: 5111.5±		PHOTOS: Yes	Page 1 of 6

COMPLIANCE CHECKLIST

1. CONDITION SUMMARY / LICENSE / EAP / NEXT INSPECTION	NOT APPLICABLE	NO	YES	MONITOR	REPAIR	INVESTIGATE
a. Recorded downstream hazard: **High** Should hazard be revised? **No**		X				
b. If High Hazard, estimate downstream persons-at-risk (PAR): <30 Is there a significant increase since the last inspection? **No**		X				
c. Recorded size: **Intermediate** Should size be revised? **No**		X				
d. Any safety deficiencies? Describe: **None**		X				
e. Any Statute or Rule violations? Describe and list required action: **AAC R12-15-1205. See Recommendations**			X	X	X	
f. Safe storage level on License: **5117.8** Should level be revised? **No**		X				
g. Any License violations? Describe and list required action:		X				
h. Date of current License: **December 11, 1998** Should new License be issued? **No**		X				
i. Date of last Emergency Action Plan revision: **November 2006** Should EAP be revised? **Should be updated**			X			
j. Any Agency Actions? **None** Describe and list required action:		X				
k. Normal inspection frequency: **Annual** Should inspection frequency be revised? **No**		X				
l. Recommended date for next inspection: **September 2008**						

MONITORING CHECKLIST

2. INSTRUMENTATION AND MONITORING						
a. Describe: **Piezometers in embankment and foundation. Settlement monuments on crest.**						
b. Any repair or replacement required? Describe:		X				
c. Date of last monitoring report: **June 2006** Should new readings be taken and new report provided?			X			

DAM INSPECTION REPORT	Page 2 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						

DAM EMBANKMENT CHECKLIST

	N/A	NO	YES	MON.	REP.	INV.
3. DAM CREST						
a. Settlements, slides, depressions?		X				
b. Misalignment?		X				
c. Longitudinal/Transverse cracking? **Longitudinal and transverse cracking; under investigation See photos 8,9,10**			X			X
d. Animal burrows? **Minor**			X	X	X	
e. Adverse Vegetation? **Minor. Should be cleared during routine maintenance**			X	X	X	
f. Erosion?		X				
4. UPSTREAM SLOPE						
a. Erosion?		X				
b. Inadequate ground cover?		X				
c. Adverse vegetation? **Small salt cedars and other vegetation. Should be removed during routine maintenance**			X	X	X	
d. Longitudinal/Transverse cracking? **Unable to observe because of riprap cover**	X					
e. Inadequate riprap?		X				
f. Stone deterioration? **Generally in good condition, but occasional stones have deteriorated.**			X	X		
g. Settlements, slides, depressions, bulges?		X				
h. Animal burrows?		X				
5. DOWNSTREAM SLOPE						
a. Erosion? **Raised section has no riprap and shows minor erosion rills. Remainder of slope has riprap**			X	X		
b. Inadequate ground cover?		X				
c. Adverse vegetation? **Moderate vegetation at several locations. Should be cleared during maintenance**			X		X	
d. Longitudinal/Transverse cracking? **Unable to observe due to riprap**	X					
e. Inadequate riprap?		X				
f. Stone deterioration?		X				
g. Settlements, slides, depressions, bulges?		X				
h. Soft spots or boggy areas? **Right groin area near seepage weir**			X	X		
i. Movement at or beyond toe?		X				
j. Animal burrows? **Minor**			X	X		
6. ABUTMENT CONTACTS						
a. Erosion?		X				
b. Differential movement?		X				
c. Cracks?		X				
d. Settlements, slides, depressions, bulges?		X				
e. Seepage? Est. Left ___ gpm; Est. Right ___ gpm **Weir near downstream (See Photo 14), right groin showed a flow. Seepage conditions difficult to observe due to thick vegetation (See Photo 13). Vegetation should be cleared, and a formal measurement weir/system should be installed.**			X	X	X	
f. Animal burrows?		X				
7. SEEPAGE/PIPING CONTROL DESIGN FEATURE(S)						
a. Describe: **None**						
b. Internal drains flowing? Est. Left ___ gpm; Est. Right ___ gpm						
c. Seepage at or beyond toe? Estimated ___ gpm **Seepage beyond downstream toe collected in drain and pumped back to impoundment**						
e. If so, does seepage contain fines?						

DAM INSPECTION REPORT	Page 3 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						
d. Evidence of sand boils at or beyond toe?				X				

OUTLET WORKS CHECKLIST

8. APPROACH CHANNEL						
a. Describe: **None**						
b. Eroding or backcutting?	X					
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
9. INLET STRUCTURE						
a. Describe: **None**						
b. Seepage into structure?	X					
c. Debris or obstructions?	X					
d. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
e. *If metal*, do surfaces show:						
1. Corrosion?	X					
2. Protective coating deficient?	X					
3. Misalignment or split seams?	X					
f. Do the joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
g. Are the trash racks:						
1. Broken or bent?.	X					
2. Corroded or rusted?	X					
3. Obstructed?	X					
h. Operator, gates and valves:						
1. Describe:						
2. Date(s) last operated:						
3. Broken or bent?	X					
4. Corroded or rusted?	X					
5. Leaking?	X					
6. Not seated properly?	X					
7. Not operational?	X					
8. Not periodically maintained?	X					
10. CONDUIT						

DAM INSPECTION REPORT	Page 4 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						
a. Describe: None								
b. Seepage into conduit?			X					
c. Debris present?			X					
d. *If concrete*, do surfaces show:								
1. Spalling or scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
e. *If metal*, do surfaces show:								
1. Corrosion?			X					
2. Protective coating deficient?			X					
3. Misalignment or split seams?			X					
f. Do the joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
11. STILLING BASIN / ENERGY DISSIPATOR								
a. Describe: None								
b. Do surfaces show:								
1. Spalling or Scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
12. OUTLET CHANNEL								
a. Describe: None								
b. Eroding or backcutting?			X					
c. Sloughing?			X					
d. Obstructions or restrictions?			X					
e. Poorly riprapped?			X					
f. Tailwater elevation and flow condition:								

13. ENTRANCE CHANNEL

DAM INSPECTION REPORT	Page 5 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						

	N/A	NO	YES	MON.	REP.	INV.
a. Describe None						
b. Eroding or backcutting?	X					
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
14. CONTROL SECTION						
a. Describe: None						
b. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
c. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
f. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Is crest eroding?	X					
g. Is the control structure (i.e. weir, sill, etc.) in poor condition?	X					
15. DISCHARGE CHANNEL						
a. Describe: None						
b. Obstructions or restrictions?	X					
c. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
d. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
e. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Poorly protected w/ vegetation/riprap?	X					
16. STILLING BASIN / ENERGY DISSIPATOR						
a. Describe: None						
b. Do surfaces show:						

DAM INSPECTION REPORT	Page 6 of 6	SID: 09.27	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept 24, 2008						
1. Spalling or Scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
17. OUTLET CHANNEL								
a. Eroding or backcutting?			X					
b. Sloughing?			X					
c. Obstructions or restrictions?			X					

RESERVOIR CHECKLIST

18. RESERVOIR						
a. High water marks?		X				
b. Erosion/Slides into pool area?		X				
c. Sediment accumulation? Bottom Ash			X			
d. Floating debris present?		X				
e. Depressions, sinkholes or vortices?		X				
f. Low ridges/saddles allowing overflow?		X				
g. Structures below dam crest elevation? Discharge pipes. See Photo 6			X			

ADDITIONAL COMMENTS AND RECOMMENDATIONS:

1. The Department has received your report documenting the investigation of the transverse cracking on the dam crest. We will contact you with questions and comments once we complete our review.
2. Vegetation on the downstream face, at the downstream toe, and in the area of the right, downstream groin should be cleared.
3. The seepage measurement weir near the right downstream groin of the dam is not useable and should be replaced with a standard weir box and weir plate, or an approved alternate system for measurement of rates of seepage.
4. The Emergency Action Plan should be updated to meet current ADWR requirements.

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

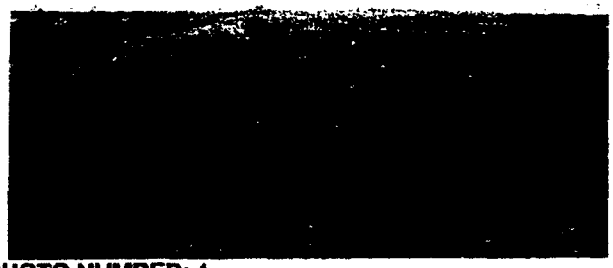

PHOTO NUMBER: 1
DESCRIPTION: Partial view of crest and downstream slope from the right abutment.

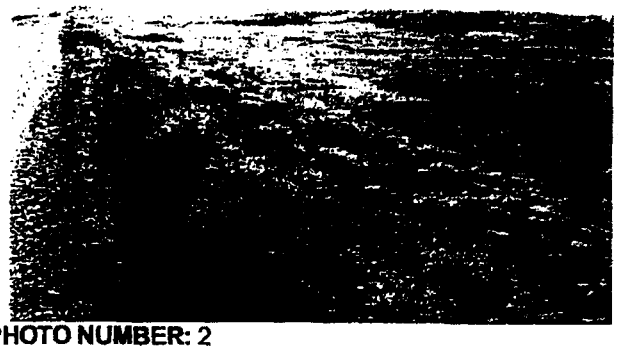

PHOTO NUMBER: 2
DESCRIPTION: Partial view of the downstream slope from the right abutment.

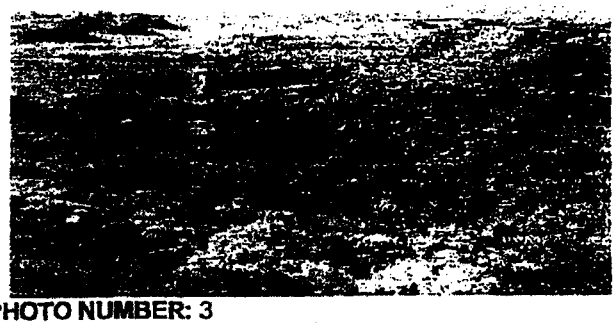

PHOTO NUMBER: 3
DESCRIPTION: Downstream view from the crest of the dam

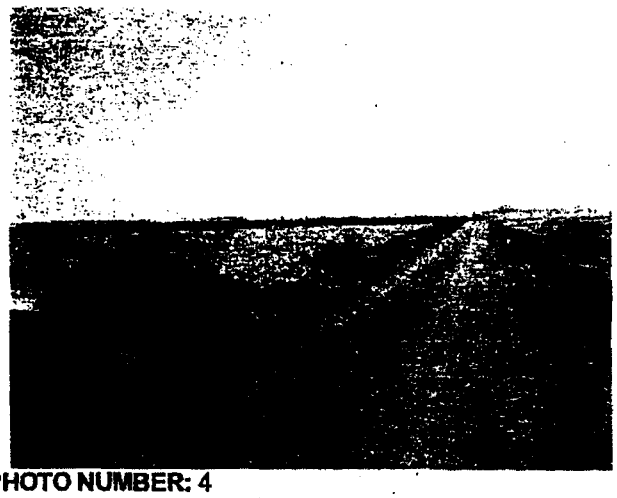

PHOTO NUMBER: 4
DESCRIPTION: Partial view of the crest and the upstream impoundment from the crest of the dam

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

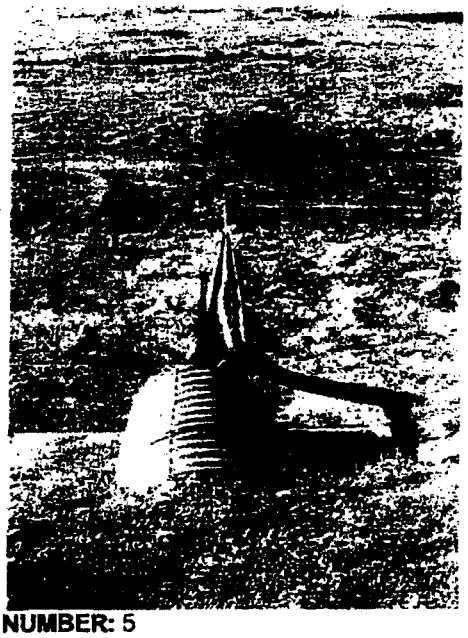

PHOTO NUMBER: 5
DESCRIPTION: Intake line, downstream segment.

PHOTO NUMBER: 6
DESCRIPTION: Intake line, upstream segment

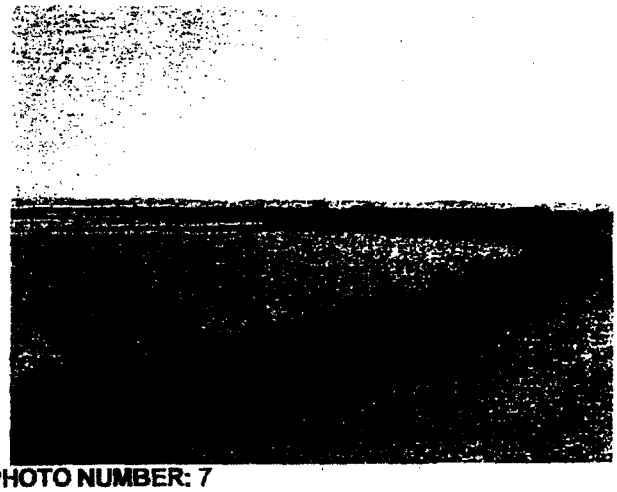

PHOTO NUMBER: 7
DESCRIPTION: View of the impoundment

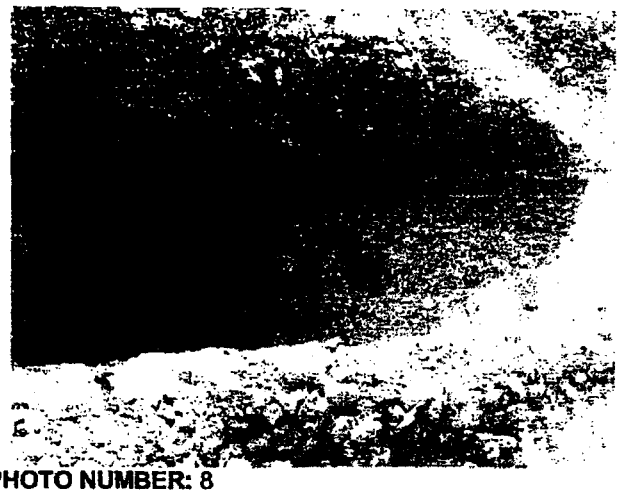

PHOTO NUMBER: 8
DESCRIPTION: Longitudinal crack in trench on dam crest

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

PHOTO NUMBER: 9
DESCRIPTION: Transverse crack in wall of trench excavated in dam crest.

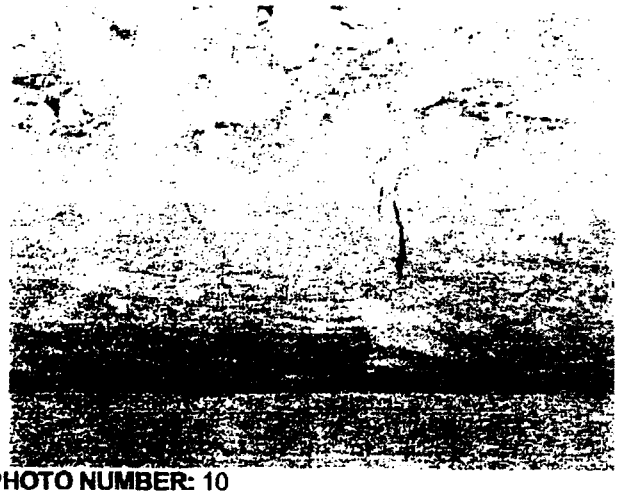

PHOTO NUMBER: 10
DESCRIPTION: Transverse crack in wall of trench excavated in dam crest.

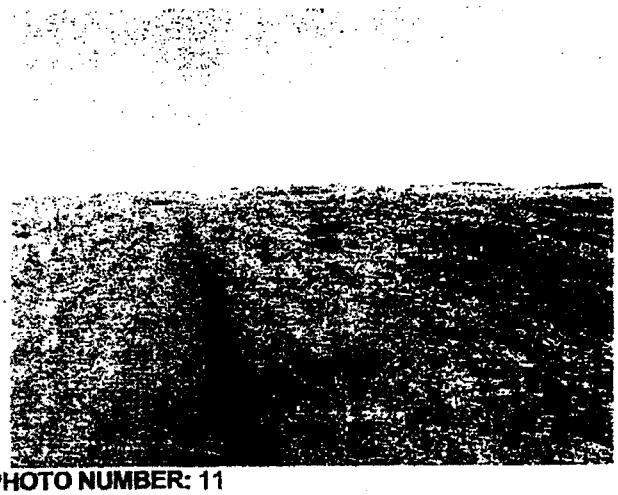

PHOTO NUMBER: 11
DESCRIPTION: View of the dam crest

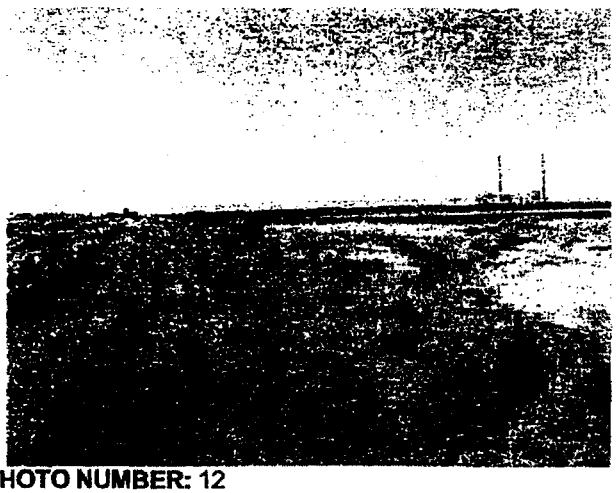

PHOTO NUMBER: 12
DESCRIPTION: Partial view of the dam crest and impoundment

Cholla Bottom Ash Pond (09.27)

Safety Inspection Conducted on September 24,2008

Photographer: Ravi Murthy, P.E.

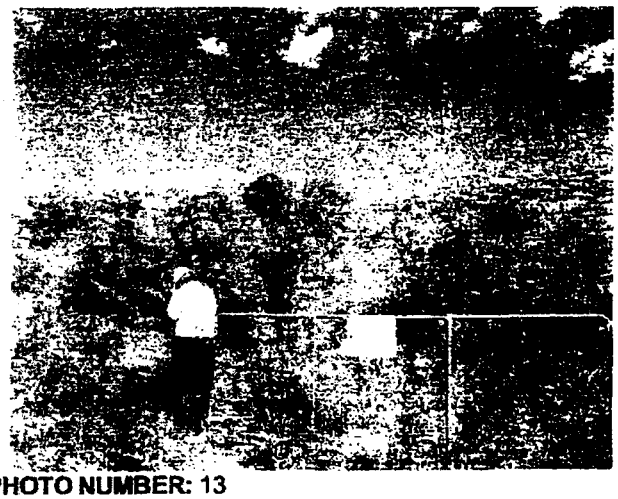

PHOTO NUMBER: 13
DESCRIPTION: Thick vegetation in the right downstream groin and downstream toe

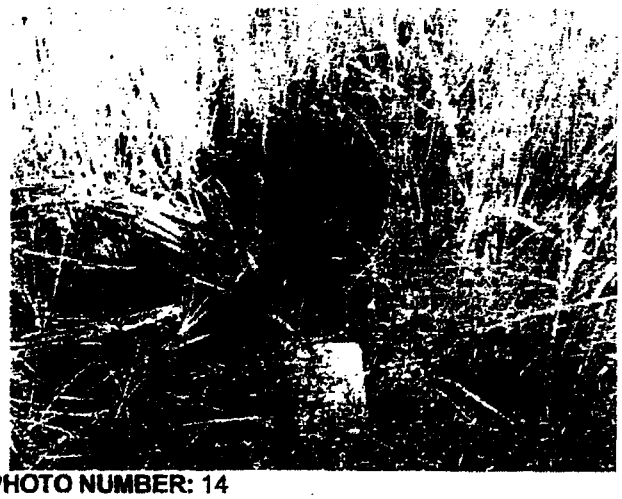

PHOTO NUMBER: 14
DESCRIPTION: Wooden tie used as seepage flow measurement weir

Well Registration No. _____ Application/Right No. _____ Permit/License No. _____
Regulated Person: _____ Address: _____
_____ Phone: _____

ARIZONA DEPARTMENT OF WATER RESOURCES
500 North Third Street, Phoenix, Arizona 85004
NOTIFICATION OF INSPECTION AND DUE PROCESS RIGHTS

In compliance with A.R.S. § 41-1009, this document is being provided to you by the Arizona Department of Water Resources (ADWR) to inform you of your rights concerning this inspection of the following described property:
CHOLLA BOTTOM ASH + CHOLLA FLYASH DAMS
on the following date(s): SEPT 24, 25 2008
ADWR must present this document for your signature, or the signature of an authorized representative, indicating that you have been informed of your rights concerning this inspection and have read both sides of this document. If you decline to sign, or signature is unavailable, ADWR must note that fact on this document and the inspection will proceed.

1. **ADWR Inspector.** This inspection is being conducted by an inspector for ADWR who must present photo identification upon entry of the inspected property, and whose name and phone number are indicated below. The ADWR inspector will be available to answer questions regarding this inspection.
   Name: KAYE HURTIN Phone: [illegible]
2. **Purpose of Inspection.** This inspection is being conducted by an ADWR inspector either for the purpose of ☐ issuing a permit/license, or ☒ determining compliance with permit/license requirements.
3. **Legal Authority.** This inspection is being conducted under the following legal authority: [illegible]
4. **Fees.** The following inspection fees apply and will be billed separately: [illegible]
5. **Ombudsmen.** Questions regarding due process rights described in paragraph 10 on the reverse should be directed to one of the following Ombudsmen:

Name (ADWR): [illegible] Phone: [illegible]
Name (Arizona): [illegible] Phone: [illegible]

(continued on reverse)

Signature. This signature below is made by either the regulated person or the regulated person's authorized representative who has been informed of inspection and due process rights relating to this inspection and who has read both sides of this Notification.

Name (please print): [illegible]
Signature: [illegible] Title: [illegible]

Signature Declined. The regulated person or the regulated person's authorized representative indicated below was present during the inspection but declined to sign this Notification.

Name: Title:

Signature Unavailable. Neither the regulated person nor the regulated person's authorized representative was present during this inspection. The ADWR inspector contacted or attempted to contact the regulated person by the following method:

ARIZONA DEPARTMENT OF WATER RESOURCES

Agency Inspector: _____ (SIGNATURE) Date: [illegible]
☐ Photo identification presented.
☐ Copy provided prior to inspection to: _____ Time: _____

Well Registration No. _____ Application/Right No. _____ Permit/License No. _____
Regulated Person: _____ Address: _____
_____ Phone: _____

ARIZONA DEPARTMENT OF WATER RESOURCES
500 North Third Street, Phoenix, Arizona 85004
NOTIFICATION OF INSPECTION AND DUE PROCESS RIGHTS

In compliance with A.R.S. § 41-1009, this document is being provided to you by the Arizona Department of Water Resources (ADWR) to inform you of your rights concerning this inspection of the following described property:
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on the following date(s): SEPT 24, 25 2008
ADWR must present this document for your signature, or the signature of an authorized representative, indicating that you have been informed of your rights concerning this inspection and have read both sides of this document. If you decline to sign, or signature is unavailable, ADWR must note that fact on this document and the inspection will proceed.

1. **ADWR Inspector.** This inspection is being conducted by an inspector for ADWR who must present photo identification upon entry of the inspected property, and whose name and phone number are indicated below. The ADWR inspector will be available to answer questions regarding this inspection.
   Name: KANI MURTHY Phone: 602 771 8656
2. **Purpose of Inspection.** This inspection is being conducted by an ADWR inspector either for the purpose of ☐ issuing a permit/license, or ☑ determining compliance with permit/license requirements.
3. **Legal Authority.** This inspection is being conducted under the following legal authority: ARS 45-1212
4. **Fees.** The following inspection fees apply and will be billed separately: $260 + $246 = $506
5. **Ombudsmen.** Questions regarding due process rights described in paragraph 10 on the reverse should be directed to one of the following Ombudsmen:

Name (ADWR): FRED BREEDLOVE Phone: 602 771 8039
Name (Arizona): PATRICK SHANAHAN Phone: 800 872 2879

(continued on reverse)

Signature. This signature below is made by either the regulated person or the regulated person's authorized representative who has been informed of inspection and due process rights relating to this inspection and who has read both sides of this Notification.

Name (please print): John Rozanowski
Signature: [signature] Title: Environmental Consultant

Signature Declined. The regulated person or the regulated person's authorized representative indicated below was present during the inspection but declined to sign this Notification.

Name: Title:

Signature Unavailable. Neither the regulated person nor the regulated person's authorized representative was present during this inspection. The ADWR inspector contacted or attempted to contact the regulated person by the following method:

ARIZONA DEPARTMENT OF WATER RESOURCES

Agency Inspector: [signature] (SIGNATURE) Date: 9/24/08
☑ Photo identification presented.
☐ Copy provided prior to inspection to: _____ Time: _____

JANICE K. BREWER
Governor

HERBERT R. GUENTHER
Director

ARIZONA DEPARTMENT OF WATER RESOURCES

3550 North Central Avenue, Second Floor
PHOENIX, ARIZONA 85012-2105
(602) 771-8500

RECEIVED
MAR 09 2009
CHOLLA POWER PLANT

February 18, 2009

Mr. Douglas Lavarnway
Environmental Manager
Arizona Public Services Company
Cholla Power Plant
P.O. Box 188
Joseph City, Arizona 86032

Subject: **Cholla Flyash Pond (09.28)**
September 2008 Dam Safety Inspection Report
Finding of No Safety Deficiency

Dear Mr. Lavarnway

Enclosed for your information and action is a copy of the Arizona Department of Water Resources (Department) report of the most recent inspection conducted by Ravi Murthy, P.E. on September 25, 2008 on the above listed dam. Along with the enclosed invoice, please remit payment in the amount of $ 260.00 to:

Peggy Beckett
Arizona Department of Water Resources
Surface Water Division
3550 North Central Avenue
Phoenix, Arizona 85012

In compliance with Arizona Revised Statutes (A.R.S.) § 41-1009, this letter notifies you that the inspection found no safety deficiencies that must be corrected. The dam safety inspection report identifies maintenance and repair action items that need to be addressed at the dam before the next scheduled inspection. Please provide the Department a schedule of when you intend to do this work and also notify us in writing when you complete the items listed below. For additional information on how to conduct these repairs, please refer to the inspection report and/or contact the Department.

The Department has reviewed the size and hazard potential classifications for the dam. The classifications have not changed from intermediate size and high hazard potential.

Printed on recycled paper. Each ton of recycled paper saves 7,000 gallons of water.

It is Department policy to review the License of Approval of each operating dam within state jurisdiction following its dam safety inspection. Based on the findings of the inspection and a review of our files, the License, issued October 21, 1986, requires no changes and remains in full force and effect.

The next inspection by the Department is tentatively scheduled for September 2009. We will contact you in advance to arrange a mutually convenient inspection date and time. Please notify the Department promptly of any unusual or alarming condition, which may occur at the dam

If you or anyone connected this dam have any questions regarding this letter, please contact Ravi Murthy, P.E. at (602) 771 8656.

Sincerely,

Michael Johnson, Ph.D., P.E.
Assistant Director
Surface Water Division

Enclosures:
1. Inspection Report & Photos
2. Invoice
3. Notification of Inspection and Due Process Rights

cc: Mr. John Mitchell, P.E. – APS Generation Engineering, Phoenix, Arizona.

ARIZONA DEPARTMENT OF WATER RESOURCES
SURFACE WATER DIVISION, DAM SAFETY SECTION
DAM SAFETY INSPECTION REPORT

Each item of the checklist should be completed. Repair is required when obvious problems are observed. Monitoring is recommended if there is a potential for a problem to occur in the future. Investigation is necessary if the reason for the observed problem is not obvious.

SID: (09.28)	DAM NAME: Cholla Flyash Dam	TYPE: Earthfill	PURPOSE: Flyash disposal
CONTACT(S): Douglas Lavarnway & John Roznovak (accompanied) – APS Cholla Plant		REPORT DATE: February 18, 2009	
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: September 25, 2008	
REVIEWED BY: Michael J. Johnson, PhD, P.E.		DATE: 2-24-09	
DESIGN DAM CREST ELEVATION: 5120 ft		DESIGN SPILLWAY CREST ELEVATION: No Emergency Spillway	
DESIGN TOTAL FREEBOARD (FT): 6		*MEASURED TOTAL FREEBOARD (FT): 26.4±*	
STATUTORY DAM HEIGHT (FT): 80		STRUCTURAL HEIGHT (FT): 80	
DAM CREST LENGTH (FT): 4,565	UPSTREAM SLOPE: 3:1	DOWNSTREAM SLOPE: 2:1	
DAM CREST WIDTH (FT): 24	GPS: Lat.: 34°54'49" Long.: -110°16'06"	WATER RIGHTS: N/A	
RSRVR. AREA (AC): 420	RSRVR. STORAGE (AC-FT): 15,400	MAX. STORAGE (AC-FT): 18,000	
INFLOW DESIGN FLOOD / SAFE FLOOD-PASSING CAPACITY: PMF/Not Applicable (PMF fully contained)			
RESERVOIR LEVEL DURING INSPECTION: 5093.6±		PHOTOS: Yes	Page 1 of 6

COMPLIANCE CHECKLIST

1. CONDITION SUMMARY / LICENSE / EAP / NEXT INSPECTION	NOT APPLICABLE	NO	YES	MONITOR	REPAIR	INVESTIGATE
a. Recorded downstream hazard: **High** Should hazard be revised? **No**		X				
b. If High Hazard, estimate downstream persons-at-risk (PAR): **30 - 300** Is there a significant increase since the last inspection? **No**		X				
c. Recorded size: **Intermediate** Should size be revised? **No**		X				
d. Any safety deficiencies? Describe: **None**		X				
e. Any Statute or Rule violations? Describe and list required action: **None**		X				
f. Safe storage level on License: **5114.0 ft.** Should level be revised? **No**		X				
g. Any License violations? Describe and list required action: **None**		X				
h. Date of current License: **10/21/1986** Should new License be issued? **No**		X				
i. Date of last Emergency Action Plan revision: **November 2006** Should EAP be revised? **Update**			X			
j. Any Agency Actions? **None** Describe and list required action:		X				
k. Normal inspection frequency: **Annual** Should inspection frequency be revised? **No**		X				
l. Recommended date for next inspection: **September 2009**						

MONITORING CHECKLIST

2. INSTRUMENTATION AND MONITORING						
a. Describe: **Piezometers in the core, shell and foundation. Settlement monuments on embankment crest. Flow measurement devices at each downstream sump to estimate seepage rates, and on return lines to the impoundment.**						
b. Any repair or replacement required? Describe: **Past inspections identified roots that invaded some of the downstream seepage collection drains and sumps. The systems should be checked and the roots should be removed periodically.**			X	X	X	
c. Date of last monitoring report: **June 2006** Should new readings be taken and new report provided?						

DAM INSPECTION REPORT	Page 2 of 6	SID: 09.28	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 25, 2008						

DAM EMBANKMENT CHECKLIST

	N/A	NO	YES	MON.	REP.	INV.
***3. DAM CREST* (See Photos 1, 2 and 10)**						
a. Settlements, slides, depressions?		X				
b. Misalignment?		X				
c. Longitudinal/Transverse cracking? **Embankment known to have transverse cracks. Flyash beach built out as mitigation measure. Continue to monitor for unusual conditions.**			X	X		
d. Animal burrows? **Minor burrows along the edges of the crest**			X	X		
e. Adverse Vegetation?		X				
f. Erosion?		X				
***4. UPSTREAM SLOPE* (See Photo 5)**						
a. Erosion?		X				
b. Inadequate ground cover?		X				
c. Adverse vegetation? **Minor. Should be cleared during routine maintenance**			X		X	
d. Longitudinal/Transverse cracking? **Unable to observe because of impoundment and riprap on upstream slope**	X					
e. Inadequate riprap?		X				
f. Stone deterioration? **Overall good condition, with isolated stones deteriorated**			X	X		
g. Settlements, slides, depressions, bulges?		X				
h. Animal burrows? **Minor, near crest**			X	X		
***5. DOWNSTREAM SLOPE* (See Photos 1,4, and 6)**						
a. Erosion?		X				
b. Inadequate ground cover?		X				
c. Adverse vegetation?		X				
d. Longitudinal/Transverse cracking?		X				
e. Inadequate riprap?		X				
f. Stone deterioration? **Overall good condition, with isolated stones deteriorated**			X	X		
g. Settlements, slides, depressions, bulges?		X				
h. Soft spots or boggy areas?		X				
i. Movement at or beyond toe?		X				
j. Animal burrows?		X				
***6. ABUTMENT CONTACTS* (See Photo 11)**						
a. Erosion?		X				
b. Differential movement?		X				
c. Cracks?		X				
d. Settlements, slides, depressions, bulges?		X				
e. Seepage? Est. Left ___ gpm; Est. Right ___ gpm **Areas of historic seepage and staining along right abutment/downstream groin**			X	X		
f. Animal burrows? **Minor**			X	X		
7. SEEPAGE/PIPING CONTROL DESIGN FEATURE(S)						
a. Describe: **Flyash beach along upstream dam face (See Photos 2,3,5 &7) keeps free water pond away from the face of the dam. Downstream seepage intercept and pump back systems in place, primarily for fluid capture and less for dam safety reasons.**						
b. Internal drains flowing? Est. Left ___ gpm; Est. Right ___ gpm	X					
c. Seepage at or beyond toe? Estimated ___ gpm			X	X		
e. If so, does seepage contain fines?		X				
d. Evidence of sand boils at or beyond toe?						

DAM INSPECTION REPORT	Page 3 of 6	SID: 09-28	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 25, 2008						

OUTLET WORKS CHECKLIST

	N/A	NO	YES	MON.	REP.	INV.
8. APPROACH CHANNEL **None**						
a. Describe:						
b. Eroding or backcutting?	X					
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
9. INLET STRUCTURE **None**						
a. Describe:						
b. Seepage into structure?	X					
c. Debris or obstructions?	X					
d. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
e. *If metal*, do surfaces show:						
1. Corrosion?	X					
2. Protective coating deficient?	X					
3. Misalignment or split seams?	X					
f. Do the joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
g. Are the trash racks:						
1. Broken or bent?.	X					
2. Corroded or rusted?	X					
3. Obstructed?	X					
h. Operator, gates and valves:						
1. Describe:						
2. Date(s) last operated:						
3. Broken or bent?	X					
4. Corroded or rusted?	X					
5. Leaking?	X					
6. Not seated properly?	X					
7. Not operational?	X					
8. Not periodically maintained?	X					
10. CONDUIT **None**						
a. Describe:						
b. Seepage into conduit?	X					

DAM INSPECTION REPORT	Page 4 of 6	SID: 09.28	N/A	NO.	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 25, 2008						
c. Debris present?			X					
d. *If concrete,* do surfaces show:								
1. Spalling or scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
e. *If metal,* do surfaces show:								
1. Corrosion?			X					
2. Protective coating deficient?			X					
3. Misalignment or split seams?			X					
f. Do the joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
11. STILLING BASIN / ENERGY DISSIPATOR **None**								
a. Describe:								
b. Do surfaces show:								
1. Spalling or Scaling?			X					
2. Cracking?			X					
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
12. OUTLET CHANNEL **None**								
a. Describe:								
b. Eroding or backcutting?			X					
c. Sloughing?			X					
d. Obstructions or restrictions?			X					
e. Poorly riprapped?			X					
f. Tailwater elevation and flow condition:								

EMERGENCY SPILLWAY CHECKLIST

13. ENTRANCE CHANNEL **None**							
a. Describe							
b. Eroding or backcutting?		X					

DAM INSPECTION REPORT	Page 5 of 6	SID: 09.28	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 25, 2008						

	N/A	NO	YES	MON.	REP.	INV.
c. Sloughing?	X					
d. Restricted by vegetation?	X					
e. Obstructed with debris?	X					
f. Silted in?	X					
14. CONTROL SECTION **None**						
a. Describe:						
b. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
c. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
f. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Is crest eroding?	X					
g. Is the control structure (i.e. weir, sill, etc.) in poor condition?	X					
15. DISCHARGE CHANNEL **None**						
a. Describe:						
b. Obstructions or restrictions?	X					
c. *If concrete*, do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					
3. Erosion?	X					
4. Exposed reinforcement?	X					
d. *If concrete*, do joints show:						
1. Displacement or offset?	X					
2. Loss of joint material?	X					
3. Leakage?	X					
e. If spillway is *unlined*:						
1. Are slopes eroding?	X					
2. Are slopes sloughing?	X					
3. Poorly protected w/ vegetation/riprap?	X					
16. STILLING BASIN / ENERGY DISSIPATOR **None**						
a. Describe:						
b. Do surfaces show:						
1. Spalling or Scaling?	X					
2. Cracking?	X					

DAM INSPECTION REPORT	Page 6 of 6	SID: 09.28	N/A	NO	YES	MON.	REP.	INV.
INSPECTED BY: Ravi Murthy, P.E.		INSPECTION DATE: Sept. 25, 2008						
3. Erosion?			X					
4. Exposed reinforcement?			X					
c. Do joints show:								
1. Displacement or offset?			X					
2. Loss of joint material?			X					
3. Leakage?			X					
d. Do energy dissipaters show:								
1. Signs of deterioration?			X					
2. Covered with debris?			X					
3. Signs of inadequacy?			X					
17. OUTLET CHANNEL **None**								
a. Eroding or backcutting?			X					
b. Sloughing?			X					
c. Obstructions or restrictions?			X					

RESERVOIR CHECKLIST

18. RESERVOIR						
a. High water marks?		X				
b. Erosion/Slides into pool area?		X				
c. Sediment accumulation? **Flyash**			X			
d. Floating debris present?		X				
e. Depressions, sinkholes or vortices?		X				
f. Low ridges/saddles allowing overflow?		X				
g. Structures below dam crest elevation?		X				

ADDITIONAL COMMENTS AND RECOMMENDATIONS:

1. We understand that the saddle dike was breached. Please re-build the dike, or provide us with an assessment that demonstrates that the dike is not required. We first made this request following our inspection in 2006, and APS has not yet complied.
2. Vegetation on the dam should be cleared periodically during routine maintenance activities.
3. Evidence of some rodent activity was observed on the dam. This should be monitored and control measures should be implemented if needed.

Cholla Flyash Dam (09.28)

Safety Inspection Conducted on September 25, 2008

Photographer: Ravi Murthy, P.E.

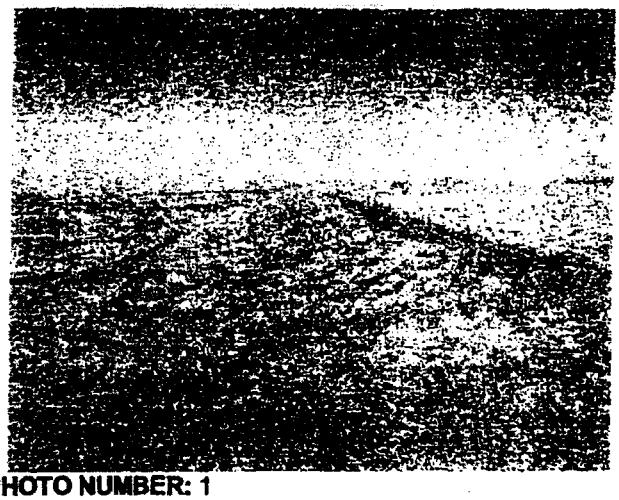

PHOTO NUMBER: 1
DESCRIPTION: Partial view of the crest, downstream slope, and impoundment from the left abutment of the dam.

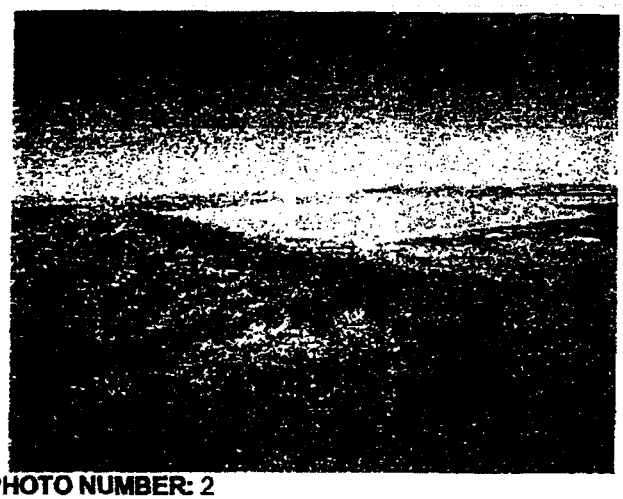

PHOTO NUMBER: 2
DESCRIPTION: Partial view of the crest and impoundment from the left abutment.

PHOTO NUMBER: 3
DESCRIPTION: View of the flyash beach and free water pond from the left abutment

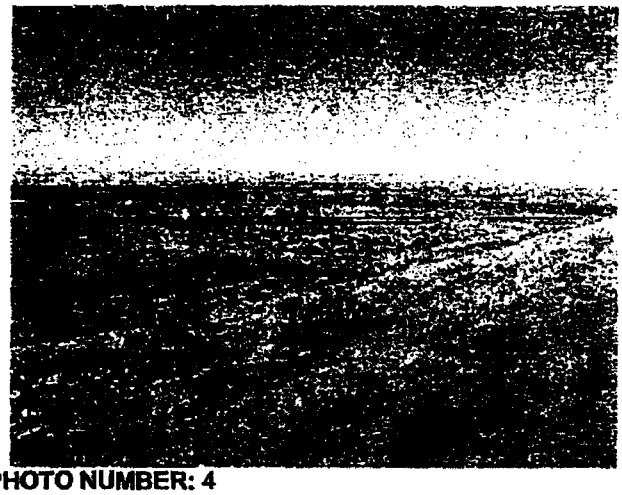

PHOTO NUMBER: 4
DESCRIPTION: Downstream view from the left abutment.

Cholla Flyash Dam (09.28)

Safety Inspection Conducted on September 25, 2008

Photographer: Ravi Murthy, P.E.

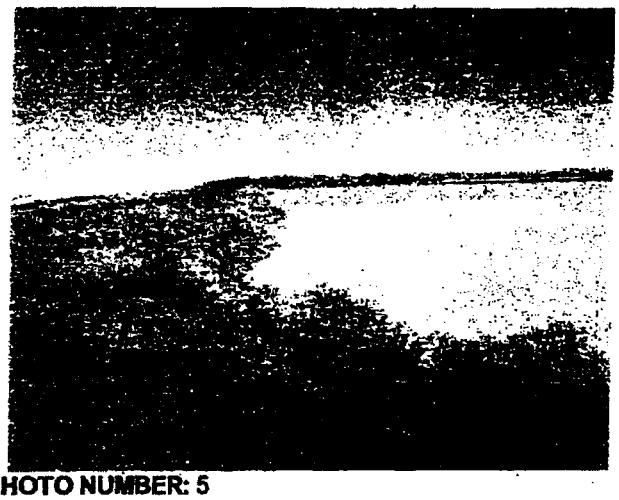

PHOTO NUMBER: 5
DESCRIPTION: Flyash beach from the crest of the dam

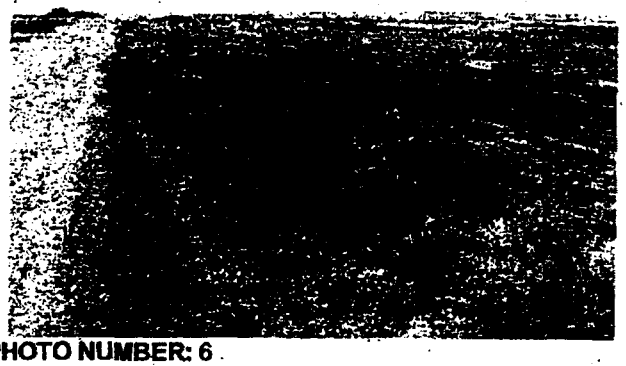

PHOTO NUMBER: 6
DESCRIPTION: View of the crest and downstream from the crest of the dam

PHOTO NUMBER: 7
DESCRIPTION: Discharge pipe, upstream

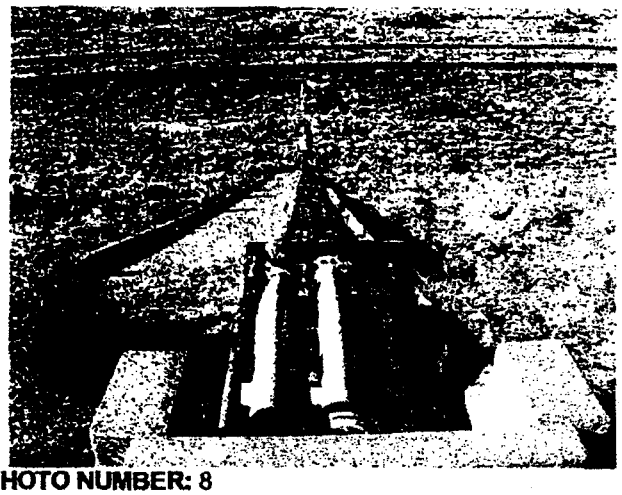

PHOTO NUMBER: 8
DESCRIPTION: Discharge pipe, downstream

Cholla Flyash Dam (09.28)

Safety Inspection Conducted on September 25, 2008

Photographer: Ravi Murthy, P.E.

PHOTO NUMBER: 9
DESCRIPTION: Area of historic seepage downstream from the dam; view from the crest

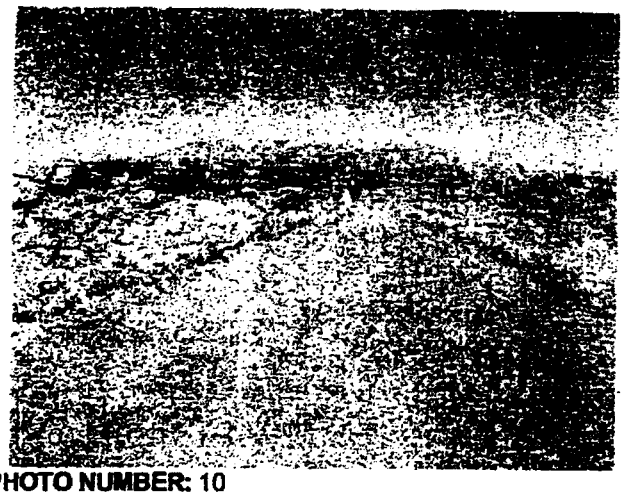

PHOTO NUMBER: 10
DESCRIPTION: Crest of the dam and right abutment

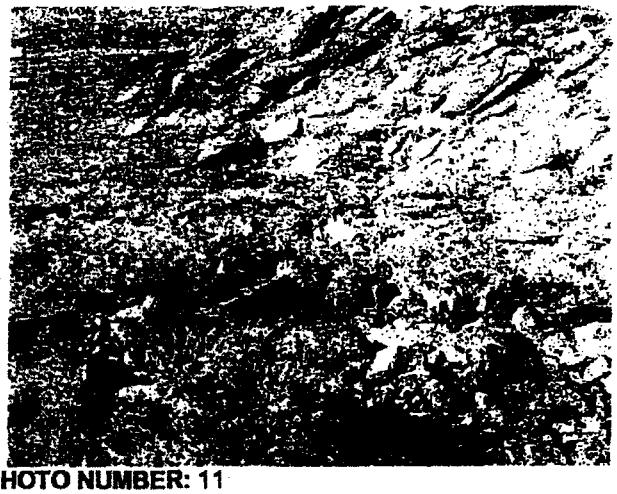

PHOTO NUMBER: 11
DESCRIPTION: Right downstream groin; view from the right abutment

PHOTO NUMBER: 12
DESCRIPTION:

Cholla Flyash Dam (09.28)

Safety Inspection Conducted on September 25, 2008

Photographer: Ravi Murthy, P.E.

PHOTO NUMBER: 13
DESCRIPTION: Area of historic seepage downstream from the dam

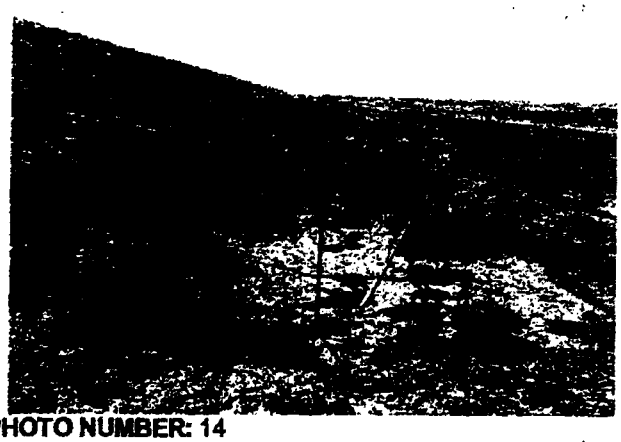

PHOTO NUMBER: 14
DESCRIPTION: Area of historic seepage just beyond the downstream toe of the dam

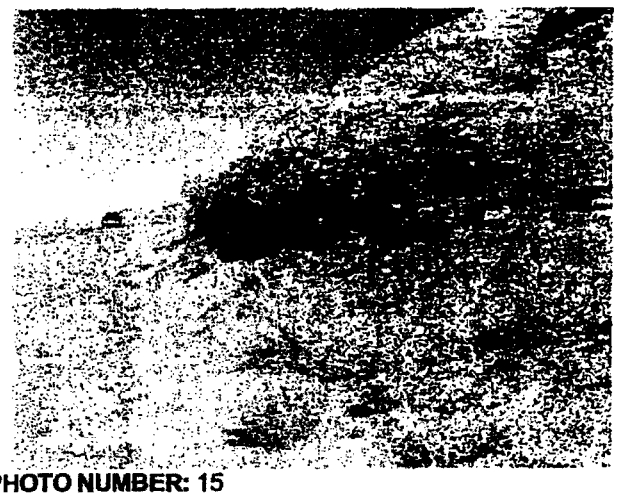

PHOTO NUMBER: 15
DESCRIPTION: Area of seepage along I-40

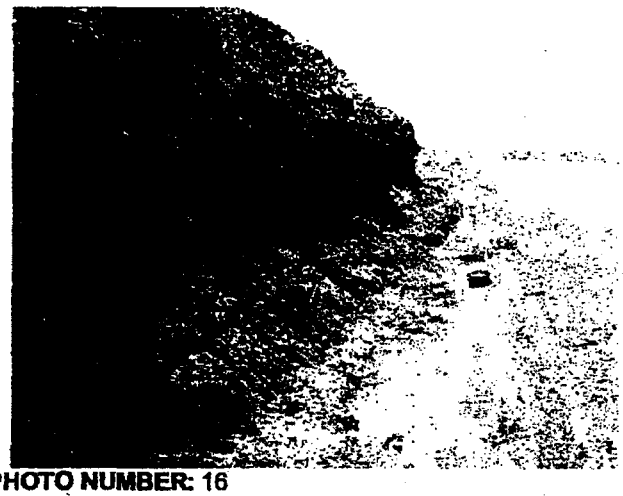

PHOTO NUMBER: 16
DESCRIPTION: Area of seepage along I-40

APS Responses to Questions Raised at Hearing

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Does APS have any analysis of what the 2011 PSA will be?*(2171:1)*

Response: Please see Table A in Attachment A to APS's Response to Commissioner Newman's letter of September 17, 2009.

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Please provide the Commission a list of utilities who issued equity from late 2008 to present. *(2423:16-25)*

Response: Below is a table with the requested information:

Pricing Date	Issuer
11/06/08	Pepco Holdings Inc
12/03/08	Hawaiian Electric
12/31/08	SCANA
01/07/09	Progress Energy
03/05/09	Portland General Electric
03/16/09	Northeast Utilities
04/01/09	American Electric Power
05/12/09	Great Plains Energy
05/20/09	UIL Holdings Corp.
09/09/09	Ameren Corporation
09/10/09	Centerpoint Energy

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Will APS please provide the Commission with an analysis of what the bill impact will be to customers with the implementation of the projects included in the Settlement (i.e. the wind project, the utility scale solar project, the transmission line, the energy efficiency provisions, etc.)? *(2172:13-2177:10)*

Response: Attached is the requested analysis. Please note that APS used a range of cost estimate for DSM after 2010 because there is such a wide range of opinion as to what they will turn out to be. Also note that APS has modeled the total impact of projected RES and DSM program costs (but not the impact of unrecovered fixed costs) because it is difficult to isolate the incremental impact (if any) of specific projects. As to the future rate impact of the pension cost deferrals, accelerated Palo Verde depreciation reset and Schedule 3 as revenues, APS has calculated the revenue impact assuming maximum pension deferrals, Palo Verde reset at the earliest possible date per the Settlement, and a return to CIAC treatment of Schedule 3 proceeds after 2012. There is no way to predict how the Commission will spread that revenue impact, so APS did not attempt to model these dollars in the attached bill analysis. Suffice it to say, these three items would increase revenue requirements and potentially bills by approximately 1%. Of course, without these mechanisms, the base rate increase per the Settlement would have to be increased by at least 2 percentage points to preserve the total economic package of the Settlement.

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

			Annual Average Monthly Bill (1), (2)	DSMAC (3)	DSMAC Increase Yr over Yr
Residential (Average - All Rates)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 132.87	$ 0.72	
	Settlement Rates	2010	$ 134.09	$ 1.99	$ 1.27
		2011		$ 3.91	$ 1.92
		2012		$ 5.94	$ 2.03
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 132.87	$ 0.72	
	Settlement Rates	2010	$ 134.09	$ 1.49	$ 0.77
		2011		$ 2.19	$ 0.70
		2012		$ 3.00	$ 0.81
Residential (Rate E-12)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 93.26	$ 0.46	
	Settlement Rates	2010	$ 94.87	$ 1.28	$ 0.82
		2011		$ 2.52	$ 1.24
		2012		$ 3.84	$ 1.32
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 93.26	$ 0.46	
	Settlement Rates	2010	$ 94.87	$ 0.96	$ 0.50
		2011		$ 1.41	$ 0.45
		2012		$ 1.93	$ 0.52
Commercial (Rate E-32)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 949.78	$ 6.52	
	Settlement Rates	2010	$ 951.35	$ 15.95	$ 9.43
		2011		$ 30.25	$ 14.30
		2012		$ 45.38	$ 15.13
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 949.78	$ 6.52	
	Settlement Rates	2010	$ 951.35	$ 12.20	$ 5.68
		2011		$ 17.40	$ 5.20
		2012		$ 23.42	$ 6.02
Industrial (Rate E34/35 Medium Load Factor)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 224,142.94	$ 2,106.39	
	Settlement Rates	2010	$ 225,242.63	$ 5,663.92	$ 3,557.53
		2011		$ 11,159.12	$ 5,495.20
		2012		$ 16,974.45	$ 5,815.33
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 224,142.94	$ 2,106.39	
	Settlement Rates	2010	$ 225,242.63	$ 4,220.07	$ 2,113.68
		2011		$ 6,221.51	$ 2,001.44
		2012		$ 8,531.64	$ 2,310.13
Industrial (Rate E34/35 High Load Factor)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 282,439.05	$ 2,106.39	
	Settlement Rates	2010	$ 268,718.25	$ 5,663.92	$ 3,557.53
		2011		$ 11,159.12	$ 5,495.20
		2012		$ 16,974.45	$ 5,815.33
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 282,439.05	$ 2,106.39	
	Settlement Rates	2010	$ 268,718.25	$ 4,220.07	$ 2,113.68
		2011		$ 6,221.51	$ 2,001.44
		2012		$ 8,531.64	$ 2,310.13

Notes:
(1) Current Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of September 1, 2009.
(2) Settlement Bill reflects the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA to projected Feb 2010 levels to occur commensurate with the new base rates
(3) DSMAC costs reflect the 2010 implementation plan and the forecast costs to meet the goals set forth in the Settlement Agreement. 2009 carry forward costs are phased in over three years.

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 100% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

			Annual Average Monthly Bill (1), (2)	DSMAC (3)	DSMAC Increase Yr over Yr
Residential (Average - All Rates)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 132.87	$ 0.72	
	Settlement Rates	2010	$ 134.09	$ 2.43	$ 1.71
		2011		$ 3.70	$ 1.27
		2012		$ 5.74	$ 2.04
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 132.87	$ 0.72	
	Settlement Rates	2010	$ 134.09	$ 1.81	$ 1.09
		2011		$ 2.06	$ 0.25
		2012		$ 2.68	$ 0.82
Residential (Rate E-12)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 93.26	$ 0.46	
	Settlement Rates	2010	$ 94.87	$ 1.56	$ 1.10
		2011		$ 2.38	$ 0.82
		2012		$ 3.70	$ 1.32
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 93.26	$ 0.46	
	Settlement Rates	2010	$ 94.87	$ 1.17	$ 0.71
		2011		$ 1.34	$ 0.17
		2012		$ 1.87	$ 0.53
Commercial (Rate E-32)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 949.78	$ 6.52	
	Settlement Rates	2010	$ 951.35	$ 19.22	$ 12.70
		2011		$ 28.64	$ 9.42
		2012		$ 43.79	$ 15.15
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 949.78	$ 6.52	
	Settlement Rates	2010	$ 951.35	$ 14.64	$ 8.12
		2011		$ 16.51	$ 1.87
		2012		$ 22.62	$ 6.11
Industrial (Rate E34/35 Medium Load Factor)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 224,142.94	$ 2,106.39	
	Settlement Rates	2010	$ 225,242.63	$ 6,921.44	$ 4,815.05
		2011		$ 10,542.16	$ 3,620.72
		2012		$ 16,367.60	$ 5,825.44
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 224,142.94	$ 2,106.39	
	Settlement Rates	2010	$ 225,242.63	$ 5,157.03	$ 3,050.64
		2011		$ 5,877.54	$ 720.51
		2012		$ 8,226.63	$ 2,349.09
Industrial (Rate E34/35 High Load Factor)					
Bill Impact from Projected DSMAC - Upper Range	Current Rates	2009	$ 282,439.05	$ 2,106.39	
	Settlement Rates	2010	$ 268,718.25	$ 6,921.44	$ 4,815.05
		2011		$ 10,542.16	$ 3,620.72
		2012		$ 16,367.60	$ 5,825.44
Bill Impact from Projected DSMAC - Lower Range	Current Rates	2009	$ 282,439.05	$ 2,106.39	
	Settlement Rates	2010	$ 268,718.25	$ 5,157.03	$ 3,050.64
		2011		$ 5,877.54	$ 720.51
		2012		$ 8,226.63	$ 2,349.09

Notes:

(1) Current Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of September 1, 2009.

(2) Settlement Bill reflects the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA to projected Feb 2010 levels to occur commensurate with the new base rates

(3) DSMAC costs reflect the 2010 implementation plan and the forecast costs to meet the goals set forth in the Settlement Agreement. 2009 carry forward costs are recovered in 2010.

ARIZONA PUBLIC SERVICE COMPANY
Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

			Annual Average Monthly Bill (1) (2)	RES (3)	RES Increase Yr over Yr
Residential (Average - All Rates)	Current Rates	2009	$ 132.87	$ 3.17	
	Settlement Rates	2010	$ 134.09	$ 3.41	$ 0.24
		2011		$ 4.58	$ 1.17
		2012		$ 5.80	$ 1.22
Residential (Rate E-12)	Current Rates	2009	$ 93.26	$ 3.17	
	Settlement Rates	2010	$ 94.87	$ 3.41	$ 0.24
		2011		$ 4.58	$ 1.17
		2012		$ 5.80	$ 1.22
Commercial (Rate E-32)	Current Rates	2009	$ 949.78	$ 69.60	
	Settlement Rates	2010	$ 951.35	$ 74.82	$ 5.22
		2011		$ 100.44	$ 25.62
		2012		$ 127.09	$ 26.65
Industrial (Rate E34/35 Medium Load Factor)	Current Rates	2009	$ 224,142.94	$ 353.78	
	Settlement Rates	2010	$ 225,242.63	$ 380.26	$ 26.48
		2011		$ 510.46	$ 130.20
		2012		$ 645.95	$ 135.49
Industrial (Rate E34/35 High Load Factor)	Current Rates	2009	$ 282,439.05	$ 353.78	
	Settlement Rates	2010	$ 268,718.25	$ 380.26	$ 26.48
		2011		$ 510.46	$ 130.20
		2012		$ 645.95	$ 135.49

Notes:

(1) Current Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of September 1, 2009.

(2) Settlement Bill reflects the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA to projected Feb 2010 levels to occur commensurate with the new base rates

(5) RES impacts are based on the 2010 implementation plan filed in July 2009.

At this time, APS has not estimated the percent of the RES budget that is attributable to the specific provisions in the Settlement Agreement

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Please provide the trajectory of the RES 2015 and beyond and any internal analysis of the RES portfolio at 25%. *(1527:17-1528:22)*

Response: As part of APS's Resource Planning Report (RPR) filed with the Commission on January 29, 2009,[1] APS evaluated a resource plan that included 25% renewable energy by 2025.[2] Sections of the report related to this scenario are attached, including the description of supply side resource planning cases, sensitivity analyses, and the detailed annual revenue requirement results. In APS's RPR, the Company selected the renewable generation portfolio from Scenario 3 and it represents APS's actual and future renewable trajectory. Relevant portions of APS RPR are attached. A summary of the results are provided below. In the RPR, Scenarios 3 and 4 are compared to an "All Gas Reference Plan", but for the purposes of examining the customer revenue requirement impacts of increasing the RES from about 15% to 25%, it is useful to directly compare Scenario 3 to Scenario 4.

Summary of Risk Analysis
APS 2009 Resource Plan Report
Net Present Value of Revenue Requirements 2008-2037
Millions of Dollars

Risk Analysis	Resource Requirements 15.16% Renewable Scenario 3	Resource Requirements 25.25% Renewable Scenario 4	Difference
Baseline Assumptions	47,035.8	48,168.8	1,133.0
A. Carbon Cost at $25/Ton[1]	51,422.6	52,193.4	770.8
B. Carbon Cost at $50/Ton[1]	55,809.5	56,217.9	408.4
C. Natural Gas Cost Increase of 30%	50,494.1	51,252.0	757.9
D. Cost of Solar Increases 1.5% Annually Other Cost at 3.0%	46,763.4	47,396.3	632.9

[1] Measured in short tons.

[1] Docket No. E-01345A-09-0037.

[2] In the RPR, renewable energy was calculated as a percent of total resource requirements whereas the RES calculates renewable energy as a percent of retail sales. Therefore, the RPR evaluated slightly more renewable energy than would be required under a 25% RES requirement. As a percent of retail sales, Scenario 3 represents 18% renewable energy and Scenario 4 represents 28% renewable energy.

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RESPONSES TO QUESTIONS POSED AT HEARING,
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E-01345A-08-0172
OCTOBER 2, 2009

These results indicate that, based on the assumptions, increasing the RES from about 15% to 25% may result in somewhat higher customer costs for each of the sensitivities considered over the long run.

Assumptions and RPR References:

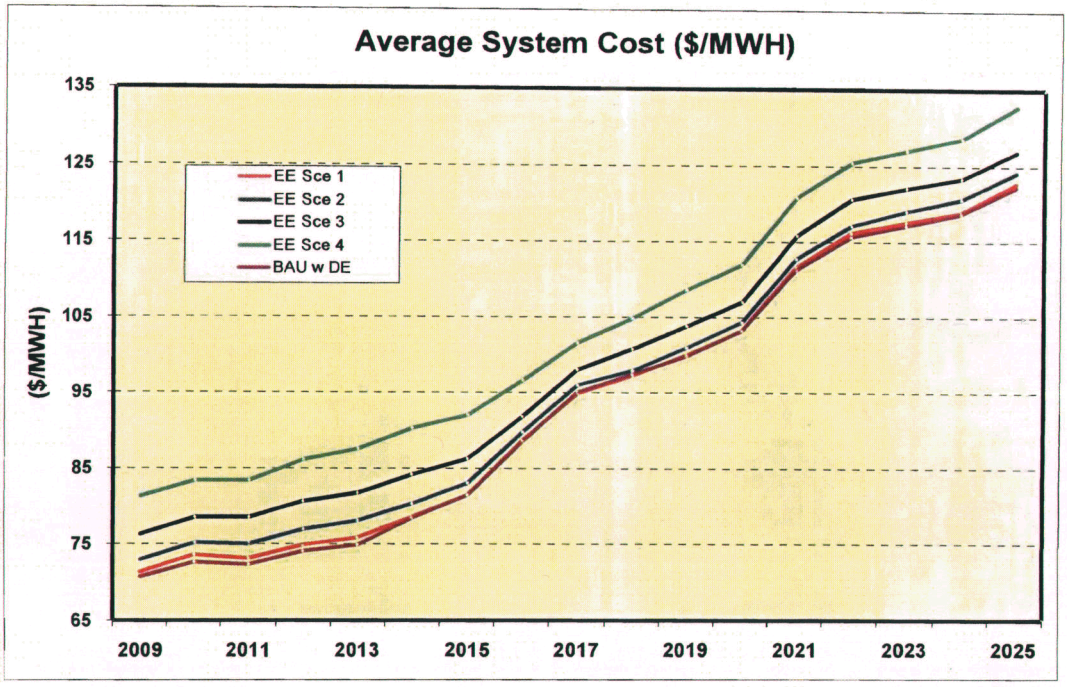
- Scenario 3 (16% renewable in 2025) - 800 MW of Nuclear and 400 MW Solar[3] is defined on page 144 of the RPR, with a more detailed load and resource plan shown in Appendix 2, Table 37 of the RPR. This option represents over 1,650 MW of renewable resources.

- Scenario 4 (25% renewable in 2025) – 800 MW Nuclear and 2,000 MW Solar[3] is defined on page 145 of the RPR, with a more detailed load and resource plan shown in Appendix 2, Table 40 of the RPR. This option represents over 3,200 MW of renewable resources.

- Some of the key results such as APS system annual gas burn, CO2 emissions, capital expenditures, and cost impacts are provided in Figures 66 through 71 (pages 148-151) of the RPR. This is followed by a series of sensitivity analyses related to carbon costs, natural gas costs, and renewable costs.

[3] MW are in addition to those strictly needed to comply with the requirements of the RES included in the base case.

Figure 62 – Average System Cost for Energy Efficiency Scenarios



3.3.A.v. Summary

The analysis of the energy efficiency scenarios clearly shows the beneficial impacts of implementing energy efficiency programs. Energy efficiency is the only resource option available at this time that can provide economic benefits as compared to conventional or renewable resource options while also providing environmental benefits and other risk reduction benefits. APS's recommended Resource Plan includes a targeted amount of energy efficiency that is based upon Scenario 2 with a more gradual ramp-up of incentive spending from current levels.

3.3.B. Analysis of Supply-Side Resource Planning Cases

By definition, a resource plan is a careful balance between a wide range of drivers, some of which are tied to individual resource technologies and some of which are the result of the blend of resource technologies selected. The drivers are both quantitative and qualitative in nature, and broadly include portfolio economics, risk trade-offs, and issues related to energy and public policy. A portfolio level analysis is required to demonstrate possible outcomes as they relate to the selection of specific supply-side resources. The previous sections provided a comparison and summary of different technologies that are available to satisfy future resource needs, important assumptions necessary for the resource planning analysis process and the value of energy efficiency in any future resource plan. This section will demonstrate the results of incorporating supply-side technology resources into APS's resource portfolio under a range of

deployment options, and it will provide a comparison of key results from the alternative scenarios.

This step involves both quantitative and qualitative analyses of different resource alternatives, including conventional generation, renewable resources, and energy efficiency (demand-side measures and distributed generation). Resource options or "scenarios" are brought forward for portfolio-level analysis in which alternative resource expansion plans are developed and analyzed through detailed production cost simulations. These detailed simulations combine the new resource alternatives with the existing resource portfolio and allow for projections of future costs (as well as other key parameters like emissions, water usage, and fuel consumption). The cost analysis provides an estimate of the future total system cost of each resource alternative and includes costs for fuel, purchased power, capital and transmission for new power plants, energy efficiency program costs, natural gas transportation, and emissions allowance costs for regulated emissions, such as SO_2.

To elucidate the economic effects of different resource technology options, it is helpful to build a descriptive range of plausible scenarios. Each scenario can then be used to demonstrate the results of specific resource related choices, such as the use of a specific resource type and/or the timing of resource deployment. This approach allows for a simplified comparison of the available resource options by illustrating the effects of specific choices against the backdrop of a resource plan that could be used to meet APS's future resource needs. In addition, this method is helpful in exploring sensitivities related to assumptions used within the analysis of the selected scenarios. For example, sensitivity analysis can be used to explore the effects of a change in the forecast price of natural gas or to explore impacts of carbon pricing resulting from GHG regulation.

Resource portfolio analysis requires the selection of discrete scenarios; however, in reality the alternatives described in the scenarios used in this evaluation are not mutually exclusive. The sizing of specific resources, timing of resource deployment, and any range of variables related to risk trade-offs can be adjusted to create a veritable continuum of resource portfolios. The scenarios chosen for presentation in this Report were selected based upon the learnings obtained from many other resource planning studies. Each scenario thoughtfully demonstrates the effects of balancing future resource needs with the drivers impacting resource selection.

3.3.B.i. Common Elements

It is important to note that each of the scenarios shares several common elements. Most notably, all of the resource portfolio scenarios are designed to satisfy APS's resource needs through 2025. In fact, the scenarios all share the same strategy in the years prior to 2013, in part because APS is generally well situated to satisfy its needs through that year, and in part because several of the resource technology alternatives

cannot be implemented in the years before 2015. Specifically, the following elements are common to all scenarios:

1. Renewable energy resources are added to meet no less than the RES requirement of 15 percent by 2025. Specifically, as described within these scenarios, the resource additions will result in the addition of nearly 1,300 MWs of utility-scale wind, solar, and geothermal generation above and beyond those already in service today.

2. Distributed resources will be added to meet no less than 30 percent of the RES requirement by 2025.

3.3.B.ii. The Role of Natural Gas Generation

As noted in the previous section, natural gas generation plays a critical role in the resource planning analysis. Low capital costs, short lead-times, and relatively low environmental impacts have led natural gas generation to become the reference resource type in the resource planning process.

In this resource planning analysis, natural gas generation plays two fundamental roles. First, as noted above and described below in more detail, a resource planning strategy that relies on natural gas generation to meet all of APS's resource needs (beyond the renewable resources required to meet RES targets) serves as the reference point against which all other planning options (scenarios) are evaluated. Second, APS believes natural gas will continue to play an important role in helping to meet future resource needs. Unless described otherwise, the portfolio scenarios presented in this section include the addition of at least some natural gas generation. In many instances, the additional natural gas capacity described in the resource planning scenarios will replace expiring contracts for market resources.

Absent a well-vetted, well-supported, long-term resource plan driven by a clear vision, a regional energy policy, and appropriate regulatory support measures, the industry will continue to pursue those resources that manifest the lowest investment. In APS's case, natural gas generation is the least-cost resource. While not necessarily satisfying specific objectives for portfolio diversification and the associated benefits, a resource plan that relies on meeting all foreseeable resource needs with natural gas generation serves as a reasonable reference against which all other alternatives are compared.

3.3.B.iii. Sensitivity Analysis

In presenting an evaluation of specific resource alternative scenarios, it is critical also to understand key risk components related to any one option. While there are a great number of variables in the economic analysis of the presented supply-side scenarios, a

few key variables best summarize comparative risks between scenarios. Analysis of these "sensitivities" is designed to explore how reasonably foreseeable changes in key risk components can affect the desirability of any one of the alternative scenarios.

The risk analysis process involves both quantitative and qualitative assessments of future potential risks, such as changes in fuel prices or future environmental regulations (the current issues surrounding climate change are a good example of this). Because many risks cannot be easily quantified, the risk assessment process inevitably requires a great deal of judgment.

a. *Cost of Carbon Emissions*

Although perhaps controversial, the baseline economic projections do not include cost projections related to potential future GHG emissions regulations. Several parties in the Resource Alternative Report process suggested that APS should explicitly include a cost related to CO_2 emissions (GHG cost) in the resource planning analysis process. Although APS has decided not to include this factor in the baseline economic analysis at this time due to the uncertain timing and outcome of climate policy, APS recognizes that it is an important factor that must be considered in the decision-making process because of the increasing likelihood of climate change legislation at either the federal or regional level. Two alternative costs for carbon have specifically been included in the sensitivity analysis of each resource scenario, $25 per short ton and $50 per short ton. For both of these sensitivity cases, the carbon cost is assessed beginning in 2012. Additionally, the carbon cost is assumed to escalate over time at a rate of 3 percent per year.

b. *Fuel Costs*

More than any other resource technology option, the cost of natural gas generation is highly dependent on the cost of fuel. Since natural gas generation has the potential to play a significant role in many of the resource planning alternatives, a discrete sensitivity for an increase in cost, at 30 percent above that presently forecast, is presented for each of the scenarios.

c. *Technology Costs*

Each of the technology alternatives is saddled with the prospect of changing development costs. In some instances, the risk (or opportunity) of this change is increased above those forces that generally apply to resource development at large. For example, there are those who speculate that the costs of developing solar resources (PV or CSP) will decline or, at a minimum, increase at a rate slower than the rate of increase for non-solar resources. While there remains uncertainty surrounding the assumptions that would drive the cost of solar development down, it is a reasonable observation that large-scale solar development is in its infancy and that the ultimate deployment of large-scale solar could indeed drive costs down. A sensitivity is included that describes the

relative cost of solar declining when compared to the cost of developing other generation resources. Specifically, as modeled, the costs of developing solar will increase at half the rate (1.5 percent) projected for cost increases related to inflation (3.0 percent).[108]

Similarly, the current and forecast cost to develop renewable resources is hinged on specific tax treatments. While there are a broad range of favorable tax related treatments applied to renewable generation, two are specifically identified for sensitivity analysis in this section because of the magnitude of their impact on the final cost of developing the affected resources. The production tax credit ("PTC") applies to both wind and geothermal generation and is currently set to expire at year-end 2009 for wind and year-end 2010 for geothermal. The investment tax credit ("ITC") applies to all types of solar generation and is currently set to expire at year-end 2016. Since both the PTC and ITC are set to expire well within the timeframe covered by the Resource Plan, a sensitivity analysis is included whereby neither of the tax credits is further extended beyond the scheduled expiration date. For the PTC, this applies to all wind projects deployed after 2009 and for geothermal projects deployed after 2010. For the ITC, this applies to solar projects deployed after 2016.

Increased interest and growing commitments for expansion of the national nuclear generation fleet are helping to better forecast the cost of construction; however, until such time as contractual commitments are firmly established, the ultimate costs will not be known. Given the long timeline, relative uncertainty, and magnitude of commitment necessary for the inclusion of nuclear generation in the resource portfolio, it is necessary to consider the prospect of development costs substantially higher than established in the baseline assumptions. The analysis that follows includes a sensitivity analysis that projects nuclear generation costs 25 percent higher than currently forecast.

d. *Changes in APS's Forecast Load*

Some of the issues surrounding the load forecast were described in a previous section of this Report. It is difficult to predict both the severity and length of the current economic downturn. Likewise, it is also difficult to predict the timing and strength of the recovery following the current business cycle. For this sensitivity analysis, APS developed both high and low load growth sensitivities around the current expected load growth case. The impact of these two sensitivities were qualitatively assessed for how they would impact APS's recommended Resource Plan and how flexible the Resource Plan is for accommodating changes in the load forecast.

[108] The inflationary factor of three percent is applied to all conventional resource costs in the baseline analysis.

e. *Summary of Analysis Sensitivities*

The follow discrete sensitivities were applied to each of the resource planning scenarios:

- Two sensitivities are provided reflecting discrete carbon costs:
  - carbon at $25/ton; and
  - carbon at $50/ton.
- Natural gas prices are 30 percent higher than the baseline forecast.
- The cost of solar will decline (or alternatively increase at a slower rate) relative to other generation technology options. Solar technologies are modeled to increase at 1.5 percent annually, while all other technologies increase in cost with the rate of inflation (assumed to be 3.0 percent annually).
- Current favorable tax treatments for renewables are not extended beyond their current effective expiration dates:
  - the PTC is not available for wind added after 2009 and geothermal generation added after 2012; and
  - the ITC is not available for solar generation added after 2016.
- The cost for developing nuclear generation exceeds that currently forecasted by 25 percent.

3.3.B.iv. Resource Portfolio Alternatives Scenarios

The following resource portfolio analysis and presented scenarios are based on APS's long history of experience in resource planning, stakeholder input from the resource planning workshops, and the most current market and resource information available. We present three scenarios that are designed to explore the implications of selecting only one resource technology alternative for purposes of meeting APS's future resource needs. Those three scenarios describe "all" natural gas, nuclear, and solar options. Neither the nuclear nor the solar scenarios are presented to impart the possibility of relying on only one resource technology option as a desirable outcome from this resource planning process. Rather, the nuclear and solar scenarios are designed to highlight the economic differences between the two resource technology alternatives. Specifically, the scenarios were designed to result in approximately the same total energy contribution and as a result, approximately the same total impact to APS's carbon profile.

In addition, four scenarios are presented to describe the range of balanced resource portfolio options that are reasonably available to meet APS's resource needs. As was previously noted, these four scenarios simply mark four points along a continuum of potential outcomes. Each of the four scenarios highlights the growing role APS envisions for solar resources in the Company's resource portfolio. The specific timing for solar resource additions has been selected to maximize the benefit for the ITC before its planned expiration in 2016. The detailed information related to all of the scenarios,

including loads and resource plans and capital cost projections are included in Appendix 2.

a. *Reference Scenario: All Natural Gas*

The all natural gas ("All Gas") scenario satisfies all incremental energy needs (beyond that met through the implementation of renewable resources to comply with the RES rules) through 2025 with the addition of natural gas generation resources. The All Gas reference scenario is included to demonstrate the most likely resource outcome absent specific energy policy and appropriate regulatory support measures. Under this scenario, 528 MWs of combined cycle generation are added in both 2020 and 2021. This scenario represents both the highest prospective carbon portfolio and creates the greatest future risk related to natural gas price fluctuation.

All Gas Reference - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
0	0	0	4,230	1,056	5,286

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

b. *Nuclear Scenario*

The nuclear scenario ("Nuclear") satisfies a portion of the incremental energy needs through the addition of 315 MWs of nuclear generation in both 2022 and 2023. The inclusion of this scenario is designed to provide a clear comparison of the cost of nuclear generation against the costs of natural gas generation and against solar generation. In this scenario, the addition of nuclear diminishes the need for intermediate natural gas generation and some natural gas peaking capacity relative to the All Gas scenario. It includes the addition of 528 MWs of combined cycle generation in 2020. Relative to the All Gas reference scenario, this scenario represents a moderate reduction in the projected carbon profile of the resource mix.

Nuclear - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
630	0	0	4,136	528	5,294

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

c. *Solar Scenario*

The solar scenario ("Solar") is designed to satisfy a portion of the incremental energy needs through the addition of solar generation while aiming to achieve a moderate reduction in the carbon profile relative to the All Gas reference. The inclusion of this

scenario is designed to provide a clear comparison of the cost of solar generation against the costs of natural gas generation and against nuclear generation. Specifically, the energy contributed by the added solar resources is approximately the same amount of energy as added by nuclear resource additions included in the nuclear scenario. The scenario describes the addition of 200 MWs of CSP in each year starting in 2014 until 1,400 MWs of CSP has been incorporated in 2020. The Solar scenario reduces the need for natural gas peaking capacity relative to the All Gas scenario.

Solar - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
0	1,400	0	3,854	0	5,254

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

A second solar scenario ("Solar 2") was evaluated to help explore the implications of using a blend of CSP and PV in meeting the objectives of the Solar scenario. While that scenario is not included in this section, insights from that scenario are included in the scenarios that follow. Specifically, for the Solar 2 scenario, the 1,400 MWs of CSP from the Solar scenario were replaced with 700 MWs of CSP and 1,148 MWs of PV, which was aimed to achieve the same total energy contribution. Details of the Solar 2 scenario are included in Appendix 2.

Review of Solar 2 highlights that in many respects solar resources, regardless of technology, produce many of the same system benefits. For example, after all resources are operational, both Solar and Solar 2 result in the same gas burn and carbon profile for the resulting resource portfolio. Likewise, once installed, both Solar and Solar 2 demonstrate very similar average annual system costs. For purposes of this analysis, CSP is assumed to include six hours of thermal storage and, as a result, more PV capacity is required to replace the energy "removed" when PV has been modeled to replace CSP.[109] While the two scenarios represent different total capacities, the capital costs for each are similar, where the total capital expense through 2025 for the Solar scenario is approximately $22.6 billion and the total capital expense through 2025 for Solar 2 is approximately $21.7 billion. APS believes that it is appropriate to use a balance of both CSP and PV solar resources in the resource planning scenarios described below. The actual mix of solar resources will be determined through future procurement activities.

d. *Scenario 1: 500 MW Nuclear and 290 MW Solar*

The 500 MW nuclear and 290 MW solar scenario ("Scenario 1") is designed to satisfy incremental energy needs through the addition of both nuclear and solar generation. While neither the addition of the nuclear resource nor the addition of the

[109] CSP with thermal storage will produce more energy per unit capacity than solar resources without storage.

solar resource increase APS's carbon profile, the cumulative composition of resource technologies in this scenario results in only a moderate reduction of carbon emissions relative to the All Gas reference scenario. The scenario includes the addition of 100 MWs in 2014 and 2015 and 90 MWs in 2016 of CSP; and 250 MWs of nuclear in 2022 and 2023. The scenario reduces the need for both natural gas intermediate and peaking capacity relative to the All Gas reference scenario.

Scenario 1 - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
500	290	0	3,948	528	5,266

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

e. *Scenario 2: 650 MW Nuclear and 800 MW Solar*

The 650 MW nuclear and 800 MW solar scenario ("Scenario 2") is designed to satisfy incremental energy needs through the addition of both nuclear and solar generation while aiming to achieve a more moderate increase in carbon emissions relative to 2008 levels (note that all of these cases are prior to incorporating the beneficial impacts of incremental energy efficiency investments). The scenario describes the addition of 100 MWs of CSP in 2014, 2015, and 2016; 100 MWs of PV in 2014 to 2017 and 92 MWs in 2018; and 325 MWs of nuclear in 2022 and 2023. This scenario reduces the need for both natural gas intermediate and peaking capacity relative to the All Gas scenario.

Scenario 2 - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
650	300	492	3,572	528	5,542

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

f. *Scenario 3: 800 MW Nuclear and 400 MW Solar*

The 800 MW nuclear and 400 MW solar scenario ("Scenario 3") is designed to satisfy incremental energy needs through the addition of both nuclear and solar generation, while aiming to achieve a more moderate increase in carbon emissions relative to 2008 levels. Scenario 3 contrasts with Scenario 2 in that it attempts to demonstrate the results of the increased role of nuclear generation. The scenario includes the addition of 100 MWs in 2014 and 50 MWs in 2015 of CSP; 100 MWs of PV in 2014 and 2015 and 46 MWs in 2016; and 400 MWs of nuclear in 2022 and 2023. The scenario reduces the need for both natural gas intermediate and peaking capacity relative to the All Gas scenario.

Scenario 3 - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
800	150	246	3,666	528	5,390

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

g. *Scenario 4: 800 MW Nuclear and 2,000 MW Solar*

The 800 MW nuclear and 2,000 MW solar scenario ("Scenario 4") is designed to satisfy incremental energy needs through the addition of both nuclear and solar generation while aiming to decrease carbon emissions to below current levels. The primary impact of implementing this scenario is eliminating the need for intermediate gas generation and dramatically reducing the need to replace/increase natural gas peaking capacity. Scenario 4 represents a plausible option for reducing carbon emissions in conformance with Arizona's commitment to the WCI (after the impacts of energy efficiency are also added to this scenario). The scenario includes the addition of 100 MWs of CSP in 2014 to 2020 and 50 MWs in 2021; 100 MWs of PV in 2014 and 2015, 200 MWs in 2016 to 2020, and 30 MWs in 2021; and 400 MWs of nuclear in 2022 and 2023.

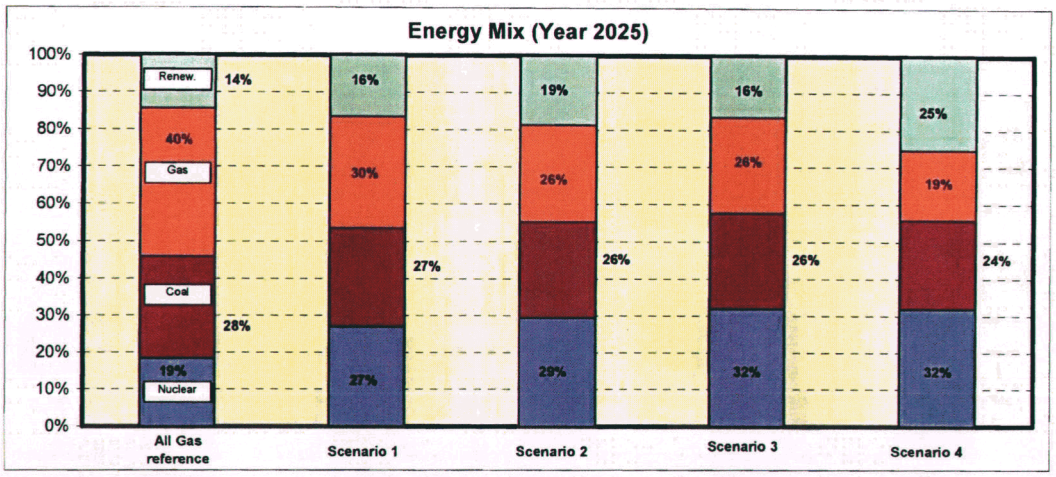
Scenario 4 - Resource Additions Thru 2025 (in MW)					
Nuclear	Solar (CSP)	Solar (PV)	Gas Peaking	Gas CC	Total Additions[1]
800	750	1,230	3,102	0	5,882

Note: 1. Additions required to meet RES compliance (approximately 1,300 MWs) are included in all scenarios (but not explicitly portrayed in this summary table).

h. *Summary of Energy Mix from all Resource Alternative Scenarios*

One way to summarize the scenarios is to illustrate the resulting energy mix of the portfolio in 2025. The following figure provides the energy mix for 2025. Under the All Gas reference case, natural gas comprises approximately 40 percent of the system energy mix in 2025. The scenarios represent a progression of increasing amounts of other resource additions (*i.e.*, not natural gas resources) and the natural gas contribution decreases with each scenario. In Scenario 4, natural gas represents just 19 percent of the overall system energy mix by 2025.

Figure 63 – Summary of Scenarios – Relative Energy Mix



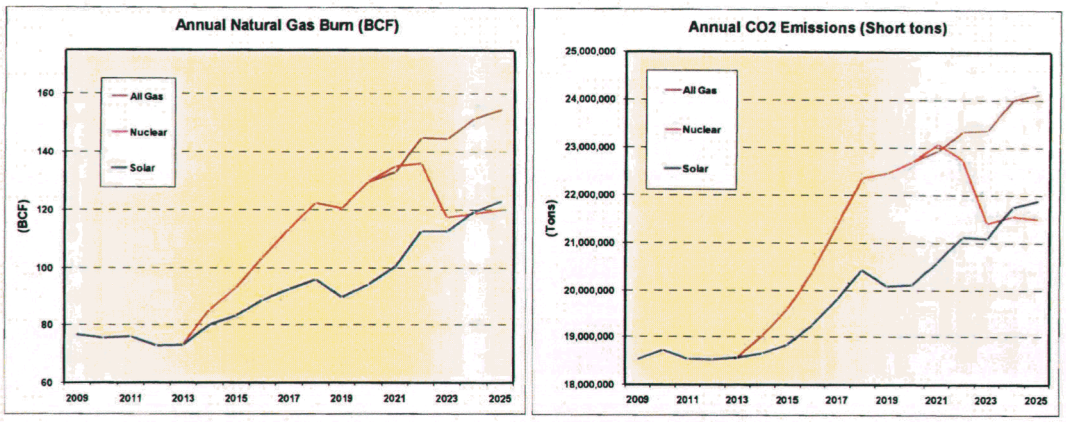
Note: Renewable energy contribution illustrated in this figure is not directly comparable to RES targets as this chart is based upon total system energy requirements (rather than as a percent of retail sales as is the case with the RES targets).

3.3.B.v. Summary of Results

Portfolio-level simulations provide a means to measure the impact of resource decisions upon the overall resource portfolio. Each of the previously described resource scenarios was simulated through APS's production cost model to assess the economics and the key risk parameters (capital costs, natural gas consumption, and CO_2 and other emissions). The following sections describe the results of that analysis.

Beginning the overview of the portfolio-level analysis with a review of the characteristics differentiating between nuclear and solar resources will prove helpful when reviewing the results of the four prospective resource scenarios. While both the Nuclear and Solar scenarios were designed to achieve the same ultimate (year 2025) energy contribution, it is valuable to note that manifesting the benefit of a nuclear resource with respect to both natural gas burn and carbon emissions will take some years. The incremental nature of solar resources allows for their progressive addition over a longer and earlier window of the planning horizon. Therefore, while the long-term benefits of both of these carbon-emissions free resources is very similar, relying on nuclear alone will increase near-term risk resulting from reliance on natural gas and a near-term increase in carbon emissions.

Figure 64 – Characterizing Nuclear and Solar Scenarios by Gas Burn and CO_2 Emissions



Perhaps the most pronounced long-term distinctions between the Nuclear and Solar scenarios are those surrounding cost. The table below summarizes both cumulative and annual average system costs for both of the scenarios.

Figure 65 – Summary of Costs for Nuclear and Solar Scenarios

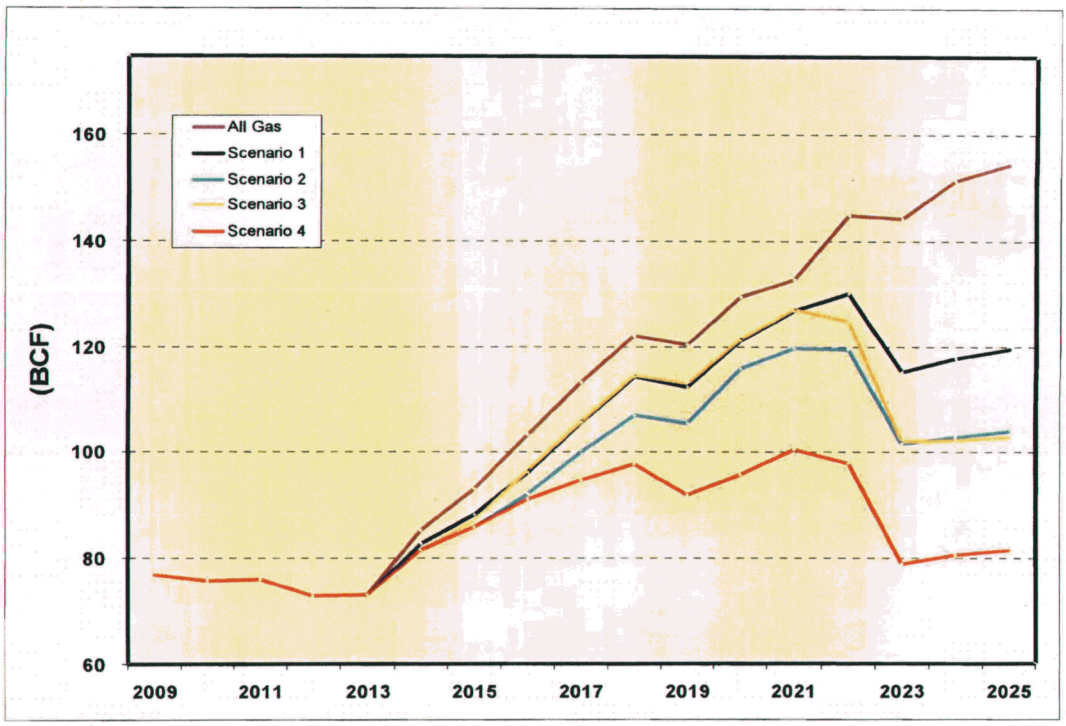
	CPW of Revenue Requirements (billions of $s, 2008-2037)		Average Annual System Cost $/MWH		
	Cumulative Total	Increase above All Gas	Increase over 2009 Cost	System Cost in 2025	Increase above All Gas
All Gas	45.997	-	181%	127.5	-
Nuclear	46.534	0.537	183%	128.4	0.9
Solar	47.352	1.355	189%	132.6	5.1

In all instances, the simulations include the cost for generation additions, incremental transmission requirements, purchased power, natural gas transport, imputed debt, and costs for emission (not including prospective costs for carbon). Costs for nuclear generation additions are modeled assuming CWIP in rates as a necessary financial support measure during the development and construction phase. The Solar scenario shows a cost increase of approximately $1.4 billion over the All Gas reference case and about $0.8 billion more than the Nuclear scenario (both numbers represent the cumulative present worth of revenue requirements over the 30 year study period). The average annual system cost projected for 2009 is $70.3/MWh. The Solar scenario represents an eight percent cost increase above the All Gas reference and a six percent increase over the Nuclear scenario.

The next comparisons illustrate the differences between the All Gas reference case and the previously described Scenarios 1-4. First, an important measure of portfolio risk is the percentage of the energy portfolio met by natural gas energy sources (including both generation and energy purchased from the market). The following chart

demonstrates the projected annual natural gas consumption under each of the planning scenarios.[110]

Figure 66 – Annual Natural Gas Burn in BCF



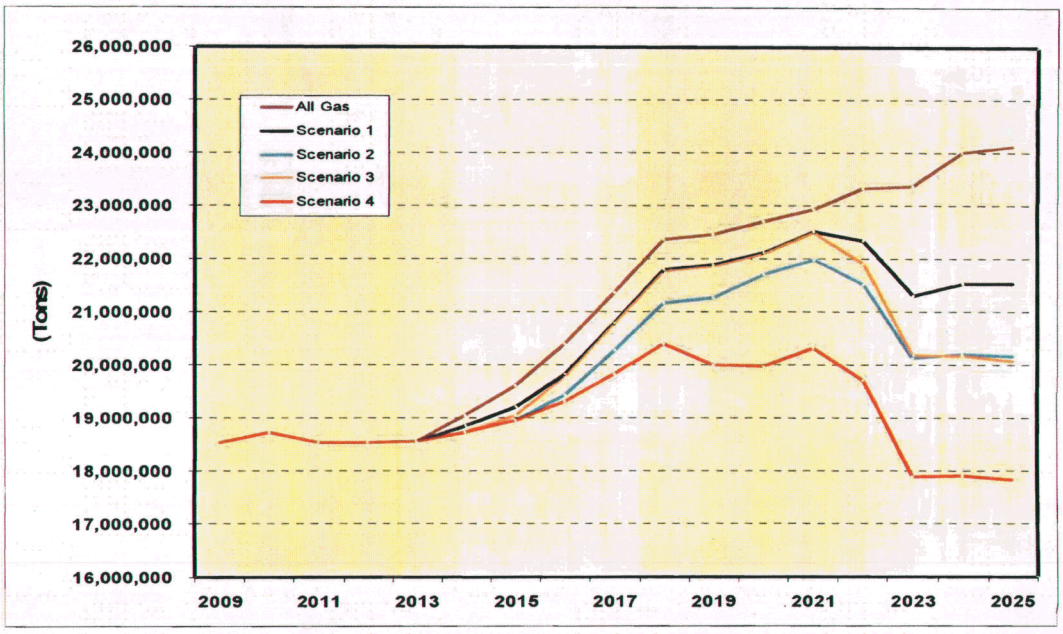
Under the All Gas reference scenario, the total annual gas burn climbs to nearly 155 BCF, an approximate doubling of the 2009 gas consumption of approximately 77 BCF. All four of the planning scenarios represent a marked decrease in reliance on natural gas resources, and therefore, each will impart a reduction in the risks associated with natural gas resources. This decreasing reliance on natural gas resources is most clearly manifested in two key areas. First, it is observed below in the projected annual carbon emissions of each of the four scenarios. Second, the decreased reliance on natural gas resources is observed in the sensitivity analysis for natural gas costs. As the scenarios decreasingly rely on natural gas, their "up-side" cost risk decreases when higher natural gas costs are forecast. This chart allows a relatively simple qualitative risk assessment. It is easy to see the differences in the scenarios in terms of the natural gas consumption. This is demonstrated further below in the next important risk illustration.

The All Gas reference scenario projects an APS portfolio-wide carbon emissions increase of approximately six million tons—a 30 percent increase over current carbon emissions. The four planning scenarios can be generally grouped into three categories: 1) moderate reduction in carbon emissions relative to the All Gas reference (Scenario 1); 2)

[110] The scenarios share identical resource additions prior to 2013.

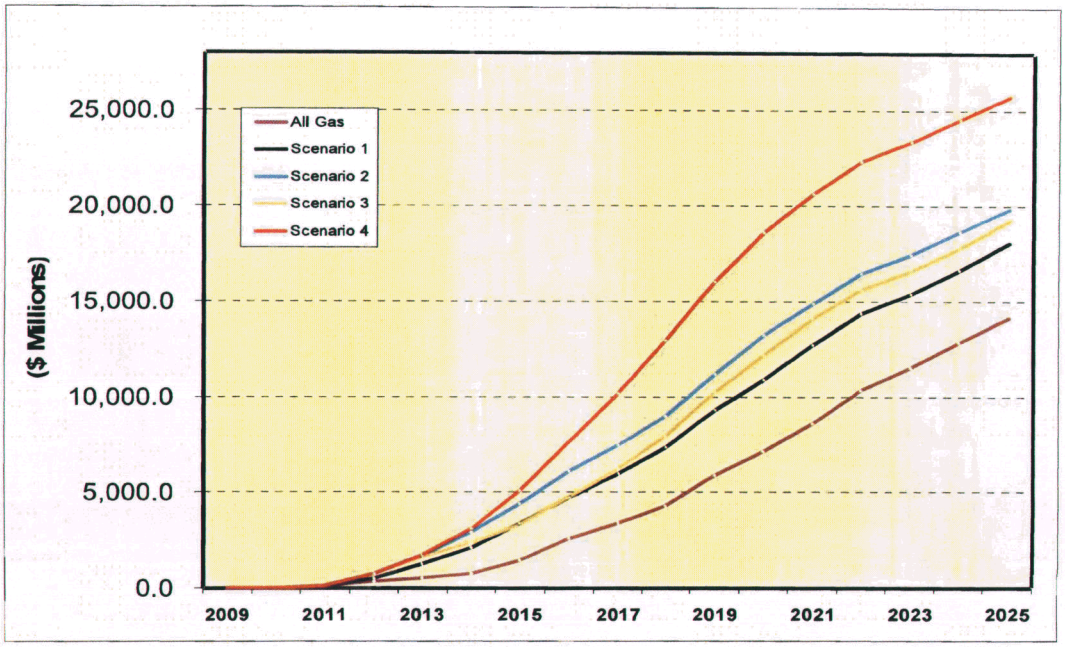
dramatic decrease in carbon emissions relative to the All Gas reference (Scenarios 2 and 3) but not below 2009 carbon emissions; and 3) decrease from 2009 carbon emissions (Scenario 4). It is important to note that under all scenarios, carbon emissions are projected to increase until nuclear resources are brought into service. Scenarios that increasingly leverage the use of solar resources manage to slow the rate of carbon emission increases until the dramatic drop caused by nuclear resource additions. As with natural gas, the risk of cost impacts resulting from carbon regulation decreases with the forecast reduction in carbon emissions.

Figure 67 – Annual CO_2 Emissions (Short tons)



As has been highlighted throughout this Report, the increasing demand on capital expenditures to meet customer resource needs through 2025 is very large, ranging from nearly $14 billion for the All Gas reference to nearly $26 billion for Scenario 4. The following figure is a helpful comparison of projected capital expenditures associated with each of the planning scenarios. The graph includes capital expenditures associated with conventional and renewable resource additions and transmission and provides a way to compare the expected capital requirements associated with each scenario. It is not meant to presume a specific procurement method (*i.e.*, build versus buy).

Figure 68 – Cumulative Capital Expenditures



While the demand on capital is very great by 2025, it is also important to recognize that commitments on capital are very significant as soon as 2015. Figure 68 helps to demonstrate that significance. As was observed in the Nuclear/Solar economic comparison, as each of the planning scenarios increasingly relies on solar resources, the capital cost of that scenario increases. By 2025, those differences could exceed $7.5 billion between Scenario 1 and Scenario 4, which represents a more than $11.5 billion dollar increase over the All Gas reference scenario.

Figure 69 – Summary of Capital Expenditures

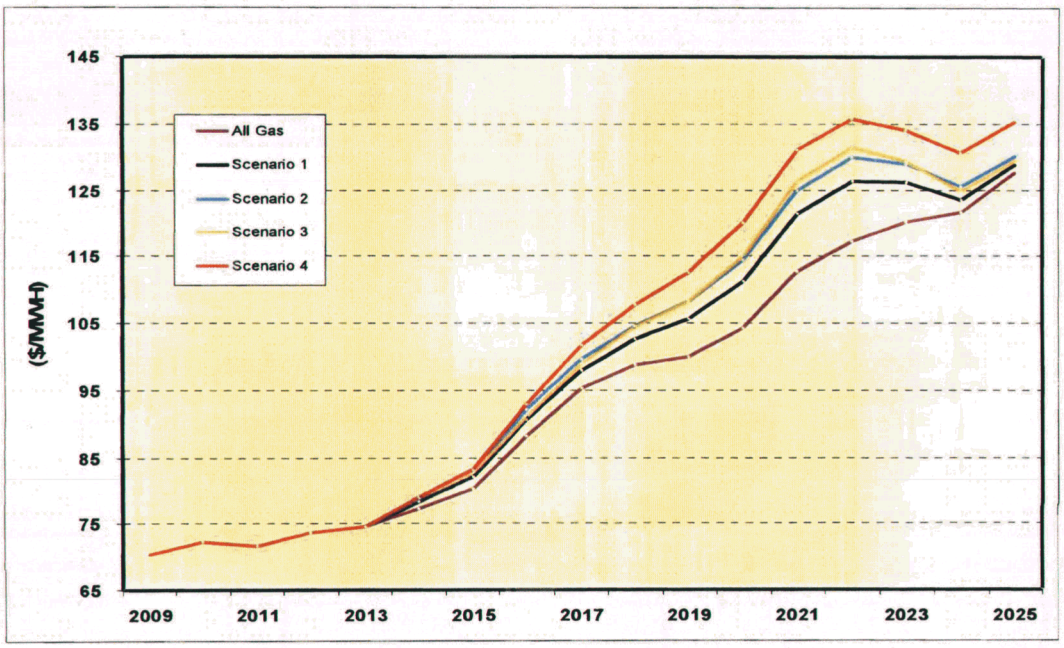
	Cumulative Capital Expenditures (billions $s)		
	2015	**2020**	**2025**
All Gas	1.44	7.13	14.18
Scenario 1	3.33	10.95	18.09
Scenario 2	4.37	13.27	19.80
Scenario 3	3.33	12.21	19.21
Scenario 4	5.04	18.63	25.74

The average annual system cost and the 30-year present worth economic comparisons provide excellent tools for review of the cumulative portfolio impacts of each of the scenarios. The average annual system cost is also an excellent vehicle for monitoring the end impacts of the sensitivities that were evaluated as part of this portfolio-level analysis. While a cross-comparison of each scenario and the relevant sensitivities, both individually and cumulatively, is certainly plausible, it is not necessary to demonstrate the most important observations of this analysis. Each of the analyses and results from the sensitivities has been included as Appendix 2.

Figure 70 – Summary of Costs for Scenarios

	CPW of Revenue Requirements (billions of $s, 2008-2037)		Average Annual System Cost $/MWH	
	Cumulative Total	Increase above All Gas	System Cost in 2025	Increase above All Gas
All Gas	45.997	-	127.5	-
Scenario 1	46.797	0.800	128.9	1.4
Scenario 2	47.175	1.178	130.1	2.6
Scenario 3	47.036	1.039	129.5	2.0
Scenario 4	48.169	2.172	135.2	7.7

Figure 71 – Average System Cost ($/MWh)

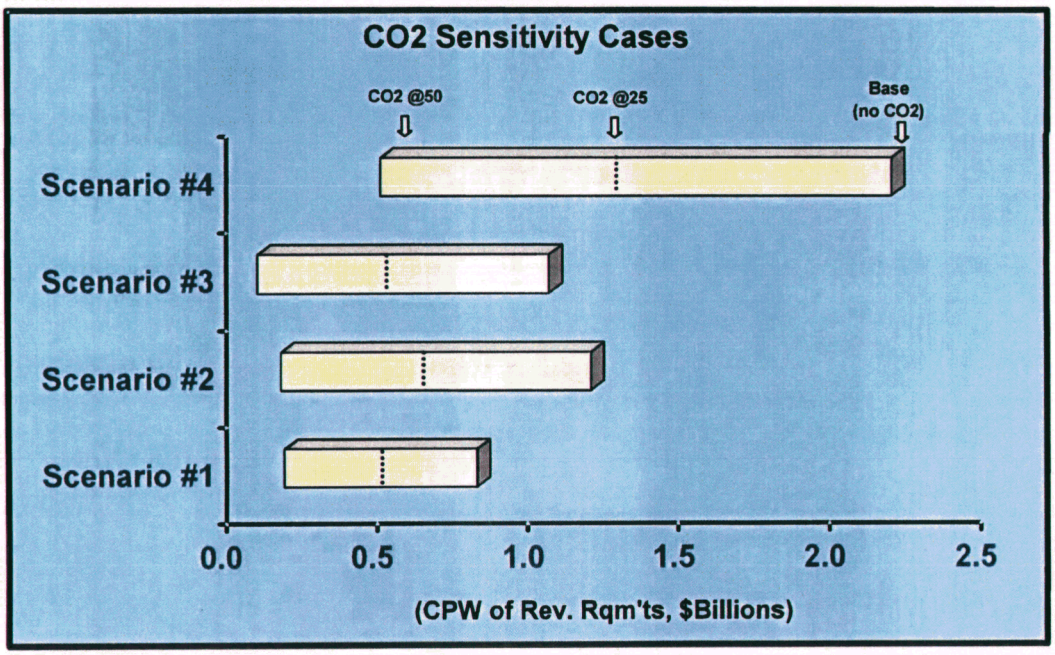


3.3.C. Sensitivity Analysis

Under the baseline assumptions (no cost for carbon, no changes to the forecast cost of natural gas, and capital costs as currently projected), the All Gas reference provides for the lowest overall system cost. This "discount" is most pronounced in the years prior to operation of a nuclear facility; thereafter, the difference between the All Gas reference and each of the modeled resource portfolio scenarios declines. Increasing the relative role for solar in each of the scenarios results in a higher ultimate average system cost in 2025. This result is highly dependent upon the forecast natural gas price and represents a significant uncertainty due to the demonstrated volatility of natural gas prices.

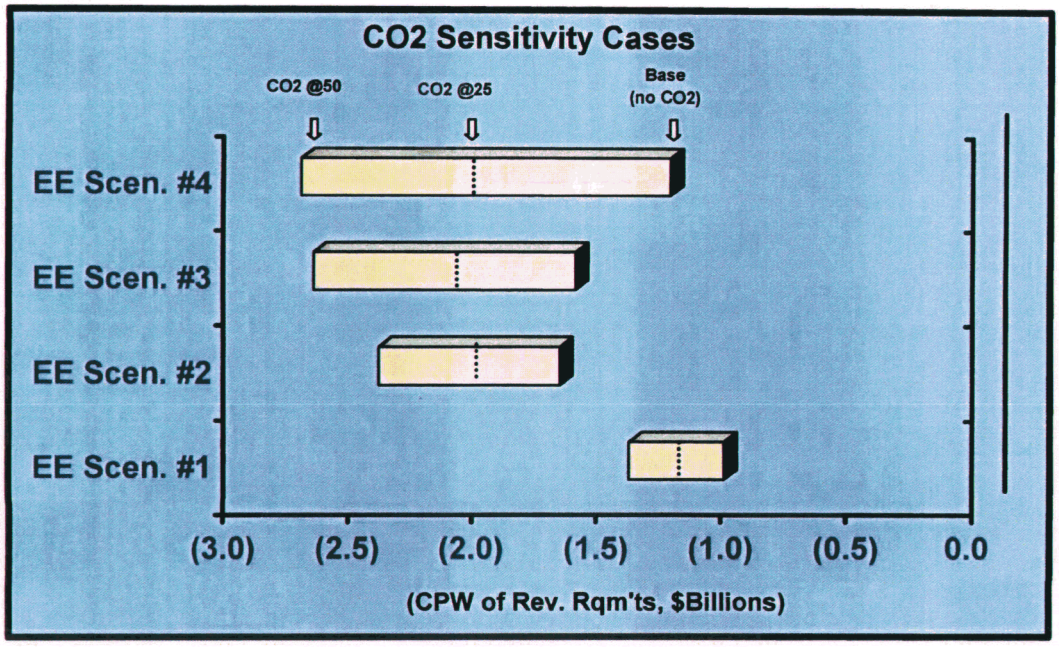
The following series of figures illustrate the effects of the sensitivity analyses across scenarios. The first set of comparisons illustrates the results of the CO_2 sensitivity cases. As described previously, two carbon cost sensitivity cases were analyzed: the first with a starting carbon cost of $25/ton (short ton); and the second with a carbon cost of $50/ton (also short ton). The impact on the economics of each scenario is shown below. The figure provides a comparison of the economic impacts for the 30-year study period, which are presented as the cost (or savings) versus the All Gas reference case. Although all of the resource scenarios still show costs as compared to the All Gas reference case, all scenarios show dramatic improvement with increasing carbon costs, particularly under the $50/ton carbon cost sensitivity. Additionally, Scenario 3 comes close to break-even economics under the $50/ton sensitivity case.

Figure 72 – Results of CO_2 Sensitivity Analysis vs. All Gas Scenario



The identical type of figure for the four energy efficiency scenarios is provided below. Once again, each scenario provides increasingly more favorable results with the inclusion of carbon costs.

Figure 73 – Results of CO_2 Sensitivity Analysis for Energy Efficiency Scenarios



The next figure provides a different comparison of the CO_2 sensitivity analysis. This figure illustrates how the different carbon costs impact the average system cost in 2025. It is interesting to note that all of the resource scenarios have an average cost that is below the reference case for the $50/ton carbon cost sensitivity.

The CO_2 sensitivity analysis is an important part of this resource planning study. Although future carbon costs will be somewhat dependent upon the design features of future climate change regulatory structures, APS believes that carbon costs in the range represented by the two sensitivity cases are possible and seem to be within the range of potential carbon costs described in a number of studies of future cap-and-trade regulatory schemes.

Figure 74 – Average System Cost for CO_2 Sensitivity Analyses

Comparison of Average System Cost for 2025 (all values in $/MWH)						
	Base Analysis (no CO2)		CO2 at 25 $/ton		CO2 at 50 $/ton	
	Yr 2025 Average Cost	Over / (Under) Reference	Yr 2025 Average Cost	Over / (Under) Reference	Yr 2025 Average Cost	Over / (Under) Reference
All Gas - Reference Case	127.5	-	143.2	-	158.8	-
Scenario #1 (500 Nuc, 290 Solar)	128.9	1.4	142.6	(0.6)	156.2	(2.6)
Scenario #2 (650 Nuc, 800 Solar)	130.1	2.6	142.7	(0.5)	155.3	(3.5)
Scenario #3 (800 Nuc, 400 Solar)	129.5	2.0	142.1	(1.1)	154.6	(4.2)
Scenario #4 (800 Nuc, 2000 Solar)	135.2	7.7	146.1	2.9	156.9	(1.9)

The next figures provide a summary of the results from the high natural gas price sensitivity cases. The first figure provides results for the four resource scenarios while

the second figure shows the results for the four energy efficiency cases. As expected, all cases will demonstrate more favorable results under a higher natural gas price environment as each of the cases resulted in lower natural gas consumption than the reference case.

Figure 75 – High Natural Gas Price Sensitivity for Resource Scenarios

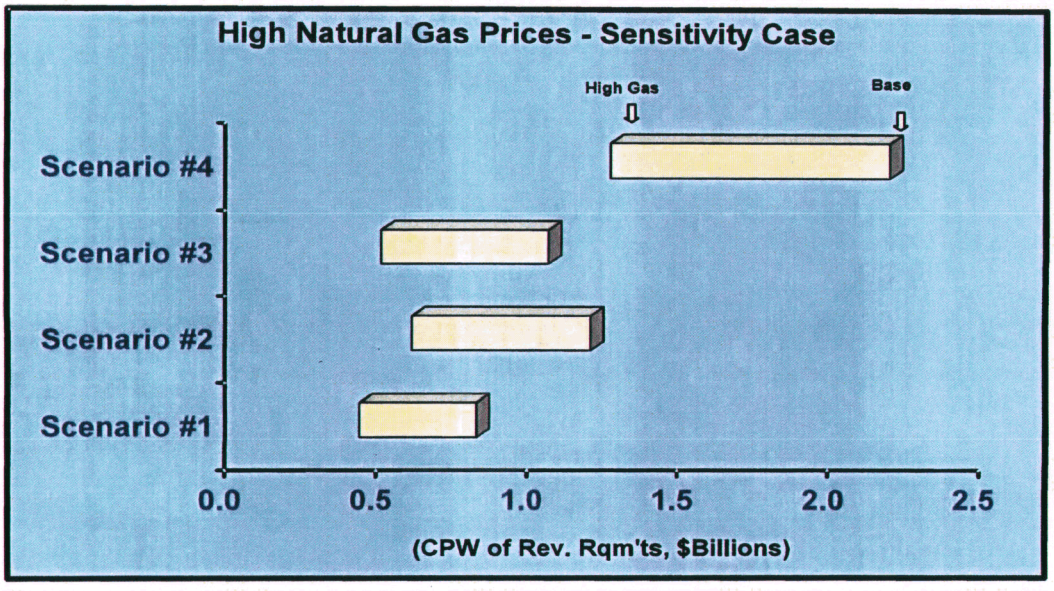
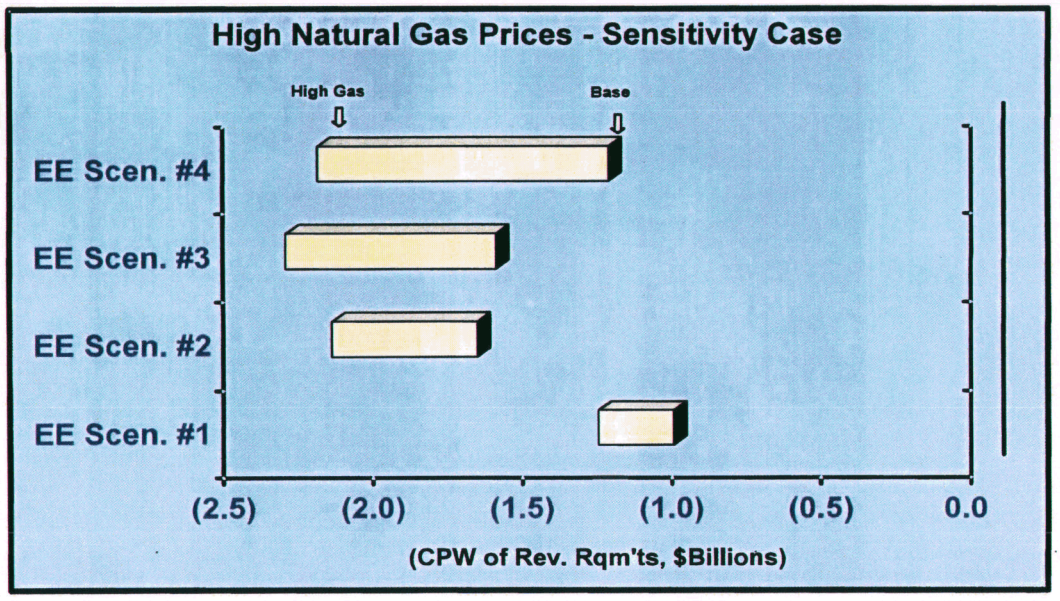
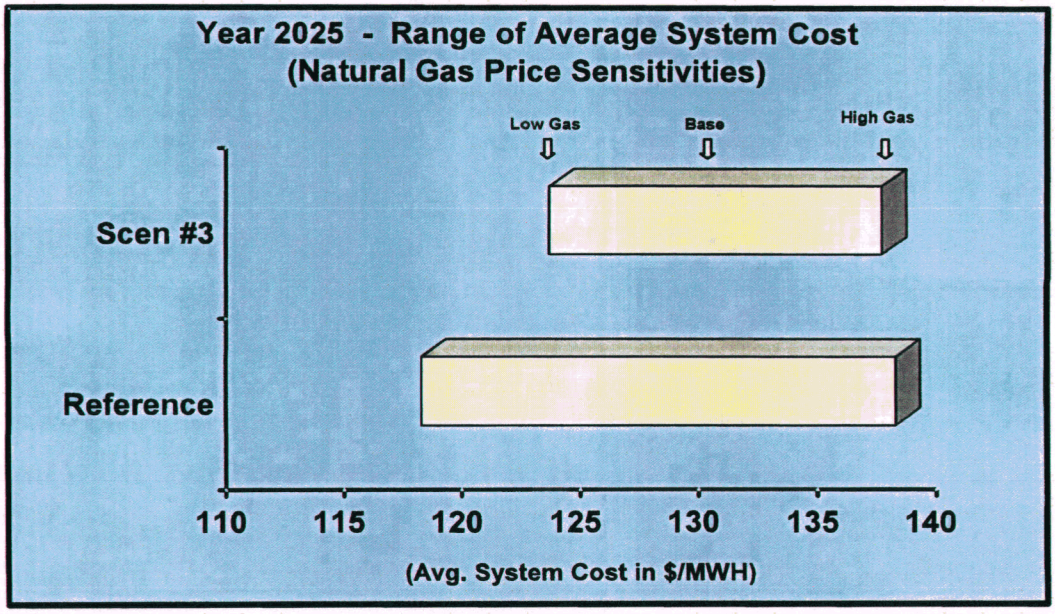


Figure 76 – High Natural Gas Price Sensitivity Case for Energy Efficiency Scenarios



The next figure provides another perspective on the risk reduction impacts of pursuing resources that do not consume natural gas. The following figure illustrates the range of average system cost for the All Gas reference with resource Scenario 3. As shown in a previous figure (Figure 75), resource Scenario 3 provides a substantial reduction in natural gas burns versus the reference case. In 2025, this amounts to a reduction of about 50 BCF. The figure compares the range of potential impacts on average system cost under both high and low natural gas price sensitivities. This is an excellent illustration of the much wider range of outcomes under the All Gas reference resulting from the significantly higher natural gas consumption. Scenario 3 would provide a meaningful reduction in the volatility of customer prices.

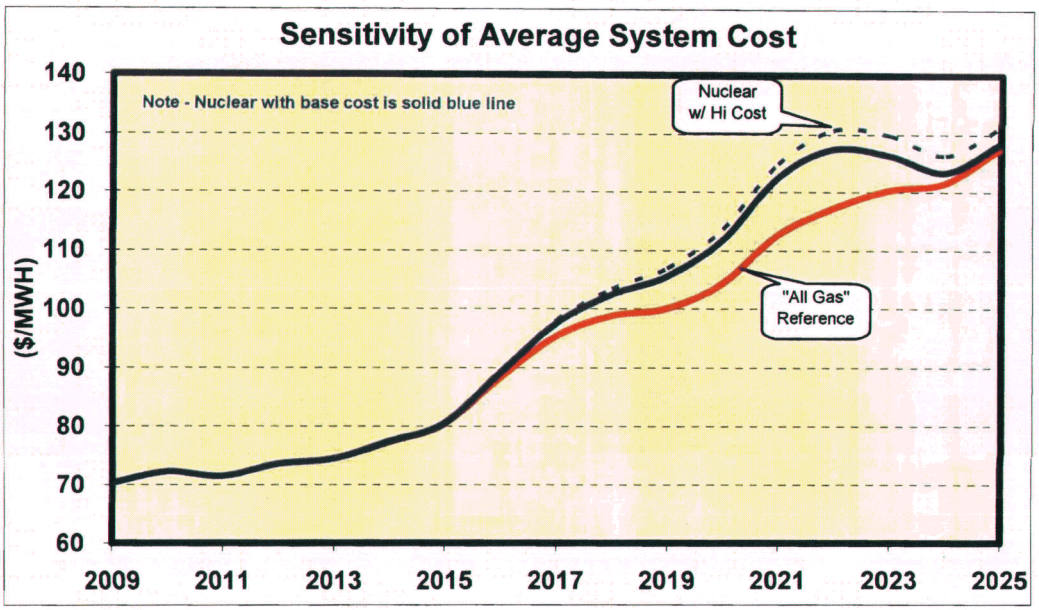
Figure 77 – Illustration of Risk Reduction Benefits



The next sensitivity analysis concerns the cost of constructing new nuclear power plants. With any major construction project, there is significant uncertainty surrounding construction costs. With nuclear power plants, this uncertainty is presently heightened because of the lack of recent experience in this country with the construction of new nuclear plants. For this sensitivity, the cost of building a new nuclear power plant is increased by 25 percent relative to the base assumption. Although this sensitivity analysis was conducted for all resource scenarios that include a nuclear addition, the results are illustrated in the following figure for the Nuclear scenario only (this scenario included 630 MWs of nuclear resource). The figure shows the impact on the average system cost for the increase in nuclear construction costs as compared to the All Gas reference. Following the in-service date of a nuclear plant, average system cost is increased by about $3/MWh with the assumed 25 percent higher construction cost. From

a 30-year economics perspective, the increased nuclear construction costs increase the cost of this scenario to $1.04 billion above the All Gas reference.[111]

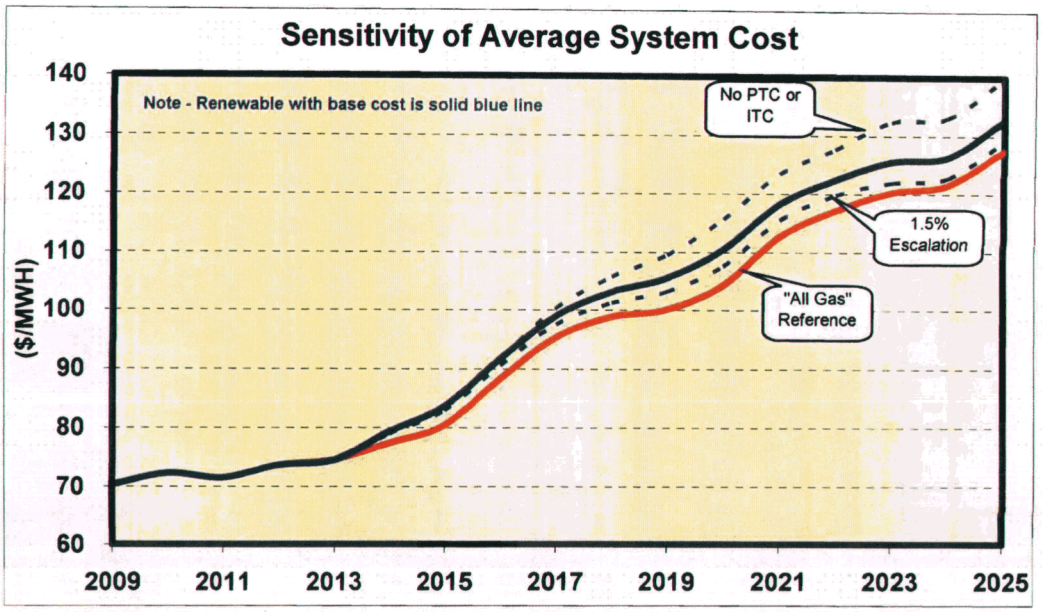
Figure 78 – Impact of Higher Nuclear Construction Cost



The following sensitivity comparisons illustrate several uncertainties around the future cost of renewable resources. For simplicity, the uncertainties are shown in the figure below by comparing the Solar scenario (in which 1,400 MWs of CSP are added) versus the All Gas reference. The first sensitivity results in a large increase in cost for renewable resources under the assumption that the current federal tax incentives are not extended beyond their current expiration dates. The second sensitivity assumes that solar becomes more cost competitive with conventional resources over time by assuming a cost escalation rate of one-half the assumed rate of inflation. Figure 79 shows that under this second sensitivity, the cost differential between renewable resources and conventional resources (as portrayed through the All Gas reference) is greatly reduced and the renewable scenario approaches parity by 2025.

[111] The base nuclear scenario showed a cost of $0.54 billion more than the reference case.

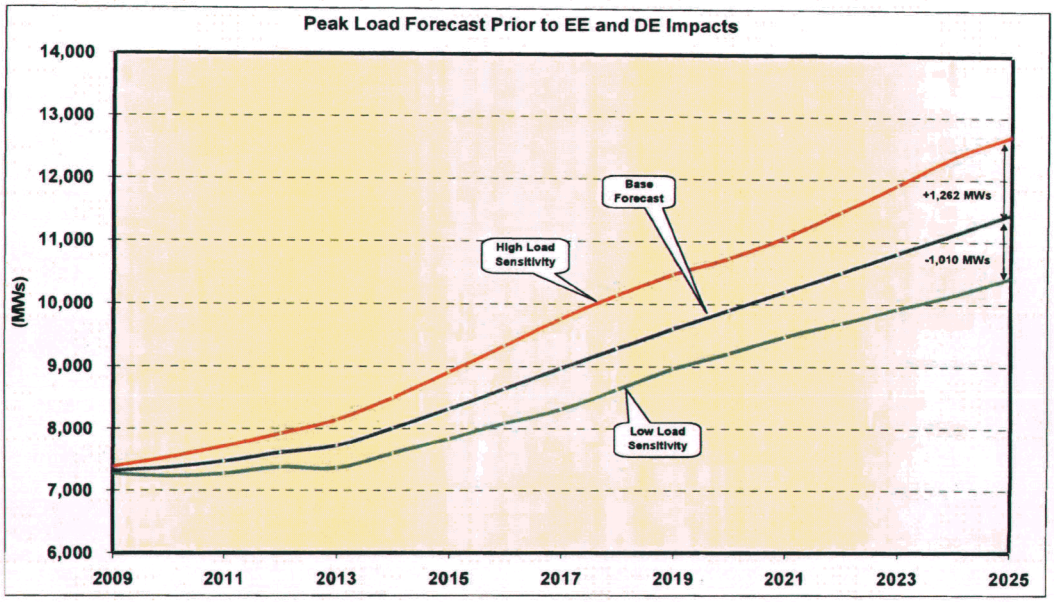
Figure 79 – Renewable Cost Sensitivity Analysis



The current economic conditions highlight the difficulty in forecasting customer growth. Long-term growth trends will exhibit more stability than short-term trends that are influenced by economic cycles; however, near-term volatility induces a degree of uncertainty in forecasting long-term customer growth. The following figure illustrates the impact of changes in long-term customer growth rates on APS's peak load forecast. Figure 80 shows the high and low load forecast sensitivity cases along with the base case peak load forecast.[112]

[112] All load forecasts depict peak load prior to factoring the impact of customer side efforts such as energy efficiency and distributed energy.

Figure 80 – Peak Load Forecast Sensitivities



The high load sensitivity case results in a peak load that is more than 1,200 MWs higher than the base case in 2025. The low load sensitivity case results in a peak load that is approximately 1,000 MWs lower than the base case in 2025.

One measure of the robustness of this Resource Plan is the degree of flexibility it embodies. This flexibility is largely dependent upon the type of resources included and the timing of necessary commitments to those resources. For example, APS's Resource Plan includes a substantial quantity of gas-fired peaking resources. This type of resource is relatively flexible because decisions related to resource procurement can generally be made within about three years of the needed in-service date of that resource. Additionally, these resources can be procured in relatively small increments such that the quantity of planned additions can be adjusted to more closely match the expected need. The renewable resources specified in APS's Resource Plan also provide for a degree of flexibility. The lead-times associated with these resources are relatively short, allowing for adjustment of procurement efforts in response to changes in customer needs. In contrast, baseload resource additions typically represent the biggest challenge to the flexibility of a resource plan. Baseload resources can involve extensive lead-times in which major capital commitments must be made many years in advance of the needed in-service date. For a new nuclear plant, the actual construction and startup testing phase is projected to be about 5 years. However, significant commitments related to project development and procurement of long lead-time plant components must precede the construction phase. Additionally, these large baseload projects may be carried out by a consortium of utility companies due to the size of the required investment and relatively large size of individual nuclear units. As the project development moves forward, it can become increasingly costly and difficult to make adjustments in response to changing

customer load forecasts as agreement must be reached with other owners and contractual commitments may need to be modified.

In response to higher or lower customer load relative to forecast conditions used to develop this Resource Plan, APS will revisit and adjust the size and timing of resources included in this Resource Plan. The extent and nature of the revisions will be largely dependent upon the circumstances that exist at the time and will factor in other appropriate variables in addition to the changed customer requirements. However, all other things being equal, APS will strive to maintain the overall philosophy of this Resource Plan. Some of the resource plan changes that would be considered in response to changing customer requirements include:

1. Changes to the timing and quantity of future peaking resources. For example, under the low load sensitivity, the first required peaking resource addition could be delayed until 2017 and the total amount of peaking resource needed by 2025 would then be reduced.

2. Timing and quantity of baseload generation could change. For example, under the high load sensitivity, APS would require increased baseload generation amounts. Advancing the in-service date for the baseload unit additions may not be possible depending upon the status of the development process. Similarly, for the low load sensitivity case, less baseload generation may be required.

3. Adjustments to the timing and quantity of renewable resources could also occur in response to changing load forecasts. These adjustments could be constrained by the necessity to comply with the minimum levels established by the RES rules. Otherwise, with the relatively short lead-times associated with renewable resources, procurement plans can be adjusted to either increase or decrease renewable resource additions in response to changing customer demand and opportunities unveiled by technology development and cost reductions.

Water is playing an increasing role in resource technology selection in Arizona and in the southwest. While it is possible to model portfolio demand on water resources, those modeling results are filled with speculation surrounding public policy, technology efficiencies, and ultimately the availability of actual water resources (including potential future sources for effluent). For example, recent public policy decisions suggest that future gas generation will require the use of dry cooling technologies. While demanding similar water usage, planned CSP facilities in the southwest are not currently employing hybrid or dry cooling technologies. While this is likely the result of a combination of factors (the public desire to increase solar usage and moderate costs, and little operating experience with dry cooled CSP), it is not presently clear whether or when this might

change, and if it does, what the resulting impact will be to the cost and ultimate desirability of CSP.

Analysis of potential water use for the modeled scenarios is included in Appendix 2. The All Gas reference serves as a useful benchmark for prospective demands on water resources. Water consumption in 2009 is expected to be approximately 56,000 acre-feet (total system including estimated impact of water consumed through "tolled" units controlled through long-term PPAs). The All Gas reference projects water usage in 2025 to exceed 72,000 acre-feet. Because all future natural gas resources are assumed to be dry-cooled, all increases in water consumption can be attributed to resource additions (specifically CSP and geothermal) associated with meeting the RES requirements. APS anticipates that future revisions of the Resource Plan will place an increased focus on water consumption and more specifically on strategies to minimize water consumption for the resources selected.

TABLE 37.
SUPPLY SIDE SCENARIO 3 (SS-3)
800 MW NUCLEAR and 400 MW SOLAR GENERATION by 2025
LOADS AND RESOURCES SUMMARY

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1.	**Load Requirements:**																	
2.	Peak Demand (prior to EE and DE)	7,321	7,372	7,474	7,612	7,722	8,005	8,316	8,644	8,976	9,293	9,605	9,905	10,207	10,513	10,820	11,128	11,442
3.	Reserve Requirements	1,000	1,034	1,049	1,070	1,086	1,129	1,175	1,225	1,274	1,322	1,369	1,414	1,531	1,577	1,623	1,669	1,716
4.	**Total Load Requirements**	8,321	8,406	8,523	8,681	8,808	9,134	9,491	9,869	10,250	10,615	10,973	11,319	11,738	12,090	12,442	12,798	13,158
5.	**Existing Resources:**																	
6.	Existing Generation	6,267	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270
7.	Seasonal Exchange	480	480	480	480	480	480	480	480	480	480	480	480	0	0	0	0	0
8.	Purchases - Renewable Energy *	55	61	61	331	326	326	326	326	326	326	326	326	325	325	315	315	315
9.	Purchase - SRP T&C	238	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Purchases - Gas CC Tolling	500	1,060	1,060	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0
11.	Purchases - Market Call Options	650	650	650	650	650	650	650	150	150	150	150	150	150	0	0	0	0
12.	Demand Response Contract	0	28	59	83	83	83	83	105	105	105	105	105	105	105	105	105	0
13.	**Total Existing Resources:**	8,190	8,548	8,579	8,873	8,868	8,868	8,868	8,391	7,891	7,891	7,890	7,330	6,850	6,700	6,690	6,690	6,585
14.	**Future Planned Resource Additions:**																	
15.	Energy Efficiency *	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16.	Distributed Renewable Energy *	16	26	39	55	65	75	86	107	129	152	176	200	226	253	281	309	339
17.	Renewable Energy Resources *	0	0	0	0	70	220	320	343	343	343	343	343	423	423	703	703	793
18.	Baseload Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	400	800	800	800
19.	Gas Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	528	528	528	528	528	528
20.	Peaking Resources	0	0	0	0	0	0	0	564	1,410	1,786	2,068	2,444	3,290	3,290	3,290	3,290	3,666
21.	Short-Term Market Purchases	0	0	0	0	0	0	217	465	478	444	496	474	421	496	151	478	447
22.	**Total Future Resource Additions:**	16	26	39	55	135	295	623	1,478	2,359	2,724	3,083	3,988	4,888	5,389	5,752	6,107	6,573
23.	**Total Resources:**	8,206	8,574	8,618	8,928	9,003	9,163	9,491	9,869	10,250	10,615	10,973	11,319	11,738	12,090	12,442	12,798	13,158
	New Renewable Nameplate Capacity •	100	106	106	389	459	659	809	855	855	855	955	955	1,035	1,035	1,314	1,314	1,664

* Note resources shown as their expected capacity contribution at time of system peak
- Existing resources exclude short-term market purchase or sale transactions
• New Renewable Nameplate Capacity includes all future renewable resources plus any existing renewable resources in service after Jan 1, 2009. (Lines 8 and 17)

TABLE 38.
SUPPLY SIDE SCENARIO 3 (SS-3)
800 MW NUCLEAR and 400 MW SOLAR GENERATION by 2025
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	(10.8)	51.4	2,535.0	74.5
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	(11.7)	54.9	2,766.5	78.9
2015	639.1	855.8	51.6	462.7	89.7	2,098.9	125.2	678.0	803.3	(33.0)	56.8	29.2	(12.2)	58.3	3,001.3	82.7
2016	835.8	936.2	59.0	438.2	137.8	2,407.0	153.7	720.8	874.4	(37.0)	64.8	27.0	(12.7)	93.4	3,416.8	91.0
2017	1,064.4	1,160.4	75.1	455.2	160.8	2,915.9	164.4	611.0	775.4	(39.2)	72.4	23.8	(13.4)	100.0	3,834.9	98.9
2018	1,265.3	1,333.4	89.8	473.7	177.6	3,339.8	127.7	547.1	674.7	(38.4)	82.2	21.4	(14.3)	107.3	4,172.8	104.4
2019	1,404.5	1,361.8	92.1	489.0	181.5	3,528.9	129.6	589.9	719.5	(5.2)	85.9	20.7	(15.2)	114.3	4,448.9	108.1
2020	1,678.1	1,593.7	114.6	513.3	194.0	4,093.7	72.5	471.3	543.8	(2.6)	93.3	18.1	(16.5)	121.1	4,850.9	114.8
2021	1,995.4	1,686.5	126.1	544.6	240.9	4,593.5	63.5	578.2	641.8	0.0	102.4	23.6	(17.6)	127.8	5,471.6	126.3
2022	2,288.1	1,718.4	129.0	581.8	256.3	4,973.6	57.5	554.4	611.9	0.0	110.3	22.7	(19.0)	134.8	5,834.3	131.3
2023	2,288.8	1,557.1	116.6	628.8	249.0	4,840.3	23.2	778.6	801.9	0.0	94.6	26.5	(20.5)	142.6	5,885.2	129.2
2024	2,132.9	1,609.1	120.0	653.3	241.7	4,757.1	33.4	779.8	813.2	0.0	94.5	25.6	(21.7)	150.3	5,818.9	124.8
2025	2,159.1	1,650.8	124.0	671.0	255.7	4,860.5	56.1	998.1	1,054.2	0.0	103.3	32.1	(23.0)	158.2	6,185.3	129.5
2026	2,223.5	1,808.0	137.7	691.4	259.1	5,119.7	48.9	1,000.6	1,049.5	0.0	110.9	30.8	(24.3)	92.2	6,378.7	130.2
2027	2,332.2	1,949.5	153.1	714.8	252.8	5,402.5	11.9	1,015.5	1,027.5	0.0	120.9	30.4	(25.4)	92.2	6,648.0	132.3
2028	2,414.9	2,067.6	167.7	742.1	245.5	5,837.8	48.9	1,020.6	1,069.5	0.0	132.3	29.1	(26.8)	98.1	6,940.0	134.8
2029	2,471.1	2,257.6	183.8	767.6	239.5	5,919.6	43.0	1,019.4	1,062.4	0.0	148.7	27.6	(28.7)	98.0	7,227.6	136.6
2030	2,549.2	2,420.8	197.7	794.9	256.1	6,218.7	41.7	1,011.5	1,053.2	0.0	160.1	26.1	(30.7)	97.3	7,524.7	138.7
2031	2,595.6	2,574.3	211.6	822.2	260.4	6,464.0	59.0	1,012.9	1,071.9	0.0	172.8	24.5	(32.2)	96.8	7,797.7	140.3
2032	2,647.4	2,810.6	231.3	852.1	278.2	6,819.5	53.3	1,018.1	1,071.3	0.0	190.3	22.8	(35.3)	96.2	8,164.9	143.7
2033	2,737.1	2,965.2	245.5	882.2	283.5	7,113.3	43.8	1,049.9	1,093.7	0.0	199.1	22.7	(37.3)	95.9	8,487.4	145.7
2034	2,780.7	3,119.5	262.9	912.4	275.0	7,350.4	58.3	1,278.4	1,336.7	0.0	222.4	32.4	(40.5)	95.1	8,996.4	151.0
2035	2,829.6	3,316.0	281.2	943.1	266.6	7,636.5	47.1	1,321.5	1,368.7	0.0	238.1	32.3	(43.3)	94.4	9,326.7	153.1
2036	2,901.6	3,472.3	295.0	980.7	288.3	7,937.9	36.1	1,370.0	1,406.1	0.0	251.9	32.1	(46.7)	93.8	9,675.1	155.6
2037	2,937.4	3,695.6	317.2	993.2	294.1	8,237.4	99.7	1,414.6	1,514.4	0.0	273.7	31.9	(46.9)	93.3	10,103.8	158.9
CPW@ 7.86%																
(2008-2017)	4,236.0	5,503.7	320.5	2,890.2	338.5	13,288.8	726.6	2,971.1	3,697.8	(122.8)	331.0	155.8	(57.1)	415.1	17,708.6	76.6
(2008-2027)	10,274.6	10,556.9	690.8	4,722.9	1,051.2	27,296.4	946.8	5,166.7	6,113.5	(142.6)	641.0	232.9	(117.2)	807.6	34,831.6	93.7
(2008-2037)	14,215.2	14,661.1	1,031.8	5,988.6	1,445.8	37,342.5	1,023.6	6,834.4	7,858.0	(142.6)	922.8	274.2	(169.8)	950.7	47,035.8	103.2

TABLE 39.
SUPPLY SIDE SCENARIO 3 (SS-3)
800 MW NUCLEAR and 400 MW SOLAR GENERATION by 2025
OWN LOAD ENERGY REQUIREMENTS
(GWh)

2008	32,171.7
2009	32,731.8
2010	32,892.0
2011	33,217.8
2012	33,673.2
2013	34,025.9
2014	35,064.3
2015	36,292.3
2016	37,534.2
2017	38,791.4
2018	39,981.8
2019	41,136.5
2020	42,238.3
2021	43,333.3
2022	44,435.5
2023	45,535.2
2024	46,637.5
2025	47,745.3
2026	48,993.4
2027	50,246.5
2028	51,500.3
2029	52,917.3
2030	54,252.7
2031	55,588.2
2032	56,833.5
2033	58,259.0
2034	59,594.5
2035	60,929.8
2036	62,166.8
2037	63,600.7
(2008-2017)	346,394.6
(2008-2027)	796,677.8
(2008-2037)	1,372,320.6

TABLE 40.
SUPPLY SIDE SCENARIO 4 (SS-4)
800 MW NUCLEAR and 2,000 MW SOLAR GENERATION by 2025
LOADS AND RESOURCES SUMMARY

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1.	**Load Requirements:**																	
2.	Peak Demand (prior to EE and DE)	7,321	7,372	7,474	7,612	7,722	8,005	8,316	8,644	8,976	9,293	9,605	9,905	10,207	10,513	10,820	11,128	11,442
3.	Reserve Requirements	1,000	1,034	1,049	1,070	1,086	1,129	1,175	1,225	1,274	1,322	1,369	1,414	1,531	1,577	1,623	1,669	1,716
4.	**Total Load Requirements**	8,321	8,406	8,523	8,681	8,808	9,134	9,491	9,869	10,250	10,615	10,973	11,319	11,738	12,090	12,442	12,798	13,158
5.	**Existing Resources:**																	
6.	Existing Generation	6,267	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270	6,270
7.	Seasonal Exchange	480	480	480	480	480	480	480	480	480	480	480	480	0	0	0	0	0
8.	Purchases - Renewable Energy *	55	61	61	331	326	326	326	326	326	326	326	326	325	325	315	315	315
9.	Purchase - SRP T&C	238	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Purchases - Gas CC Tolling	500	1,060	1,060	1,060	1,060	1,060	1,060	1,060	560	560	560	0	0	0	0	0	0
11.	Purchases - Market Call Options	650	650	650	650	650	650	650	150	150	150	150	150	150	0	0	0	0
12.	Demand Response Contract	0	28	59	83	83	83	83	105	105	105	105	105	105	105	105	105	0
13.	**Total Existing Resources:**	8,190	8,548	8,579	8,873	8,868	8,868	8,868	8,391	7,891	7,891	7,890	7,330	6,850	6,700	6,690	6,690	6,585
14.	**Future Planned Resource Additions:**																	
15.	Energy Efficiency *	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16.	Distributed Renewable Energy *	16	26	39	55	65	75	86	107	129	152	176	200	226	253	281	309	339
17.	Renewable Energy Resources *	0	0	0	0	70	220	370	570	770	970	1,170	1,370	1,515	1,515	1,795	1,795	1,885
18.	Baseload Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	400	800	800	800
19.	Gas Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20.	Peaking Resources	0	0	0	0	0	0	0	376	1,034	1,128	1,316	1,974	2,726	2,726	2,726	2,726	3,102
21.	Short-Term Market Purchases	0	0	0	0	0	0	167	426	427	475	421	445	421	496	151	478	447
22.	**Total Future Resource Additions:**	16	26	39	55	135	295	623	1,478	2,359	2,724	3,083	3,988	4,888	5,389	5,752	6,107	6,573
23.	**Total Resources:**	8,206	8,574	8,618	8,928	9,003	9,163	9,491	9,869	10,250	10,615	10,973	11,319	11,738	12,090	12,442	12,798	13,158
	New Renewable Nameplate Capacity •	100	106	106	389	459	659	859	1,159	1,459	1,759	2,159	2,459	2,619	2,619	2,898	2,898	3,248

* Note resources shown as their expected capacity contribution at time of system peak
- Existing resources exclude short-term market purchase or sale transactions
• New Renewable Nameplate Capacity includes all future renewable resources plus any existing renewable resources in service after Jan 1, 2009. (Lines 8 and 17)

TABLE 41.
SUPPLY SIDE SCENARIO 4 (SS-4)
800 MW NUCLEAR and 2,000 MW SOLAR GENERATION by 2025
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	0.0	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	0.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	0.0	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	0.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	0.0	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	(10.8)	51.4	0.0	2,535.0	74.5
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	(11.7)	54.9	(0.1)	2,766.4	78.9
2015	639.1	846.7	51.1	462.7	89.7	2,089.4	120.9	707.6	828.5	(33.0)	56.0	30.6	(12.2)	58.3	(0.1)	3,017.4	83.1
2016	810.8	893.6	56.0	437.2	137.8	2,335.4	147.5	863.5	1,011.1	(37.0)	61.7	33.7	(12.8)	93.4	(0.0)	3,485.4	92.9
2017	996.9	1,067.7	67.8	452.4	160.2	2,745.0	158.0	893.5	1,051.5	(39.2)	65.5	36.7	(13.5)	100.0	(0.0)	3,946.0	101.7
2018	1,142.4	1,184.6	78.7	468.4	161.3	3,035.4	128.6	974.2	1,102.8	(38.4)	71.6	40.7	(14.4)	107.3	(0.0)	4,304.9	107.7
2019	1,244.7	1,168.9	77.5	481.8	157.3	3,130.3	125.4	1,163.1	1,288.5	(5.2)	71.6	46.4	(15.5)	114.3	(0.9)	4,629.5	112.5
2020	1,458.0	1,342.9	90.4	501.3	170.4	3,562.9	66.1	1,214.9	1,281.1	(2.6)	76.4	50.4	(16.8)	121.1	(1.4)	5,071.1	120.1
2021	1,728.5	1,421.8	96.9	528.7	217.2	3,993.0	63.4	1,370.7	1,434.1	0.0	84.8	57.6	(17.8)	127.8	(2.8)	5,676.8	131.0
2022	2,020.5	1,442.2	98.1	564.9	233.0	4,358.7	59.5	1,354.9	1,414.4	0.0	91.4	56.2	(19.3)	134.8	(2.6)	6,033.6	135.8
2023	2,031.1	1,304.1	86.8	611.4	226.4	4,259.8	25.2	1,578.8	1,604.0	0.0	76.7	59.5	(21.1)	142.6	(20.1)	6,101.4	134.0
2024	1,884.8	1,364.5	90.5	635.4	268.2	4,243.5	35.2	1,582.2	1,617.5	0.0	76.8	57.9	(22.3)	150.3	(36.9)	6,086.9	130.5
2025	1,920.4	1,403.2	93.3	652.5	288.1	4,357.6	57.9	1,798.6	1,856.5	0.0	84.1	63.8	(23.6)	158.2	(39.1)	6,457.5	135.2
2026	1,994.2	1,538.8	104.5	672.4	280.9	4,590.8	50.6	1,800.8	1,851.4	0.0	91.2	61.9	(24.9)	92.2	(28.7)	6,633.8	135.4
2027	2,058.2	1,686.4	115.9	690.8	294.6	4,845.9	45.6	1,815.7	1,861.3	0.0	102.1	60.8	(25.9)	92.2	(24.8)	6,911.8	137.6
2028	2,131.6	1,801.0	125.2	714.8	296.9	5,069.5	61.0	1,822.5	1,883.5	0.0	114.5	58.7	(27.2)	98.1	(21.5)	7,175.5	139.3
2029	2,211.6	1,975.6	139.8	740.1	288.6	5,355.6	54.7	1,819.8	1,874.5	0.0	130.7	56.5	(29.1)	98.0	(12.8)	7,473.4	141.2
2030	2,300.1	2,134.2	152.5	766.5	304.2	5,657.6	52.9	1,811.8	1,864.7	0.0	141.7	54.1	(31.1)	97.3	(11.3)	7,773.0	143.3
2031	2,377.1	2,281.6	164.3	793.7	307.7	5,924.4	47.5	1,813.0	1,860.5	0.0	154.0	51.7	(32.6)	96.8	(9.2)	8,045.5	144.7
2032	2,452.3	2,506.5	183.1	823.3	300.2	6,265.4	42.2	1,820.1	1,862.3	0.0	171.3	49.1	(35.6)	96.2	(5.3)	8,403.5	147.9
2033	2,527.8	2,660.1	195.5	851.7	317.6	6,552.7	56.8	1,850.0	1,906.8	0.0	178.5	47.9	(37.6)	95.9	(4.0)	8,740.1	150.0
2034	2,586.0	2,818.5	210.0	881.3	320.6	6,816.5	46.4	2,078.5	2,124.9	0.0	201.7	56.5	(40.9)	95.1	(3.4)	9,250.4	155.2
2035	2,658.1	3,001.7	227.5	911.7	311.0	7,110.0	35.5	2,121.7	2,157.2	0.0	217.9	55.3	(43.7)	94.4	(2.5)	9,588.7	157.4
2036	2,713.1	3,151.7	239.7	947.4	331.4	7,383.4	74.7	2,171.8	2,246.6	0.0	229.9	54.0	(47.2)	93.8	(2.8)	9,957.7	160.2
2037	2,764.9	3,369.0	259.7	959.2	335.8	7,688.6	14.3	2,214.8	2,229.1	0.0	251.5	52.5	(47.2)	93.3	(1.5)	10,266.4	161.4
CPW@ 7.86%																	
(2008-2017)	4,191.7	5,433.7	315.2	2,888.3	338.2	13,167.1	718.2	3,192.1	3,910.3	(122.8)	325.8	166.0	(57.2)	415.1	(0.1)	17,804.2	77.1
(2008-2027)	9,530.1	9,741.7	604.8	4,675.7	1,032.8	25,585.1	944.7	7,646.5	8,591.3	(142.6)	582.9	337.5	(118.4)	807.6	(41.3)	35,602.1	95.8
(2008-2037)	13,141.1	13,405.3	873.5	5,897.4	1,491.8	34,809.0	1,018.9	10,505.1	11,524.0	(142.6)	835.8	417.7	(171.6)	950.7	(54.2)	48,168.8	105.6

TABLE 42.
SUPPLY SIDE SCENARIO 4 (SS-4)
800 MW NUCLEAR and 400 MW SOLAR GENERATION by 2025
OWN LOAD ENERGY REQUIREMENTS
(GWh)

2008	32,171.7
2009	32,731.8
2010	32,892.0
2011	33,217.8
2012	33,673.2
2013	34,025.9
2014	35,064.3
2015	36,292.3
2016	37,534.2
2017	38,791.4
2018	39,981.8
2019	41,136.5
2020	42,238.3
2021	43,333.3
2022	44,435.5
2023	45,535.2
2024	46,637.5
2025	47,745.3
2026	48,993.4
2027	50,246.5
2028	51,500.3
2029	52,917.3
2030	54,252.7
2031	55,588.2
2032	56,833.5
2033	58,259.0
2034	59,594.5
2035	60,929.8
2036	62,166.8
2037	63,600.7
(2008-2017)	346,394.6
(2008-2027)	796,677.8
(2008-2037)	1,372,320.6

TABLE 43.
SUPPLY SIDE SCENARIO COMPARISONS
ANNUAL NATURAL GAS BURNS
(BCF)

	SS-D	SS-N	SS-S1	SS-S2	SS-1	SS-2	SS-3	SS-4
2008	73.6	73.6	73.6	73.6	73.6	73.6	73.6	73.6
2009	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6
2010	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5
2011	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9
2012	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9
2013	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0
2014	85.1	85.1	80.1	80.9	82.6	81.4	81.4	81.4
2015	92.8	92.8	83.3	84.5	88.1	85.8	87.0	85.8
2016	103.2	103.2	88.6	92.7	96.1	92.0	96.5	91.0
2017	113.3	113.3	92.7	94.7	105.6	100.0	105.9	94.7
2018	122.2	122.2	95.9	98.3	114.3	107.1	114.5	97.6
2019	120.5	120.5	89.8	92.9	112.5	105.5	113.0	91.8
2020	129.5	129.5	94.1	97.6	121.3	116.0	121.6	95.8
2021	132.8	134.7	100.4	102.6	126.9	119.9	127.1	100.5
2022	144.9	136.0	112.5	114.6	130.2	119.6	124.9	97.9
2023	144.3	117.1	112.5	114.5	115.2	101.5	102.1	78.8
2024	151.4	118.5	119.5	121.7	117.9	103.0	102.2	80.5
2025	154.5	119.8	122.8	124.9	119.5	103.9	102.8	81.4
2026	165.3	131.0	133.1	135.3	130.7	114.6	113.8	90.3
2027	170.7	138.8	141.6	140.9	137.8	124.8	122.3	99.6
2028	180.9	146.1	153.5	150.5	145.7	131.7	128.5	105.9
2029	192.0	157.8	164.2	161.8	157.2	143.8	140.5	116.7
2030	199.6	164.5	171.3	169.2	166.6	150.3	149.1	125.4
2031	208.2	171.9	179.6	177.5	174.8	157.8	156.8	133.0
2032	223.1	188.3	195.1	192.7	191.0	174.3	173.4	148.8
2033	231.7	194.5	204.0	201.2	197.8	180.3	179.1	154.8
2034	237.9	201.8	211.8	208.1	205.7	188.3	187.0	163.5
2035	245.6	210.9	218.6	215.6	214.2	196.9	196.2	172.1
2036	252.5	216.6	225.6	221.7	220.1	202.7	201.6	177.6
2037	265.4	228.4	239.8	235.4	232.7	214.1	213.1	188.9
(2008-2017)	841.9	841.9	792.2	800.4	819.9	806.7	818.3	800.3
(2008-2027)	2,277.9	2,110.1	1,914.4	1,943.5	2,046.1	1,922.5	1,962.6	1,714.7
(2008-2037)	4,514.8	3,991.0	3,877.9	3,877.4	3,952.0	3,662.7	3,688.0	3,201.3

TABLE 44.
SUPPLY SIDE SCENARIO COMPARISONS
CO2 TOTAL PLANT EMISSIONS
(Tons)

	SS-D	SS-N	SS-S1	SS-S2	SS-1	SS-2	SS-3	SS-4
2008	18,427,317	18,427,317	18,427,317	18,427,317	18,427,317	18,427,317	18,427,317	18,427,317
2009	18,528,365	18,528,365	18,528,365	18,528,365	18,528,365	18,528,365	18,528,365	18,528,365
2010	18,715,038	18,715,038	18,715,038	18,715,038	18,715,038	18,715,038	18,715,038	18,715,038
2011	18,537,583	18,537,583	18,537,583	18,537,583	18,537,583	18,537,583	18,537,583	18,537,583
2012	18,524,901	18,524,901	18,524,901	18,524,901	18,524,901	18,524,901	18,524,901	18,524,901
2013	18,554,573	18,554,573	18,554,573	18,554,517	18,554,573	18,554,573	18,554,573	18,554,573
2014	19,032,066	19,032,066	18,656,706	18,642,023	18,842,213	18,712,756	18,712,756	18,712,756
2015	19,596,172	19,596,172	18,832,297	18,820,279	19,215,617	18,944,747	19,040,972	18,944,533
2016	20,389,992	20,389,992	19,247,885	19,431,077	19,836,969	19,438,791	19,781,250	19,301,580
2017	21,366,129	21,366,129	19,816,056	19,836,804	20,801,747	20,280,488	20,772,355	19,837,249
2018	22,355,551	22,355,551	20,418,823	20,462,304	21,786,428	21,171,535	21,764,118	20,399,098
2019	22,458,796	22,458,796	20,083,273	20,128,074	21,895,307	21,257,763	21,857,022	19,995,605
2020	22,694,748	22,694,748	20,109,096	20,186,555	22,122,424	21,704,731	22,093,395	19,984,638
2021	22,925,541	23,072,863	20,580,416	20,535,663	22,514,625	21,987,382	22,486,257	20,329,010
2022	23,328,987	22,730,589	21,114,799	21,063,575	22,336,562	21,512,197	21,904,897	19,712,318
2023	23,357,181	21,406,412	21,086,045	21,057,068	21,303,225	20,128,783	20,192,297	17,882,585
2024	23,999,477	21,543,265	21,752,540	21,709,783	21,532,448	20,199,690	20,163,750	17,914,649
2025	24,117,103	21,497,466	21,890,957	21,854,705	21,526,614	20,170,971	20,075,169	17,832,902
2026	24,588,397	22,126,660	22,403,126	22,368,343	22,124,959	20,800,368	20,761,610	18,543,143
2027	25,128,892	22,805,470	23,148,196	22,900,101	22,794,507	21,680,306	21,493,199	19,468,554
2028	25,789,503	23,258,448	23,963,182	23,589,209	23,294,595	22,221,349	21,908,665	19,944,674
2029	26,515,694	24,122,076	24,674,824	24,320,194	24,113,556	23,108,415	22,803,346	20,864,884
2030	27,273,075	24,832,831	25,396,839	25,065,405	25,000,670	23,795,507	23,641,639	21,737,490
2031	27,853,542	25,382,003	25,944,559	25,634,663	25,610,063	24,339,933	24,240,635	22,354,327
2032	28,202,124	25,869,918	26,363,513	26,030,153	26,115,357	24,851,068	24,786,115	22,978,151
2033	29,027,070	26,608,783	27,214,098	26,898,751	26,863,375	25,611,354	25,528,444	23,745,465
2034	29,193,351	26,895,172	27,514,508	27,122,525	27,161,591	25,917,395	25,861,420	24,138,633
2035	30,013,610	27,775,106	28,267,772	27,933,167	28,016,185	26,795,941	26,755,216	25,009,015
2036	30,434,926	28,142,512	28,685,072	28,312,998	28,385,349	27,154,012	27,101,920	25,350,830
2037	31,056,553	28,716,348	29,423,384	29,056,111	29,008,031	27,741,530	27,676,169	25,960,526
(2008-2017)	191,672,136	191,672,136	187,840,721	188,017,904	189,984,323	188,664,559	189,595,110	188,083,895
(2008-2027)	426,626,809	414,363,955	400,427,993	400,284,075	409,921,424	399,278,285	402,386,824	380,146,397
(2008-2037)	711,986,257	675,967,151	667,875,743	664,247,252	673,490,197	650,814,790	652,690,393	612,230,392

TABLE 57.
RISK ANALYSIS A - CARBON COST AT $25/TON
SUPPLY SIDE SCENARIO 3 (SS-3/A)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	245.5	84.9	2,735.8	81.2
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	255.4	51.4	2,801.3	82.3
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	268.7	54.9	3,046.9	86.9
2015	639.1	855.8	51.6	462.7	89.7	2,098.9	125.2	678.0	803.3	(33.0)	56.8	29.2	287.6	58.3	3,301.1	91.0
2016	835.8	936.2	59.0	438.2	137.8	2,407.0	153.7	720.8	874.4	(37.0)	64.8	27.0	319.2	93.4	3,748.7	99.9
2017	1,064.4	1,160.4	75.1	455.2	160.8	2,915.9	164.4	611.0	775.4	(39.2)	72.4	23.8	359.5	100.0	4,207.8	108.5
2018	1,265.3	1,333.4	89.8	473.7	177.6	3,339.8	127.7	547.1	674.7	(38.4)	82.2	21.4	414.1	107.3	4,601.2	115.1
2019	1,404.5	1,361.8	92.1	489.0	181.5	3,528.9	129.6	589.9	719.5	(5.2)	85.9	20.7	443.9	114.3	4,908.0	119.3
2020	1,678.1	1,593.7	114.6	513.3	194.0	4,093.7	72.5	471.3	543.8	(2.6)	93.3	18.1	479.1	121.1	5,346.6	126.6
2021	1,995.4	1,686.5	126.1	544.6	240.9	4,593.5	63.5	578.2	641.8	0.0	102.4	23.6	534.3	127.8	6,023.4	139.0
2022	2,288.1	1,718.4	129.0	581.8	256.3	4,973.6	57.5	554.4	611.9	0.0	110.3	22.7	545.4	134.8	6,398.6	144.0
2023	2,288.8	1,557.1	116.6	628.8	249.0	4,840.3	23.2	778.6	801.9	0.0	94.6	26.5	517.1	142.6	6,422.9	141.1
2024	2,132.9	1,609.1	120.0	653.3	241.7	4,757.1	33.4	779.8	813.2	0.0	94.5	25.6	547.0	150.3	6,387.5	137.0
2025	2,159.1	1,650.8	124.0	671.0	255.7	4,860.5	56.1	998.1	1,054.2	0.0	103.3	32.1	575.5	158.2	6,783.7	142.1
2026	2,223.5	1,808.0	137.7	691.4	259.1	5,119.7	48.9	1,000.6	1,049.5	0.0	110.9	30.8	648.2	92.2	7,051.3	143.9
2027	2,332.2	1,949.5	153.1	714.8	252.8	5,402.5	11.9	1,015.5	1,027.5	0.0	120.9	30.4	726.1	92.2	7,399.6	147.3
2028	2,414.9	2,067.6	167.7	742.1	245.5	5,637.8	48.9	1,020.6	1,069.5	0.0	132.3	29.1	794.3	98.1	7,761.0	150.7
2029	2,471.1	2,257.6	183.8	767.6	239.5	5,919.6	43.0	1,019.4	1,062.4	0.0	148.7	27.6	884.3	98.0	8,140.6	153.8
2030	2,549.2	2,420.8	197.7	794.9	256.1	6,218.7	41.7	1,011.5	1,053.2	0.0	160.1	26.1	960.7	97.3	8,516.1	157.0
2031	2,595.6	2,574.3	211.6	822.2	260.4	6,464.0	59.0	1,012.9	1,071.9	0.0	172.8	24.5	1,030.5	96.8	8,860.4	159.4
2032	2,647.4	2,810.6	231.3	852.1	278.2	6,819.5	53.3	1,018.1	1,071.3	0.0	190.3	22.8	1,083.9	96.2	9,284.0	163.4
2033	2,737.1	2,965.2	245.5	882.2	283.5	7,113.3	43.8	1,049.9	1,093.7	0.0	199.1	22.7	1,150.0	95.9	9,674.7	166.1
2034	2,780.7	3,119.5	262.9	912.4	275.0	7,350.4	58.3	1,278.4	1,336.7	0.0	222.4	32.4	1,198.3	95.1	10,235.2	171.7
2035	2,829.6	3,316.0	281.2	943.1	266.6	7,636.5	47.1	1,321.5	1,368.7	0.0	238.1	32.3	1,276.8	94.4	10,646.8	174.7
2036	2,901.6	3,472.3	295.0	980.7	288.3	7,937.9	36.1	1,370.0	1,406.1	0.0	251.9	32.1	1,330.6	93.8	11,052.4	177.8
2037	2,937.4	3,695.6	317.2	993.2	294.1	8,237.4	99.7	1,414.6	1,514.4	0.0	273.7	31.9	1,401.8	93.3	11,552.5	181.6
CPW@ 7.86%																
(2008-2017)	4,236.0	5,503.7	320.5	2,890.2	338.5	13,288.8	726.6	2,971.1	3,697.8	(122.8)	331.0	155.8	959.2	415.1	18,724.9	81.0
(2008-2027)	10,274.6	10,556.9	690.8	4,722.9	1,051.2	27,296.4	946.8	5,166.7	6,113.5	(142.6)	641.0	232.9	2,624.8	807.6	37,573.6	101.1
(2008-2037)	14,215.2	14,661.1	1,031.8	5,988.6	1,445.8	37,342.5	1,023.6	6,834.4	7,858.0	(142.6)	922.8	274.2	4,217.1	950.7	51,422.6	112.8

TABLE 58.
RISK ANALYSIS A - CARBON COST AT $25/TON
SUPPLY SIDE SCENARIO 4 (SS-4/A)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	0.0	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	0.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	0.0	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	0.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	245.5	84.9	0.0	2,735.8	81.2
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	255.4	51.4	0.0	2,801.3	82.3
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	268.7	54.9	(0.1)	3,046.8	86.9
2015	639.1	846.7	51.1	462.7	89.7	2,089.4	120.9	707.6	828.5	(33.0)	56.0	30.6	285.0	58.3	(0.1)	3,314.6	91.3
2016	810.8	893.6	56.0	437.2	137.8	2,335.4	147.5	863.5	1,011.1	(37.0)	61.7	33.7	305.6	93.4	(0.0)	3,803.8	101.3
2017	996.9	1,067.7	67.8	452.4	160.2	2,745.0	158.0	893.5	1,051.5	(39.2)	65.5	36.7	332.3	100.0	(0.0)	4,291.8	110.6
2018	1,142.4	1,184.6	78.7	468.4	161.3	3,035.4	128.6	974.2	1,102.8	(38.4)	71.6	40.7	373.3	107.3	(0.0)	4,692.6	117.4
2019	1,244.7	1,168.9	77.5	481.8	157.3	3,130.3	125.4	1,163.1	1,288.5	(5.2)	71.6	46.4	386.5	114.3	(0.9)	5,031.4	122.3
2020	1,458.0	1,342.9	90.4	501.3	170.4	3,562.9	66.1	1,214.9	1,281.1	(2.6)	76.4	50.4	412.1	121.1	(1.4)	5,500.0	130.2
2021	1,728.5	1,421.8	96.9	528.7	217.2	3,993.0	63.4	1,370.7	1,434.1	0.0	84.8	57.6	463.6	127.8	(2.8)	6,158.2	142.1
2022	2,020.5	1,442.2	98.1	564.9	233.0	4,358.7	59.5	1,354.9	1,414.4	0.0	91.4	56.2	471.4	134.8	(2.6)	6,524.2	146.8
2023	2,031.1	1,304.1	86.8	611.4	226.4	4,259.8	25.2	1,578.8	1,604.0	0.0	76.7	59.5	436.7	142.6	(20.1)	6,559.1	144.0
2024	1,884.8	1,364.5	90.5	635.4	268.2	4,243.5	35.2	1,582.2	1,617.5	0.0	76.8	57.9	466.2	150.3	(36.9)	6,575.4	141.0
2025	1,920.4	1,403.2	93.3	652.5	288.1	4,357.6	57.9	1,798.6	1,856.5	0.0	84.1	63.8	492.5	158.2	(39.1)	6,973.6	146.1
2026	1,994.2	1,538.8	104.5	672.4	280.9	4,590.8	50.6	1,800.8	1,851.4	0.0	91.2	61.9	563.8	92.2	(28.7)	7,222.5	147.4
2027	2,058.2	1,686.4	115.9	690.8	294.6	4,845.9	45.6	1,815.7	1,861.3	0.0	102.1	60.8	646.8	92.2	(24.8)	7,584.4	150.9
2028	2,131.6	1,801.0	125.2	714.8	296.9	5,069.5	61.0	1,822.5	1,883.5	0.0	114.5	58.7	715.1	98.1	(21.5)	7,917.7	153.7
2029	2,211.6	1,975.6	139.8	740.1	288.6	5,355.6	54.7	1,819.8	1,874.5	0.0	130.7	56.5	803.8	98.0	(12.8)	8,306.2	157.0
2030	2,300.1	2,134.2	152.5	766.5	304.2	5,657.6	52.9	1,811.8	1,864.7	0.0	141.7	54.1	879.2	97.3	(11.3)	8,683.3	160.1
2031	2,377.1	2,281.6	164.3	793.7	307.7	5,924.4	47.5	1,813.0	1,860.5	0.0	154.0	51.7	947.4	96.8	(9.2)	9,025.4	162.4
2032	2,452.3	2,506.5	183.1	823.3	300.2	6,265.4	42.2	1,820.1	1,862.3	0.0	171.3	49.1	1,001.9	96.2	(5.3)	9,441.0	166.1
2033	2,527.8	2,660.1	195.5	851.7	317.6	6,552.7	56.8	1,850.0	1,906.8	0.0	178.5	47.9	1,066.7	95.9	(4.0)	9,844.5	169.0
2034	2,586.0	2,818.5	210.0	881.3	320.6	6,816.5	46.4	2,078.5	2,124.9	0.0	201.7	56.5	1,115.4	95.1	(3.4)	10,406.7	174.6
2035	2,658.1	3,001.7	227.5	911.7	311.0	7,110.0	35.5	2,121.7	2,157.2	0.0	217.9	55.3	1,190.3	94.4	(2.5)	10,822.7	177.6
2036	2,713.1	3,151.7	239.7	947.4	331.4	7,383.4	74.7	2,171.8	2,246.6	0.0	229.9	54.0	1,241.2	93.8	(2.8)	11,246.0	180.9
2037	2,764.9	3,369.0	259.7	959.2	335.8	7,688.6	14.3	2,214.8	2,229.1	0.0	251.5	52.5	1,311.6	93.3	(1.5)	11,625.3	182.8
CPW@ 7.86%																	
(2008-2017)	4,191.7	5,433.7	315.2	2,888.3	338.2	13,167.1	718.2	3,192.1	3,910.3	(122.8)	325.8	166.0	938.1	415.1	(0.1)	18,799.5	81.4
(2008-2027)	9,530.1	9,741.7	604.8	4,675.7	1,032.8	25,585.1	944.7	7,646.5	8,591.3	(142.6)	582.9	337.5	2,384.3	807.6	(41.3)	38,104.9	102.6
(2008-2037)	13,141.1	13,405.3	873.5	5,897.4	1,491.8	34,809.0	1,018.9	10,505.1	11,524.0	(142.6)	835.8	417.7	3,853.0	950.7	(54.2)	52,193.4	114.5

TABLE 71.
RISK ANALYSIS B - CARBON COST AT $50/TON
SUPPLY SIDE SCENARIO 3 (SS-3/B)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	501.5	84.9	2,991.7	88.8
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	521.7	51.4	3,067.5	90.2
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	549.2	54.9	3,327.3	94.9
2015	639.1	855.8	51.6	462.7	89.7	2,098.9	125.2	678.0	803.3	(33.0)	56.8	29.2	587.5	58.3	3,601.0	99.2
2016	835.8	936.2	59.0	438.2	137.8	2,407.0	153.7	720.8	874.4	(37.0)	64.8	27.0	651.1	93.4	4,080.6	108.7
2017	1,064.4	1,160.4	75.1	455.2	160.8	2,915.9	164.4	611.0	775.4	(39.2)	72.4	23.8	732.4	100.0	4,580.7	118.1
2018	1,265.3	1,333.4	89.8	473.7	177.6	3,339.8	127.7	547.1	674.7	(38.4)	82.2	21.4	842.6	107.3	5,029.7	125.8
2019	1,404.5	1,361.8	92.1	489.0	181.5	3,528.9	129.6	589.9	719.5	(5.2)	85.9	20.7	903.1	114.3	5,367.2	130.5
2020	1,678.1	1,593.7	114.6	513.3	194.0	4,093.7	72.5	471.3	543.8	(2.6)	93.3	18.1	974.8	121.1	5,842.3	138.3
2021	1,995.4	1,686.5	126.1	544.6	240.9	4,593.5	63.5	578.2	641.8	0.0	102.4	23.6	1,086.1	127.8	6,575.2	151.7
2022	2,288.1	1,718.4	129.0	581.8	256.3	4,973.6	57.5	554.4	611.9	0.0	110.3	22.7	1,109.7	134.8	6,963.0	156.7
2023	2,288.8	1,557.1	116.6	628.8	249.0	4,840.3	23.2	778.6	801.9	0.0	94.6	26.5	1,054.8	142.6	6,960.6	152.9
2024	2,132.9	1,609.1	120.0	653.3	241.7	4,757.1	33.4	779.8	813.2	0.0	94.5	25.6	1,115.6	150.3	6,956.2	149.2
2025	2,159.1	1,650.8	124.0	671.0	255.7	4,860.5	56.1	998.1	1,054.2	0.0	103.3	32.1	1,173.9	158.2	7,382.2	154.6
2026	2,223.5	1,808.0	137.7	691.4	259.1	5,119.7	48.9	1,000.6	1,049.5	0.0	110.9	30.8	1,320.8	92.2	7,723.8	157.7
2027	2,332.2	1,949.5	153.1	714.8	252.8	5,402.5	11.9	1,015.5	1,027.5	0.0	120.9	30.4	1,477.6	92.2	8,151.1	162.2
2028	2,414.9	2,067.6	167.7	742.1	245.5	5,637.8	48.9	1,020.6	1,069.5	0.0	132.3	29.1	1,615.4	98.1	8,582.1	166.6
2029	2,471.1	2,257.6	183.8	767.6	239.5	5,919.6	43.0	1,019.4	1,062.4	0.0	148.7	27.6	1,797.2	98.0	9,053.5	171.1
2030	2,549.2	2,420.8	197.7	794.9	256.1	6,218.7	41.7	1,011.5	1,053.2	0.0	160.1	26.1	1,952.1	97.3	9,507.4	175.2
2031	2,595.6	2,574.3	211.6	822.2	260.4	6,464.0	59.0	1,012.9	1,071.9	0.0	172.8	24.5	2,093.1	96.8	9,923.0	178.5
2032	2,647.4	2,810.6	231.3	852.1	278.2	6,819.5	53.3	1,018.1	1,071.3	0.0	190.3	22.8	2,203.0	96.2	10,403.2	183.0
2033	2,737.1	2,965.2	245.5	882.2	283.5	7,113.3	43.8	1,049.9	1,093.7	0.0	199.1	22.7	2,337.3	95.9	10,861.9	186.4
2034	2,780.7	3,119.5	262.9	912.4	275.0	7,350.4	58.3	1,278.4	1,336.7	0.0	222.4	32.4	2,437.1	95.1	11,474.0	192.5
2035	2,829.6	3,316.0	281.2	943.1	266.6	7,636.5	47.1	1,321.5	1,368.7	0.0	238.1	32.3	2,596.9	94.4	11,966.9	196.4
2036	2,901.6	3,472.3	295.0	980.7	288.3	7,937.9	36.1	1,370.0	1,406.1	0.0	251.9	32.1	2,707.9	93.8	12,429.8	199.9
2037	2,937.4	3,695.6	317.2	993.2	294.1	8,237.4	99.7	1,414.6	1,514.4	0.0	273.7	31.9	2,850.5	93.3	13,001.2	204.4
CPW@ 7.86%																
(2008-2017)	4,236.0	5,503.7	320.5	2,890.2	338.5	13,288.8	726.6	2,971.1	3,697.8	(122.8)	331.0	155.8	1,975.4	415.1	19,741.1	85.4
(2008-2027)	10,274.6	10,556.9	690.8	4,722.9	1,051.2	27,296.4	946.8	5,166.7	6,113.5	(142.6)	641.0	232.9	5,366.8	807.6	40,315.6	108.5
(2008-2037)	14,215.2	14,661.1	1,031.8	5,988.6	1,445.8	37,342.5	1,023.6	6,834.4	7,858.0	(142.6)	922.8	274.2	8,603.9	950.7	55,809.5	122.4

TABLE 72.
RISK ANALYSIS B - CARBON COST AT $50/TON
SUPPLY SIDE SCENARIO 4 (SS-4/B)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	0.0	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	0.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	0.0	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	0.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	501.5	84.9	0.0	2,991.7	88.8
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	521.7	51.4	0.0	3,067.5	90.2
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	549.2	54.9	(0.1)	3,327.2	94.9
2015	639.1	846.7	51.1	462.7	89.7	2,089.4	120.9	707.6	828.5	(33.0)	56.0	30.6	582.2	58.3	(0.1)	3,611.8	99.5
2016	810.8	893.6	56.0	437.2	137.8	2,335.4	147.5	863.5	1,011.1	(37.0)	61.7	33.7	624.0	93.4	(0.0)	4,122.2	109.8
2017	996.9	1,067.7	67.8	452.4	160.2	2,745.0	158.0	893.5	1,051.5	(39.2)	65.5	36.7	678.1	100.0	(0.0)	4,637.6	119.6
2018	1,142.4	1,184.6	78.7	468.4	161.3	3,035.4	128.6	974.2	1,102.8	(38.4)	71.6	40.7	760.9	107.3	(0.0)	5,080.3	127.1
2019	1,244.7	1,168.9	77.5	481.8	157.3	3,130.3	125.4	1,163.1	1,288.5	(5.2)	71.6	46.4	788.4	114.3	(0.9)	5,433.4	132.1
2020	1,458.0	1,342.9	90.4	501.3	170.4	3,562.9	66.1	1,214.9	1,281.1	(2.6)	76.4	50.4	841.0	121.1	(1.4)	5,928.9	140.4
2021	1,728.5	1,421.8	96.9	528.7	217.2	3,993.0	63.4	1,370.7	1,434.1	0.0	84.8	57.6	945.1	127.8	(2.8)	6,639.7	153.2
2022	2,020.5	1,442.2	98.1	564.9	233.0	4,358.7	59.5	1,354.9	1,414.4	0.0	91.4	56.2	962.0	134.8	(2.6)	7,014.9	157.9
2023	2,031.1	1,304.1	86.8	611.4	226.4	4,259.8	25.2	1,578.8	1,604.0	0.0	76.7	59.5	894.4	142.6	(20.1)	7,016.8	154.1
2024	1,884.8	1,364.5	90.5	635.4	268.2	4,243.5	35.2	1,582.2	1,617.5	0.0	76.8	57.9	954.7	150.3	(36.9)	7,063.8	151.5
2025	1,920.4	1,403.2	93.3	652.5	288.1	4,357.6	57.9	1,798.6	1,856.5	0.0	84.1	63.8	1,008.7	158.2	(39.1)	7,489.8	156.9
2026	1,994.2	1,538.8	104.5	672.4	280.9	4,590.8	50.6	1,800.8	1,851.4	0.0	91.2	61.9	1,152.4	92.2	(28.7)	7,811.2	159.4
2027	2,058.2	1,686.4	115.9	690.8	294.6	4,845.9	45.6	1,815.7	1,861.3	0.0	102.1	60.8	1,319.5	92.2	(24.8)	8,257.1	164.3
2028	2,131.6	1,801.0	125.2	714.8	296.9	5,069.5	61.0	1,822.5	1,883.5	0.0	114.5	58.7	1,457.3	98.1	(21.5)	8,660.0	168.2
2029	2,211.6	1,975.6	139.8	740.1	288.6	5,355.6	54.7	1,819.8	1,874.5	0.0	130.7	56.5	1,636.6	98.0	(12.8)	9,139.1	172.7
2030	2,300.1	2,134.2	152.5	766.5	304.2	5,657.6	52.9	1,811.8	1,864.7	0.0	141.7	54.1	1,789.6	97.3	(11.3)	9,593.6	176.8
2031	2,377.1	2,281.6	164.3	793.7	307.7	5,924.4	47.5	1,813.0	1,860.5	0.0	154.0	51.7	1,927.3	96.8	(9.2)	10,005.4	180.0
2032	2,452.3	2,506.5	183.1	823.3	300.2	6,265.4	42.2	1,820.1	1,862.3	0.0	171.3	49.1	2,039.4	96.2	(5.3)	10,478.5	184.4
2033	2,527.8	2,660.1	195.5	851.7	317.6	6,552.7	56.8	1,850.0	1,906.8	0.0	178.5	47.9	2,171.0	95.9	(4.0)	10,948.8	187.9
2034	2,586.0	2,818.5	210.0	881.3	320.6	6,816.5	46.4	2,078.5	2,124.9	0.0	201.7	56.5	2,271.7	95.1	(3.4)	11,563.0	194.0
2035	2,658.1	3,001.7	227.5	911.7	311.0	7,110.0	35.5	2,121.7	2,157.2	0.0	217.9	55.3	2,424.2	94.4	(2.5)	12,056.6	197.9
2036	2,713.1	3,151.7	239.7	947.4	331.4	7,383.4	74.7	2,171.8	2,246.6	0.0	229.9	54.0	2,529.5	93.8	(2.8)	12,534.3	201.6
2037	2,764.9	3,369.0	259.7	959.2	335.8	7,688.6	14.3	2,214.8	2,229.1	0.0	251.5	52.5	2,670.5	93.3	(1.5)	12,984.1	204.2
CPW@ 7.86%																	
(2008-2017)	4,191.7	5,433.7	315.2	2,888.3	338.2	13,167.1	718.2	3,192.1	3,910.3	(122.8)	325.8	166.0	1,933.4	415.1	(0.1)	19,794.8	85.7
(2008-2027)	9,530.1	9,741.7	604.8	4,675.7	1,032.8	25,585.1	944.7	7,646.5	8,591.3	(142.6)	582.9	337.5	4,887.1	807.6	(41.3)	40,607.6	109.3
(2008-2037)	13,141.1	13,405.3	873.5	5,897.4	1,491.8	34,809.0	1,018.9	10,505.1	11,524.0	(142.6)	835.8	417.7	7,877.5	950.7	(54.2)	56,217.9	123.3

TABLE 85.
RISK ANALYSIS C - NATURAL GAS COST INCREASE of 30%
SUPPLY SIDE SCENARIO 3 (SS-3/C)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	878.1	40.5	404.2	8.6	1,855.5	72.7	338.9	411.6	(10.8)	38.5	13.6	(0.9)	26.6	2,334.1	72.5
2009	549.1	949.3	42.9	412.2	8.6	1,962.2	76.8	380.6	457.3	(8.3)	43.1	14.5	(1.2)	56.0	2,523.7	77.1
2010	573.3	900.7	43.1	422.9	20.9	1,961.0	115.7	409.8	525.5	(9.1)	43.4	24.5	(9.5)	54.8	2,590.6	78.8
2011	580.5	953.0	46.2	419.9	28.5	2,028.1	102.9	339.9	442.8	(10.0)	45.0	23.2	(9.9)	67.0	2,586.2	77.9
2012	578.7	861.8	42.9	423.8	30.7	1,937.9	105.2	506.8	612.0	(14.0)	44.9	27.8	(10.5)	84.9	2,682.9	79.7
2013	583.5	872.2	45.7	429.0	49.2	1,979.7	105.8	554.3	660.1	(19.0)	47.3	27.2	(10.9)	51.4	2,735.9	80.4
2014	601.0	1,005.2	53.8	446.3	66.1	2,172.4	106.2	609.6	715.8	(24.3)	54.8	29.0	(11.7)	54.9	2,990.8	85.3
2015	639.1	1,018.1	53.8	462.7	89.7	2,263.4	125.2	749.0	874.3	(33.0)	56.7	29.2	(12.2)	58.3	3,236.7	89.2
2016	835.8	1,112.3	61.1	438.2	137.8	2,585.2	153.7	802.8	956.4	(37.0)	64.8	27.0	(12.7)	93.4	3,677.0	98.0
2017	1,064.4	1,392.9	76.2	455.2	160.8	3,149.5	164.4	665.8	830.1	(39.2)	72.4	23.8	(13.4)	100.0	4,123.2	106.3
2018	1,265.3	1,606.1	90.3	473.7	177.6	3,613.0	127.7	587.7	715.4	(38.4)	82.0	21.4	(14.3)	107.3	4,486.4	112.2
2019	1,404.5	1,634.7	92.5	489.0	181.5	3,802.2	129.6	631.3	760.9	(5.2)	85.8	20.7	(15.2)	114.3	4,763.5	115.8
2020	1,678.1	1,932.3	115.1	513.3	194.0	4,432.8	72.5	479.1	551.6	(2.6)	93.3	18.1	(16.5)	121.1	5,197.8	123.1
2021	1,995.4	2,048.4	126.9	544.6	240.9	4,956.2	63.5	585.1	648.6	0.0	102.4	23.6	(17.5)	127.8	5,841.1	134.8
2022	2,288.1	2,080.8	129.9	581.8	256.3	5,336.9	57.5	554.4	611.9	0.0	110.3	22.7	(19.0)	134.8	6,197.6	139.5
2023	2,288.8	1,858.2	117.8	628.8	249.0	5,142.5	23.2	778.6	801.9	0.0	94.5	26.5	(20.5)	142.6	6,187.5	135.9
2024	2,132.9	1,918.0	120.8	653.3	241.7	5,066.7	33.4	779.8	813.2	0.0	94.3	25.6	(21.7)	150.3	6,128.3	131.4
2025	2,159.1	1,967.8	124.5	671.0	255.7	5,178.1	56.1	998.2	1,054.3	0.0	103.2	32.1	(23.0)	158.2	6,502.9	136.2
2026	2,223.5	2,166.2	138.3	691.4	259.1	5,478.6	48.9	1,000.6	1,049.5	0.0	110.6	30.8	(24.3)	92.2	6,737.4	137.5
2027	2,332.2	2,342.1	154.0	714.8	252.8	5,796.0	11.9	1,015.5	1,027.5	0.0	120.7	30.4	(25.4)	92.2	7,041.5	140.1
2028	2,414.9	2,486.8	169.0	742.1	245.5	6,058.4	48.9	1,020.6	1,069.5	0.0	132.1	29.1	(26.7)	98.1	7,360.4	142.9
2029	2,471.1	2,727.9	184.5	767.6	239.5	6,390.6	43.0	1,019.4	1,062.4	0.0	148.6	27.6	(28.6)	98.0	7,698.6	145.5
2030	2,549.2	2,931.1	198.4	794.9	256.1	6,729.7	41.7	1,011.5	1,053.2	0.0	160.1	26.1	(30.7)	97.3	8,035.7	148.1
2031	2,595.6	3,120.5	212.6	822.2	260.4	7,011.2	59.0	1,012.9	1,071.9	0.0	172.7	24.5	(32.1)	96.8	8,344.9	150.1
2032	2,647.4	3,427.0	232.2	852.1	278.2	7,436.9	53.3	1,018.1	1,071.4	0.0	190.2	22.8	(35.2)	96.2	8,782.2	154.5
2033	2,737.1	3,616.2	246.4	882.2	283.5	7,765.3	43.8	1,049.9	1,093.7	0.0	199.0	22.7	(37.2)	95.9	9,139.4	156.9
2034	2,780.7	3,814.7	263.6	912.4	275.0	8,046.3	58.3	1,278.4	1,336.7	0.0	222.3	32.4	(40.5)	95.1	9,692.2	162.6
2035	2,829.6	4,058.8	282.1	943.1	266.6	8,380.2	47.1	1,321.5	1,368.7	0.0	238.1	32.3	(43.2)	94.4	10,070.4	165.3
2036	2,901.6	4,252.0	296.0	980.7	288.3	8,718.7	36.1	1,370.0	1,406.1	0.0	251.9	32.1	(46.7)	93.8	10,455.9	168.2
2037	2,937.4	4,535.6	318.0	993.2	294.1	9,078.2	99.7	1,414.6	1,514.4	0.0	273.6	31.9	(46.8)	93.3	10,944.6	172.1
CPW@ 7.86%																
(2008-2017)	4,236.0	6,560.8	329.1	2,890.2	338.5	14,354.6	726.6	3,405.0	4,131.6	(122.8)	331.3	155.8	(57.2)	415.1	19,208.5	83.1
(2008-2027)	10,274.6	12,639.2	701.7	4,722.9	1,051.2	29,389.5	946.8	5,640.2	6,587.1	(142.6)	641.0	232.9	(117.2)	807.6	37,398.3	100.7
(2008-2037)	14,215.2	17,633.7	1,044.0	5,988.6	1,445.8	40,327.3	1,023.6	7,308.0	8,331.6	(142.6)	922.7	274.2	(169.8)	950.7	50,494.1	110.7

TABLE 86.
RISK ANALYSIS C - NATURAL GAS COST INCREASE of 30%
SUPPLY SIDE SCENARIO 4 (SS-4/C)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	878.1	40.5	404.2	8.6	1,855.5	72.7	338.9	411.6	(10.8)	38.5	13.6	(0.9)	26.6	0.0	2,334.1	72.5
2009	549.1	949.3	42.9	412.2	8.6	1,962.2	76.8	380.6	457.3	(8.3)	43.1	14.5	(1.2)	56.0	0.0	2,523.7	77.1
2010	573.3	900.7	43.1	422.9	20.9	1,961.0	115.7	409.8	525.5	(9.1)	43.4	24.5	(9.5)	54.8	0.0	2,590.6	78.8
2011	580.5	953.0	46.2	419.9	28.5	2,028.1	102.9	339.9	442.8	(10.0)	45.0	23.2	(9.9)	67.0	0.0	2,586.2	77.9
2012	578.7	861.8	42.9	423.8	30.7	1,937.9	105.2	506.8	612.0	(14.0)	44.9	27.8	(10.5)	84.9	0.0	2,682.9	79.7
2013	583.5	872.2	45.7	429.0	49.2	1,979.7	105.8	554.3	660.1	(19.0)	47.3	27.2	(10.9)	51.4	0.0	2,735.9	80.4
2014	601.0	1,005.2	53.8	446.3	66.1	2,172.4	106.2	609.6	715.8	(24.3)	54.8	29.0	(11.7)	54.9	(0.1)	2,990.7	85.3
2015	639.1	1,006.7	53.2	462.7	89.7	2,251.5	120.9	777.2	898.1	(33.0)	56.1	30.6	(12.2)	58.3	(0.1)	3,249.2	89.5
2016	810.8	1,057.5	57.9	437.2	137.8	2,501.2	147.5	941.7	1,089.2	(37.0)	61.6	33.7	(12.8)	93.4	(0.0)	3,729.2	99.4
2017	996.9	1,275.9	69.1	452.4	160.2	2,954.5	158.0	941.4	1,099.5	(39.2)	65.5	36.7	(13.5)	100.0	(0.0)	4,203.5	108.4
2018	1,142.4	1,417.3	79.3	468.4	161.3	3,268.8	128.6	1,007.7	1,136.3	(38.4)	71.6	40.7	(14.4)	107.3	(0.0)	4,571.8	114.3
2019	1,244.7	1,388.6	77.9	481.8	157.3	3,350.4	125.4	1,197.3	1,322.7	(5.2)	71.6	46.4	(15.5)	114.3	(1.2)	4,883.6	118.7
2020	1,458.0	1,611.0	90.6	501.3	170.4	3,831.3	66.1	1,220.1	1,286.2	(2.6)	76.3	50.4	(16.8)	121.1	(1.8)	5,344.2	126.5
2021	1,728.5	1,707.0	97.0	528.7	217.2	4,278.3	63.4	1,377.2	1,440.7	0.0	84.7	57.6	(17.8)	127.8	(3.7)	5,967.7	137.7
2022	2,020.5	1,727.9	98.3	564.9	233.0	4,644.7	59.5	1,355.1	1,414.6	0.0	91.4	56.2	(19.3)	134.8	(3.4)	6,318.9	142.2
2023	2,031.1	1,538.5	87.1	611.4	226.4	4,494.5	25.2	1,578.8	1,604.0	0.0	76.7	59.5	(21.1)	142.6	(26.2)	6,329.9	139.0
2024	1,884.8	1,607.7	90.8	635.4	268.2	4,487.0	35.2	1,582.4	1,617.7	0.0	76.8	57.9	(22.2)	150.3	(48.0)	6,319.4	135.5
2025	1,920.4	1,654.7	93.5	652.5	288.1	4,609.3	57.9	1,798.7	1,856.6	0.0	84.1	63.8	(23.6)	158.2	(50.8)	6,697.6	140.3
2026	1,994.2	1,825.5	104.6	672.4	280.9	4,877.6	50.6	1,800.8	1,851.4	0.0	91.2	61.9	(24.9)	92.2	(37.3)	6,912.0	141.1
2027	2,058.2	2,009.1	115.9	690.8	294.6	5,168.6	45.6	1,815.7	1,861.3	0.0	102.1	60.8	(25.9)	92.2	(32.2)	7,227.0	143.8
2028	2,131.6	2,150.4	125.3	714.8	296.9	5,419.0	61.0	1,822.5	1,883.5	0.0	114.5	58.7	(27.2)	98.1	(28.0)	7,518.6	146.0
2029	2,211.6	2,369.8	139.8	740.1	288.6	5,749.8	54.7	1,819.9	1,874.6	0.0	130.8	56.5	(29.1)	98.0	(16.6)	7,863.9	148.6
2030	2,300.1	2,565.4	152.6	766.5	304.2	6,088.8	52.9	1,811.9	1,864.7	0.0	141.7	54.1	(31.1)	97.3	(14.6)	8,200.9	151.2
2031	2,377.1	2,748.8	164.2	793.7	307.7	6,391.6	47.5	1,813.0	1,860.5	0.0	154.0	51.7	(32.6)	96.8	(12.0)	8,509.9	153.1
2032	2,452.3	3,039.0	183.1	823.3	300.2	6,797.9	42.2	1,820.2	1,862.4	0.0	171.2	49.1	(35.6)	96.2	(6.9)	8,934.4	157.2
2033	2,527.8	3,226.7	195.5	851.7	317.6	7,119.3	56.8	1,850.0	1,906.8	0.0	178.5	47.9	(37.6)	95.9	(5.3)	9,305.5	159.7
2034	2,586.0	3,429.0	209.9	881.3	320.6	7,426.9	46.4	2,078.5	2,124.9	0.0	201.7	56.5	(40.9)	95.1	(4.4)	9,859.8	165.4
2035	2,658.1	3,655.5	227.7	911.7	311.0	7,764.1	35.5	2,121.7	2,157.2	0.0	217.7	55.3	(43.6)	94.4	(3.2)	10,241.9	168.1
2036	2,713.1	3,841.2	239.7	947.4	331.4	8,072.9	74.7	2,171.8	2,246.6	0.0	229.8	54.0	(47.2)	93.8	(3.6)	10,646.2	171.3
2037	2,764.9	4,116.9	259.7	959.2	335.8	8,436.5	14.3	2,214.8	2,229.1	0.0	251.5	52.5	(47.2)	93.3	(1.9)	11,013.8	173.2
CPW@ 7.86%																	
(2008-2017)	4,191.7	6,472.0	323.9	2,888.3	338.2	14,214.0	718.2	3,620.0	4,338.3	(122.8)	326.2	166.0	(57.2)	415.1	(0.2)	19,279.4	83.4
(2008-2027)	9,530.1	11,601.5	614.3	4,675.7	1,032.8	27,454.4	944.7	8,107.2	9,051.9	(142.6)	583.3	337.5	(118.5)	807.6	(53.7)	37,919.9	102.1
(2008-2037)	13,141.1	16,034.2	883.0	5,897.4	1,491.8	37,447.5	1,018.9	10,965.8	11,984.7	(142.6)	836.1	417.7	(171.6)	950.7	(70.4)	51,252.0	112.4

RISK ANALYSIS D - COST OF SOLAR INCREASES 1.5% ANNUALLY, OTHER COST AT 3.0%

TABLE 94.
SUPPLY SIDE SCENARIO 3 (SS-3/D)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Capital Rev. Req.	Generation					Purchases			Sales					Total	
		Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	493.8	599.6	(19.0)	47.3	27.2	(10.8)	51.4	2,532.0	74.4
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	545.0	651.2	(24.3)	54.7	29.0	(11.7)	54.9	2,755.4	78.6
2015	639.1	855.8	51.6	462.7	89.7	2,098.9	125.2	660.4	785.6	(33.0)	56.8	29.2	(12.2)	58.3	2,983.7	82.2
2016	835.8	936.2	59.0	438.2	137.8	2,407.0	153.7	701.2	854.9	(37.0)	64.8	27.0	(12.7)	93.4	3,397.3	90.5
2017	1,064.4	1,160.4	75.1	455.2	160.8	2,915.9	164.4	591.5	755.9	(39.2)	72.4	23.8	(13.4)	100.0	3,815.4	98.4
2018	1,265.3	1,333.4	89.8	473.7	177.6	3,339.8	127.7	527.6	655.2	(38.4)	82.2	21.4	(14.3)	107.3	4,153.3	103.9
2019	1,404.5	1,361.8	92.1	489.0	181.5	3,528.9	129.6	570.4	700.0	(5.2)	85.9	20.7	(15.2)	114.3	4,429.4	107.7
2020	1,678.1	1,593.7	114.6	513.3	194.0	4,093.7	72.5	451.8	524.3	(2.6)	93.3	18.1	(16.5)	121.1	4,831.4	114.4
2021	1,995.4	1,686.5	126.1	544.6	240.9	4,593.5	63.5	558.8	622.3	0.0	102.4	23.6	(17.6)	127.8	5,452.1	125.8
2022	2,288.1	1,718.4	129.0	581.8	256.3	4,973.6	57.5	534.9	592.4	0.0	110.3	22.7	(19.0)	134.8	5,814.8	130.9
2023	2,288.8	1,557.1	116.6	628.8	249.0	4,840.3	23.2	714.3	737.5	0.0	94.6	26.5	(20.5)	142.6	5,820.9	127.8
2024	2,132.9	1,609.1	120.0	653.3	241.7	4,757.1	33.4	715.3	748.7	0.0	94.5	25.6	(21.7)	150.3	5,754.4	123.4
2025	2,159.1	1,650.8	124.0	671.0	255.7	4,860.5	56.1	933.8	989.9	0.0	103.3	32.1	(23.0)	158.2	6,120.9	128.2
2026	2,223.5	1,808.0	137.7	691.4	259.1	5,119.7	48.9	936.3	985.1	0.0	110.9	30.8	(24.3)	92.2	6,314.3	128.9
2027	2,332.2	1,949.5	153.1	714.8	252.8	5,402.5	11.9	951.2	963.1	0.0	120.9	30.4	(25.4)	92.2	6,583.7	131.0
2028	2,414.9	2,067.6	167.7	742.1	245.5	5,637.8	48.9	956.1	1,005.0	0.0	132.3	29.1	(26.8)	98.1	6,875.5	133.5
2029	2,471.1	2,257.6	183.8	767.6	239.5	5,919.6	43.0	955.0	998.0	0.0	148.7	27.6	(28.7)	98.0	7,163.2	135.4
2030	2,549.2	2,420.8	197.7	794.9	256.1	6,218.7	41.7	947.2	988.8	0.0	160.1	26.1	(30.7)	97.3	7,460.3	137.5
2031	2,595.6	2,574.3	211.6	822.2	260.4	6,464.0	59.0	948.5	1,007.5	0.0	172.8	24.5	(32.2)	96.8	7,733.4	139.1
2032	2,647.4	2,810.6	231.3	852.1	278.2	6,819.5	53.3	953.6	1,006.9	0.0	190.3	22.8	(35.3)	96.2	8,100.4	142.5
2033	2,737.1	2,965.2	245.5	882.2	283.5	7,113.3	43.8	981.6	1,025.4	0.0	199.1	22.7	(37.3)	95.9	8,419.1	144.5
2034	2,780.7	3,119.5	262.9	912.4	275.0	7,350.4	58.3	1,180.6	1,238.9	0.0	222.4	32.4	(40.5)	95.1	8,898.6	149.3
2035	2,829.6	3,316.0	281.2	943.1	266.6	7,636.5	47.1	1,218.3	1,265.5	0.0	238.1	32.3	(43.3)	94.4	9,223.5	151.4
2036	2,901.6	3,472.3	295.0	980.7	288.3	7,937.9	36.1	1,260.7	1,296.9	0.0	251.9	32.1	(46.7)	93.8	9,565.9	153.9
2037	2,937.4	3,695.6	317.2	993.2	294.1	8,237.4	99.7	1,299.2	1,398.9	0.0	273.7	31.9	(46.9)	93.3	9,988.4	157.0
CPW@ 7.86% (2008-2017)	4,236.0	5,503.7	320.5	2,890.2	338.5	13,288.8	726.6	2,934.0	3,660.7	(122.8)	331.0	155.8	(57.1)	415.1	17,871.5	76.5
(2008-2027)	10,274.6	10,558.9	690.8	4,722.9	1,051.2	27,296.4	946.8	5,010.0	5,956.8	(142.6)	641.0	232.9	(117.2)	807.6	34,674.9	93.3
(2008-2037)	14,215.2	14,661.1	1,031.8	5,988.6	1,445.8	37,342.5	1,023.6	6,562.1	7,585.7	(142.6)	922.8	274.2	(169.8)	950.7	46,763.4	102.6

TABLE 95.
RISK ANALYSIS D - COST OF SOLAR INCREASES 1.5% ANNUALLY, OTHER COST AT 3.0%
SUPPLY SIDE SCENARIO 4 (SS-4/D)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	0.0	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	0.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	0.0	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	0.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	0.0	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	493.8	599.6	(19.0)	47.3	27.2	(10.8)	51.4	0.0	2,532.0	74.4
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	545.0	651.2	(24.3)	54.7	29.0	(11.7)	54.9	(0.1)	2,755.3	78.6
2015	639.1	846.7	51.1	462.7	89.7	2,089.4	120.9	686.8	807.7	(33.0)	56.0	30.6	(12.2)	58.3	(0.1)	2,996.7	82.6
2016	810.8	893.6	56.0	437.2	137.8	2,335.4	147.5	827.4	974.9	(37.0)	61.7	33.7	(12.8)	93.4	(0.0)	3,449.3	91.9
2017	996.9	1,067.7	67.8	452.4	160.2	2,745.0	158.0	839.8	997.9	(39.2)	65.5	36.7	(13.5)	100.0	(0.0)	3,892.3	100.3
2018	1,142.4	1,184.6	78.7	468.4	161.3	3,035.4	128.6	900.5	1,029.1	(38.4)	71.6	40.7	(14.4)	107.3	(0.0)	4,231.2	105.8
2019	1,244.7	1,168.9	77.5	481.8	157.3	3,130.3	125.4	1,066.9	1,192.3	(5.2)	71.6	46.4	(15.5)	114.3	(0.9)	4,533.3	110.2
2020	1,458.0	1,342.9	90.4	501.3	170.4	3,562.9	66.1	1,093.3	1,159.5	(2.6)	76.4	50.4	(16.8)	121.1	(1.4)	4,949.5	117.2
2021	1,728.5	1,421.8	96.9	528.7	217.2	3,993.0	63.4	1,240.5	1,304.0	0.0	84.8	57.6	(17.6)	127.8	(2.8)	5,546.6	128.0
2022	2,020.5	1,442.2	98.1	564.9	233.0	4,358.7	59.5	1,224.8	1,284.2	0.0	91.4	56.2	(19.3)	134.8	(2.6)	5,903.4	132.9
2023	2,031.1	1,304.1	86.8	611.4	226.4	4,259.8	25.2	1,403.8	1,428.9	0.0	76.7	59.5	(21.1)	142.6	(20.1)	5,926.3	130.1
2024	1,884.8	1,364.5	90.5	635.4	268.2	4,243.5	35.2	1,406.8	1,442.1	0.0	76.8	57.9	(22.3)	150.3	(36.9)	5,911.5	126.8
2025	1,920.4	1,403.2	93.3	652.5	288.1	4,357.6	57.9	1,623.5	1,681.4	0.0	84.1	63.8	(23.6)	158.2	(39.1)	6,282.5	131.6
2026	1,994.2	1,538.8	104.5	672.4	280.9	4,590.8	50.6	1,625.7	1,676.4	0.0	91.2	61.9	(24.9)	92.2	(28.7)	6,458.8	131.8
2027	2,058.2	1,686.4	115.9	690.8	294.6	4,845.9	45.6	1,640.7	1,686.3	0.0	102.1	60.8	(25.9)	92.2	(24.8)	6,736.7	134.1
2028	2,131.6	1,801.0	125.2	714.8	296.9	5,069.5	61.0	1,647.1	1,708.1	0.0	114.5	58.7	(27.2)	98.1	(21.5)	7,000.1	135.9
2029	2,211.6	1,975.6	139.8	740.1	288.6	5,355.6	54.7	1,644.8	1,699.4	0.0	130.7	56.5	(29.1)	98.0	(12.8)	7,298.4	137.9
2030	2,300.1	2,134.2	152.5	766.5	304.2	5,657.6	52.9	1,636.8	1,689.7	0.0	141.7	54.1	(31.1)	97.3	(11.3)	7,597.9	140.0
2031	2,377.1	2,281.6	164.3	793.7	307.7	5,924.4	47.5	1,638.0	1,685.5	0.0	154.0	51.7	(32.6)	96.8	(9.2)	7,870.4	141.6
2032	2,452.3	2,506.5	183.1	823.3	300.2	6,265.4	42.2	1,644.7	1,687.0	0.0	171.3	49.1	(35.6)	96.2	(5.3)	8,228.1	144.8
2033	2,527.8	2,660.1	195.5	851.7	317.6	6,552.7	56.8	1,671.1	1,727.8	0.0	178.5	47.9	(37.6)	95.9	(4.0)	8,561.2	146.9
2034	2,586.0	2,818.5	210.0	881.3	320.6	6,816.5	46.4	1,870.1	1,916.4	0.0	201.7	56.5	(40.9)	95.1	(3.4)	9,042.0	151.7
2035	2,658.1	3,001.7	227.5	911.7	311.0	7,110.0	35.5	1,907.8	1,943.4	0.0	217.9	55.3	(43.7)	94.4	(2.5)	9,374.9	153.9
2036	2,713.1	3,151.7	239.7	947.4	331.4	7,383.4	74.7	1,951.7	2,026.4	0.0	229.9	54.0	(47.2)	93.8	(2.8)	9,737.5	156.6
2037	2,764.9	3,369.0	259.7	959.2	335.8	7,688.6	14.3	1,988.7	2,003.0	0.0	251.5	52.5	(47.2)	93.3	(1.5)	10,040.3	157.9
CPW@ 7.86%																	
(2008-2017)	4,191.7	5,433.7	315.2	2,888.3	338.2	13,167.1	718.2	3,128.8	3,847.1	(122.8)	325.8	166.0	(57.2)	415.1	(0.1)	17,741.0	76.8
(2008-2027)	9,530.1	9,741.7	604.8	4,675.7	1,032.8	25,585.1	944.7	7,154.3	8,099.1	(142.6)	582.9	337.5	(118.4)	807.6	(41.3)	35,109.9	94.5
(2008-2037)	13,141.1	13,405.3	873.5	5,897.4	1,491.8	34,809.0	1,018.9	9,732.6	10,751.5	(142.6)	835.8	417.7	(171.6)	950.7	(54.2)	47,396.3	104.0

TABLE 103.
RISK ANALYSIS E - NO PTC AVAILABLE AFTER 2009, NO ITC AVAILABLE AFTER 2016
SUPPLY SIDE SCENARIO 3 (SS-3/E)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales					Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	(10.8)	51.4	2,535.0	74.5
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	(11.7)	54.9	2,766.5	78.9
2015	639.1	855.8	51.6	462.7	89.7	2,098.9	125.2	678.0	803.3	(33.0)	56.8	29.2	(12.2)	58.3	3,001.3	82.7
2016	835.8	936.2	59.0	438.2	137.8	2,407.0	153.7	720.8	874.4	(37.0)	64.8	27.0	(12.7)	93.4	3,416.8	91.0
2017	1,064.4	1,160.4	75.1	455.2	160.8	2,915.9	164.4	611.0	775.4	(39.2)	72.4	23.8	(13.4)	100.0	3,834.9	98.9
2018	1,265.3	1,333.4	89.8	473.7	177.6	3,339.8	127.7	547.1	674.7	(38.4)	82.2	21.4	(14.3)	107.3	4,172.8	104.4
2019	1,404.5	1,361.8	92.1	489.0	181.5	3,528.9	129.6	596.4	726.0	(5.2)	85.9	20.7	(15.2)	114.3	4,455.4	108.3
2020	1,678.1	1,593.7	114.6	513.3	194.0	4,093.7	72.5	477.8	550.4	(2.6)	93.3	18.1	(16.5)	121.1	4,857.4	115.0
2021	1,995.4	1,686.5	126.1	544.6	240.9	4,593.5	63.5	597.0	660.5	0.0	102.4	23.6	(17.6)	127.8	5,490.3	126.7
2022	2,288.1	1,718.4	129.0	581.8	256.3	4,973.6	57.5	573.1	630.6	0.0	110.3	22.7	(19.0)	134.8	5,853.0	131.7
2023	2,288.8	1,557.1	116.6	628.8	249.0	4,840.3	23.2	880.7	904.0	0.0	94.6	26.5	(20.5)	142.6	5,987.4	131.5
2024	2,132.9	1,609.1	120.0	653.3	241.7	4,757.1	33.4	882.1	915.5	0.0	94.5	25.6	(21.7)	150.3	5,921.2	127.0
2025	2,159.1	1,650.8	124.0	671.0	255.7	4,860.5	56.1	1,128.8	1,184.9	0.0	103.3	32.1	(23.0)	158.2	6,315.9	132.3
2026	2,223.5	1,808.0	137.7	691.4	259.1	5,119.7	48.9	1,131.3	1,180.1	0.0	110.9	30.8	(24.3)	92.2	6,509.3	132.9
2027	2,332.2	1,949.5	153.1	714.8	252.8	5,402.5	11.9	1,146.2	1,158.1	0.0	120.9	30.4	(25.4)	92.2	6,778.7	134.9
2028	2,414.9	2,067.6	167.7	742.1	245.5	5,637.8	48.9	1,151.5	1,200.4	0.0	132.3	29.1	(26.8)	98.1	7,070.9	137.3
2029	2,471.1	2,257.6	183.8	767.6	239.5	5,919.6	43.0	1,150.0	1,193.0	0.0	148.7	27.6	(28.7)	98.0	7,358.2	139.1
2030	2,549.2	2,420.8	197.7	794.9	256.1	6,218.7	41.7	1,142.2	1,183.8	0.0	160.1	26.1	(30.7)	97.3	7,655.3	141.1
2031	2,595.6	2,574.3	211.6	822.2	260.4	6,464.0	59.0	1,143.5	1,202.5	0.0	172.8	24.5	(32.2)	96.8	7,928.4	142.6
2032	2,647.4	2,810.6	231.3	852.1	278.2	6,819.5	53.3	1,149.0	1,202.3	0.0	190.3	22.8	(35.3)	96.2	8,295.8	146.0
2033	2,737.1	2,965.2	245.5	882.2	283.5	7,113.3	43.8	1,187.6	1,231.4	0.0	199.1	22.7	(37.3)	95.9	8,625.1	148.0
2034	2,780.7	3,119.5	262.9	912.4	275.0	7,350.4	58.3	1,466.8	1,525.1	0.0	222.4	32.4	(40.5)	95.1	9,184.7	154.1
2035	2,829.6	3,316.0	281.2	943.1	266.6	7,636.5	47.1	1,518.9	1,566.1	0.0	238.1	32.3	(43.3)	94.4	9,524.1	156.3
2036	2,901.6	3,472.3	295.0	980.7	288.3	7,937.9	36.1	1,577.4	1,613.5	0.0	251.9	32.1	(46.7)	93.8	9,882.5	159.0
2037	2,937.4	3,695.6	317.2	993.2	294.1	8,237.4	99.7	1,631.6	1,731.3	0.0	273.7	31.9	(46.9)	93.3	10,320.8	162.3
CPW@ 7.86%																
(2008-2017)	4,236.0	5,503.7	320.5	2,890.2	338.5	13,288.8	726.6	2,971.1	3,697.8	(122.8)	331.0	155.8	(57.1)	415.1	17,708.6	76.6
(2008-2027)	10,274.6	10,556.9	690.8	4,722.9	1,051.2	27,296.4	946.8	5,336.2	6,283.1	(142.6)	641.0	232.9	(117.2)	807.6	35,001.2	94.2
(2008-2037)	14,215.2	14,661.1	1,031.8	5,988.6	1,445.8	37,342.5	1,023.6	7,232.3	8,255.9	(142.6)	922.8	274.2	(169.8)	950.7	47,433.7	104.0

TABLE 104.
RISK ANALYSIS E - NO PTC AVAILABLE AFTER 2009, NO ITC AVAILABLE AFTER 2016
SUPPLY SIDE SCENARIO 4 (SS-4/E)
TOTAL REVENUE REQUIREMENTS
(MILLIONS OF DOLLARS)

	Generation						Purchases			Sales						Total	
	Capital Rev. Req.	Fuel	Variable O&M	Fixed Fuel + O&M	New Transmission	Sub Total	Demand	Energy	Sub Total		Gas Trans	Imputed Debt	EMIS Costs	DE-EE Costs	DumpEnergy Credit	$Millions	$/MWH
2008	523.9	742.6	40.2	404.2	8.6	1,719.6	72.7	272.9	345.6	(10.8)	38.6	13.6	(1.0)	26.6	0.0	2,132.3	66.3
2009	549.1	797.5	42.6	412.2	8.6	1,810.1	76.8	310.1	386.9	(8.3)	43.0	14.5	(1.2)	56.0	0.0	2,301.0	70.3
2010	573.3	755.6	42.3	422.9	20.9	1,815.0	115.7	340.5	456.2	(9.1)	43.2	24.5	(9.5)	54.8	0.0	2,375.1	72.2
2011	580.5	799.8	44.8	419.9	28.5	1,873.4	102.9	284.3	387.2	(10.0)	44.9	23.2	(9.9)	67.0	0.0	2,375.8	71.5
2012	578.7	721.3	41.7	423.8	30.7	1,796.2	105.2	445.8	551.0	(14.0)	44.4	27.8	(10.5)	84.9	0.0	2,479.8	73.6
2013	583.5	730.3	44.2	429.0	49.2	1,836.3	105.8	496.8	602.6	(19.0)	47.3	27.2	(10.8)	51.4	0.0	2,535.0	74.5
2014	601.0	837.3	50.8	446.3	66.1	2,001.6	106.2	556.1	662.3	(24.3)	54.7	29.0	(11.7)	54.9	(0.1)	2,766.4	78.9
2015	639.1	846.7	51.1	462.7	89.7	2,089.4	120.9	707.6	828.5	(33.0)	56.0	30.6	(12.2)	58.3	(0.1)	3,017.4	83.1
2016	810.8	893.6	56.0	437.2	137.8	2,335.4	147.5	863.5	1,011.1	(37.0)	61.7	33.7	(12.8)	93.4	(0.0)	3,485.4	92.9
2017	996.9	1,067.7	67.8	452.4	160.2	2,745.0	158.0	942.2	1,100.3	(39.2)	65.5	36.7	(13.5)	100.0	(0.0)	3,994.7	103.0
2018	1,142.4	1,184.6	78.7	468.4	161.3	3,035.4	128.6	1,073.1	1,201.7	(38.4)	71.6	40.7	(14.4)	107.3	(0.0)	4,403.9	110.1
2019	1,244.7	1,168.9	77.5	481.8	157.3	3,130.3	125.4	1,320.3	1,445.7	(5.2)	71.6	46.4	(15.5)	114.3	(0.9)	4,786.7	116.4
2020	1,458.0	1,342.9	90.4	501.3	170.4	3,562.9	66.1	1,425.9	1,492.0	(2.6)	76.4	50.4	(16.8)	121.1	(1.4)	5,282.1	125.1
2021	1,728.5	1,421.8	96.9	528.7	217.2	3,993.0	63.4	1,611.5	1,675.0	0.0	84.8	57.6	(17.8)	127.8	(2.8)	5,917.6	136.6
2022	2,020.5	1,442.2	98.1	564.9	233.0	4,358.7	59.5	1,595.7	1,655.2	0.0	91.4	56.2	(19.3)	134.8	(2.6)	6,274.4	141.2
2023	2,031.1	1,304.1	86.8	611.4	226.4	4,259.8	25.2	1,903.0	1,928.2	0.0	76.7	59.5	(21.1)	142.6	(20.1)	6,425.6	141.1
2024	1,884.8	1,364.5	90.5	635.4	268.2	4,243.5	35.2	1,907.1	1,942.4	0.0	76.8	57.9	(22.3)	150.3	(36.9)	6,411.8	137.5
2025	1,920.4	1,403.2	93.3	652.5	288.1	4,357.6	57.9	2,151.3	2,209.2	0.0	84.1	63.8	(23.6)	158.2	(39.1)	6,810.2	142.6
2026	1,994.2	1,538.8	104.5	672.4	280.9	4,590.8	50.6	2,153.5	2,204.1	0.0	91.2	61.9	(24.9)	92.2	(28.7)	6,986.6	142.6
2027	2,058.2	1,686.4	115.9	690.8	294.6	4,845.9	45.6	2,168.4	2,214.0	0.0	102.1	60.8	(25.9)	92.2	(24.8)	7,264.5	144.6
2028	2,131.6	1,801.0	125.2	714.8	296.9	5,069.5	61.0	2,176.0	2,236.9	0.0	114.5	58.7	(27.2)	98.1	(21.5)	7,528.9	146.2
2029	2,211.6	1,975.6	139.8	740.1	288.6	5,355.6	54.7	2,172.5	2,227.2	0.0	130.7	56.5	(29.1)	98.0	(12.8)	7,826.1	147.9
2030	2,300.1	2,134.2	152.5	766.5	304.2	5,657.6	52.9	2,164.6	2,217.4	0.0	141.7	54.1	(31.1)	97.3	(11.3)	8,125.7	149.8
2031	2,377.1	2,281.6	164.3	793.7	307.7	5,924.4	47.5	2,165.8	2,213.2	0.0	154.0	51.7	(32.6)	96.8	(9.2)	8,398.2	151.1
2032	2,452.3	2,506.5	183.1	823.3	300.2	6,265.4	42.2	2,173.6	2,215.8	0.0	171.3	49.1	(35.6)	96.2	(5.3)	8,756.9	154.1
2033	2,527.8	2,660.1	195.5	851.7	317.6	6,552.7	56.8	2,209.8	2,266.5	0.0	178.5	47.9	(37.6)	95.9	(4.0)	9,099.9	156.2
2034	2,586.0	2,818.5	210.0	881.3	320.6	6,816.5	46.4	2,489.0	2,535.3	0.0	201.7	56.5	(40.9)	95.1	(3.4)	9,660.9	162.1
2035	2,658.1	3,001.7	227.5	911.7	311.0	7,110.0	35.5	2,541.1	2,576.7	0.0	217.9	55.3	(43.7)	94.4	(2.5)	10,008.2	164.3
2036	2,713.1	3,151.7	239.7	947.4	331.4	7,383.4	74.7	2,601.8	2,676.5	0.0	229.9	54.0	(47.2)	93.8	(2.8)	10,387.6	167.1
2037	2,764.9	3,369.0	259.7	959.2	335.8	7,688.6	14.3	2,653.8	2,668.1	0.0	251.5	52.5	(47.2)	93.3	(1.5)	10,705.4	168.3
CPW@ 7.86%																	
(2008-2017)	4,191.7	5,433.7	315.2	2,888.3	338.2	13,167.1	718.2	3,215.0	3,933.2	(122.8)	325.8	166.0	(57.2)	415.1	(0.1)	17,827.1	77.2
(2008-2027)	9,530.1	9,741.7	604.8	4,675.7	1,032.8	25,585.1	944.7	8,453.9	9,398.7	(142.6)	582.9	337.5	(118.4)	807.6	(41.3)	36,409.5	98.0
(2008-2037)	13,141.1	13,405.3	873.5	5,897.4	1,491.8	34,809.0	1,018.9	11,871.3	12,890.3	(142.6)	835.8	417.7	(171.6)	950.7	(54.2)	49,535.1	108.6

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Please provide the Commission the results of the small generation RFP and the distributed energy RFP? *(1544:23-1550:25)*

Response: A summary of the 2009 Distributed Energy RFP and the associated Final Independent Auditor Report prepared by Merrimack Energy Group, Inc. are attached. In addition, a summary of the results of the Small Generation RFP is also attached. The Small Generation RFP Independent Auditor Report is expected to be completed later this month.

2009 Small Generation RFP
Final Selection

September 25, 2009

Proposals Summary

	Bid Submittal	Conforming Bids
Entities	30	23
Proposals [1]	65	45
Offers [2]	118	93

Bid Submittal Breakdown	Entities	Proposals	Offers
Solar-Fixed/Tracking PV [3]	25	57	108
Solar-Other [4]	3	5	7
Wind	1	1	1
Biogas [5]	1	2	2
Total	30	65	118

- All received bids, proposals, and offers were in-state.
- Respondents were required to meet 3 of 5 Threshold Criteria including : (1) Community Partnership, (2) Educational Partnership, (3) Geographic Diversity, (4) Job Creation, and (5) Public Funding (other than tax credits). Respondents not meeting 3 of the 5 criteria were considered non-conforming.

[1] Mutually exclusive sites or projects
[2] Offers are generally different pricing or term options on a proposal
[3] 6 of the 25 entities were non-conforming
[4] Concentrating photovoltaic and dish
[5] Non-conforming

2009 Small Gen RFP

Final Risk Assessment for Shortlisted Developers

Developer	Project(ac)	Partner	Viability	Interconnection	Financing	PPA
Company V	Prescott Air 10 MW	Prescott, Yavapai College	Low Risk	Med Risk	Low Risk	Low Risk
Company W	Buckeye 6 MW	ASU	Med Risk	Med Risk	Med Risk	Low Risk
Company V	Prescott Air 5 MW	Prescott, Yavapai College	Low Risk	Low Risk	Low Risk	Low Risk
Company V	Prescott Air 3 MW	Prescott, Yavapai College	Low Risk	Low Risk	Low Risk	Low Risk
Company X	Ajo 4.5 MW	ASU	Low Risk	Med Risk/FERC	Low Risk	Med Risk
Company Y	Wickenburg 3 MW	Wickenburg	Low Risk	Low Risk	Low Risk	***High Risk***
Company X	Douglas 4.5 MW	ASU	Med Risk	Low Risk	Low Risk	Med Risk
Company Y	Surprise 2 MW	Surprise	Low Risk	Low Risk	Low Risk	***High Risk***
Company X	Bisbee 4.5 MW	ASU	Low Risk	Low Risk	Low Risk	Med Risk
Company Z	Orme 10 MW	Orme Ranch & School	Low Risk	Low Risk/FERC	Low Risk	Med Risk
Company Z	Orme 7 MW	Orme Ranch & School	Low Risk	Low Risk/FERC	Low Risk	Med Risk

Notes: 1) FERC designates the need for an SGIA through APS Transmission.

2) All parties are subject post development credit requirements through an instrument acceptable to APS.

APS

2009 Small Gen RFP

Refreshed Pricing Comparison from Shortlisted Developers

Developer	Project (ac)	Original AAC	Refresh AAC
Company V	Prescott 10 MW**	153%	137%
Company W	Buckeye 10/6 MW	148% (10 MW)	138% (6MW)
Company V	Prescott 5 MW**	153%	139%
Company V	Prescott 3 MW**	167%	143%
Company X	Ajo 4.5 MW	160%	151%
Company Y	Wick. 3 MW	159%	159%
Company X	Doug. 4.5 MW	160%	160%
Company Y	Surprise 2 MW	162%	162%
Company X	Bisbee 4.5 MW	166%	166%
Company Z	Mayer 10 MW	167%	167%
Company Z	Mayer 7 MW	new offer	202%
Company X	Chino Val. 4.5 MW	163%	withdrawn

* Bid prices include imputed debt.

** All 3 Company V projects are on the same site at the Prescott Airport.

APS

Final Selection

Project	Partner	2011 MWh	2011 RES $M	2012 MWh	2012 RES $M
Company V 10 MW	City of Prescott, Yavapai College	0		25,000	
Company W 6 MW	ASU	8,900		12,900	
Company X 4.5 MW	ASU	8,100		10,100	
Total		17,000	$1.05	48,000	$2.30

- Diverse mix of projects
  - Prescott, Buckeye, and Ajo sites
- Three least cost bids
- Within RES full year budget of $2.5 million in 2011 and 2012

2008 Distributed Energy RFP
Final Selection

Proposals Summary

	Bid Submittal	Conforming Bids
Total Entities	12	8
Total Proposals[1]	22	13
Total Offers	43	18
Total Transactable Offers[2]	25	12

Bid Submittal Breakdown	Entities	Proposals	Offers
Solar	10	20	40
Other[3]	2	2	3
Customer-Specific Projects	10	18	38
Customer Aggregation Projects	2	4	5

[1] A proposal may contain one or more offers

[2] Transactable Offers reflect restrictions on transacting by Proposal and by stated APS customers

[3] Other includes 1 Biogas and 1 modified Solar

Reasons for Non-Conforming Proposals

- Small generator proposal requiring a transmission wheel
- Customer predominantly or totally served by a utility other than APS
- Pricing more expensive than what otherwise is available via the Renewable Energy Incentive Program
- Proposed systems sized from greater than the applicable customer's annual load requirements
- Proposal does not meet RFP requirement of being installed prior to 2013
- Unproven/non-commercially viable technology

Qualitative Results

Entity	Proposal	Credit Risk	Viability Risk	Technology Risk
Company A	Proposal 1	LOW	LOW	LOW
Company B	Proposal 1	LOW	LOW	LOW
Company B	Proposal 2	LOW	LOW	LOW
Company B	Proposal 3	LOW	LOW	LOW
Company C	Proposal 1	LOW	LOW/MEDIUM	LOW
Company D	Proposal 1	MEDIUM	LOW	LOW
Company D	Proposal 2	MEDIUM	MEDIUM	LOW
Company E	Proposal 1	HIGH	LOW	MEDIUM
Company F	Proposal 1	MEDIUM	MEDIUM	LOW
Company G	Proposal 1	LOW	MEDIUM	LOW
Company G	Proposal 2	LOW	LOW	LOW
Company G	Proposal 3	LOW	MEDIUM	LOW
Company G	Proposal 4	LOW	MEDIUM	LOW
Company H	Proposal 1	MEDIUM	MEDIUM	MEDIUM/HIGH

Avoided Cost Analysis of Conforming Proposals

Bidder	Customer	Screening Cost Analysis (Compared to REIP Cost)	Detailed Cost (Compared to REIP Cost)
Company A	Proposal 1	100%	Not short-listed
Company B	Proposal 1	63%	79%
Company B	Proposal 2	64%	84%
Company B	Proposal 3	68%	WITHDREW FROM RFP
Company C	Proposal 1	99%	WITHDREW FROM RFP
Company D	Proposal 1	78%	81%
Company D	Proposal 2	54%	68% - not selected for negotiations*
Company E	Proposal 1	100%	Not short-listed
Company F	Proposal 1	36%	WITHDREW FROM RFP
Company G	Proposals 1,3, 4	86-92% (multiple options)	46%
Company G	Proposal 2	87%	37%*
Company H	Proposal 1	107%	Not short-listed

*2 Respondents proposed projects @ the same customer site.

APS

Final Selection

Bidder	Customer	MWdc	Avg Annual MWh[1]	Levelized REC $/MWh
Company B	Proposal 1	9.35	17,971	
Company B	Proposal 2	2.48	4,977	
Company D	Proposal 1	5	6,956	
Company G	Proposals 1,3, 4	39	65,527	
Company G	Proposal 2	12	26,454	
		67.83	**121,885**	**$90.28**

DE RFP resulted in REC pricing of approximately half the then-applicable PBI payment

1: Average Annual MWh takes into account panel degradation and ramping schedules

APS

Arizona Public Service Company
2008 Request for Proposals for Distributed Energy Resources

Final Report of the Independent Auditor

July, 2009

Prepared by
Merrimack Energy Group, Inc.

Merrimack
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Energy

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I. Introduction

Arizona Public Service Company (APS) retained Merrimack Energy Group, Inc. (Merrimack Energy) to serve as the Independent Auditor (IA) for Arizona Public Service Company's 2008 Request for Proposal for Distributed Energy Resources. Merrimack Energy's role as Independent Auditor began during the development of the RFP and continued through the final selection of the preferred resources.

Arizona Public Service Company issued its Request for Proposal for Distributed Resources on August 14, 2008, with the objective of securing distributed energy resources to meet a portion of its overall resource needs and to fulfill the regulatory requirements of the Arizona Renewable Energy Standard (RES). A successful outcome of the RFP will be an increase in the quantity of distributed energy at a lower cost than the current Renewable Energy Incentive Program ("REIP"). Through the RFP, APS is willing to entertain offers that are phased in over several years rather than the standard REIP that operates on an allocation period basis and does not currently allow for multi-year or phased-in project financing. APS sought up to 200,000 MWhs per year under this solicitation.

The role of the Independent Auditor is defined in the April 2007 Renewable Energy Competitive Procurement Procedure ("Competitive Procurement Procedure" or "CPP"). The purpose of the Competitive Procurement Procedure is to ensure the process is implemented in a fair and unbiased manner. The CPP outlines the role of the Independent Auditor and also describes the requirements of the competitive bidding process, including the evaluation and selection process. The CPP applies only to the competitive procurement process for any solicitation initiated to meet Arizona Public Service Company's renewable energy needs.

The Scope of Work of Merrimack Energy as the Independent Auditor was contained in the July 11, 2008 Scope of Work for the Independent Auditor (IA) prepared by APS as well as the Renewable Energy Competitive Procurement Procedure. The combined documents identify the following activities for the Independent Auditor:

- Review the draft RFP documents and provide feedback to ensure the documents are complete and concise and adhere to the Competitive Procurement Procedure.
- Monitor and audit the bid evaluation and final selection process, confirm that response data was applied appropriately, and assure the application of the RFP process complies with the CPP.
- Attend the Bidder's Conference (via telephone) and selected meetings between APS and bidders.
- Review assumptions and inputs used by APS in the RFP process. APS's methodology and reasoning applied in the bid evaluation and ranking, as well as bid evaluation rationale would also be reviewed.

- Provide testimony and participate in Arizona Corporation Commission (ACC) hearings on the RFP process and final shortlist acknowledgment (if required).
- Provide monthly RFP progress updates to ACC staff (if required).
- Inform APS of matters that could affect the integrity of the RFP process. The matter(s) must be presented to APS in a timely manner so the situation can be rectified.
- Prepare and submit a report to APS detailing the Independent Auditor's scope of review, observations and findings relating to the conduct of the Competitive Procurement Procedure and any recommendations for improvements of the solicitation process.
- Upon such a finding, the IA will prepare a certification that indicates that the procurement procedures were fair and unbiased and have been appropriately applied.

This final Report meets the requirements listed above and addresses the activities associated with the solicitation process from the development of the RFP to final selection on May 12, 2009.

II. Requirements of the Renewable Energy Competitive Procurement Procedure (CPP)

The role of the IA in the process is to ensure the solicitation is conducted in an unbiased, equitable and transparent manner in accordance with the Certified Renewable Energy Competitive Procurement Procedure (CPP) dated April 10, 2007.[1] The CPP applies only to the Competitive Procurement Process for any solicitation initiated to meet APS renewable energy needs. According to the CPP, each RFP will provide a description of the following:

1. Product description including timeframe for energy delivery, eligible renewable technologies, capacity and energy requirements, contract term, ownership structure options and system deliverability requirements.

2. Schedule for the process that lists the critical dates including RFP issuance date, bidders' conference, notice of intent to bid, date for submission of proposals, notification of the short list, and final selection.

3. Bid submittal instructions including the information and materials required from bidders during the process in order for the bidders to be eligible for the process. These include the Confidentiality Agreement, Proposal Certification and Summary Agreement (which includes the project description, pricing information, and bidder qualifications), and Statement of Financial Conditions and Creditworthiness Qualifications Disclosure (which includes bidders financial information, credit contacts and bank references).

4. Evaluation process and evaluation criteria. APS will use several stages in the evaluation process to review Proposals and determine the best alternatives. Price will be a major factor, with appropriate consideration given to Respondent experience and qualifications, operational performance, resource reliability, firmness, deliverability, predictability, credit, environmental impacts, contract considerations and other relevant criteria. As defined, the process will include several stages including proposal threshold requirements, screening process and detailed evaluation and selection process. Bids that pass the threshold stage will be subject to a quantitative and qualitative evaluation by APS. The analysis will include a comparison of a bidders total bid cost relative to APS's market cost of comparable conventional generation. The total bid cost will be comprised of the bid price plus costs associated with system integration, delivery of resource to load, and imputed debt. The market cost of comparable conventional generation is comprised of avoided energy and capacity costs. Bids are evaluated based on quantitative and qualitative factors. From this evaluation a short list of bidders will be developed. APS will conduct a detailed evaluation for bids selected to the

[1] In this Request for Proposals for Distributed Energy Resources bid prices were compared to the Production Based Incentive (PBI) caps established in APS Renewable Energy Incentive Program, which was not referenced in the CPP.

short list. APS will use production cost models in its final evaluation of the proposals to simulate the resource in the APS portfolio.

5. Contracts and regulatory approval

In subsequent sections of this report, Merrimack Energy will describe the actual development and implementation of the competitive procurement process and assess whether APS carried out the process in conformance with the CPP.

III. Arizona Public Service Company's Competitive Bidding Process

A. Background

The 2008 Request for Proposals for Distributed Energy Resources (RFP) was designed to supplement the existing distributed energy incentive program in the Distributed Energy Administration Plan (DEAP). APS prepared an initial draft of the RFP in June 2008 and sent the draft to the IA for comment. Merrimack Energy provided comments on the RFP and also asked clarifying questions about select provisions of the RFP. APS made adjustments to documents to reflect comments of the IA and also responded to the questions with an explanation of their approach for addressing the issues raised. The RFP was issued on August 14, 2008. This Chapter of the report will focus on the key characteristics and requirements of the final RFP document and will also describe the process undertaken by APS to solicit proposals, select a short list of proposals, and final selection. [2]

B. Summary of the Components of the RFP

The RFP clearly identified the requirements of APS regarding the types of products requested, the term of the bid, the amount of power (MWh) requested, the timing of need, schedule for the solicitation process, evaluation and selection criteria and process, price and non-price factors, and a description of the role of transmission cost and access. As background, a brief summary of the key components and requirements of the RFP are presented in Exhibit 1.

Exhibit 1: Summary of Key RFP Provisions

RFP Characteristics/Requirements	2008 Request For Proposals for Distributed Energy Resources, August 14, 2008
Resource Requirements	APS is seeking up to 200,000 MWhs per year under this solicitation. APS may elect to procure more or less depending on the quality of the proposals received.
Objective of the RFP	In this RFP, APS is seeking competitive proposals for distributed energy resources to meet a portion of its overall resource needs and to fulfill the regulatory requirements of the Arizona Renewable Energy Standard Rule (RES). A successful outcome of this RFP will be an increase in the quantity of distributed energy at a lower cost than the current Renewable Energy Incentive Program (REIP). Through this RFP, APS is willing to entertain offers that are phased-in over several years rather than the standard REIP that operates on

[2]Merrimack Energy had no involvement in actual contract negotiations.

	an allocation period basis and does not currently allow for multi-year or phased-in project funding.
Resource Timing	System production and delivery shall commence no earlier than 1/1/2009, and no later than 12/31/2013. Priority will be given to projects that are reasonably expected to begin production and delivery prior to 12/31/2010. The contract term shall be a minimum of 5 years and a maximum of 30 years.
Eligibility	APS will only consider proposals whose enabling technologies meet the qualifications of being a Distributed Renewable Energy Resource pursuant to A.A.C. R14-2-1802(B). The minimum annual energy output per project shall be no less than 1,500 MWh per year. A project is either a single location or an aggregation of several sites that results in one agreement between APS and the Respondent. Each project shall contain a minimum annual energy guarantee. A minimum nameplate capacity guarantee is also desired and will be considered in contracting. APS will not accept proposals where the systems are sized for greater than the aggregated customer annual energy requirements.
Product Requirements	Each project must have a clear, specific and defined relationship to an APS retail customer. Specific customers need not be identified in the Proposal. Proposals may include customer-owned generation or third-party generation. Proposals may also include any other arrangements that clearly define the relationship between the generation-owner, the APS customer, and APS. Such arrangements could include centrally-located systems serving multiple customers (e.g. one generation facility centrally located and serving a specific group of customers) or utility-owned systems (e.g. financial configuration where APS ultimately owns the proposed generating systems). The financial arrangements and system output benefits must be explicitly defined. APS retains all rights, title, and benefits to all environmental attributes associated with the Respondent's bid energy, including but not limited to Renewable Energy Credits,

	greenhouse gas or carbon credits, and all other emissions attributes.
Bidding Process	The Company will conduct a three stage process to determine the best proposals with which to pursue contracts: (1) Proposal threshold requirements; (2) screening evaluation, and (3) detailed evaluation.
Pricing Requirements	Pricing must be fixed or relatively stable with escalation rates fixed per year. Any proposal for renewable energy credits priced above the APS DEAP Project Incentive Matrix for each applicable in-service year, for each of the respective distributed technologies, will not be considered. The incentive levels by technology are posted on the RFP website.
Threshold Requirements	Threshold requirements include: (1) the proposal is received on-time and complies with the submission instructions; (2) the proposal submittal includes the submission fee, confidentiality agreement, proposal certification and summary, a completed statement of financial conditions and creditworthiness qualifications; (3) the proposal's generation sources meets the definition of a Distributed Renewable Energy Resource.
Screening Evaluation	The screening process consists of quantitative and qualitative analyses to identify the proposal that will be short-listed. Respondents are advised that price will be a major factor in APS' evaluation, but APS will consider other quantitative and qualitative risk factors. The quantitative analysis includes a review of the cost components of each proposal as well as the costs associated with transmission facilities, system integration costs, and imputed debt. Also, the corresponding payment responsibilities of each of the parties (payee versus payer) involved in the transaction (i.e. APS, the customer, and the Respondent) will also be considered. This relationship must be clearly defined in each Proposal. APS will not consider any Proposals in which APS' cost responsibilities for Renewable Energy Credits exceed the stated maximum for each of the respective distributed technologies, as listed in the APS Distributed Energy Administration Plan Project Incentive Matrix, or any proposals where APS' total cost responsibilities for energy and RECs exceed the total of APS' existing retail tariffs plus the stated maximum incentive for each of the respective distributed technologies, as listed in the APS Distributed

	Energy Administration Plan Project Incentive Matrix. The qualitative analysis is comprised of a high level risk assessment that considers risk factors such as project viability, financial, regulatory, counterparty credit, transmission, distribution, operations, and project development experience. APS will qualitatively assess the Respondent's ability to deliver proposed project(s) as well as the certainty of delivery. Demonstrated previous projects and existing customer commitments will be significant factors in the analysis.
Detailed Evaluation	Proposals selected for the short-list will then be subject to the detailed evaluation. The detailed evaluation is similar to the screening evaluation, except: (1) it incorporates bid information into a more detailed analysis involving integration with the APS portfolio, and (2) relies on a more detailed risk assessment. Based on the results of the detailed evaluation, APS will select proposals for contract negotiation and regulatory approval.
Imputed Debt	The effects of imputed debt may be considered if applicable to the bidder's proposal.
Bid Fees	A non-refundable RFP submission of $1500 per respondent is required to qualify the proposal.

C. Overview of the Solicitation Process

As noted, APS issued the RFP to the market on August 14, 2008. The RFP and related documents[3] were posted on the Company's website established for this RFP under the heading of 2008 RFP for Distributed Energy Resources.

Outreach Activities

APS issued a press release on August 14, 2008 notifying the market of the release of the RFP and informing bidders of the availability of the RFP, the requirements solicited through the RFP, the website address for gaining access to the RFP and related documents, and a listing of names and phone numbers for key contacts at APS. The press release received wide distribution in local Arizona newspapers as well as national industry trade publications. In addition, APS contacted renewable resource organizations in Arizona that may have members interested in participating in the bidding process.

[3] The documents contained as part of the RFP package include the RFP Schedule, RFP Document, Notice of Intent to Bid, Confidentiality Agreement, Proposal Certification Summary, Annual Estimated Delivered Energy form, Statement of Financial Conditions and Creditworthiness Qualifications, APS Distributed Energy Administrative Plan Project Incentive Matrix, Interconnection Requirements and Application, Distributed Energy Equipment Qualifications and Installation Guidance, Renewable Energy Standard and Tariff, and Bidders Conference Information.

Bidders Conference

The Company also held a Bidder's Conference on September 5, 2008 for prospective bidders and other interested parties designed to provide an overview of the RFP, identify the purpose of the process and the schedule, provide a summary list of proposal requirements, describe the evaluation process and selection criteria, provide a description of the eligible technologies, a discussion of the potential project structure models under which the bidders could propose options, provide the names and phone numbers for the Company contacts, and to answer questions that prospective bidders may have on the procurement process.

The presentation by APS at the Bidders Conference also identified and described four potential business models that bidders could propose. These included:

- Incentive-Driven Distributed Energy System, similar to the conventional program
- Distributed Energy Power Purchase Agreement whereby APS contracts with a third-party for products and services
- Customer Direct Distributed Energy Model whereby APS contracts directly with the customer
- Aggregated Customer Distributed Energy Model

APS also indicated at the Bidders Conference that it would consider other proposed structures.

The presentation of APS also focused on informing prospective bidders about the interconnection and metering requirements associated with different potential project structures

Prospective bidders and interested parties had the option of either attending in person or calling into the Conference. The response to the Bidders Conference was robust with attendees both in-person and on the phone totaling between 50-60 attendees, including the IA, who participated via teleconference.

APS received a number of questions at the Bidders Conference and also received questions via the website for the RFP. A total of 40 questions were received and the Company posted the question and response on the website. The IA also received the Company's response to bidder's questions and provided comments to the APS project team if the IA felt that responses needed further clarification. APS also added a clarification to the RFP document regarding the 60% cap for project costs via a response to a bidder question (see page 16 of the report for details associated with the 60% cap).

Bidders were requested to submit non-binding Notices of Intent to Bid on-line by September 22, 2008 and a signed Confidentiality Agreement to APS by September 29, 2008. The Company received 25 Notices of Intent to Bid. The majority of the projects were solar technologies which included commercial and industrial applications. Twenty-three Confidentiality Agreements were executed with prospective bidders.

Development of the Bid Evaluation Methodology

On October 6, 2008 the IA and the Company conducted a full day meeting at the Company's offices to discuss the bid evaluation process and prepare for receipt of bids. In preparation for the meeting the IA prepared a "watch list" of issues or suggested issues for discussion at the meeting.[4] One of the issues, the quantitative evaluation methodology, was the subject of several conference calls and discussions prior to the scheduled meeting based on the unique nature of the RFP (for distributed resources) and the potential project structures.

The "watch list" of issues identified included the following:

1. Quantitative analysis methodology for each of the project structure models
2. Bid evaluation protocols for the evaluation process
3. Imputed debt application and methodology
4. Facility cost and integration cost impacts for each project structure model
5. Evaluation criteria associated with qualitative factors
6. Combination of quantitative and qualitative factors
7. Detailed evaluation process and methodology
8. Credit evaluation methodology
9. Calculation of avoided energy and capacity costs
10. Treatment of lost revenues [5]
11. PPA Agreement [6]
12. Receipt of bids and distribution of the bids to the IA

Based on the unique nature of the RFP and the project structure options envisioned, the quantitative analysis methodology had to be designed specifically for this process. As noted above, several conference calls were held to discuss the development of the quantitative evaluation methodology. In preparation for the meeting between the IA and APS project team, the IA requested that the Company Project team prepare "test or hypothetical bids" or examples for different project structures (i.e. sales of RECs only to APS, sales of RECs and energy to APS, and load aggregation sales of RECs and energy to APS) to assess the methodology proposed by the Company for evaluating the bids received. The Company prepared three test bids and walked through the evaluation of the bids during two conference calls before the scheduled meeting. Based on the comments and questions raised during the conference call, APS subsequently modified its evaluation methodology to provide more specific details regarding the bid evaluation methodology and evaluation process. The updated examples and methodology were sent to the IA and a follow-up discussion was held to review the test bid results.

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[4] The "watch list" issues are those issues which the IA believes could have a major influence on the outcome of the process and which need to be fully vetted with the utility in detail before and during the solicitation process.

[5] The issue of inclusion of lost revenues in the evaluation process was discussed at the meeting. APS decided not to include lost revenues in the bid evaluation process.

[6] APS did not include a PPA with the RFP but instead identified in the RFP document that it may request a sample contract from a bidder or present a sample contract to any short-listed respondent.

In addition to discussions on the quantitative evaluation methodology and input assumptions, during the October 6, 2008 meeting, the IA also met with staff from other areas within the company that were involved in the quantitative and qualitative evaluation process. This included representatives from Credit, Resource Planning (discussion of input assumptions and avoided cost methodology), Regulatory, and Technical, to get a detailed briefing on the role of each group and to ask any follow-up questions. These discussions also centered on assessment of the proposed methodologies to be used in the evaluation process. In addition to the quantitative methodology, the IA and APS staff also discussed the qualitative evaluation process. APS staff indicated that the qualitative evaluation process was designed to rank each proposal in one of three categories: (1) high risk; (2) medium risk; and (3) low risk. Project viability risk and technology risk were viewed as primary concerns. Also discussed were potential different regulatory treatments if a project was located on the customer side or APS side of the meter.

Receipt of Bids

Bids were received by October 17, 2008. A total of 12 different respondents submitted responses which included 22 distinct proposals and 43 total offers when considering options offered. Ten of the twelve proposals offered solar projects. A total of ten proposals represented customer-specific projects and two offered customer aggregation projects. The proposals offered distributed energy resources significantly above the amount of energy solicited in the RFP, illustrating the robustness of the process. In total, the proposals represented a maximum of 915,000 MWh of energy and 472 MW of nameplate capacity.

Threshold Evaluation

The first stage in the evaluation process consisted of the threshold requirements analysis. Bids had to meet the required eligibility and threshold requirements listed in the RFP in order to be eligible for the next stage of the evaluation. In addition to the eligibility and threshold requirements, the RFP (as clarified in responses to bidder questions) listed other "must requirements" that bids had to meet. For example, the bid price for RECs had to be less than or equal to the PBI cap established in the standard program (REIP). As a result of the eligibility and threshold evaluation, eight of the twelve bidders were classified as conforming proposals by APS. Four bidders, along with specific offers from some of the entities that submitted conforming proposals, were classified as non-conforming. In total, 18 of the 43 offers were classified as conforming.

Among the reasons why proposals or offers were classified as non-conforming include:

- The proposal violated the 60% cap rule (i.e. REC payments cannot exceed 60% of total project costs plus the cost of financing);
- REC only and REC plus Energy prices were above the Performance-Based Incentives (PBI) or established cap for the technology in question;
- The bidder provided incomplete or inadequate information in its response;

- The customer underlying the proposal was not an APS customer;
- The proposal was not consistent with the requirement to site the project at a customer site.
- The proposal does not meet the requirement to be on-line by 2013
- The proposal is classified as a small generator proposal rather than as a distributed generation option
- The technology is not proven

Merrimack Energy also conducted a separate summary of the proposals received and was able to replicate the same number of proposals and offers submitted. In addition, prior to classifying a proposal as non-conforming, APS' Project Management contacted the IA with regard to its findings and basis for decision. APS and Merrimack Energy convened several conference calls to discuss whether or not a proposal should be classified as non-conforming. It was obvious that several proposals were non-conforming after initial review and communications with bidders by APS to ensure the bidder agreed with interpretation of its submission. For others, APS had to undertake additional research and due diligence to assess whether the proposed customer was in fact an APS customer or assess whether the bidder met the 60% cap. The Company conducted follow-up discussions with bidders deemed non-conforming for the latter reason to ensure the bidder understood these requirements. For example, several bidders did not provide information on the capital cost of the project and APS had to request that bidders provide such information to assess eligibility. [7]

Merrimack Energy was in agreement with APS' decisions regarding bidder eligibility and threshold requirements and whether a proposal was conforming or non-conforming based on our review of the proposal, email traffic between APS and the bidder, and follow-up discussions with APS.

Communications With Bidders

As highlighted above, APS' competitive procurement process has involved a significant level of communications with prospective bidders through the development and maintenance of the RFP website, outreach activities designed to publicize the RFP, responses to questions from bidders, initiation of a bidders conference to address questions from the bidders about the procurement process and RFP requirements, and posting of the names and numbers of the key APS contracts.

On October 22, 2008 an inquiry was posted on the APS website by a prospective bidder raising some concerns about the clarity of the RFP document and bidding requirements. In particular, the prospective bidder asked whether the 10/20 option[8] included in the Conforming Project Incentive Matrix was an eligible option. The bidder stated that an APS representative indicated at the Bidders conference that APS was proposing to eliminate the 10/20 option. This bidder did not submit a proposal on time as required but

[7] APS provided the IA with a record of the email traffic between APS and the bidders.
[8] Under the 10/20 option in the Incentive Matrix, there is an option for bidders to receive payment for 10 years and sell RECs under the contract for 20 years.

complained about the "lack of clarity" in the RFP and "inconsistency" in the information presented by APS regarding the allowable pricing and term options included in the Conforming Project Incentive Matrix. The prospective bidder claimed they did not submit a bid because they were concerned that their bid would not qualify and they would risk losing the $1,500 bid fee.

APS sent an email to the prospective bidder on October 23, 2008 indicating that APS will not (and did not) reject conforming bids utilizing the 10/20 option for pricing. APS indicated that the incentive caps in the matrix are the incentives APS currently offers for eligible technologies. Removal of the 10/20 option was requested by APS in its 2009 Implementation Plan but had not been reviewed by the ACC. APS also indicated in the email that the procedures it had followed including a detailed Q&A process and transparent schedules and deadlines had produced a clear and transparent process that all bidders could follow.

Two follow-up emails were submitted by the prospective bidder. One email indicated that there was apparent confusion on the part of the two employees developing the company bid with regard to the allowable incentives (i.e. 10/20 option). The prospective bidder realized their misunderstanding while developing the pricing proposal on Wednesday evening before the bids were due on Friday, October 17 based on their perceived lack of clarity in the RFP and response to bidders questions regarding the availability of the 10/20 option.

The second email, which was sent on October 24, indicated that the prospective bidder attempted to call APS personnel on Thursday, October 16, 2008. The bidder indicated that to their regret they did not submit a question to the website because they did not believe a response would have been received on time. In the email, the prospective bidder indicated that due to the confusion over the availability of the 10/20 option it did not believe it could resolve the issue on time to submit a bid and encouraged APS to reconsider acceptance of the bid. The bidder also indicated that if their bid is rejected without clarification of this issue, the prospective bidder would consider the process to be an unfair process.[9]

To address the concerns of the prospective bidder, APS suggested that a conference call be held with the prospective bidder and IA to discuss the positions of the parties. Such a call was held on October 27, 2008. The positions of the parties presented during the conference call are summarized below.

The prospective bidder reaffirmed their confusion about the requirements of the RFP, particularly their interpretation that the 10/20 option had been eliminated. The prospective bidder also indicated that they did not anticipate that the Company would use an RFP to solicit resources under the DE program and were concerned that the RFP would be funded out of the DE program funds. Furthermore, the prospective bidder questioned whether the RFP was reasonably publicized and noted that two other prospective bidders active in the Arizona market did not know about the issuance of the

[9] It is important to note here that the bidder never submitted a bid. Therefore, their bid was not rejected.

RFP and therefore did not submit a bid. Finally, the prospective bidder indicated that the RFP was not approved by the Commission and stated the process was unfair because the requirements for the bidders was not clear.

The Company's position was that the 2009 Implementation Plan proposal to eliminate the 10/20 option was not connected to the requirements of this RFP. The RFP was not designed to eliminate anything in the existing incentive program but to supplement the program. The Uniform Credit Purchase Program (UCPP) parameters and project incentive values will still be in place as it remains unaffected by the RFP. The Company noted that no other bidder has raised an issue or complained about the RFP. The Company also stated that the matrix values only establish the incentive cap, as explained in the RFP document. Also, the Company stated that the values in the matrix are functionally the same on a net present value basis and therefore there should not be different incentive values over the contract term, which should allow bidders to select the incentive mechanism appropriate to their needs.

As IA, Merrimack Energy reviewed the emails and participated on the call with the Company and the prospective bidder. The conclusion of the IA was that the bidder had missed the deadline by more than 5 days and should not have an opportunity to submit a proposal at this time, as requested. The IA's conclusion was based on the following factors:

1. Only one prospective bidder raised any concern about the clarity of the RFP. No other bidder indicated they were confused by the requirements of the RFP and to our knowledge there were no prospective bidders who did not submit a proposal because they were confused by the Company's responses to bidders or the requirements of the RFP. Furthermore, as noted, the response to the RFP was robust.

2. In a competitive solicitation process of this nature, it is important that all bidders are treated fairly. It is not fair to other bidders or prospective bidders if a competitive option is allowed to submit a proposal several days after bids are due. Some prospective bidders may not have submitted a bid due to time constraints. With more time, they may have reconsidered. Furthermore, those that did submit a bid on time are compromised as well since they did not have the same time opportunity as the prospective bidder in question. It is important to maintain the integrity of the process if it is to be a successful process.

3. Apparently, the prospective bidder realized on Wednesday, two days before the bids were due, that they misinterpreted the requirements of the RFP. The bidder could have contacted APS' RFP contacts listed in the Bidders Conference presentation and in the RFP or submitted a clarifying question to the Company. Contrary to the communication procedures outlined in the RFP, the prospective bidder indicated it attempted to contact another APS employee they regularly communicate with but did

not leave a message. Furthermore, the prospective bidder indicated in its email that it made a mistake by not contacting the appropriate company contacts once it realized there was confusion in their minds about the requirements of the RFP.

4. There is still an opportunity for the prospective bidder to submit an offer through the existing UCPP Incentive program option. Thus, the inability of the prospective bidder to compete for the sale of distributed energy to APS should not be an issue given the availability of the existing program and the opportunities afforded by that program.

During the timeframe from receipt of bids through selection of the initial short list, a substantial amount of communications occurred between APS and the bidders involving clarification of information contained in the proposal to fully assess each proposal. APS provided access to the email traffic between APS and the bidders along with any other documentation to the IA during this process. In addition, APS and the IA had several conference calls during this phase in the process to discuss the status of the evaluation.

D. Proposal Evaluation Process

The proposals were initially subject to the screening process which consisted of quantitative and qualitative analysis, with the quantitative analysis serving as the primary metric for initially ranking proposals. The quantitative evaluation was effectively undertaken in three steps. Proposals had to meet the requirements of Step 1 and 2 below to be eligible to continue in the evaluation process. The first two steps were effectively part of the eligibility criteria and bids had to conform to these two requirements to be eligible for the evaluation. Each of the steps is described below:

Step 1: Comparison to the PBI Cap[10]

In Step 1, the bid price for RECs would be compared to the current PBI for the specific technology proposed. For the proposal to be eligible, the bid price for RECs had to be at or lower than the price included in the APS DEAP Project Incentive Matrix for each applicable in-service year, for each of the respective distributed technologies. For this evaluation, APS compared the initial year price as well as the levelized price of each proposal relative to the DEAP Project Incentive Matrix. As previously noted, a few bidders did not submit proposal pricing that conformed to this requirement. Also, a few other bidders proposed a price equivalent to the established cap in the standard program, which meant the bid would provide no inherent economic value relative to the standard program.

[10] Production Based Incentives (PBIs) are designed to pay the customer at an established price cap by technology for the environmental attributes associated with its renewable energy system over time instead of an initial, up-front incentive payment. The current structure for incentive payments to the customer is up to 20 years or a cap of 60% of the Real Project Cost (including acceptable financing charges), whichever comes first. The Customer is then obligated to provide APS with all Renewable Energy Credits (REC) produced for 10, 15, or 20 years, depending on the term of the agreement.

Step 2: Comparison to Project Cost Cap

Step 2 was designed to determine if the total payment to the bidder (in as-incurred or non-discounted dollars) exceeded 60% of the total project cost (total system cost plus financing charges). Projects which contained bid prices above the cap would be classified as non-conforming unless they agreed to either revise their pricing or receive payment for RECs for a shorter period of time than they are required to provide RECs to APS.[11] During the evaluation of this criterion, it became clear that some bidders did not understand this requirement or how they would be evaluated. In addition, several bidders did not provide the required total project cost information. APS did consult with bidders to ensure they understood the requirements and attempted to resolve any inconsistencies in the assessment. Bidders did eventually provide this information, generally as a result of email correspondence between the bidder and APS.

Step 3: Total Bid Cost as a Percentage of Avoided Cost

The purpose of this step in the process was to calculate the levelized cost of the proposal relative to APS system avoided cost.

The cost of the proposal consisted of the bid price plus integration costs, where integration costs consisted of system integration costs plus transmission costs plus imputed debt.[12] In the evaluation, none of the bids were assessed system integration costs or transmission costs. The only integration cost considered in the evaluation was imputed debt. The Net Present Value (NPV) of total cost stream was calculated and levelized over 20 years (and 30 years) based on the Company's discount rate.

APS also calculated the NPV and levelized avoided energy and capacity cost associated with each proposal. For avoided energy cost, in this stage of the evaluation APS calculated the system average hourly avoided energy cost for each month and applied that cost to the energy generation profile proposed by the bidder as the basis for calculating the avoided energy cost. The avoided capacity cost was based on the real levelized capacity cost for the proxy capacity resource (GE LMS100 combustion turbine) times the amount of capacity bid times the capacity value for the type of resource proposed. The capacity value was derived from an outside consultant study which calculated a capacity contribution or capacity value for each renewable technology.

The metric used by APS in the proposal ranking process was the levelized bid cost as a percentage of avoided cost. The ratio of the net present value of the bid cost to the net present value of avoided cost was initially calculated for each proposal. For purposes of unitizing the total net present value of the bid cost and avoided cost streams, APS discounted the output or generation stream as well (in levelized MWh). Both the bid costs

[11] For example, a bidder may reach the cap in year 10 of a 20 year contract. The bidder could accept payment over the first 10 years of the contract for the RECs but agree to deliver RECs to APS for 20 years.
[12] Merrimack Energy assessed the methodology used by APS to calculate imputed debt and found the methodology to be reasonable and consistent with the methodologies used by other utilities.

and avoided costs were then calculated in dollars per MWh, the ratio of the bid cost to avoided cost determined, and the bids were then ranked accordingly.

APS provided Merrimack Energy with the total outputs for all conforming proposals evaluated. Merrimack Energy also modeled a sample of the bids using its independently developed spreadsheet model and applying our own interpretation of the proposal pricing. Merrimack Energy used APS' avoided energy and capacity charges as inputs into the analysis. Based on this analysis, we were able to confirm that the methodology was consistently applied and the results of APS' analysis were consistent.

From a qualitative perspective, APS applied four primary criteria in the evaluation of each eligible proposal:

- Credit Risk
- Regulatory Approval
- Viability Risk
- Technology Risk

For each criterion, each proposal was ranked as low, medium or high risk. The definitions and conditions for each ranking were pre-established by the members of the evaluation team responsible for each criterion. APS' evaluation team developed the back-up information to support its evaluation and provided the documentation to the IA for review.

E. Short-List Determination

The IA and the Company's Evaluation Team met on January 12, 2009 to discuss the short list selection process. APS presented the results of its assessment from a quantitative and qualitative perspective, including a recommendation for short list selection. The IA had also reviewed the bids in advance of the meeting. APS chose five bidders with a total of eleven different proposals. These included seven customer options and four aggregation options. Seven of the proposals were for RECs only and four were for RECs and Energy. Two of the proposals were designed to serve the same customer. The proposals included on the short list totaled nearly 240 MW and over 440,000 MWh. Essentially, all bids that proposed a price lower than the PBI cap were selected for the short-list.

Merrimack Energy agreed with the selection of the short listed bidders. Not only were all selected bids lower than the PBI cap but the ratio of the bid price to avoided cost was much higher for those bids eliminated in this stage of the evaluation. A natural break point between bids was obvious, which led to a logical decision regarding short listed bid selection.

F. Detailed Evaluation

Following the selection of the short list, APS notified the bidders of their status and informed short listed bidders that APS would like to meet with the bidder to discuss its proposal in more detail. Meetings were scheduled for mid-February with each of the short listed bidders. APS established a consistent agenda for the bidders which included the following topics:

- Bidder company and project experience overview
- Project description as submitted in their proposal
- Technology, permitting, interconnection and project schedule
- Contract discussions
- Financing of the project

Meetings were held with all bidders. The IA attended two of the meetings in person and others by phone and also received the presentations from all bidder meetings.

Shortly after the bidder meetings, one of the short listed bidders withdrew from the process. The bidder informed APS that it was concerned about the structure (contractual arrangements) and feasibility of their proposal at this time and therefore elected to withdraw.

Two bidders on the short list had proposed to serve the same customer. The customer wanted a REC plus energy option. As a result, APS asked the two bidders to provide updated proposals for the REC and energy option as requested by the customer.

Also, two bidders offered load aggregation options. The bidders had offered multiple aggregation options that had different characteristics. To equitably evaluate both options, APS asked each bidder to offer a revised proposal for an aggregation option for a fixed amount of MWh of generation by 2013 from customer sited systems. APS emphasized to bidders to propose a least cost mix of customers and technologies in their proposal. The bidders could propose a phase-in schedule and customer aggregation options to meet the stated requirements. APS also asked the two bidders to propose pricing for two other MWh targets by 2013. In early May, 2009 one of the bidders for the aggregation option announced that it was withdrawing its proposal from the RFP because of concern about securing financing.

APS also sent a list of contract terms and provisions that APS will be seeking if it chooses to execute an agreement to short listed bidders. While APS did not provide a model contract to short listed bidders, the terms and conditions of interest provided a starting point for discussions with short listed bidders.

During the detailed evaluation phase of the process, APS calculated revised avoided capacity and energy costs as part of the detailed evaluation. For the avoided energy costs, APS completed a detailed production cost model simulation using PROMOD IV. This assessment of the short listed bids used a similar methodology as was used in other APS

RFPs. To undertake this assessment, APS worked with each of the short listed bidders to update the load profile of the customer using three years of historical data. The evaluation was based on the bid price for RECs only.

To calculate avoided energy costs, APS modeled the generation profile of the renewable resource with zero costs added to the base case in the production cost model. The avoided energy cost was calculated as the difference in production costs between the base case and the case with the renewable resource.[13] The net present value of the bid price was then compared to the net present value of the avoided cost stream to assess the relationship between the bid price and avoided cost. The results of this analysis were generally very similar to the results of the screening analysis previously undertaken.

The avoided capacity cost assessment was based on the average net impact capacity over APS' top 90 load duration hours divided by the maximum hourly capacity of the resource over the entire year based on the revised generation profile.

APS then selected five bids for final selection, including two REC only options and three REC plus energy proposals. The total capacity for these options equals 54.33 MWac and 121,885 average annual MWh. Merrimack Energy reviewed the detailed evaluation results and agreed with APS' final selection.[14] Bidders who either offered pricing at or near the PBI Matrix values or were non-conforming from a technology perspective in this RFP were encouraged by APS to either reconsider the standard program or consider bidding into the 2009 Request for Proposal for Renewable Energy Small Generation Resources. As a result, it is possible that additional generation may be provided in any case, but through other program options.

[13] The base case was the same as the base case used in the initial screening analysis.
[14] While the amount of energy actually selected was less than the target of 200,000 MWh, this target included both residential and non-residential customers. However, there were no residential bids.

IV. Framework and Principles for Evaluating Arizona Public Service Company's Implementation of the Bid Evaluation and Selection Process

The 2008 Request for Proposals for Distributed Energy Resources is a unique competitive solicitation process based on the nature of the products requested.[15] As a result, the evaluation methodologies and project structure requirements evolved somewhat over the course of RFP design and implementation. As such, our evaluation of the process takes into consideration that the methodologies and approaches for evaluating bids may have initially been somewhat unique to this RFP, since there have been limited industry applications. Based on Merrimack Energy's experience with competitive bidding processes and observations regarding such processes, the key areas of inquiry and the underlying principles used by Merrimack Energy to evaluate the bid evaluation and selection process undertaken by the host utility include the following:

1. Were the solicitation targets, principles and objectives clearly defined and consistent with the requirements of the Renewable Energy Competitive Procurement Procedure?

2. Did the solicitation process result in competitive benefits for customers from the process?

3. Was the solicitation process designed to encourage broad participation from potential bidders?

4. Did Arizona Public Service Company implement adequate outreach initiatives to encourage a significant response from bidders?

5. Was the solicitation process consistent, fair and equitable, comprehensive and unbiased to all bidders?

6. Were the bid evaluation and selection process and criteria reasonably transparent such that bidders would have a reasonable indication as to how they would be evaluated and selected?

7. Did the evaluation methodology reasonably identify how quantitative and qualitative measures would be considered and applied?

8. Did the Request for Proposals (i.e. RFP document, the Bid Form, and Standard Contract) describe the bidding guidelines, the bidding requirements to guide bidders in preparing and submitting their proposals, and the bid evaluation and selection criteria?

[15]Based on our experience with competitive bidding processes, we are aware of only a few solicitation processes for distributed resources.

9. Did the utility adequately document the results of the evaluation and selection process?

10. Did the solicitation process include thorough, consistent and accurate information on which to evaluate bids, a consistent and equitable evaluation process, documentation of decisions, and guidelines for undertaking the solicitation process?

The implementation of the 2008 Request for Proposals for Distributed Resources process relative to the characteristics identified previously is described below. Merrimack Energy has had no involvement in the contract preparation process and is thus not in a position to discuss this objective.

1. Solicitation Targets

The RFP document clearly defined the amount of power requested, the timing for providing the power, the type of products and product characteristics required, the duration of the contract, bidder eligibility, schedule for undertaking the process, the evaluation and selection criteria and process, and the context of the RFP and associated documents consistent with the requirements of the Arizona Corporation Commission as described in the Certified Renewable Energy Competitive Procurement Procedure. In our view, APS's process meets the requirements of the Certified Renewable Energy Competitive Procurement Procedure.

2. Competitive Benefits

The solicitation process encouraged a significant response from the market, with 43 total offers from a reasonably large number of bidders. This resulted in a response of over 4.5 times the amount of energy requested. In addition, the bidders included some of the largest and most experienced solar project developers. The majority of the proposals were also relatively thorough and mature and met the requirements outlined by APS. The significant level of competition ensured that the best projects could be identified and selected. The process should result in competitive benefits to customers relative to the existing standard program the RFP was designed to supplement by resulting in prices overall significantly below the incentive matrix levels.

3. Broad Participation from Potential Bidders

As noted above, the process encouraged a robust and competitive response from a range of respondents, including several large, experienced, and financially sound project developers, local project development firms, and APS customers. The level of interest from the market as witnessed by the number of bids and participation in the bidder's conferences was substantial. In our view, the solicitation process certainly succeeded in securing distributed energy resources to meet a portion of APS's overall resource needs

at a lower cost than the current Renewable Energy Incentive Program, although there were no residential bids.

4. Outreach Initiatives

APS undertook reasonable efforts to inform the market of the issuance of the RFP and the Company's requirements through targeting both national and local entities. The Company established an easily accessible website which included all the information required by bidders to submit a proposal. The availability of documents, questions and answers, and notifications about the process allow bidders to maintain accessible contact. In addition, participation at the Bidder's Conferences was outstanding, indicating significant market interest and involvement.

5. The solicitation process should be consistent, fair and equitable, unbiased, and comprehensive

The principal focus of our assessment of APS's RFP process and the Company's performance in carrying out the process was on the bid evaluation and selection process. The key criteria (fair, equitable, consistent and unbiased) are applied to APS's implementation of the evaluation and selection process as well as APS's ability to adhere to the requirements outlined in the RFP documents and associated requirements of the Certified Renewable Energy Competitive Procurement Procedure. Therefore, the critique will focus on the implementation of the process rather than specific issues regarding the process.

In our view, APS's evaluation and selection process was consistent throughout and was easily reviewable and verified by the IA. Merrimack Energy's independent review of the evaluation confirms that the bids were consistently and fairly evaluated from a quantitative perspective in both the screening and detailed evaluation stage.

In addition, the level of detail and support of the qualitative evaluation was reasonable and consistently applied across proposals.

The price evaluation methodologies were designed to evaluate bids using the same or consistent set of input parameters and assumptions. The methodology used by APS to compare bid prices to avoided costs is a reasonable methodology frequently used by other utilities in similar processes. In our view, the methodology was fairly and consistently applied to all bidders.

With regard to bias, the most obvious consideration is whether the process favors one type of bidder, technology or project structure over another. Since all bids were for a similar type technology any presence of bias would likely be in the implementation of the process itself or project structures, rather than the criteria or other information that could affect different bidders. Based on our direct involvement in the process, we could find no examples where one bid or project structure was more favorably treated than another. In both the short list and final detailed process bids for RECs, RECs and energy, load

aggregation, and individual customer options were selected. The RFP was also designed to explain in detail the evaluation process, the requirements of APS, and the information that all bidders were required to submit, leading to a consistent set of information provided by all conforming bidders.

We do not believe any bid had an inherent competitive advantage within the parameters of the RFP. The non-compliance assessment and follow-up information requirements ensured all bidders provided the same information for evaluation purposes. Also, APS was focused on ensuring that all bidders competed on an equal footing and had access to the same information. In all cases, bids that were classified as non-conforming submitted offers that were clearly inconsistent with the requirements of the RFP. Also, several bidders decided on their own to withdraw their offers prior to completion of the final evaluation.

The solicitation process was well structured to ensure that the information required in the RFP documents were linked to the evaluation criteria. APS requested a reasonable amount of information from the bidder to gain an in-depth assessment of the proposed project and utilized all the relevant information to evaluate the offer.

6. Transparency of the Process

The RFP documents and responses to questions led to a process where reasonably sophisticated bidders would be aware how to effectively compete. The threshold, quantitative and qualitative criteria were provided as well as a description of the requirements. The information required of bidders was generally clear and concise as witnessed by the complete and consistent proposals submitted by most bidders. The only area of confusion on the part of several bidders was with the 60% cap on project costs for purposes of establishing the payment stream. While APS attempted to clarify this requirement via a response to a question, there still appeared to be some confusion regarding this requirement on the part of the bidders. However, APS did allow bidders to clarify their proposals to conform to this requirement.

7. Application of Quantitative and Qualitative Measures

The RFP document articulated the quantitative and qualitative criteria and methodology and requirements associated with the evaluation process. The methodologies, cost components and models were generally described in the RFP. Also, the pricing forms were included in the RFP document.

8. The Call for Tenders Documents should describe the process clearly and provide adequate information on which bidders could complete their proposals

This objective deals with the quality of the documents contained in the RFP (i.e. RFP documents, Proposal Certification and Summary (information requirements from bidders), Statement of Financial Conditions and Creditworthiness Qualifications, Interconnection requirements, and information on the standard program. APS's RFP

provided considerable detail regarding the information required of bidders, the basis for evaluation and selection, and the criteria of importance. The RFP process clearly provides a direct link between the RFP document and Proposal Certification and Summary. The quality of the RFP documents and the clarity of such documents for the bidders can be observed by the quality and organization of the bids. For the most part, the proposals submitted were complete, thorough in terms of providing the information requested and well organized. We view this to largely be the result of the quality of the Bidding documents.

9. Documentation of Results

Based on our review, it is obvious that all evaluators maintained very detailed information to support their evaluation of the bids from both a quantitative and qualitative perspective. In addition, Merrimack Energy was provided with detailed spreadsheets and other consistent documentation to support the evaluation of the bids.

10. The solicitation process should include thorough, consistent, and accurate information on which to evaluate bids

The bid form requires a significant amount of information that bidders must include in their proposals. Under APS's evaluation process, the vast majority of this information is used in the analysis and is consistent with the evaluation criteria developed. The level of information provided by bidders ensured that APS could undertake a consistent and comprehensive analysis of each proposal and reflect the individual attributes of each proposal in the evaluation. We found no biases in the evaluation criteria or process and found the documentation to be very thorough.

V. Conclusions and Recommendations

A. Conclusions

The RFP procedures followed by APS and the subsequent bid evaluation and selection processes and methodologies are, in substance, consistent with industry standards and represent a fair, consistent, and unbiased evaluation and selection process. The process and requirements are also consistent with the Renewable Energy Competitive Procurement Procedure. The following summarize some of the major considerations relative to the consistency of the RFP for Tenders with industry standards.

In the opinion of Merrimack Energy, the bid evaluation and selection process was undertaken by APS in a fair, consistent and comprehensive manner. In addition, in our view, this process was a very thorough, rigorous, and comprehensive evaluation and selection process, with every eligible bid scrutinized in detail. Both the quantitative and qualitative assessments were expertly undertaken, which should result in competitive prices, viable projects, and benefits to customers. The implementation of the solicitation process was expertly managed by APS, was conducted in conformance to the schedule outlined in the RFP, and should lead to benefits to consumers in the form of lower prices and creative solutions.

The bid evaluation and selection process was undertaken in a consistent and comprehensive manner with all bids treated fairly and equitably. A list of important aspects of the Call for Tenders bid evaluation and selection process is provided below.

1. The RFP was a very competitive process, with over 4.5 times the amount of energy bid than the amount required. The significant response to the RFP led to a competitive process, with 43 offers received from 12 bidders.

2. The RFP documents were detailed and transparent documents that clearly identified the unique nature of the solicitation process, the products requested, the information required of the bidders, and the bid evaluation and selection process.

3. The outreach process was broad reaching and targeted to potential bidders. The activities were designed to attract a wide audience of bidders. The outreach activities in question include marketing of the RFP, access to the website for bidders, response to questions, and the Bidders Conference.

4. APS responded to a number of questions from bidders and posted the responses on its RFP website. In our view, APS staff was very responsive to the needs of bidders and such communication with bidders led to comprehensive and responsive proposals.

5. APS addressed all of Merrimack Energy's watch list issues in a reasonable and satisfactory manner. There were no outstanding issues that affected the integrity of the solicitation process. APS effectively addressed the issues raised by a prospective bidder in a manner which did not affect the integrity of the process.

6. The three-stage evaluation process followed by APS (i.e. Threshold Requirements, Proposal Screening Process based on quantitative and qualitative criteria, and Detailed Evaluation on the short listed bids) outlined in the RFP is, in substance, consistent with the approaches followed by other utilities. In particular, the use of quantitative analysis as a primary criterion for selection of the preferred proposals is common practice in the industry.

7. The quantitative analysis undertaken in both the Screening Process and Detailed Evaluation stage to compare the bid price to APS's avoided costs is similar to methodologies used by other utilities for competitive solicitation processes of renewable resources. While some utilities may compare the bid price to the value of the power supplied to the market as an alternative, a number of utilities also apply an avoided cost methodology as a substitute. In our view, such an approach is appropriate and consistent for such processes.

   The first two steps applied by APS for undertaking the quantitative analysis in the screening stage are unique to this RFP but are consistent with the required methodology identified in the RFP and distributed generation program design. In particular, the comparison of bids to the PBI and total cost cap are unique but proved to be effective measures in evaluating and selecting bids since all bids selected for the short list had a bid price lower than the PBI cap, to the benefit of APS's customers.

8. The quantitative evaluation methodology was effective in comparing bids with different commercial operation dates, generation levels, project structures and degradation rates. This methodology proved effective in evaluating and ranking the different proposals and variants.

9. All proposals that passed the threshold requirements stage were thoroughly and consistently evaluated and ranked based on a detailed quantitative and qualitative assessment. All evaluation results were thoroughly scrutinized by APS's bid evaluation team and Merrimack Energy. Merrimack Energy conducted an independent quantitative evaluation using its own model for a sample of proposals for the three steps in the quantitative evaluation screening stage and compared the results of the analysis with the results from APS's own analysis. Merrimack Energy reviewed the avoided cost calculations completed by APS and used the avoided cost values in its analysis. The results of Merrimack Energy's analysis for each bid were consistent with APS's results.

10. Merrimack Energy was in agreement with APS's selection of both the short listed bids and the final bids for negotiation. With regard to the short list, there was a clear distinction between lower cost and higher cost bids. Furthermore, with few exceptions, the short listed bids also performed well in the qualitative evaluation.

11. The qualitative criteria used were generally consistent with those criteria used by other utilities for renewable resource solicitations. While some utilities apply broader criteria and apply weights in combination with quantitative factors to determine a short list, the approach used by APS is reasonable and consistent with industry standards. Furthermore, the RFP and related materials clearly identified the key parameters and criteria that will be applied in selecting short list and final bids.

12. The face-to-face meetings with short listed bidders was a very valuable component of the process and served as an opportunity to assess the status of a bidders' proposal and gain a better perspective of the experience and capabilities of prospective bidders.

In conclusion, it is our view that the solicitation process and assessment undertaken by APS was fair, consistent, comprehensive and unbiased. APS established procedures and rules which guided the evaluation and selection process, and consistently applied such procedures. While the RFP was unique with regard to the type of resources solicited and project structures, the evaluation and selection process effectively conforms to the requirements of the RFP, reflect the practices of other similar utilities in conducting such a process, and represents good utility practice.

B. Recommendations

While Merrimack Energy found overall that the RFP process was well conceived and managed and produced very competitive resource options, we have a few recommendations for future solicitations of a similar nature.

1. The methodology and requirements for calculating the 60% cap based on the cost of the project and financing costs appeared to create some confusion on the part of bidders. As a result, a number of bidders did not initially conform to this requirement and APS had to request additional clarifying information from several bidders and discuss with bidders issues associated with meeting such a requirement. Given the apparent confusion, we would suggest that APS either include an Excel spreadsheet in future RFPs, which allow bidders to input their own data to assess if their pricing proposal meets the requirements or provide examples of the application of the evaluation methodology in the Bidders Conference presentation.

2. The 60% cap requirement also appears to offer the potential for bidders to game the system by "backing" into a project cost estimate to meet the 60%

cap requirements. In fact, it did appear to the IA that several bidders provided estimates for project cost and financing costs based on such an approach rather than provide an accurate assessment of project costs. While APS reserves the right to require the bidders to justify their costs, this requirement may not be taken seriously by the bidder. One solution would be to require bidders to provide more detailed supporting cost data on their project costs during the short listing period.

3. We recommend that APS include either Term Sheets or model PPAs in the RFP package as part of the next RFP. We recommend term sheets or model PPAs be included for the most obvious project structure models.

ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Chairman Mayes:

Please provide an analysis of the above market costs for renewable projects in the settlement that include the effects of cap and trade.*(1606:7-17)*

Response:

While APS has not forecast CO_2 prices that may result from pending carbon legislation, the Company used two reference values in the Resource Planning Report[1] to indicate the sensitivity of resource decisions to possible CO_2 prices at $25 and $50/ton[2].

At the hearing, Ms. Lockwood provided a range of renewable costs and a range of above market costs for each renewable project contemplated under the Settlement. Those figures are provided below, along with the CO_2 benefit at the assumed $25 and $50/ton prices. The premiums associated with renewable generation if such legislation is passed are also provided below:

Wind (75 MW)	Annual Premium Low	Annual Premium High
From	$8.00	$12.00
To (@ $25)	$5.00	$9.00
To (@ $50)	$2.00	$6.00

PV (25 MW)	Annual Premium Low	Annual Premium High
From	$2.00	$7.00
To (@ $25)	$1.00	$6.00
To (@ $50)	$0.20	$5.00

1: All values are in millions of dollars.

Assumptions:

<u>Arizona Wind[3]</u>
Lifetime cost $450 – $500 million
Above market cost $8 - $12 million per year
Impact of CO_2 at $25 and $50 /ton reduces above market costs by approximately $3 and $6 million dollars per year

[1] Docket No. E-01345A-09-0037 (January 29, 2009).
[2] Measured in short tons.
[3] Wind and PV costs are based on current market intelligence. Assumptions are based on current market prices.

ARIZONA PUBLIC SERVICE COMPANY
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OCTOBER 2, 2009

Utility Scale PV[2]
Lifetime cost $175 - $200 million
Above market cost $2 - $7 million per year
Impact of CO_2 at $25 and $50/ton reduces above market costs by approximately $1 and $2 million dollars per year

Schools – Various Technologies
The schools program is based on incentives which by definition are above market. If carbon legislation is enacted the incentives required for customer projects could possibly be reduced due to increased electric rates.

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E-01345A-08-0172
OCTOBER 2, 2009

Commissioner Pierce:

Please provide the following two analyses:

(a) If APS had limited its allocation towards residential DG to $8 million and had increased its allocation towards utility-scale projects by $50 million, how much more renewable energy could APS have acquired in 2009?

(b) How much renewable energy could APS have acquired in 2009 had the Commission required APS to spend the entire $78.6 million on utility-scale renewable projects? *(1585:10-1586:22)*

Response: This analysis is provided only as a hypothetical discussion. Utility scale projects can take 2-5 years to develop and put in service.[1] In 2009, the total RES eligible renewable energy is estimated to result in an annual production of over 1 million MWh. Modifying the budget allocation to 1) decrease the 2009 annual residential distributed generation (DG) budget to $8 million and 2) increase the annual utility scale generation by $50 million could result in an increase in annual production by approximately 2 million MWh. Please see Scenario 1 below for more detail.

Furthermore, if we carry out the assumption that the entire approved 2009 RES budget of $78.6 million is applied to only utility scale projects, then the entire RES portfolio would increase by approximately 2.2 million MWh.[2] Please see Scenario 2 below for more detail.

Renewable Energy Production (in MWH) in 2009

	Current 2009 Production	2009 Production Scenario 1	2009 Production Scenario 2
Residential DG Target	*44,298*	*7,195*	-
Non-Residential/Wholesale Target	*44,298*	*44,298*	-
Total DG Target	88,595	51,493	-
Total RG in 2009	880,175	2,957,817	3,266,053
Total Renewable Energy	1,013,068	3,009,310	3,266,053
Increase/Decrease in Renewable Energy	-	1,996,242	2,252,985

[1] For purposes of this analysis, it is assumed that all utility scale projects are in service at the start of 2009.
[2] Of course, APS has made legal commitments to DG that extend many years into the future, and thus APS could not redirect all DG funding to utility scale projects.

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E-01345A-08-0172
OCTOBER 2, 2009

Judge Farmer:

Please provide transcript citation where APS stated what portion of the Original Cost Rate Base is attributable to Schedule 3, if Schedule 3 had been in place for the past 30 years. *(2577:21-2579:15)*

Response: On September 16, 2009, Mr. Rumolo stated that the Original Cost Rate Base would have been reduced from $5,582,135,000 to $4,873,439,000 if Schedule 3 had been in place since 1990. See Rumolo testimony at 2110:22-2111:19

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E-01345A-08-0172
OCTOBER 2, 2009

Judge Farmer:

Please provide a copy of the Credit Suisse Upgrade Rating article referenced in page 9 of Mr. Hatfield's Direct Settlement Testimony. *(2536:14-22)*

Response: Attached is the requested article.

CREDIT SUISSE

Suisse Credit Report

26 May 2009
Americas/United States
Equity Research
Electric Utilities

Pinnacle West Capital Corp. (PNW)

UPGRADE RATING

Rating	(from Neutral) **OUTPERFORM***
Price (22 May 09, US$)	26.15
Target price (US$)	32.00[1]
52-week price range	36.35 - 23.00
Market cap. (US$ m)	2,641
Enterprise value (US$ m)	6,799

*Stock ratings are relative to the relevant country index.
[1]Target price is for 12 months.

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More than a Mirage -- Upgrade to Outperform

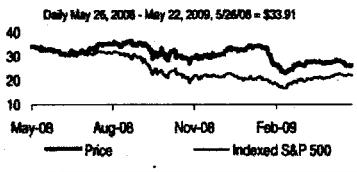
We are raising our rating on PNW to Outperform from Neutral with a target of $32 and new '09-'11 estimates of $2.28, $2.98, and $3.10.

We see the PNW story at the cross roads of evolving into an investable story as evidenced by the constructive rate case settlement and recent actions incl. forward looking transmission rates, interim rate increase and line connection adder. PNW's '09 / '10 guidance of $2.30 / $3.00 (vs Street's $2.31 and $2.80) **demonstrates that earnings power is resetting and offers a map toward earning a fair ROE** (from today's mid-5%). Our thesis:

- **The settlement seems to strike a fair balance between the demands** (all reasonable and ordinary) of PNW, Arizona Staff, and Interveners **which should hopefully ease its way to Commission approval, although nothing is ever easy in Arizona.**
- **Improved visibility while maintaining leverage to an economic recovery.** Reduced rate case frequency should help alleviate the normal AZ overhang while offering earnings upside through load growth until the next rate case (we assume effective in 2012). **We model a conservative 2% load growth post-2010** (vs ~5% historically) **and see $0.04-0.07 of EPS leverage for every 1% move in demand – a good recovery play.**
- **Structurally Safe 8% dividend yield** vs group of 6.6% -- today's near 100% payout ratio will comfortably be 71% in 2010 with the settlement.
- **Valuation looks compelling** under our re-rated estimates, trading cheap at 11.5x / 8.8x / 8.4x '09-'11 P/E vs 11.0x / 9.6x / 8.8x for its peer group.

Risks to PNW shares: (1) settlement terms significantly decay during Commission review, **(2)** Commission order on settlement extends into '10 **(3)** load growth doesn't return.

Share price performance



On 05/22/09 the S&P 500 index closed at 887.

Quarterly EPS	Q1	Q2	Q3	Q4
2008A	-0.05	1.03	1.53	-0.10
2009E	-0.31	0.90	1.63	0.06
2010E	0.20	1.06	1.40	0.15

Financial and valuation metrics

Year	12/08A	12/09E	12/10E
EPS (CS adj., US$)	2.42	2.28	2.98
Prev. EPS (US$)	—	2.39	2.84
P/E (x)	10.8	11.5	8.8
P/E rel. (%)	93.1	109.2	98.6
Revenue (US$ m)	5,177.0	4,893.9	5,291.8
EBITDA (US$ m)	963	992	1,152
EV/EBITDA (current)	6.7	6.9	6.0
Net debt (US$ m)	3,774	4,158	4,276
FFO/Interest	—	—	—
FFO/Total Debt	—	—	—

Number of shares (m)	101	BV/share (current, US$)	32
Net debt (current, US$ m)	4,070	Dividend (current, US$)	2.10
Net debt/tot. cap. (current, %)	56.0	Dividend yield (%)	8.0

Source: Company data, Credit Suisse estimates.

DISCLOSURE APPENDIX CONTAINS IMPORTANT DISCLOSURES, ANALYST CERTIFICATIONS, INFORMATION ON TRADE ALERTS, ANALYST MODEL PORTFOLIOS AND THE STATUS OF NON-U.S ANALYSTS. U.S. Disclosure: Credit Suisse does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision. Customers of Credit Suisse in the United States can receive independent, third party research on the company or companies covered in this report, at no cost to them, where such research is available. Customers can access this independent research at www.credit-suisse.com/ir or call 1 877 291 2683 or email equity.research@credit-suisse.com to request a copy of this research.

Exhibit 1: PNW Arizona Rate Case Procedural Schedule

June 12,'09	Definitive Settlement Filing
July 1,'09	Supporting Testimony
July 22,'09	Opposing Testimony
August 6,'09	Supporting Reply
August 19,'09	Hearing Begins

Source: Company data, Credit Suisse estimates

Exhibit 2: PNW Income Statement

Gross Margin	**2,071**	**382**	**530**	**648**	**397**	**1,958**	**2,117**	**2,191**	**2,335**	**2,442**
Utility O&M	799	208	185	199	198	790	822	856	890	926
Real Estate Operations	149	28	17	6	2	52	8	4	4	4
Other Taxes	125	34	33	29	32	128	141	146	156	163
Other Expenses	34	6	(3)	(4)	(4)	(5)	(6)	0	0	0
Total Operating Expenses	**1,107**	**276**	**232**	**229**	**228**	**966**	**965**	**1,006**	**1,050**	**1,094**
EBITDA	**963**	**106**	**298**	**419**	**170**	**992**	**1,152**	**1,185**	**1,286**	**1,348**
D&A	390	100	100	100	100	400	402	399	377	381
Operating Income	**573**	**6**	**198**	**319**	**70**	**592**	**749**	**787**	**909**	**968**
AFUDC	19	5	5	5	2	18	12	12	12	12
Other Income	12	0	8	3	0	12	0	(2)	(4)	(16)
Other Expense	(32)	(10)	(7)	(8)	(2)	(27)	(28)	(28)	(28)	(28)
Total Other Income	(1)	(4)	6	(0)	1	3	(16)	(18)	(20)	(32)
EBIT	**572**	**1**	**204**	**319**	**71**	**595**	**733**	**769**	**889**	**936**
			65	63	64	248	271	283	290	287
Interest Expense	216	58	66	64	65	253	275	288	299	296
Interest Rate	*6.2%*	*6.1%*	*6.5%*	*6.5%*	*6.5%*	*6.4%*	*6.5%*	*6.5%*	*6.5%*	*6.5%*
Capitalized Interest	(19)	(4)	(4)	(4)	(4)	(15)	(15)	(15)	(15)	(15)
EBT	**375**	**(53)**	**142**	**258**	**10**	**356**	**474**	**497**	**606**	**655**
Tax Expense	131	(21)	51	93	3	126	171	179	218	236
Effective Tax Rate	*34.9%*	*40.7%*	*36.0%*	*36.0%*	*36.0%*	*35.3%*	*36.0%*	*36.0%*	*36.0%*	*36.0%*
Recurring Net Income	**244**	**(31)**	**91**	**165**	**6**	**231**	**303**	**318**	**388**	**419**
Recurring EPS	**2.42**	**(0.31)**	**0.90**	**1.63**	**0.06**	**2.28**	**2.98**	**3.10**	**3.64**	**3.78**
Growth	*-18.4%*	*568.1%*	*-13.3%*	*7.0%*	*-161.4%*	*-5.7%*	*30.8%*	*3.7%*	*17.8%*	*3.7%*
Diluted Shares	101	101	101	101	101	101	102	103	106	111
Share Price	34.09	29.76	27.00	27.54	28.09	28.10	29.52	31.96	34.59	37.44

Source: Company data, Credit Suisse estimates

Exhibit 3: PNW Balance Sheet

Cash & Equiv.	105	33	637	637	637	637	637	637	637	637
Accounts Receivable	389	299	304	309	314	314	334	354	374	394
Inventories	203	215	215	215	215	215	215	215	215	215
Energy Risk-Mgmt Assets	33	64	64	64	64	64	64	64	64	64
Other	152	191	196	201	203	203	215	227	239	251
Current Assets	**882**	**802**	**1,416**	**1,426**	**1,433**	**1,433**	**1,465**	**1,497**	**1,529**	**1,561**
Gross PP&E	12,265	12,330	12,370	12,610	12,851	12,851	13,535	14,453	15,162	15,883
Acc. Depreciation	4,142	4,205	4,305	4,405	4,505	4,505	4,908	5,306	5,683	6,064
CWIP	572	622	622	622	622	622	622	622	622	622
Nuclear Fuel	89	99	99	99	99	99	99	99	99	99
Net PP&E	**8,785**	**8,846**	**8,786**	**8,927**	**9,067**	**9,067**	**9,348**	**9,868**	**10,201**	**10,541**
Nuclear Decommissioning Trust	343	336	336	336	336	336	336	336	336	336
Other Investments	415	213	213	213	213	213	213	213	213	213
Intangible Assets	132	143	143	143	143	143	143	143	143	143
Energy Risk-Mgmt Assets	34	34	34	34	34	34	34	34	34	34
Deferred Fuel & Purchased Power	8	0	0	0	0	0	0	0	0	0
Other	1,021	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
Total Assets	**11,620**	**11,418**	**11,972**	**12,122**	**12,270**	**12,270**	**12,584**	**13,135**	**13,500**	**13,872**
ST & Current LT Debt	648	574	574	574	574	574	574	574	574	574
Accrued Interest Pay.	41	45	45	45	45	45	45	45	45	45
Income Taxes Pay.	110	28	28	28	28	28	28	28	28	28
Cust. Security Deposits	79	78	78	78	78	78	78	78	78	78
Other Acc'ts Pay. & Accrued Exp.	261	170	168	165	163	163	163	163	163	163
Energy Risk-mgmt Liab.	70	64	64	64	64	64	64	64	64	64
Other	98	73	73	73	73	73	73	73	73	73
Total Current Liabilities	**1,506**	**1,033**	**1,030**	**1,028**	**1,025**	**1,025**	**1,025**	**1,025**	**1,025**	**1,025**
Postretirement Benefits	676	689	689	689	689	689	689	689	689	689
Deferred Tax Liab.	1,403	1,394	1,402	1,410	1,418	1,418	1,450	1,482	1,514	1,546
LT Debt	3,032	3,529	4,029	4,048	4,221	4,221	4,339	4,591	4,556	4,517
Energy Risk-mgmt Liab.	127	136	136	136	136	136	136	136	136	136
Other	1,431	1,440	1,448	1,459	1,472	1,472	1,535	1,602	1,669	1,736
Total Liabilities	**8,174**	**8,220**	**8,734**	**8,770**	**8,961**	**8,961**	**9,173**	**9,525**	**9,589**	**9,649**
Shareholders' Equity	**3,446**	**3,197**	**3,238**	**3,353**	**3,309**	**3,309**	**3,410**	**3,610**	**3,911**	**4,223**
Balance	0	0	0	0	0	0	0	0	0	0

Source: Company data, Credit Suisse estimates

Exhibit 4: PNW Cash Flow

Net Income	242	(171)	91	165	6	91	303	318	388	419
D&A	390	100	100	100	100	400	402	399	377	381
Def. Fuel Amortization & Nuc. Fuel	217	39	0	0	0	39	0	0	0	0
Def. Taxes & ITC	158	(4)	8	8	8	20	32	32	32	32
Operating AFUDC	(19)	(5)	(5)	(5)	(2)	(18)	(12)	(12)	(12)	(12)
Change in Working Capital	24	(101)	(8)	(8)	(8)	(124)	(20)	(20)	(20)	(20)
Other	(199)	86	8	11	13	118	63	67	67	67
Operating Cash Flow	**814**	**(56)**	**194**	**271**	**117**	**527**	**769**	**784**	**832**	**867**
Capex	(875)	(174)	(240)	(240)	(240)	(895)	(684)	(918)	(710)	(721)
Cash Flow from Asset Purchases	0	0	0	0	0	0	0	0	0	0
Cash Flow from Asset Sales	94	0	200	0	0	200	0	0	0	0
Other	(34)	(8)	0	0	0	(8)	0	0	0	0
Investing Cash Flow	**(815)**	**(182)**	**(40)**	**(240)**	**(240)**	**(703)**	**(684)**	**(918)**	**(710)**	**(721)**
Net Change in ST Debt	332	(263)	0	0	0	(263)	0	0	0	0
Net Change in LT Debt	(85)	483	500	19	173	1,176	117	253	(36)	(39)
Net Preferred Issues	0	0	0	0	0	0	0	0	0	0
Net Common Issues	4	1	3	3	3	10	20	115	165	165
Dividends Paid to Sharehold.	(204)	(51)	(53)	(53)	(53)	(211)	(222)	(233)	(251)	(272)
Other	4	(4)	0	0	0	(4)	0	0	0	0
Financing Cash Flow	**51**	**166**	**450**	**(31)**	**123**	**708**	**(85)**	**134**	**(122)**	**(146)**
Other Cash Flow	0	0	0	0	0	0	0	0	0	0
Net Change in Cash	**49**	**(72)**	**604**	**0**	**0**	**532**	**0**	**0**	**0**	**0**
Beginning Cash	56	105	33	637	637	105	637	637	637	637
Ending Cash	**105**	**33**	**637**	**637**	**637**	**637**	**637**	**637**	**637**	**637**

Source: Company data, Credit Suisse estimates

Companies Mentioned *(Price as of 22 May 09)*
Pinnacle West Capital Corp. (PNW, $26.15, OUTPERFORM, TP $32.00)

Disclosure Appendix

Important Global Disclosures

I, Dan Eggers, CFA, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

See the Companies Mentioned section for full company names.

3-Year Price, Target Price and Rating Change History Chart for PNW

PNW Date	Closing Price (US$)	Target Price (US$)	Rating	Initiation/ Assumption
8/18/06	44.86	48	O	X
10/25/06	48.62		N	
6/20/07	42.26	41		
10/29/07	41.22	43		
1/31/08	38.3	41		
4/29/08	34.02	39		
7/31/08	33.57	37		
2/3/09	34.26	34		
3/10/09	23.65	32		

O=Outperform; N=Neutral; U=Underperform; R=Restricted; NR=Not Rated; NC=Not Covered

Trading Alerts for PNW were produced on:

Date
11/5/2007

The analyst(s) responsible for preparing this research report received compensation that is based upon various factors including Credit Suisse's total revenues, a portion of which are generated by Credit Suisse's investment banking activities.

Analysts' stock ratings are defined as follows*:**

Outperform (O): The stock's total return is expected to exceed the industry average* by at least 10-15% (or more, depending on perceived risk) over the next 12 months.

Neutral (N): The stock's total return is expected to be in line with the industry average* (range of ±10%) over the next 12 months.

Underperform (U):** The stock's total return is expected to underperform the industry average* by 10-15% or more over the next 12 months.

**The industry average refers to the average total return of the relevant country or regional index (except with respect to Europe, where stock ratings are relative to the analyst's industry coverage universe).*

***In an effort to achieve a more balanced distribution of stock ratings, the Firm has requested that analysts maintain at least 15% of their rated coverage universe as Underperform. This guideline is subject to change depending on several factors, including general market conditions.*

****For Australian and New Zealand stocks a 7.5% threshold replaces the 10% level in all three rating definitions, with a required equity return overlay applied.*

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Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

**An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

***The broad market benchmark is based on the expected return of the local market index (e.g., the S&P 500 in the U.S.) over the next 12 months.*

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	Global Ratings Distribution	
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Neutral/Hold*	44%	(59% banking clients)
Underperform/Sell*	19%	(48% banking clients)
Restricted	2%	

**For purposes of the NYSE and NASD ratings distribution disclosure requirements, our stock ratings of Outperform, Neutral, and Underperform most closely correspond to Buy, Hold, and Sell, respectively; however, the meanings are not the same, as our stock ratings are determined on a relative basis. (Please refer to definitions above.) An investor's decision to buy or sell a security should be based on investment objectives, current holdings, and other individual factors.*

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See the Companies Mentioned section for full company names.
Price Target: (12 months) for (PNW)
Method: Our $32 target price on Pinnacle West Capital Corp.'s shares is based on our discounted cash flow (DCF) analysis using a 6.7% discount rate. In addition, we use a sum of the parts analysis valuing the utility at group multiples (15.5x 2008 EPS and 8.0x 2008 EBITDA), and a net plant property and equipment valuation for the real estate business (which equates to $5 of value).
Risks: Risks to our $32 target price include significant increases in commodity prices that are not recoverable in rates, as PNW is short natural gas and electricity and must rely on the ability to pass through rising fuel and purchased power costs to its end use customers. In addition, the company is exposed to regulatory risk from APS' future rate cases that are brought before the Arizona Corporation Commission (ACC).

See the Companies Mentioned section for full company names.
The subject company (PNW) currently is, or was during the 12-month period preceding the date of distribution of this report, a client of Credit Suisse.
Credit Suisse provided investment banking services to the subject company (PNW) within the past 12 months.
Credit Suisse provided non-investment banking services, which may include Sales and Trading services, to the subject company (PNW) within the past 12 months.
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The analyst(s) involved in the preparation of this report have not visited the material operations of the subject company (PNW) within the past 12 months.

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ARIZONA PUBLIC SERVICE COMPANY
RESPONSES TO QUESTIONS POSED AT HEARING,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 2, 2009

Maureen Scott:

Please provide a late filed exhibit listing the Companies that comprise APS Exhibit 34, the IOU Distribution Chart as amended by Mr. Hatfield on the stand. *(2487:7-15)*

Response: Attached is the requested schedule.

Public Electric Utility Companies by S&P Credit Rating

AA- (2 Companies)
Madison Gas & Electric Co.
NSTAR Gas Co.

A+ (6 Companies)
American Transmission Co.
Central Maine Power Co.
Duke Energy Kentucky Inc.
Midwest Independent Transmission System Operator Inc.
NSTAR Electric Co.
San Diego Gas & Electric Co.

A (27 Companies)
Alabama Power Co.
Central Hudson Gas & Electric Corp.
Dayton Power & Light Co.
Duke Energy Carolinas LLC
Duke Energy Indiana Inc.
Duke Energy Ohio Inc.
Florida Power & Light Co.
Georgia Power Co.
Gulf Power Co.
KeySpan Energy Delivery Long Island
KeySpan Energy Delivery New York
Massachusetts Electric Co.
MidAmerican Energy Co.
Mississippi Power Co.
Narragansett Electric Co.
North Shore Gas Co.
Northern Natural Gas Co.
Northern States Power Co.
Northern States Power Wisconsin
PacifiCorp
Portland General Electric Co.
Public Service Co. of Colorado
Southern California Edison Co.
Southern Connecticut Gas Co.
Southern Indiana Gas & Electric Co.
Virginia Electric & Power Co.
Wisconsin Public Service Corp.

A- (33 Companies)
Atlantic City Electric Co.
Carolina Power & Light Co d/b/a Progress Energy Carolinas Inc.
Commonwealth Edison Co.
Connecticut Natural Gas Corp.
Consolidated Edison Co. of New York Inc.
Delmarva Power & Light Co.
Detroit Edison Co.
Entergy Arkansas Inc.
Entergy Louisiana LLC
Entergy Mississippi Inc.
Florida Power Corp d/b/a Progress Energy Florida Inc.
Green Mountain Power Corp.
Idaho Power Co.
International Transmission Co.
ITC Midwest LLC
Michigan Electric Transmission Co.
New England Power Co.
Niagara Mohawk Power Corp.
NorthWestern Corp.
Orange and Rockland Utilities Inc.
PECO Energy Co.
Pennsylvania Power Co.
Peoples Gas Light & Coke Co. (The)
PPL Electric Utilities Corp.
Public Service Electric & Gas Co.
Puget Sound Energy Inc.
Rochester Gas & Electric Corp.
Rockland Electric Co.
South Carolina Electric & Gas Co.
Southwestern Electric Power Co.
Wisconsin Electric Power Co.
Wisconsin Gas LLC
Wisconsin Power & Light Co.

Public Electric Utility Companies by S&P Credit Rating

BBB+ (37 Companies)
Avista Corp.
CenterPoint Energy Houston Electric LLC
Central Illinois Light Co.
Central Illinois Public Service Co.
Central Vermont Public Service Corp.
Cleveland Electric Illuminating Co.
Connecticut Light & Power Co.
El Paso Electric Co.
Empire District Electric Co.
Enogex LLC
Entergy Gulf States Louisiana LLC
Entergy New Orleans Inc.
Entergy Texas, Inc
Interstate Power & Light Co
Kansas City Power & Light Co.
Kentucky Utilities Co.
Louisville Gas & Electric Co.
Metropolitan Edison Co.
Michigan Consolidated Gas Co.
Monongahela Power Co.
Montana-Dakota Utilities Co.
New York State Electric & Gas Corp.
Ohio Edison Co.
Oklahoma Gas & Electric Co.
Oncor Electric Delivery Co. LLC
Pacific Gas & Electric Co.
Peoples Energy Corp.
Potomac Edison Co.
Potomac Electric Power Co.
Public Service Co. of New Hampshire
Public Service Co. of North Carolina Inc.
Southwestern Public Service Co.
System Energy Resources Inc.
The Berkshire Gas Co.
Toledo Edison Co.
Tucson Electric Power Co.
West Penn Power Co.

BBB (28 Companies)
AEP Texas Central Co
AEP Texas North Co
Appalachian Power Co.
Baltimore Gas & Electric Co.
Black Hills Power Inc.
CenterPoint Energy Resources Corp
Cleco Power LLC
Columbus Southern Power Co.
Consumers Energy Co.
Duquesne Light Co.
Hawaiian Electric Co. Inc.
Illinois Power Co.
Indiana Michigan Power Co.
Indianapolis Power & Light Co.
Jersey Central Power & Light Co.
Kansas Gas & Electric Co.
KCP&L Greater Missouri Operations Co.
Kentucky Power Co.
Nevada Power Co.
Ohio Power Co.
Pennsylvania Electric Co.
Public Service Co. of Oklahoma
Sierra Pacific Power Co.
Tampa Electric Co.
Union Electric Co. d/b/a AmerenUE
Westar Energy Inc.
Western Massachusetts Electric Co.
Yankee Gas Services Co

BBB- (7 Companies)
Arizona Public Service Co.
CILCORP Inc.
IPALCO Enterprises Inc.
Northern Indiana Public Service Co.
Ohio Valley Electric Corp.
Otter Tail Power Co.
Texas-New Mexico Power Co.

BB+ (1 Company)
Public Service Co. of New Mexico