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ARIZONA CORPORATION COMMISSION

IN THE MATTER

of the
Application of Arizona Public Service Company for a
Hearing to Determine the Fair Value of the Utility Property of the Company
for Ratemaking Purposes, to Fix a Just and Reasonable
Rate of Return Thereon, to Approve Rate Schedules Designed to Develop
Such Return, and for Approval of Purchased Power Contract

Docket No. E-01345A-03-0437

Direct Testimony of

David A. Schlissel

On behalf of

The Residential Utility Consumer Office

January 9, 2004

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and

Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

Q. Mr. Schlissel, have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Dockets Nos. U-1345-85, U-1345-90-007, and E-01345A-01-0822. I also filed testimony in Docket No. U-1551-93-272 but that case was settled before hearings were held.

Q. What is the purpose of your testimony.

A. Synapse was retained by RUCO to evaluate Arizona Public Service Company's ("APS" or "the Company") request that the depreciated cost of the five units built by the Pinnacle West Energy Corporation ("PWEC")[1] be included in its rate base and that the costs related to these units be afforded cost-of-service ratemaking treatment. This testimony presents the results of our evaluation.

Q. Please explain how Synapse conducted its investigations and analyses in this proceeding.

A. We first reviewed APS's Application and the testimony and supporting materials appended to the Application. We also submitted discovery to APS and reviewed the materials that were provided in response to RUCO's data requests and to the discovery requests submitted by the other active parties to this proceeding. In particular, we examined the Applicant's economic analyses concerning the five PWEC generating units and the various planning studies prepared by APS since 1995.

We also reviewed materials from ACC Docket No. E-01345A-01-0822 concerning APS's proposed 28 year power purchase agreement with PWEC

[1] Redhawk Units 1 and 2, West Phoenix Unit 4, West Phoenix Unit 5, and Saguaro Combustion Turbine Unit 3.

covering the same five generating units that the Company is seeking to ratebase in this proceeding.

Finally, we reviewed the transmission studies prepared for the ACC Staff as part of the past two biennial transmission reviews.

Q. Please summarize your findings.

A. I have found that:

1. The fact that APS has received and is presently receiving power under contract from the PWEC units is not sufficient evidence, on its own, to demonstrate that APS should be allowed to acquire and ratebase the units. Instead, in the current situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

2. PWEC is being compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

3. APS has not provided any evidence showing that the PWEC units represent the most economic capacity it could acquire in the market.

4. Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million in present value 2004 dollars.

5. Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

6. Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been

ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2020 or 2021.

7. Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers until significantly beyond the year 2022.

8. Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2018.

9. Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers in 2007 and a present value cumulative economic savings by 2009.

10. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of ratepayers will see an overall savings from the units until two decades in the future, if at all.

11. Available evidence suggests [

]

12. Numerous APS and PWEC planning studies from the years 1998-2002 indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona, not primarily to serve APS load.

13. [ ]

14. The PWEC units were built in locations where they could serve APS loads and supply power to markets outside Arizona.

15. It appears that in order to improve its ability to sell power in the regional markets PWEC built a resource mix with more baseload combined cycle capacity and less peaking capacity than would have been needed just to serve the growing APS loads.

16. More than 70 percent of APS's current generation units are baseload capacity. This is a very baseload-heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor due to extreme summer temperatures and the relative lack of a substantial industrial process baseload. Approximately 94 percent, i.e., 1,600 MW, of the PWEC capacity that APS is now seeking to acquire also is baseload combined cycle capacity. Only the 79 MW from the Saguaro CT3 represents peaking capacity.

17. [ ]

18. The limited number of hours that APS needs RMR capacity in the Phoenix Valley load pocket and the [ ] that APS currently projects for the West Phoenix and Redhawk units suggest that some of the new capacity needed by APS should have been single cycle turbines instead of baseload combined cycle.

19. There is no capacity crisis requiring the Commission to act at this time to allow APS to acquire the PWEC units and to include them in rate base.

20. For these reasons, the Commission should deny APS's request to acquire and ratebase the PWEC units.

21. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part or all of existing generation facilities. This plan should be developed in order to be in place immediately following the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

22. Planned transmission system upgrades suggest that merchant generators will be able to supply power to APS in the Phoenix load pocket in place of the PWEC units.

Q. Do you agree with the claim by APS witness Bhatti that the test applied by Commission when determining whether to include Palo Verde in the Company's rate base also should apply to the instant situation with the five PWEC generating units?[2]

A. No. The current situation is not analogous to that faced by the Commission in Docket No. U-1345-90-007 concerning the Palo Verde nuclear power plants. Palo

[2] Testimony of Ajit Bhatti, at page 8, line 22, to page 9, line 7.

Verde had been built by APS, a regulated company, and, at the time it was requesting rate base treatment APS already owned shares of each of the three Palo Verde units. The question before the Commission then was how much of APS's share of Palo Verde capacity was used and useful in the test year.

In contrast, APS in this Docket is seeking Commission approval to both acquire and place into rate base the five PWEC units. In this situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

The current situation is analogous to a Company seeking Commission approval to enter into a life-of-asset capacity purchase agreement except that APS wants to acquire the units from its affiliate PWEC and place their cost into rate base. The Commission previously has declined to approve a request by APS to enter into a long-term power purchase agreement with PWEC. APS is now seeking to achieve the same goal by acquiring the units outright from PWEC.

As a result of the deregulation of the wholesale market APS currently has options that were not on the table when then Commission addressed Palo Verde in Docket No. U-1345-90-007 back in 1991. APS's requested ratebasing of the PWEC units must be weighed against these available alternatives.

The PWEC units represent new resources for APS, the regulated utility, and as such, their acquisition should be evaluated in the same way that resources procured by APS from a non-affiliated company would be judged – that is, subject to a prudence standard viewed from today's perspective. The used and useful test, a legitimate regulatory standard, would only apply after a prudence test was satisfied.

Thus, APS must show that the capacity it is seeking to acquire is the most economic capacity now available in the market and that this capacity will produce net economic benefits for ratepayers within a reasonable period of time.

Q. Do you agree that the PWEC units are actually being used to provide power to APS's customers?

A. Yes.

Q. Is PWEC being compensated for the power it is providing to APS?

A. Yes. PWEC is being fairly compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

Q. Has APS provided any evidence showing that the PWEC generating units represent the most economic capacity it could acquire in the existing market?

A. No.

Q. Have you seen any evidence that the acquisition of the PWEC units will provide net economic benefits for APS's ratepayers within a reasonable number of years?

A. No. In fact, the evidence we have seen suggests that, if the PWEC units are ratebased, the Redhawk and the West Phoenix Units will not produce net economic savings for ratepayers until a decade or two into the future.

Q. Please explain.

A. As shown in Tables 1 through 5 below, we have compared the annual revenue requirements resulting from the ratebasing of the PWEC units and the total annual market revenues associated with these units. These total market revenues represent what it would cost for APS to purchase from the market the same amounts of capacity and energy that would be provided by each of the PWEC units. These comparisons show the net costs/savings from ratebasing the units.

Table 1 shows that:

- Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million, in present value 2004 dollars.

- Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

Table 1: The Economic Costs and Benefits of Ratebasing the PWEC Units

	Redhawk Annual Savings/(Costs) Current Year $ ($000)	West Phoenix Unit 4 Annual Savings/(Costs) Current Year $ ($000)	West Phoenix Unit 5 Annual Savings/(Costs) Current Year $ ($000)	Saguaro CT3 Annual Savings/(Costs) Current Year $ ($000)	All Units Annual Savings/(Costs) Current Year $ ($000)	All Units Cumulative Savings/(Costs) Current Year $ ($000)	All Units Annual Savings/Costs PV @ 8.25% ($000)	All Units Cumulative Savings/(Costs) PV @8.25% ($000)	All Units Annual Savings/Costs PV @ 7.07% ($000)	All Units Cumulative Savings/(Costs) PV @7.07% ($000)
2004	(28,503)	(3,363)	(12,863)	(1,093)	(45,822)	(45,822)	(45,822)	(45,822)	(45,822)	(45,822)
2005	(66,579)	(7,139)	(28,853)	(1,785)	(104,356)	(150,178)	(96,403)	(142,225)	(97,465)	(143,287)
2006	(4,622)	(2,237)	1,461	(240)	(5,638)	(155,817)	(4,812)	(147,037)	(4,918)	(148,206)
2007	(9,676)	(1,849)	5,321	576	(5,628)	(161,445)	(4,437)	(151,474)	(4,585)	(152,791)
2008	(10,558)	(1,645)	(2,422)	1,840	(12,786)	(174,230)	(9,311)	(160,785)	(9,729)	(162,519)
2009	(9,004)	(1,653)	(2,374)	1,974	(11,056)	(185,286)	(7,438)	(168,223)	(7,857)	(170,377)
2010	(11,076)	(324)	6,783	2,758	(1,859)	(187,146)	(1,156)	(169,378)	(1,234)	(171,611)
2011	5,970	(491)	5,917	3,030	14,427	(172,719)	8,283	(161,096)	8,943	(162,668)
2012	17,006	178	7,692	3,235	28,112	(144,607)	14,910	(146,186)	16,276	(146,392)
2013	1,668	156	10,237	2,577	14,638	(129,970)	7,172	(139,015)	7,915	(138,477)
2014	25,213	(2,107)	12,129	3,159	38,394	(91,576)	17,377	(121,637)	19,390	(119,086)
2015	19,881	203	8,316	3,194	31,594	(59,982)	13,210	(108,428)	14,902	(104,184)
2016	21,135	(678)	11,028	3,223	34,707	(25,275)	13,405	(95,022)	15,290	(88,894)
2017	6,718	(138)	8,959	2,774	18,313	(6,963)	6,534	(88,488)	7,535	(81,359)
2018	38,499	1,724	19,129	3,601	62,953	55,990	20,750	(67,738)	24,192	(57,168)
2019	50,831	3,992	29,569	4,732	89,124	145,114	27,138	(40,600)	31,987	(25,181)
2020	64,902	6,276	37,947	6,168	115,293	260,406	32,431	(8,169)	38,647	13,467
2021	90,961	8,193	48,064	5,896	153,113	413,519	39,787	31,617	47,936	61,402
2022	74,538	7,758	47,927	6,362	136,586	550,105	32,787	64,404	39,938	101,340

Tables 2 through 5 show that:

- Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until the year 2020 or 2021.

- Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until significantly beyond the year 2022.

- Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, breakeven, until the year 2018.

- Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers beginning in 2007 and a present value cumulative economic savings by 2009.

Table 2: The Economic Costs and Benefits of Ratebasing Redhawk Units 1 and 2

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	91,546	120,049	(28,503)	(28,503)	(28,503)	(28,503)	(28,503)
2005	158,993	225,572	(66,579)	(61,505)	(90,008)	(62,183)	(90,686)
2006	232,826	237,448	(4,622)	(3,944)	(93,952)	(4,032)	(94,717)
2007	240,928	250,604	(9,676)	(7,628)	(101,580)	(7,883)	(102,600)
2008	288,579	299,137	(10,558)	(7,689)	(109,269)	(8,034)	(110,634)
2009	279,780	288,784	(9,004)	(6,058)	(115,327)	(6,399)	(117,033)
2010	274,327	285,403	(11,076)	(6,884)	(122,210)	(7,352)	(124,384)
2011	276,394	270,424	5,970	3,428	(118,783)	3,701	(120,683)
2012	308,302	291,296	17,006	9,019	(109,763)	9,846	(110,837)
2013	307,160	305,492	1,668	817	(108,946)	902	(109,935)
2014	330,672	305,459	25,213	11,412	(97,534)	12,733	(97,202)
2015	324,324	304,443	19,881	8,312	(89,222)	9,378	(87,824)
2016	340,372	319,237	21,135	8,163	(81,059)	9,311	(78,514)
2017	363,802	357,084	6,718	2,397	(78,662)	2,764	(75,749)
2018	373,173	334,674	38,499	12,690	(65,972)	14,794	(60,955)
2019	385,951	335,120	50,831	15,478	(50,494)	18,244	(42,711)
2020	413,798	348,896	64,902	18,256	(32,238)	21,756	(20,956)
2021	430,499	339,538	90,961	23,636	(8,601)	28,478	7,522
2022	431,581	357,043	74,538	17,893	9,291	21,795	29,317

Table 3: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 4

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	7,934	11,297	(3,363)	(3,363)	(3,363)	(3,363)	(3,363)
2005	14,307	21,446	(7,139)	(6,595)	(9,959)	(6,668)	(10,031)
2006	19,982	22,219	(2,237)	(1,909)	(11,868)	(1,952)	(11,983)
2007	20,773	22,622	(1,849)	(1,458)	(13,326)	(1,506)	(13,490)
2008	23,159	24,804	(1,645)	(1,198)	(14,524)	(1,252)	(14,741)
2009	22,454	24,107	(1,653)	(1,112)	(15,636)	(1,175)	(15,916)
2010	24,563	24,887	(324)	(201)	(15,837)	(215)	(16,131)
2011	23,668	24,159	(491)	(282)	(16,119)	(304)	(16,435)
2012	26,569	26,391	178	95	(16,025)	103	(16,332)
2013	26,266	26,110	156	76	(15,948)	84	(16,248)
2014	29,327	31,434	(2,107)	(954)	(16,902)	(1,064)	(17,312)
2015	27,055	26,852	203	85	(16,817)	96	(17,216)
2016	29,731	30,409	(678)	(262)	(17,079)	(299)	(17,515)
2017	33,614	33,752	(138)	(49)	(17,129)	(57)	(17,572)
2018	30,940	29,216	1,724	568	(16,560)	663	(16,910)
2019	29,551	25,559	3,992	1,216	(15,345)	1,433	(15,477)
2020	29,423	23,147	6,276	1,765	(13,579)	2,104	(13,373)
2021	31,469	23,276	8,193	2,129	(11,451)	2,565	(10,808)
2022	32,584	24,826	7,758	1,862	(9,588)	2,269	(8,540)

Table 4: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 5

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	60,515	73,378	(12,863)	(12,863)	(12,863)	(12,863)	(12,863)
2005	102,430	131,283	(28,853)	(26,654)	(39,517)	(26,948)	(39,811)
2006	133,516	132,055	1,461	1,247	(38,270)	1,275	(38,536)
2007	138,079	132,758	5,321	4,195	(34,075)	4,335	(34,201)
2008	130,823	133,245	(2,422)	(1,764)	(35,839)	(1,843)	(36,044)
2009	151,192	153,566	(2,374)	(1,597)	(37,436)	(1,687)	(37,731)
2010	156,015	149,232	6,783	4,215	(33,221)	4,502	(33,229)
2011	157,661	151,744	5,917	3,397	(29,824)	3,668	(29,561)
2012	163,714	156,022	7,692	4,080	(25,744)	4,454	(25,107)
2013	176,538	166,301	10,237	5,016	(20,728)	5,536	(19,572)
2014	168,718	156,589	12,129	5,489	(15,239)	6,125	(13,446)
2015	175,390	167,074	8,316	3,477	(11,762)	3,923	(9,524)
2016	180,352	169,324	11,028	4,259	(7,502)	4,858	(4,666)
2017	188,738	179,779	8,959	3,197	(4,306)	3,686	(979)
2018	195,343	176,214	19,129	6,305	2,000	7,351	6,372
2019	203,894	174,325	29,569	9,004	11,003	10,613	16,984
2020	220,655	182,708	37,947	10,674	21,677	12,720	29,704
2021	242,753	194,689	48,064	12,489	34,167	15,047	44,752
2022	234,023	186,096	47,927	11,505	45,671	14,014	58,765

Table 5: The Economic Costs and Benefits of Ratebasing Saguaro CT3

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	2,799	3,892	(1,093)	(1,093)	(1,093)	(1,093)	(1,093)
2005	5,792	7,577	(1,785)	(1,649)	(2,741)	(1,667)	(2,760)
2006	8,824	9,064	(240)	(205)	(2,947)	(210)	(2,969)
2007	8,453	7,877	576	454	(2,492)	469	(2,500)
2008	8,487	6,647	1,840	1,340	(1,152)	1,400	(1,100)
2009	8,728	6,754	1,974	1,328	176	1,403	303
2010	9,127	6,369	2,758	1,714	1,890	1,831	2,134
2011	9,414	6,384	3,030	1,740	3,630	1,878	4,012
2012	9,527	6,292	3,235	1,716	5,346	1,873	5,885
2013	8,651	6,074	2,577	1,262	6,608	1,393	7,279
2014	9,127	5,968	3,159	1,430	8,038	1,595	8,874
2015	9,053	5,859	3,194	1,336	9,373	1,507	10,381
2016	8,485	5,262	3,223	1,245	10,618	1,420	11,800
2017	8,082	5,308	2,774	990	11,608	1,141	12,942
2018	8,967	5,366	3,601	1,187	12,794	1,384	14,325
2019	9,954	5,222	4,732	1,441	14,235	1,698	16,024
2020	11,232	5,064	6,168	1,735	15,970	2,068	18,091
2021	11,013	5,117	5,896	1,532	17,502	1,846	19,937
2022	11,159	4,797	6,362	1,527	19,030	1,860	21,797

Q. What are the sources for the revenue requirements figures on Tables 1 through 5?

A. The annual revenue requirements figures presented in Tables 1 through 5 for the years 2005-2022 are taken directly from APS's response to Data Request LCA 8-237. Unfortunately, APS did not include in this response the revenue requirements for the second half of 2004 during which the PWEC units will be in rate base if the Commission approves the Company's request to acquire and ratebase the units.

Therefore, we have used the fixed costs for 2004 for each of the PWEC units that were provided in APS's response to Data Request LCA 7-219.

Q. How did you calculate the annual total market revenues presented in Tables 1 through 5?

A. The total market revenues shown in Tables 1 through 5 are based on the annual amounts of capacity and energy from each PWEC unit multiplied by the respective annual capacity and energy prices.

Q. What estimates of generation have you used for each of the PWEC units?

A. We have used APS's projections of annual generation for each of the PWEC units for the years 2005 through 2022 as presented in its response to Data Request LCA 8-237. Because we did not find any projections of the annual generation that the Company currently expects from each of the PWEC units during 2004, we assumed that each of the PWEC would generate approximately 2/3 as much power during the second half of 2004 as APS's 2003 Long Range Forecast projected the unit would generate in 2005.[3]

In addition, we used the individual unit variable fuel costs ($/MWH) that were provided in APS's response to Data Request LCA 8-237 for the year 2005 because we did not have the comparable information for the year 2004.

Q. What energy market prices have you used in the comparisons shown in Tables 1 through 5?

A. To be conservative we have used the adjusted energy prices for the years 2005 through 2022 that were provided by APS in its response to Data Request LCA 8-

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[3] The information from APS's 2003 Long Range Forecast that was provided in response to Data Request RUCO 10-8 did not include any generation projections for the PWEC units for 2004. However, the Company's 2002 Long Range Forecast projected that the units would generate about as much energy in 2004 as they would in 2005. We then assumed that because the second half of 2004, during which the PWEC units would be in rate base, would include three of the four peak summer months, that each unit would generate about 2/3 of its annual output during the second half of the year. We also tested to make sure that this assumption did not have a major impact on the results.

237. We assumed that the energy market prices (in $/MWH) for the generation from each PWEC unit would be the same in 2004 as APS has projected for 2005.

Q. What capacity prices have you have used in the comparisons shown in Tables 1 through 5?

A. We used APS's near term capacity price forecasts for the years 2004 and 2005. For the years 2006-2022 we have used the Company's forecast of capacity prices based on the long run marginal costs related to the need to maintain a 15 percent reserve margin in Arizona. APS has explained the derivation of these fundamental capacity prices as follows:

> APS assesses loads and resources of the WECC and each of the sub-regions (WECC Sub-region Supply & Demand Balance was provided in LCA 6-192). Once the plants currently under construction are completed, a capacity price is added to the energy market price that would be sufficient to incent construction of new generation when the reserve level would drop below 18% in the Desert Southwest sub-region, or 15% in Arizona. When reserve levels are above the 15%, the capacity price is reduced based on a level that supports continued operation of enough existing generation to maintain 15% reserves. The resource plans are developed so that the market is in equilibrium, i.e., it maintains 15% reserve margins once the short term excess goes away. This is represented by the "Fundamental Market Scenario" provided in response to LCA 8-237.[4]

Q. Isn't it reasonable to expect that there would be some physical and economic "lumpiness" when new large generating units are added by APS?[5]

A. Yes. It is reasonable to expect that there might be a few years of lumpiness in which the additional costs of ratebasing a new large generating unit would exceed the benefits of adding the unit. However, as Tables 1 through 5 show, ratebasing the West Phoenix and Redhawk units will not provide any overall cumulative savings for ratepayers until the year 2018 or later. This is far more than mere "lumpiness."

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4 APS response to Data Request LCA 19-478(a).

5 Testimony of APS witness Ajit Bhatti, at page 38, lines 1 through 16.

Q. What weight should the Commission give to Company analyses that show that the PWEC units might produce net economic savings over their entire operating lives?

A. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of ratepayers will see an overall savings from the units until two decades in the future, if at all.

Q. Has APS examined the economic costs and benefits of the PWEC units using any other market price forecasts?

A. Yes. APS examined a scenario in which the base market capacity price forecast is based on overbuild/underbuild ("boom and bust") cycles and wet/dry hydro cycles.[6]

APS also examined an even more severe underbuilding scenario in which no new generation would be built through 2010. As a result capacity prices spiked to about half of the observed prices in 2001. Beginning in 2011, the market would return to overbuild/underbuild cycles.

Q. Do you believe that it is reasonable to use boom and bust projections of market prices in examining the economic costs and benefits of a proposed capacity acquisition?

A. No. In theory it seems like a good idea to reflect possible boom and bust capacity cycles in the valuation of a proposed capacity acquisition. However, in practice predicting when the boom and bust phases of the cycle will occur, how long each

[6] APS response to Data Request LCA 8-237.

phase will last, how severe each phase will be and what the market prices will be really is far too speculative to produce reliable results. These important factors simply cannot be predicted with any reasonable degree of certainty.

It is far more reasonable to use the more traditional long run marginal costs to evaluate the economic costs and benefits of a proposed capacity acquisition.

Q. Have you seen any evidence that suggests that the next capacity shortage will not occur in 2007 as APS and Dr. Hieronymus hypothesize?[7]

A. Yes. Dr. Hieronymus cites a recent California Energy Commission study as the main support for his conclusion that a new shortage of capacity will reemerge in the Western U.S. by 2007.[8] This study found that although electricity supply resources in California appear to be sufficient for 2004 and 2005, there is an ongoing need to monitor new capacity proposed for the period starting 2006 and beyond. Consequently, the Commission should continue to focus on programs that improve efficiency and reduce demand and to support policies that ensure that new generation is brought to the market.[9]

In his testimony, Dr. Hieronymus cites several factors which he believes will make the capacity situation in California worse than it appears in this recent Energy Commission study. However, he ignores a number of factors which actually make the situation in California far less dire than he would suggest.

First, the California Energy Commission study assumes that only one third of the voluntary conservation achieved in the State during the 2001 electricity crisis will persist in 2003 and that this amount will decline in subsequent years. This is an extremely conservative assumption. It is very reasonable to assume that Californians who conserved energy during the 2001 crisis would again conserve if faced with the prospect of another capacity shortage in 2007 or any subsequent

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7 Testimony of William H. Hieronymus, at page 59, lines 5 through 7.

8 Testimony of William H. Hieronymus, at pages 62 and 63.

9 *California's 2003 Electricity Supply and Demand Balance and Five-Year Outlook*, available at the California Energy Commission website, www.energy.ca.gov.

year(s). Such conservation efforts could reduce future electricity demands by 2,700 MW or more over the figures shown in the 2003 California Energy Commission study.

Second, the study notes that California will have about 1,100 MW of Emergency Demand Programs/Interruptible loads that will further add to the State's reserves in 2007 and subsequent years. The California Public Utilities Commission has established a goal of increasing the amount of demand response in the State to over 1,900 MW by 2007.

Third, the California Energy Commission study assumes dry hydro conditions which it says has a one in five year probability of occurring. This assumption reduces the amounts of power imports available from the Pacific Northwest and from the spot market.

Finally, the California Energy Commission study only includes those power plants deemed as having a 75 percent or greater probability of coming on-line. This essentially means that the study only assumes that the approximately 4,000 MW of power plants that are currently under construction will be built. It does not assume that any of the additional 4,000 MW of approved plants that are currently on hold will be built or that any of the 6,000 MW of plants that are currently undergoing Energy Commission review will be built. This is an extremely conservative assumption especially if the developers of these projects agree with Dr. Hieronymus's conjecture that a new capacity shortage, with significantly higher prices, will reemerge by 2007. Clearly, the prospect of much higher capacity prices in the California market and the rest of the Western U.S. in 2007 will encourage more developers to complete their projects as expeditiously as possible.

Q. Do you think that the more severe underbuilding scenario examined by APS is more reasonable than the boom/bust cycles scenario?

A. No. The severe underbuilding scenario examined by APS is simply not credible. Given the very large number of new facilities that are undergoing review in the Western States and the amount of plants that have been announced, it is not reasonable to expect that no additional generation will be added until 2011 once the plants currently under construction are completed.

If APS wanted to examine a severe underbuilding scenario, it should also have looked at a scenario in which there is a more extreme overbuilding of new generation facilities in the short term leading to a capacity glut that will last further into the future than APS conjectures in its boom and bust cycles scenario.

Q. Have you seen any evidence that suggests that any party would be interested in selling a generating unit or in making a long-term capacity sale to APS?

A. Yes. [ ][10]

In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases:

> One way to secure long-term supplies in an otherwise dysfunctional market and to avoid the problem of potentially insolvent sellers, is to build or buy power plants. APS has questions about its ability to pursue these options but it is exploring them in any event. Thus, APS entertained representatives from Dome Valley Energy Partner LLC on October 8, 2003 to discuss the overall status of the Wellton Mohawk Generating Facility. No specific detailed and/or substantive discussions involving a firm offer for energy occurred as a result of this meeting. In addition, APS approached and has had brief discussions with two non-affiliated entities concerning the possible purchase of their generating facilities in Arizona. APS is bound by confidentiality agreements with regard to such discussions, which have led to no further communications with these entities. Finally, APS has approached and is currently in confidential discussions with one (non-affiliated) entity concerning that entity's desire to sell a generating facility in Arizona. Those discussions, all analyses in conjunction with those discussions, and even the identify of the potential seller are covered by a confidentiality agreement with such seller.[11]

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[10] [ ]

[11] APS Response to Data Request LCA 10-269.

Q. Have any power plants in Arizona recently been sold?

A. Yes. Reliant Energy recently sold the 590 MW Desert Basin plant to SRP for $288.5 million, or about $492 per KW.

Q. Have you seen any evidence that suggests that the PWEC units were not built "primarily" to serve APS load, as APS witness Bhatti has claimed?[12]

Yes. Numerous APS and PWEC planning studies indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona. For example:

- APS's "1998 Business Plan – Generation Growth Plan" noted that the "Primary Market Targets" for PWEC generation would be "Phoenix, Yuma, Gila Bend, Saguaro, Cholla, Prescott, S Nevada, California, Northwest, New Mexico, Utah & Colorado."[13]
- [ ][14] Project Hedgehog became the Redhawk units.
- [ ][15]
- A 1999 APS "Planning Scenarios Risk Assessment" revealed that PWEC was planning to add significantly more generation than would be needed just to serve APS loads. For example, PWEC expected to have approximately 8,900 MW of capacity by 2006, significantly above APS's projected load which was in the range of 6,300 MW.[16]
- The Company's September 29, 1999 Pinnacle West Press Release announcing the proposed Redhawk units noted that "The plant will compete in deregulated energy markets of Arizona, California and other western states…"[17] The press release also quoted Pinnacle West

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[12] Testimony of Ajit Bhatti, at page 17, line 19, to page 18, line 2.

[13] Provided in APS's response to Data Request LCA 11-288, at page 15 of 44.

[14] [ ]

[15] [ ]

[16] Provided in APS's response to Data Request LCA 6-200B, at page 28.

[17] Provided in APS's response to Data Request LCA 3-77.

> Generation Business Unit President William Stewart as stating that "We intend to be a vigorous player in these competitive generation markets. We have a strong record of low-cost, efficient plant operation. We can best serve the public and our shareholders by pursuing these developing markets, particularly in Arizona and the Southwest."

> The same press release also noted that the site for the proposed Redhawk units "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

This is not to say that Pinnacle West intended to abandon APS's traditional service territory in Arizona. Company management was astute enough to realize that the Phoenix area was one of the fastest growing areas in the West and could provide a strong foundation from which Pinnacle West could compete in other Western region markets.

[ ] For example:

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Q. Do you have any comment on the claim by APS witness Bhatti that the location of the PWEC units demonstrates that they were built at locations where they were needed to serve APS load and with APS customers in mind?[23]

A. Yes. Mr. Bhatti implies that siting the Redhawk and the West Phoenix units in locations where they could serve APS load was somehow inconsistent or in conflict with siting those units at locations from which they could serve other markets. As I noted earlier, the September 29, 1999 Press Release in which APS announced the Redhawk Project specifically noted that the site for the proposed plant "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

At the same time, while the West Phoenix units were built in the Phoenix Valley, their power could be exported out of the Phoenix load pocket to Palo Verde. The use of the capacity from the new West Phoenix Units 4 and 5 to serve in-Valley

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23 Testimony of Ajit Bhatti, at page 5, lines 8-10, and page 18, lines 5-7.

loads also would free up other PWEC generation located outside the load pocket to be sold in other markets.

Q. APS witness Bhatti makes a number of claims regarding the decision by Pinnacle West management not to sell power from the PWEC units forward to California.[24] Have you seen any evidence that PWEC was not interested in selling power into the California market?

A. No. Mr. Bhatti has implied that Pinnacle West declined from selling power in California in order to be able to serve APS loads. However, as I have noted above, there is no evidence that PWEC has ever abandoned its interest in selling power into the California markets.

Q. Does it appear that in order to improve its ability to sell power into the regional markets PWEC built a different resource mix with more baseload combined cycle capacity (and less peaking capacity) than would have been needed just to serve the growing APS loads?

A. Yes. By the 1990s APS was a company with a generation capacity mix that was more than 70 percent baseload.[25] This was a baseload heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor, i.e., less than 55 percent, due to the extreme summer temperatures and the relative lack of a substantial industrial process baseload.

Given this low load factor, it appears reasonable to expect that if it had been building to meet its own needs, APS, as a regulated company, would have added a significant amount of peaking capacity as part of its generation growth plan. In fact, APS's June 1998 Generation Growth Plan did specifically note that "If construction based on Arizona growth plan only, it would install new CT capacity

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[24] For example, see the Testimony of Ajit Bhatti, at page 18, lines 5-7, page 18, lines 16-19, and page 49, lines 20-22.

[25] For example, see the [

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beginning in 2004 and new combined cycle capacity, or previously installed CTs upgraded, starting in 2006.[26]

However, as a fledgling merchant generator, PWEC's interest was in developing new baseload generation that could compete in other out-of-state markets even if that baseload generation had higher installation costs than the CT capacity that APS would need to serve its growing summer peak loads. Consequently, PWEC developed a generation growth plan that included four new combined cycle units as its first four major new additions (West Phoenix Unit 4, West Phoenix Unit 5, and Redhawk Units 1 and 2). The new Saguaro unit is the only CT that PWEC has added. Thus, approximately, 1,600 MW of the 1,700 MW, or about 94 percent, of the new capacity that APS is seeking to acquire from PWEC is baseload combined cycle capacity. This is far too much for a company that already has a generation mix that is 70 percent baseload. In fact, with the PWEC units, APS's generation would be more than 75 percent baseload.

Q. Has the Company acknowledged that adding more single cycle turbine capacity would be a better mix with APS's needs?

A. [ ][27]

Q. Have you seen any other evidence that suggests that single cycle turbine peaking capacity would have been a better match for APS's needs than the combined cycle capacity built by PWEC?

A. Yes. The limited number of hours that APS needs RMR capacity in the Phoenix load pocket and the relatively low capacity factors that APS currently projects for West Phoenix Unit 4 through 2022 suggest that some of the new capacity that

[26] Provided as document RC01608 in APS's response to Data Request LCA 11-288, at page 6.

[27] [ ]

APS needs should be single cycle turbines peaking units instead of baseload combined cycle. This information is presented in Tables 6 and 7 below:

Table 6: Phoenix Area Non-APS RMR Requirements for APS Load[28]

Year	Non-APS RMR Hours
2003	152
2004	200
2005	230

Table 7: Projected West Phoenix and Redhawk Capacity Factors[29]

Year	West Phoenix Unit 4	West Phoenix Unit 5	Redhawk
2005	15.1%	39.1%	27.4%
2006	18.6%	45.0%	39.3%
2007	18.6%	44.8%	39.9%
2008	25.3%	40.4%	52.0%
2009	22.8%	50.8%	49.2%
2010	25.5%	51.2%	46.0%
2011	23.0%	49.0%	42.6%
2012	27.3%	50.3%	47.7%
2013	27.5%	55.9%	46.7%
2014	33.1%	49.9%	51.1%
2015	28.6%	53.3%	51.2%
2016	33.8%	54.5%	53.3%
2017	40.2%	56.1%	55.9%
2018	31.7%	55.1%	54.6%
2019	25.7%	54.3%	53.4%
2020	20.7%	53.4%	52.1%
2021	21.4%	57.9%	51.2%
2022	23.0%	55.1%	52.1%

These projected capacity factors also suggest that some of the Redhawk capacity should have been single cycle turbines, at least initially.

28 *APS Reliability Must-Run Analysis 2003-2005*, Table ES3, at page 8, and Table 6A, at page 28.

29 Source: APS response to Data Request LCA 8-237.

Q. Do you have any comments on the claim by APS witness Bhatti that ratebasing the PWEC units could have been anticipated to yield benefits ranging from approximately $496 million to $615 million in net present value over the life of the projects.[30]

A. Yes. Mr. Bhatti's retrospective analyses do not provide any insights into the critical question of whether acquiring the PWEC units is the most economic option available to APS at this time. APS did not actually conduct these comparisons during the years 1999 through 2002 and did not acquire the PWEC units during that timeframe. Therefore, Mr. Bhatti's comparisons have no relevance to the current proceeding.

Moreover, many of the studies upon which Mr. Bhatti bases his retrospective comparisons assumed very high capacity factors for the West Phoenix and Redhawk units.[31] This was overly optimistic given the significant number of new combined cycle units that were being proposed for Arizona and the rest of the Western region during the 1999-2002 timeframe. The use of these high capacity factors biased the results of Mr. Bhatti's comparisons in favor of the ratebasing of the PWEC units because it increased the market revenues against which the revenue requirements from ratebasing were being compared.

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30 Testimony of Ajit Bhatti, at page 68, lines 1-10.

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Q. Is there currently any capacity crisis requiring that the Commission act at this time to allow APS to acquire the PWEC units and to include them in rate base?

A. No. APS has an existing contract with PWEC for capacity from the units during the months of June, July, August and September through 2006. To the extent that APS needs additional capacity during other, non-summer peak periods, it should be able to acquire that capacity at low prices from PWEC or other sellers. After all, APS's own witness in this Docket, Dr. Hieronymus, has testified that "Near term prices are forecast to be relatively low, reflecting the glut of capacity coming on-line in the western U.S. in 2002-2003 …."[32] and has noted the "price-depressing effect" of this glut of new capacity.[33]

Q. What is your recommendation to the Commission regarding APS's request to acquire and ratebase the five PWEC units?

A. The Commission should deny APS's request to acquire and rate base the PWEC units. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part of all of existing generation facilities. This plan should be developed in order to be in place immediately following after the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

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[32] Testimony of William H. Hieronymus, at page 51, line 23, to page 52, line 1.

[33] Testimony of William H. Hieronymus, at page 59, lines 9-13.

Q. Is it possible that merchant generators could supply power to APS in the Phoenix load pocket in place of the PWEC units?

A. Yes. The addition of planned transmission facilities can be expected to increase the ability of merchant generators to send power into the Phoenix load pocket.

For example, Figure 7.5 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that the import transmission capacity into the Phoenix Valley will increase substantially by 2008 – by more than 1,200 MW. This would enhance the ability of generators outside the Valley to serve loads inside the Valley during what would otherwise be RMR hours.

Consequently, as is shown in Figure 7.4 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that during the years 2004-2010 there will be substantially more in-Valley generation and transmission capability than will be needed to serve the combined Valley peak loads.

An APS Valley Import Analysis presented in the Rebuttal Testimony of APS witness Cary Deise in Docket No. E-01345A-01-0822 similarly showed that the addition of the planned Palo Verde – Table Mesa 500 kV transmission line in 2008 would significantly reduce APS's Valley Local Generation Requirements.

In addition, new transmission system enhancements may be developed as a result of the Arizona collaborative transmission planning process, in general, and the Central Arizona Transmission planning analyses, in particular.

Q. Are you prepared to address the questions raised by Commissioner Gleason in his letter of September 5, 2003?

A. Yes.

Commissioner Gleason Question No. 1 – How should the Commission calculate the market value of a power plant?

Answer – With a deregulated wholesale market, the Commission should determine the value of a power plant through a competitive power solicitation.

Commissioner Gleason Question No. 2 – If the Commission should look at the plant's current market value instead of the original cost to build the plant, how can the Commission determine the market value?

Answer - The value of a power plant will be determined by the price at which the plant is bid if the plant is the winning bid.

Commissioner Gleason Question No. 3 – What power plants are on the market that can serve Arizona consumers?

Answer – [

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In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases

Commissioner Gleason Question No. 4 – Has any other state commission faced a situation where a regulated energy utility applied to incorporate merchant assets into its rate base? What did the commission decide?

Yes. I am aware of two state regulatory commissions which have addressed the situation where a regulated energy utility applied to incorporate merchant assets into its rate base.

The Indiana Utility Regulatory Commission, ("IURC") in December 2002 approved a request by PSI Energy , Inc., for approval to purchase two generating facilities from a merchant affiliate.[35] The IURC's reasoning in approval this application is valuable to this proceeding.

First, the IURC relied heavily on the fact that the utility's resource mix was very heavily weighted towards coal-fired baseload capacity with baseload making up 65 percent of the PSI generation. The IURC specifically found that "PSI's current generating resources are heavily weighted toward baseload capacity while,

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[34] [ ]

[35] Indiana Utility Regulatory Commission, Order in Cause No. 42145, 2002 Ind. PUC LEXIS 544, December 19, 2002.

optimally, the PSI system should be comprised of relatively more peaking capacity." The two units which PSI was seeking approval to acquire from the affiliate were both gas-fired combustion turbine peaking facilities.

Second, the utility, PSI, had conducted a detailed integrated resource planning process, involving the review of more than 4200 alternative resource plans, which identified that acquiring the two peaking facilities was the number one "least cost" plan. As I have noted earlier, APS has presented no evidence in this proceeding that acquiring the PWEC units is the least cost alternative for the Company.

In July 2002, the Public Service Commission of the State of Missouri approved a settlement between the AmerenUE Company, the Staff of the Commission and other parties that, in part, allowed AmerenUE to acquire two combustion turbine peaking generating units from an affiliated company, AEG.[36] Other terms of the settlement approved by the Missouri Commission required the utility to reduce its rates by $110 million over three years and to provide a one-time credit of $40 million to its customers. Unfortunately, the Commission's Order does not address the merits of the request to acquire the two generating facilities from the affiliate except to find that the agreement was in the public interest.

The Federal Energy Regulatory Commission ("FERC") subsequently addressed and approved this same transaction.[37] In May, 2003, FERC set a hearing on the request to transfer the generating units in order "to be certain that the purchase of the Pinckneyville and Kinmundy plants at net book value is consistent with results that would be obtained through a competitive process reflecting the interplay between AmerenUE and independent sellers and has not resulted in under preference being shown to AmerenUE's affiliate, AEG."

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[36] Public Service Commission of the State of Missouri, Case No. EC-2002-1, 2002 Mo. PSC LEXIS 1036, July 25, 2002.

[37] Federal Energy Regulatory Commission, Order Setting Disposition of Facilities Application for Hearing, Docket No. EC03-53-000, 103 F.E.R.C. P61, 128, 2003 FERC LEXIS 819. May 5, 2003.

In the present case, APS has provided no evidence at all to show that the acquisition of the PWEC units is consistent with any results that would be obtained through a competitive process reflecting the interplay between APS and independent sellers. Moreover, there has been a clear preference shown to APS's affiliate, PWEC. In fact, APS has admitted that there weren't even any negotiations between APS and PWEC.[38]

The Illinois Commerce Commission ("ICC") also needed to approve the acquisition of the power plants by AmerenUE. The Staff of the ICC filed testimony opposing the acquisition. However, the matter was never resolved as AmerenUE withdrew its application for approval of the asset transfer.[39] Apparently, AmerenUE has decided not to pursue the acquisition of the two generating units.

Q. Does this complete your testimony at this time?

A. Yes.

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38 APS's response to Data Request LCA 4-94(b).

39 Illinois Commerce Commission, Docket o. 03-0083, 2003 Ill. PUC LEXIS 632, July 23, 2003.

EXHIBIT DAS-1

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SUMMARY

I have worked for thirty years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric System Reliability - Evaluated whether new transmission lines and generation facilities were needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Nuclear Power - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Electric Industry Regulation and Markets - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and the auctions of power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115209) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)