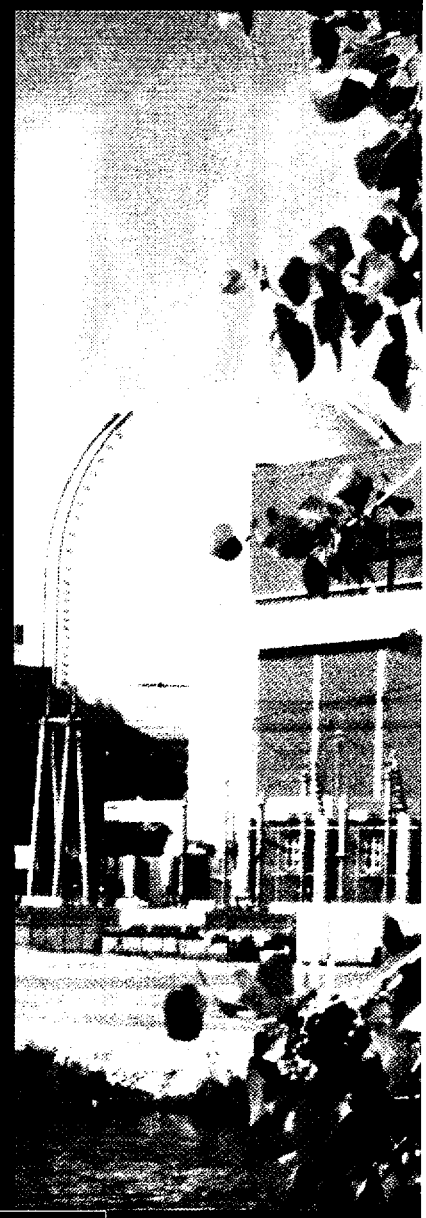
SCPPA ANNUAL REPORT



1999 2000

What is SCPPA?

The Southern California Public Power Authority (SCPPA) is a joint powers authority consisting of ten municipal utilities and one irrigation district, who deliver electricity to approximately two million customers over an area of 7,000 square miles, with a total population of 4.8 million.

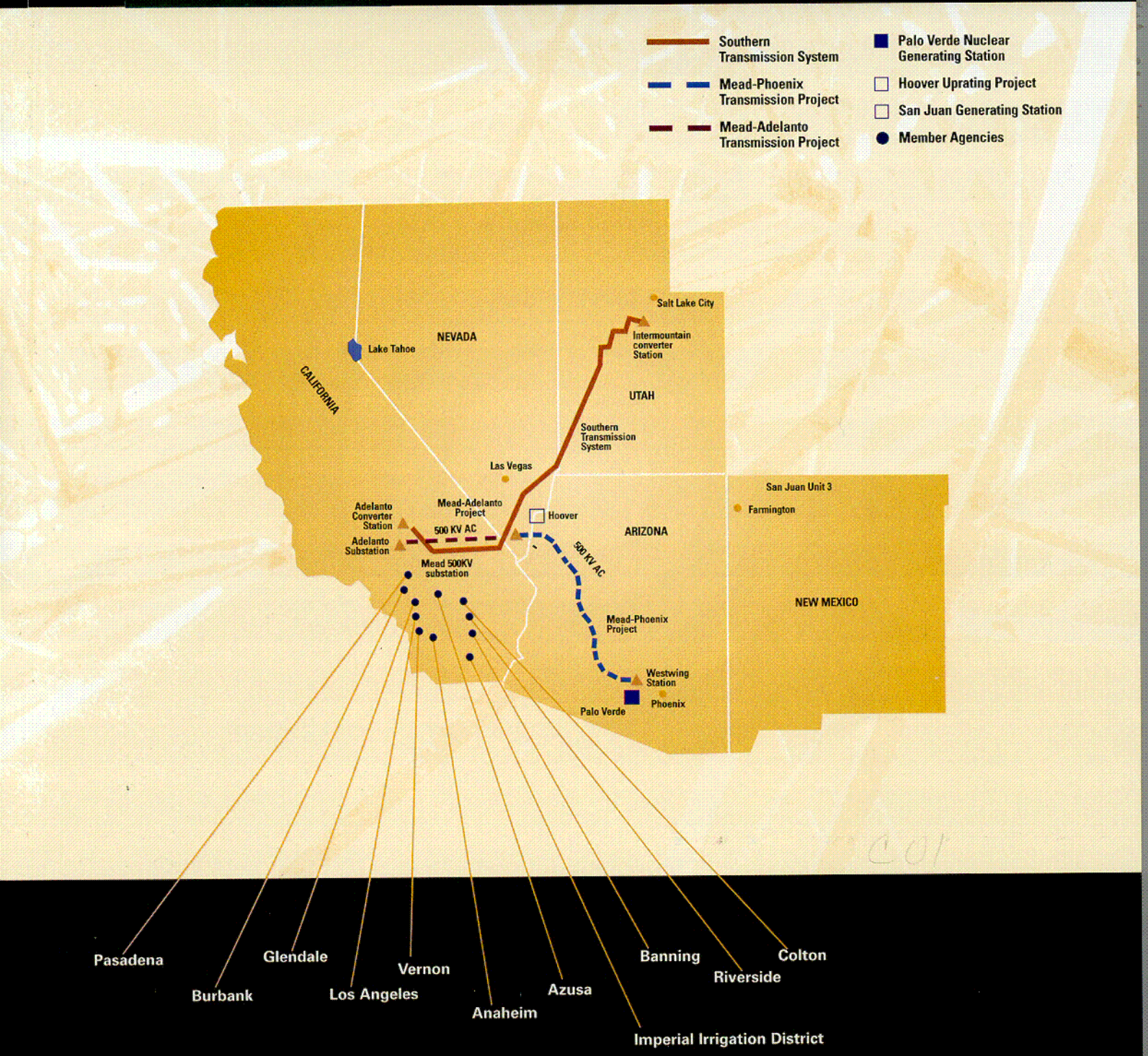
The members are the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District.

SCPPA was formed in 1980 to finance the acquisition of generation and transmission resources for its members. Currently, SCPPA has three generation projects and three transmission projects, bringing power from Arizona, New Mexico, Utah, and Nevada.

The projects were financed through the issurance of tax-exempt bonds, backed by the combined credit of the SCPPA members participating in each project. As of June 30, 2000, SCPPA had issued $9.1 billion in bonds, notes, and refunding bonds, of which $2.85 billion in principal was outstanding.

SCPPA's role has evolved over the years to include advocacy at the state and national levels, and cooperative efforts to reduce member costs and improve efficiency.

SCPPA Members and Projects



President's Letter

Fiscal Year **1999-2000 brought a change in leadership** to SCPPA. Executive Director Dan Waters retired, after five years of leading us through some of the most challenging times the electric utility industry has ever experienced. His four decades in the California municipal power business, along with his personal qualities of vision and consensus building, helped the SCPPA member utilities prepare for the restructuring of our industry.

His successor is another well-known, highly experienced California public power executive, **Bill Carnahan.** As General Manager of Riverside Public Utilities, one of SCPPA's larger members, Bill served as a SCPPA Board Member for 14 years, and was Board President for 1995 and 1996. He has represented SCPPA members on the Board of the California Independent System Operator from its inception, and will continue that role as Executive Director. He is well known in both Sacramento and Washington, D.C., and has **helped shape the debates** on restructuring and competition.

Bill knows the industry, knows California, and knows the SCPPA Members and their unique situations. We conducted a nation-wide search, and discovered that the **best man to lead us** into the 21st century is one of our own.

The name on the office door has changed, but the role and direction of the organization has not. SCPPA will continue to find innovative ways to assist its members to provide dependable service at low, stable rates.

Joseph Hsu
President

Executive Director's Letter

Life in the "electric lane" this past year in California has been an exciting and challenging ride. For the customers of the investor-owned utilities (IOUs), it has been a year of **increasing concerns about reliability** and energy prices. For the residents of the San Diego area, these concerns about prices became a reality when they were subjected to electric bills more than double those of the previous year.

Fortunately, this was not the case at all for the customers of the SCPPA members. They saw the benefits of some of our past cooperative efforts. All of us worked to ensure that California's restructuring legislation in 1996 did not contain provisions which would harm our member systems or their customers. Local control by our members' boards and councils was retained, assuring **the right to choose** the level of participation, if any, in the new open marketplace.

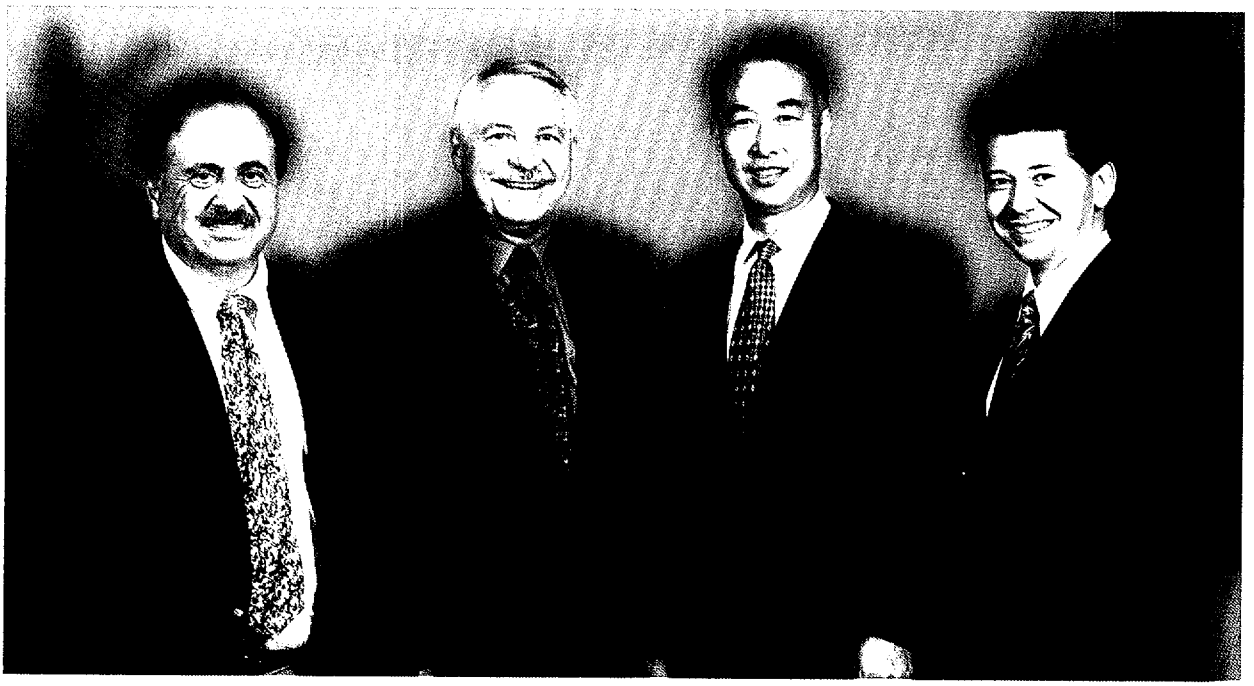
While the state's IOUs sold most of their generation resources and became more and more distribution-only companies, **SCPPA members retained their resources.** The IOUs are subject to the roller coaster prices of the developing supply and demand marketplace, while SCPPA-owned generation continues to provide our members with stable, predictable, and increasingly competitive power. The winners continue to be our customers.

SCPPA will continue to look for ways to **bring value to its members** through minimizing the long-term costs of power from SCPPA projects, jointly planning for future challenges, and working tirelessly in the state and federal arenas to assure that the benefits of public power are continued.

Even though my perspective has changed from that of a Board Member to the Executive Director, my goals remain the same. I remain committed to represent the southern California public power community at the local, state, regional and federal level, and to project and promote what is rapidly becoming the envy of the city councils of IOU-served cities – the vertically integrated public power system, willingly committed to continue its "obligation to serve" the resident stakeholder/owners.

Bill Carnahan
Executive Director

SCPPA Officers



Edward K. Aghjayan Vice President	**Bill D. Carnahan** Executive Director	**Joseph F. Hsu** President	**Robert K. Rozanski** Assistant Secretary

We're still standing

Four years ago, when California's electric restructuring legislation was passed, the state's municipal utilities were exempted from most of the requirements imposed on the investor owned utilities. Municipals were allowed to remain vertically integrated; open access was voluntary; participation in the Independent System Operator (ISO) and the Power Exchange (PX) was voluntary; and local control was retained. **SCPPA members** worked very hard to retain maximum flexibility in the new competitive world.

Many voices, both in California and nationally, said there was no place in a competitive environment for municipal utilities. On one hand they said we were inefficient and could not compete (even though our average rates were already lower than the IOUs). In the next breath they said it was unfair that we benefited from tax-exempt financing (even though the IOUs actually have more tax-exempt and tax-deferred debt than the municipals). **Other voices** urged us to get out of the generation business, and just be distribution utilities, delivering someone else's power to our customers.

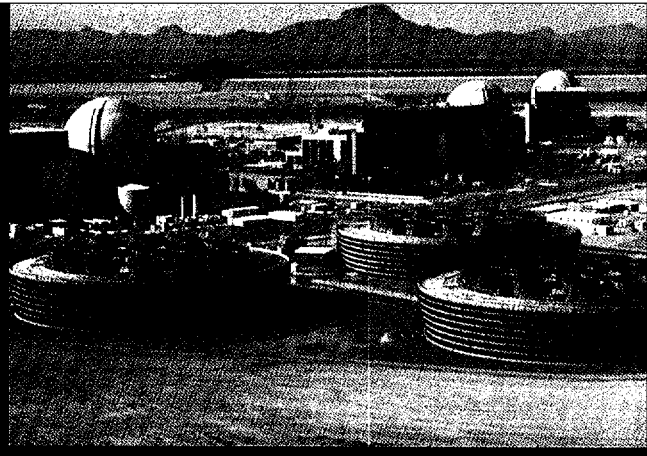
The goal of the legislature was to lower electric bills and retain businesses and jobs in California. The goal of the IOUs is to maximize profits for their stockholders. These goals are in conflict.

The goal of municipal utilities has always been to **provide reliable, reasonably priced power** at stable rates to all of our residents and businesses. Some of our members have been doing that for a hundred years. Any "profits" go toward lower rates or to benefit the local city.

After four years of the new environment, power is in short supply, reliability has decreased, and the market is not working. Some of the IOUs need more time to eliminate their stranded costs, and their customers need more rate freezes. Legislators are looking for political fixes for the "deregulated" market, and other states are putting their deregulation plans on slower tracks.

After four years, SCPPA members still feel the obligation to serve. **We have sufficient generation** to serve our customers without interruption, and our rates are stable. Our coal and nuclear generation is looking very valuable and very competitive. We are planning for the future with the best interests of our customers as the prime concern.

After four years, we're still standing. We're standing tall. **We're here to stay.**



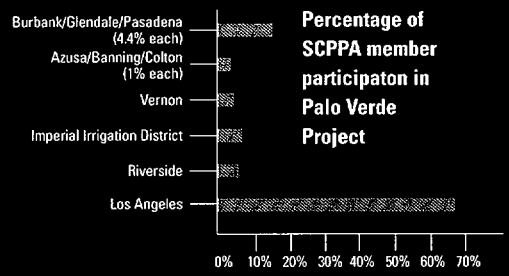
Palo Verde Operations

During fiscal year 1999-2000, **Palo Verde had yet another high production year,** and continued to break site records, many of which were set only last year.

- 30.54 million MWhs – breaking last year's new record of 30.23 million MWhs
- 510 days of continuous operation for Unit 3 – second only to last year's new site record of 515 days by Unit 2.
- 31.5 day refueling outage for Unit 3 – eclipsing last year's new plant record of 36 days by Unit 2.

In the fall of 1999, Palo Verde received its third consecutive Institute of Nuclear Power Operations (INPO) #1 rating.

For the fifth calendar year in a row (1999), Palo Verde Generating Station was the **largest producer of electricity** in the United States.



Percentage of SCPPA member participaton in Palo Verde Project

1999-2000 OPERATIONS

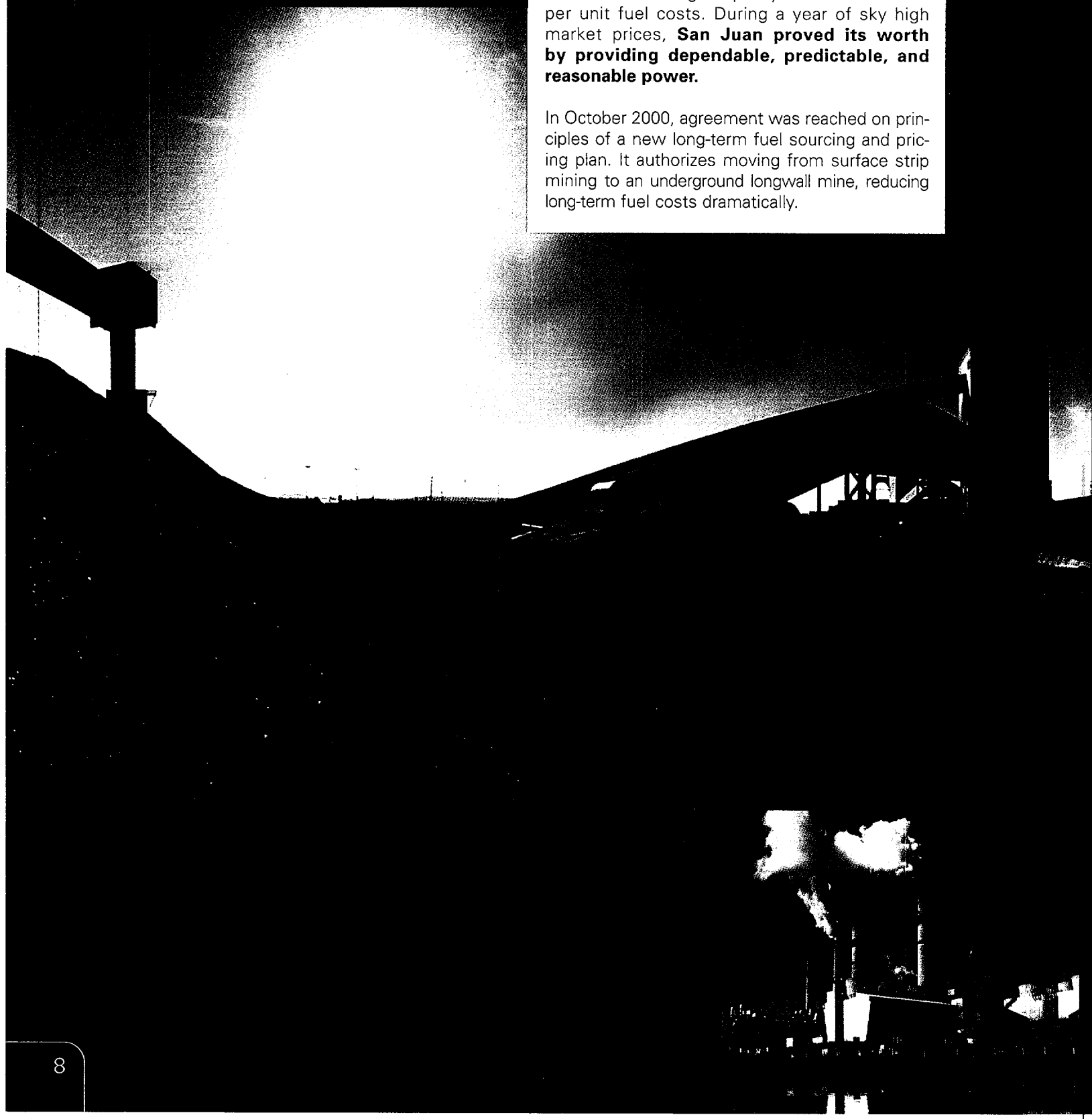
	Generation (Millions of MWHs)	Capacity Utilization (%)
Unit 1	9.8	89.3%
Unit 2	10.8	98.6%
Unit 3	10.0	91.5%
Aggregate	30.5	93.1%

PRODUCTION COST

(Operation and Maintenance plus Nuclear Fuel)

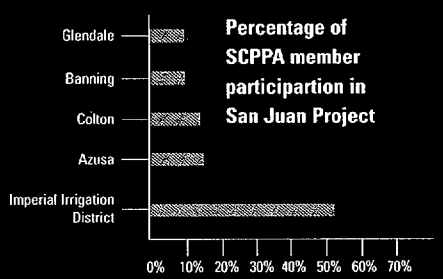
Calendar Year	Cents per kWh
1993	2.02
1994	1.93
1995	1.61
1996	1.45
1997	1.33
1998	1.28
1999	1.25

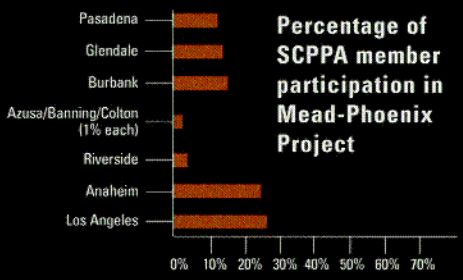
San Juan Unit 3 Operations



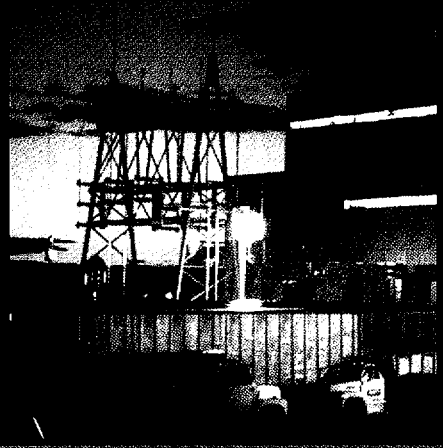
Five SCPPA participants own 41.8% of Unit 3 at the San Juan Generating Station in New Mexico. A series of Interim Invoicing Agreements for fuel has led to high capacity factors and lower per unit fuel costs. During a year of sky high market prices, **San Juan proved its worth by providing dependable, predictable, and reasonable power.**

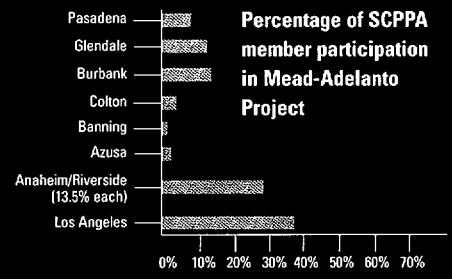
In October 2000, agreement was reached on principles of a new long-term fuel sourcing and pricing plan. It authorizes moving from surface strip mining to an underground longwall mine, reducing long-term fuel costs dramatically.


Percentage of SCPPA member participartion in San Juan Project
Glendale
Banning
Colton
Azusa
Imperial Irrigation District
0%
10%
20%
30%
40%
50%
60%
70%



Percentage of SCPPA member participation in Mead-Phoenix Project

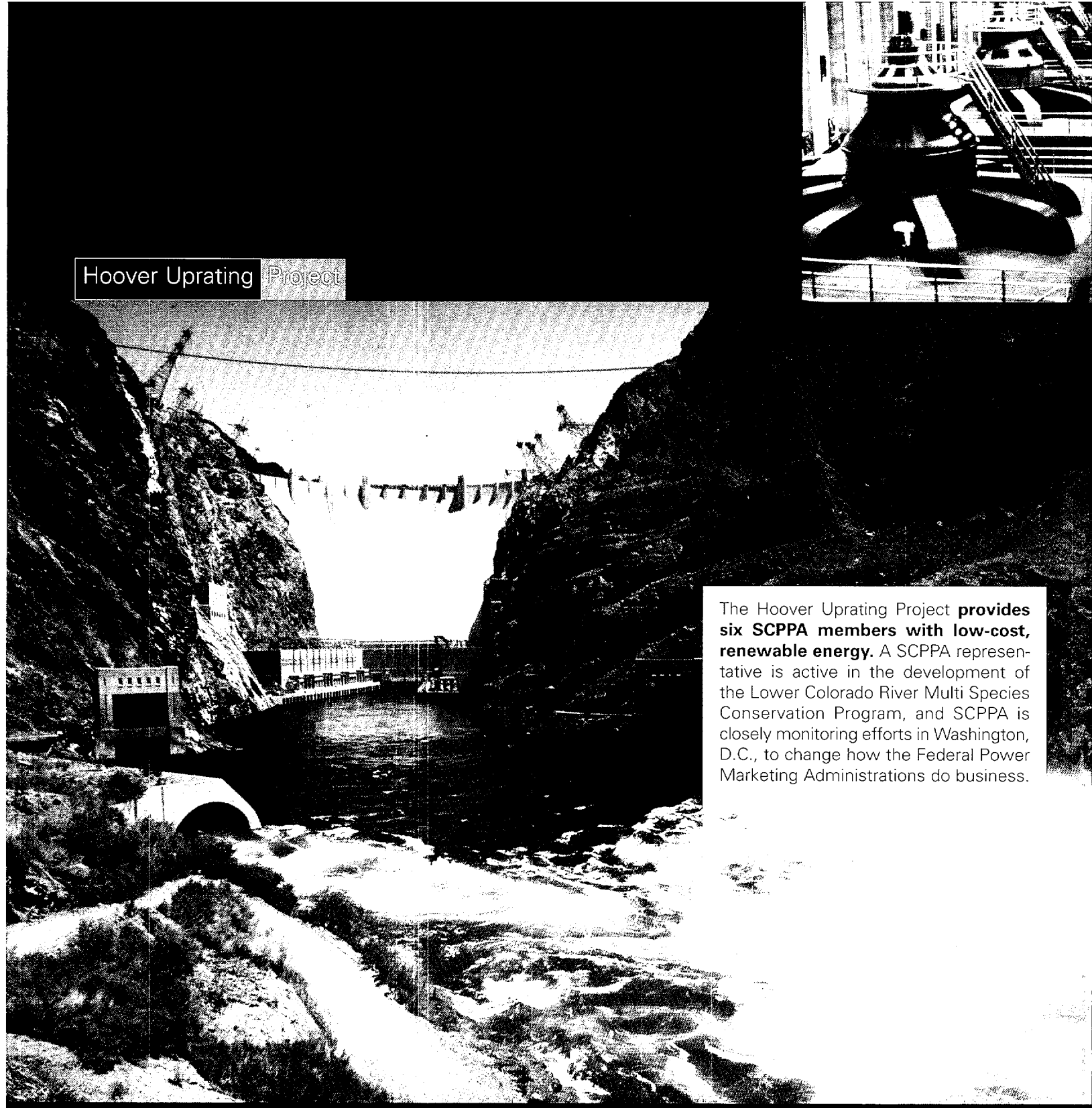




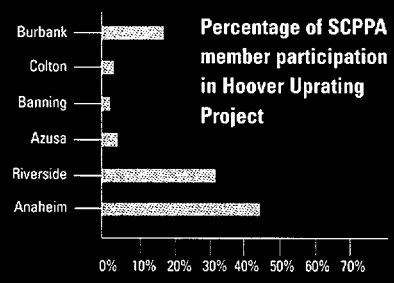
The two 500-kV transmission lines, which connect Phoenix to Las Vegas, and Las Vegas to Southern California, completed their **fourth year of dependable operation** for the nine SCPPA members who participate in the projects.

An explosion and fire at Marketplace Substation incapacitated the static var compensator, but no curtailments were necessary. Repairs are scheduled to be completed by December 31, 2000.

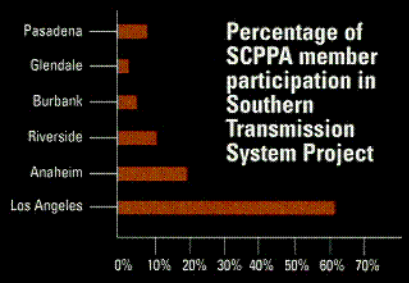
Hoover Uprating Project



The Hoover Uprating Project **provides six SCPPA members with low-cost, renewable energy.** A SCPPA representative is active in the development of the Lower Colorado River Multi Species Conservation Program, and SCPPA is closely monitoring efforts in Washington, D.C., to change how the Federal Power Marketing Administrations do business.



Percentage of SCPPA member participation in Hoover Uprating Project



Percentage of SCPPA member participation in Southern Transmission System Project

Southern Transmission System (STS)

As usual, the STS operated with **near-perfect availability (99.51%),** delivering over 14.5 million MWhs to the six SCPPA members who are participants. This represents use of over 89% of the total capacity of the line. The power comes 488 miles from the Intermountain Power Project, in Utah, over the ± 500-kv DC line.

On May 17, 2000, SCPPA closed the sale of $125 million in Southern Transmission System Subordinate Refunding Bonds, Series A. The proceeds of the sale were used to retire certain 1992 and 1993 Southern Transmission System bonds that were tendered by the bondholders to SCPPA.

The bond buy-back program, after assuming an all-in variable rate of 4.00% on the refunding bonds, will produce **gross savings of $37.8 million** and net present value savings of $26.6 million. A total of $142.6 million in bonds were bought at a cost of $141.5 million. Released reserves were utilized in the transaction to further reduce the amount of new refunding bonds issued.

Moody's upgraded its outlook on the Southern Transmission System Subordinate Lien bonds to "Positive" and confirmed its underlying rating of A1. Standard & Poor's upgraded its underlying ratings on the Senior and Subordinate Lien bonds to AA- and A+, respectively. The bonds were insured, with ratings of AAA/Aaa from Moody's and Standard & Poor's, respectively.

As of June 30, 2000

SCPPA BONDS	Outstanding Principal (000s)	Effective Interest Rate(s)	Final Maturity	Bond Ratings: Moody's Investors Service	Bond Ratings: Standard & Poor's
Hoover Uprating Project	$ 29,361	6.2%	2017	Aa3	AA-
Southern Transmission System	$ 1,097,466	4.3 - 7.2%	2023		
Senior Lien Bonds				Aa3	AA-
Subordinate Lien Bonds[1]				Aaa/VMIG1	AAA/A+
Palo Verde Project[2]	$ 897,630	4.2 - 7.2%	2017		
Senior Lien Bonds				A2	AA-
Subordinate Lien Bonds				Aaa/VMIG1	AAA/A-1+
Multiple Project Revenue Bonds					
Mead-Adelanto	$ 100,760	7.1%	2020	Aa3	A
Mead-Phoenix	$ 36,640	7.1%	2020	Aa3	A
Multiple Project[3]	$ 253,700	7.1%	2020	A2	A
Mead-Adelanto Revenue Bonds[4]	$ 173,955	5.3%	2020	Aaa	AAA
Mead-Phoenix Revenue Bonds[4]	$ 51,834	5.3%	2020	Aaa	AAA
San Juan Unit 3[5]	$ 211,700	5.6%	2020	Aaa	AAA

[1]Insured: 1991 Subordinate Variable Rate Bonds (AMBAC); 1993 Subordinate Series (MBIA); 1996 Subordinate Series A Bonds (MBIA); 1996 Subordinate Variable Rate Series B Bonds (FSA); 1998 Subordinate Series A (MBIA). 2000 Subordinate Variable Rate Series A Bonds (FSA)
[2]Insured: 1992 Senior Lien Bonds (AMBAC); 1993 Subordinate Bonds (FGIC); 1996 Subordinate Series A (AMBAC); 1996 Subordinate Variable Rate Series B and C Bonds (AMBAC); 1997 Subordinate Series A and B Bonds (FSA); Installment Deposits to Defease the 1987 and 1989 Bonds (FSA); 1999 Subordinate Refunding Series A Bonds (FSA).
[3]Uncommitted bond proceeds secured by a guaranteed rate investment contract.
[4]Insured: 1994 Series A Bonds (AMBAC).
[5]Insured: 1993 Series A Bonds (MBIA).

Summer 2000's wild California electricity market, coupled with partisan politics and policy differences, has clouded the federal electric restructuring debate. SCPPA has continued to be actively involved throughout the year in educating both state and federal policymakers on its legislative priorities to help refocus the electricity restructuring debate.

Early in 2000, significant progress seemed likely on both electricity restructuring and private use tax legislation, based on groundwork laid in 1999. Late last fall, the House Commerce Subcommittee on Energy and Power **approved a comprehensive electricity restructuring bill** (H.R. 2944) that addressed a number of issues relating to the wholesale electricity market. Though action on H.R. 2944 demonstrated an increased commitment from House policy makers on the restructuring issue, the substance of that bill would have done little to benefit public power. Upon the referral of H.R. 2944 to the House Commerce Committee, however, the bill was stalled due to personality conflicts as well as policy differences. The major point of contention was the role of the federal vs. state governments, and more specifically, how much power should be bestowed upon the Federal Energy Regulatory Commission (FERC).

Despite its best efforts, the Senate Energy Committee also found itself embroiled in partisan politics as well as substantive differences. It, too, attempted to move comprehensive restructuring legislation, but was ultimately able to pass a narrow "reliability only" bill this year. Sen. Slade Gorton's (R-WA) bill (S. 2071) would authorize **a national electric reliability organization** to establish and enforce mandatory reliability standards. Though the Senate passed the bill, the measure was never brought to a vote in the House.

Although significant progress was made in the 106th Congress on **private use tax legislation,** time ran out for final passage of a bill. In July, the American Public Power Association (APPA) reached a landmark compromise on the private use and other industry related tax issues with investor owned utilities and the Edison Electric Institute (EEI). The compromise was introduced in both the House and the Senate in late July as the "Electric Power Industry Tax Modernization Act" (H.R. 4971/S. 2967). The compromise includes minor revisions to the private use language and provisions to address the tax consequences of nuclear decommissioning, transcos and contributions in aid of construction (CIAC).

In the waning days of the 106th Congress, efforts focused on attaching the industry tax package to a larger tax vehicle in hopes of the bill's passage this year. Efforts to pass the industry bill, however, were thwarted by two factors: 1) a hefty price tag to the federal government; and 2) too few remaining days on the legislative calendar. In the absence of private use relief this year, the temporary IRS Regulations on private use are set to expire in January, 2001, but public power is working to finalize those regulations by year's end.

(Continued on Page 18)

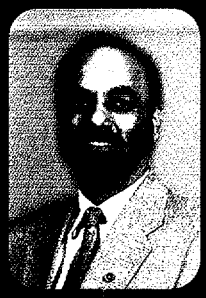
City of Anaheim
Edward K. Aghjayan
General Manager
In 1894, the citizens of Anaheim voted to create the area's first city-owned electric utility. Over a century later, Anaheim Public Utilities delivers competitively priced electricity to over 300,000 residences and 15,000 businesses. While a lot has changed, Anaheim Public Utilities remains focused on providing value to its citizen-owners. Anaheim residents enjoy the lowest electric rates in Orange County – 15% lower than in any neighboring community. In addition, Anaheim Public Utilities provides value-added services to the community through its Advantage Services. In 1999-2000, Anaheim Public Utilities provided incentives to over 6,000 commercial and residential customers and education programs to over 11,000 Anaheim students, helping them to use water and electricity efficiently and cost-effectively.

City of Azusa
Joseph Hsu
Director of Utilities
The City's electric utility was established in 1898, and for most of its history Azusa has purchased electricity wholesale from Southern California Edison. Since the mid-1980's, through successful litigation against Edison on transmission access, Azusa began to acquire energy through short- and long-term contracts with other utilities, as well as from SCPPA by participating in Palo Verde Nuclear Generating Station, Hoover Hydroelectric Plant, and San Juan Generating Station Unit #3. Since the formation of California's Independent System Operator and Power Exchange, Azusa has been certified as a Scheduling Coordinator. As such, Azusa has been actively participating in the deregulated wholesale energy market. And in preparation for retail choice for Azusa's customers, Azusa has adopted a strategic financial plan which established a rate stabilization fund to mitigate the utility's stranded investment by mid-2002, and at the same time reduce retail rates to a competitive level.

City of Pasadena
Rufus Hightower
General Manager
Established in 1906, the city built its first electric generating steam plant in 1907 and took over operation of its municipal street lighting from Edison Electric. In 1909, Pasadena began the extension of its operations to commercial and residential customers that resulted in the replacement of all Edison electric service in the city by 1920. In 1998-99, Pasadena purchased approximately 80 percent of its power needs.

City of Burbank
Ronald E. Davis
General Manager
Burbank's Public Service Department began serving both water and electric customers in 1913. The Public Service Department installed on-site generation in response to significant growth in the 1940s and 1950s. Today the Public Service Department receives power from three SCPPA projects, as well as firm and interruptible supplies from other utilities and government agencies. The Public Service Department continues to operate its own local generation.

City of Glendale
Daniel W. Waters
Interim Director
Incorporated in 1906, Glendale purchased its electric utility in 1909, obtaining power from outside suppliers. It received its first power from Hoover Dam in 1937 and inaugurated the first unit of its own steam generating plant in 1941. Now called the Grayson Power Plant, this facility today has eight generating units. Glendale continues to purchase 85 percent of its power from outside sources.



City of Banning
Paul Toor
Assistant City Manager
Established in 1913, the Banning electrical system now serves an area of approximately 21 square miles. The city owns a portion of San Juan Unit 3 and a portion of Mead-Adelanto and Mead-Phoenix transmission lines. Service is provided to Banning customers through the City-owned distribution system. With a power record of reliability, the City is committed to continue to provide quality service to both present and future customers while positioning itself for effective delivery of services in a competitive deregulated environment.

Imperial Irrigation District
Kristine K. Fontaine
Chief Financial Officer/Controller
IID entered the power industry in 1936 and today serves a peak load of 704 MW with 850 MW of generating resources. Among IID-owned resources are 24 MW of low head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, and 162 MW of peaking gas turbines. In addition to IID's share of SCPPA resources comprising 104 MW at San Juan and 14 MW at Palo Verde, IID has 179 MW of other resources under long-term purchase contracts.

Los Angeles Department of Water and Power
Ronald O. Vazquez
Chief Financial Officer
In 1916, the City of Los Angeles began distributing electric power purchased from the Pasadena Municipal Power Plant, and the following year inaugurated its first generating capacity at San Francisquito Power Plant No. 1. In 1922 the city purchased the remaining distribution system of Southern California Edison Company within the city limits. It is now the largest municipally owned electric utility in the nation and is undergoing a major business restructuring process to prepare for open market competition.

City of Riverside
Thomas P. Evans
Public Utilities Director
Riverside Public Utilities continues to position itself as the first choice full service utility provider for its customers by offering competitive rates and superior service. Power and transmission costs constitute the bulk of charges passed on to our customers through rates. Cost reduction and restructuring efforts at SCPPA have had significant impact on Riverside Public Utilities' effort in meeting operating cost targets based upon maximum efficiencies. Significant customer focused business and residential marketing efforts have resulted in continued positive community and customer approval ratings.

City of Colton
Thomas K. Clarke
Utilities Director
The Colton Electric Utility continues its commitment to meet the needs of the community it serves by providing reliable service at a competitive price. Efforts to streamline operations, reduce purchased power costs, and inititate programs to enhance service to customers have resulted in improved efficiences and significant cost savings. These efforts have positioned Colton Public Utilities to continue to offer premium service at low rates.

City of Vernon
Kenneth J. De Dario
Director of Utilities
Vernon's Utilities Department began serving industrial customers in 1933, with completion of it's diesel generating plant. In addition to its own power from diesel units and gas turbines, Vernon also receives power from Palo Verde, Hoover, and various suppliers. Vernon resides within the California Independent System Operator (CAISO) Control Area and is a certified Scheduling Coordinator with the CAISO.

In 2000, **SCPPA has been instrumental**, not only in garnering support for a fix to the private use problem, but also in educating federal legislators on the problems in California's energy markets. Following the introduction of a bill by Rep. Brian Bilbray (R-CA), SCPPA and representatives of other California municipal systems made a series of visits in Washington, D.C., this summer. In a political response to soaring energy prices in San Diego, Rep. Bilbray's bill (H.R. 5115) proposed to eliminate the preferential access of municipal utilities to the low-cost hydropower generated by the federal power marketing administrations (PMAs). The Bilbray bill is one of many attacks on the PMAs that have surfaced in recent years. SCPPA, CMUA and APPA were vocal in opposing the elimination of preference power or any similar attacks on the federal power program.

In Sacramento, the 2000 legislative session provided **positive results for SCPPA** and its member agencies. Legislation which establishes a 120-day statute of limitations on efforts to nullify an electric rate which contains a capital facilities fee was signed into law by Governor Davis. The legislation, sponsored by SCPPA, **provides rate-making stability** for municipal electric utilities which serve public agency customers.

The California Legislature adopted measures which continue support for public benefit programs. A surcharge of 2.85% of the total electric bill provides funding for low income assistance, new investment and renewable energy research and development, and electricity conservation programs determined by the governing board of the publicly owned utility. The resources necessary to implement locally identified programs has been assured through 2012.

Finally, in an ongoing effort to educate congressional staff on the functions and the legislative priorities of the SCPPA systems, SCPPA conducted its **Sixth Annual Congressional Staff Tour.** In April, SCPPA coordinated a group of congressional staff from the Southern California delegation and from key committees in a tour of SCPPA facilities. As California continues to be central to the federal restructuring debate, the tour served to educate staff on SCPPA- and California-specific issues as well as on **what lessons can be learned** from California's restructuring initiative, A.B. 1890. As in years past, a number of SCPPA members spent all or part of the tour with the group in order to cultivate good working relationships with SCPPA's Congressional delegation.

REPORT OF INDEPENDENT ACCOUNTANTS

September 15, 2000

To the Board of Directors and Participants of the
Southern California Public Power Authority

In our opinion, the accompanying combined balance sheets and the related combined statements of operations and of cash flows present fairly, in all material respects, the financial position of the Southern California Public Power Authority (the Authority) at June 30, 2000 and 1999, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the accompanying separate balance sheets and the related separate statements of operations and of cash flows present fairly, in all material respects, the financial position of each of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project, Multiple Project Fund, San Juan Project and Projects' Stabilization Fund at June 30, 2000 and 1999, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial information, as listed in the accompanying index, is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Los Angeles, California

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED BALANCE SHEET
(Amounts in thousands)

	June 30, 2000								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
ASSETS									
Utility plant:									
Production	$ 613,271	$ –	$ –	$ –	$ –	$ –	$ 177,140	$ –	$ 790,411
Transmission	14,146	674,606	–	50,846	170,896	–	–	–	910,494
General	2,526	18,911	22	2,646	341	–	7,890	–	32,336
	629,943	693,517	22	53,492	171,237	–	185,030	–	1,733,241
Less - Accumulated depreciation	377,086	272,834	10	6,407	19,261	–	65,906	–	741,504
	252,857	420,683	12	47,085	151,976	–	119,124	–	991,737
Construction work in progress	12,132	–	–	–	–	–	566	–	12,698
Nuclear fuel, at amortized cost	14,218	–	–	–	–	–	–	–	14,218
Net utility plant	279,207	420,683	12	47,085	151,976	–	119,690	–	1,018,653
Special funds:									
Investments									
Escrow accounts	131,987	19,539	–	13,215	37,192	–	–	–	201,933
Decommissioning fund	75,909	–	–	–	–	–	–	–	75,909
Other funds	140,330	96,195	6,512	9,878	33,361	254,244	4,724	29,547	574,791
	348,226	115,734	6,512	23,093	70,553	254,244	4,724	29,547	852,633
Cash and cash equivalents	47,479	37,750	977	3,773	6,525	15	35,959	5,262	137,740
Interest receivable	2,911	397	57	315	1,043	9,344	93	772	14,932
	398,616	153,881	7,546	27,181	78,121	263,603	40,776	35,581	1,005,305
Accounts receivable	1,450	87	–	–	–	–	500	–	2,037
Due from other project	–	–	–	2,827	7,774	–	–	–	10,601
Advance to IPA	–	11,550	–	–	–	–	–	–	11,550
Advances for capacity and energy, net	–	–	22,805	–	–	–	–	–	22,805
Materials and supplies	6,782	–	–	–	–	–	3,285	–	10,067
Costs recoverable from (in excess of) future billings to participants	76,496	297,743	(5,686)	3,520	14,713	–	47,625	–	434,411
Unamortized debt expenses, less accumulated amortization of $11,518	5,287	8,672	262	1,224	4,083	–	2,053	–	21,581
	$ 767,838	$ 892,616	$ 24,939	$ 81,837	$ 256,667	$ 263,603	$ 213,929	$ 35,581	$ 2,537,010
LIABILITIES									
Long-term debt	$ 689,031	$ 845,742	$ 23,790	$ 63,453	$ 204,179	$ 234,306	$ 197,042	$ –	$ 2,257,543
Current liabilities:									
Debt due within one year	43,675	24,555	615	14,850	41,645	5,800	7,140	–	138,280
Accrued interest	10,467	16,645	378	2,515	7,684	8,074	5,441	–	51,204
Accounts payable and accruals	22,313	5,674	156	383	1,797	–	3,679	–	34,002
Accrued property tax	2,352	–	–	636	1,362	–	627	–	4,977
Due to other projects	–	–	–	–	–	10,601	–	–	10,601
Funds due to participants	–	–	–	–	–	–	–	35,581	35,581
Total current liabilities	78,807	46,874	1,149	18,384	52,488	24,475	16,887	35,581	274,645
Deferred credits	–	–	–	–	–	4,822	–	–	4,822
Commitments and contingencies	–	–	–	–	–	–	–	–	–
	$ 767,838	$ 892,616	$ 24,939	$ 81,837	$ 256,667	$ 263,603	$ 213,929	$ 35,581	$ 2,537,010

The accompanying notes are an integral part of these combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED BALANCE SHEET
(Amounts in thousands)

	June 30, 1999								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
ASSETS									
Utility plant:									
Production	$ 614,843	$ –	$ –	$ –	$ –	$ –	$ 179,135	$ –	$ 793,978
Transmission	14,146	674,606	–	51,266	170,896	–	–	–	910,914
General	2,517	18,911	22	2,632	341	–	7,890	–	32,313
	631,506	693,517	22	53,898	171,237	–	187,025	–	1,737,205
Less - Accumulated depreciation	342,953	253,196	6	4,995	14,783	–	58,279	–	674,212
	288,553	440,321	16	48,903	156,454	–	128,746	–	1,062,993
Construction work in progress	11,485	–	–	–	–	–	1,791	–	13,276
Nuclear fuel, at amortized cost	13,587	–	–	–	–		–	–	13,587
Net utility plant	313,625	440,321	16	48,903	156,454	–	130,537	–	1,089,856
Special funds:									
Investments									
Escrow accounts	79,943	22,589	–	13,396	37,699	–	–	–	153,627
Decommissioning fund	65,143	–	–	–	–	–	–	–	65,143
Other funds	129,230	120,254	6,492	7,439	28,713	257,147	25,895	16,175	591,345
	274,316	142,843	6,492	20,835	66,412	257,147	25,895	16,175	810,115
Cash and cash equivalents	47,431	31,109	1,016	4,913	9,657	80	14,317	8,375	116,898
Interest receivable	2,186	489	71	683	1,989	9,450	204	284	15,356
	323,933	174,441	7,579	26,431	78,058	266,677	40,416	24,834	942,369
Accounts receivable	2,322	–	–	–	–	–	500	–	2,822
Due from other project	–	–	–	2,518	6,926	–	–	–	9,444
Advance to IPA	–	11,550	–	–	–	–	–	–	11,550
Advances for capacity and energy, net	–	–	23,412	–	–	–	–	–	23,412
Materials and supplies	6,912	–	–	–	–	–	3,325	–	10,237
Costs recoverable from (in excess of) future billings to participants	128,276	279,588	(5,944)	4,209	16,461	–	42,885	–	465,475
Unamortized debt expenses, less accumulated amortization of $11,518	6,224	8,121	290	1,332	4,343	–	2,338	–	22,648
	$ 781,292	$ 914,021	$ 25,353	$ 83,393	$ 262,242	$ 266,677	$ 220,001	$ 24,834	$ 2,577,813
LIABILITIES									
Long-term debt	$ 714,550	$ 862,447	$ 24,140	$ 77,697	$ 244,119	$ 239,426	$ 203,820	$ –	$ 2,366,199
Current liabilities:									
Debt due within one year	40,615	23,585	580	2,160	5,940	5,400	6,825	–	85,105
Accrued interest	10,837	19,644	387	2,588	7,884	8,256	5,598	–	55,194
Accounts payable and accruals	12,752	8,345	246	353	3,085	–	3,158	–	27,939
Accrued property tax	2,538	–	–	595	1,214	–	600	–	4,947
Due to other projects	–	–	–	–	–	9,444	–	–	9,444
Funds due to participants	–	–	–	–	–	–	–	24,834	24,834
Total current liabilities	66,742	51,574	1,213	5,696	18,123	23,100	16,181	24,834	207,463
Deferred credits	–	–	–	–	–	4,151	–	–	4,151
Commitments and contingencies	–	–	–	–	–	–	–	–	–
	$ 781,292	$ 914,021	$ 25,353	$ 83,393	$ 262,242	$ 266,677	$ 220,001	$ 24,834	$ 2,577,813

The accompanying notes are an integral part of these combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF OPERATIONS
(Amounts in thousands)

	Year Ended June 30, 2000								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Operating revenues:									
Sales of electric energy	$ 173,433	$ –	$ 2,054	$ –	$ –	$ –	$ 57,181	$ –	$ 232,668
Sales of transmission services	–	81,896	–	7,239	19,939	–	–	–	109,074
Total operating revenues	173,433	81,896	2,054	7,239	19,939	–	57,181	–	341,742
Operating expenses:									
Operations and maintenance	24,823	13,297	2,118	1,197	1,547	–	39,868	–	82,850
Depreciation	26,728	19,638	4	1,412	4,478	–	9,439	–	61,699
Amortization of nuclear fuel	8,545	–	–	–	–	–	–	–	8,545
Decommissioning	12,358	–	–	–	–	–	3,113	–	15,471
Total operating expenses	72,454	32,935	2,122	2,609	6,025	–	52,420	–	168,565
Operating income (loss)	100,979	48,961	(68)	4,630	13,914	–	4,761	–	173,177
Other income and expense									
Investment income	12,722	8,421	390	1,462	4,319	18,656	2,134	1,507	49,611
Debt expense	(61,921)	(71,270)	(580)	(5,403)	(16,485)	(17,985)	(11,635)	–	(185,279)
	(49,199)	(62,849)	(190)	(3,941)	(12,166)	671	(9,501)	1,507	(135,668)
Income (loss) before extraordinary item	51,780	(13,888)	(258)	689	1,748	671	(4,740)	1,507	37,509
Loss on refunding	–	(4,267)	–	–	–	–	–	–	(4,267)
	$ 51,780	$ (18,155)	$ (258)	$ 689	$ 1,748	$ 671	$ (4,740)	$ 1,507	$ 33,242

The accompanying notes are an integral part of these combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF OPERATIONS
(Amounts in thousands)

	Year Ended June 30, 1999								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Operating revenues:									
Sales of electric energy	$ 182,961	$ –	$ 1,996	$ –	$ –	$ –	$ 52,473	$ –	$ 237,430
Sales of transmission services	–	73,064	–	7,252	16,846	–	–	–	97,162
Total operating revenues	182,961	73,064	1,996	7,252	16,846	–	52,473	–	334,592
Operating expenses:									
Operations and maintenance	32,460	10,915	2,136	1,249	(26)	–	39,232	–	85,966
Depreciation	26,750	19,637	4	1,418	4,478	–	9,439	–	61,726
Amortization of nuclear fuel	8,877	–	–	–	–	–	–	–	8,877
Decommissioning	11,975	–	–	–	–	–	3,113	–	15,088
Total operating expenses	80,062	30,552	2,140	2,667	4,452	–	51,784	–	171,657
Operating income (loss)	102,899	42,512	(144)	4,585	12,394	–	689	–	162,935
Operating income and expense									
Investment income	5,155	9,069	298	1,787	5,351	18,861	2,049	950	43,520
Debt expense	(62,917)	(70,908)	(531)	(5,564)	(16,926)	(18,279)	(11,942)	–	(187,067)
	(57,762)	(61,839)	(233)	(3,777)	(11,575)	582	(9,893)	950	(143,547)
	$ 45,137	$ (19,327)	$ (377)	$ 808	$ 819	$ 582	$ (9,204)	$ 950	$ 19,388

The accompanying notes are an integral part of these combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF CASH FLOWS
(Amounts in thousands)

	Year Ended June 30, 2000								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:									
Operating income (loss)	$ 100,979	$ 48,961	$ (68)	$ 4,630	$ 13,914	$ –	$ 4,761	$ –	$ 173,177
Adjustments to reconcile operating income to net cash provided by operating activities -									
Depreciation	26,728	19,638	4	1,412	4,478	–	9,439	–	61,699
Decommissioning	12,358	–	–	–	–	–	3,113	–	15,471
Advances for capacity and energy	–	–	1,840	–	–	–	–	–	1,840
Amortization of nuclear fuel	8,545	–	–	–	–	–	–	–	8,545
Other	–	4,144	–	–	–	–	–	–	4,144
Changes in assets and liabilities:									
Accounts receivable	872	(87)	–	–	–	–	–	–	785
Accounts payable and accruals	9,375	(2,671)	(90)	71	(1,140)	–	548	–	6,093
Other	(51)	–	–	32	–	–	91	–	72
Net cash provided by operating activities	158,806	69,985	1,686	6,145	17,252	–	17,952	–	271,826
Cash flows from noncapital financing activities:									
Advances from participants	–	–	–	–	–	–	–	9,240	9,240
Cash flows from capital and related financing activities:									
Additions to plant, net	(13,213)	–	–	406	–	–	(1,705)	–	(14,512)
Debt interest payments	(43,017)	(55,675)	(1,529)	(5,103)	(15,568)	(16,330)	(11,196)	–	(148,418)
Proceeds from sale of bonds	–	125,000	–	–	–	–	–	–	125,000
Payment for defeasance of revenue bonds	–	(142,600)	–	–	–	–	–	–	(142,600)
Principal payments on debt	(40,615)	(23,585)	(580)	(2,160)	(5,940)	(5,400)	(6,825)	–	(85,105)
Decommissioning fund	–	–	–	–	–	–	–	–	–
Payment for bond issue costs	–	(2,106)	–	–	–	–	–	–	(2,106)
Net cash used for capital and related financing activities	(96,845)	(98,966)	(2,109)	(6,857)	(21,508)	(21,730)	(19,726)	–	(267,741)
Cash flows from investing activities:									
Interest received on investments	12,519	8,558	355	920	2,451	17,537	2,225	1,317	45,882
Purchases of investments	(202,555)	(30,561)	(2,453)	(3,623)	(11,519)	(65)	(13,274)	(23,717)	(287,767)
Proceeds from sale/maturity of investments	128,123	57,625	2,482	2,275	10,192	4,193	34,465	10,047	249,402
Net cash provided by (used for) investing activities	(61,913)	35,622	384	(428)	1,124	21,665	23,416	(12,353)	7,517
Net increase (decrease) in cash and cash equivalents	48	6,641	(39)	(1,140)	(3,132)	(65)	21,642	(3,113)	20,842
Cash and cash equivalents at beginning of year	47,431	31,109	1,016	4,913	9,657	80	14,317	8,375	116,898
Cash and cash equivalents at end of year	$ 47,479	$ 37,750	$ 977	$ 3,773	$ 6,525	$ 15	$ 35,959	$ 5,262	$ 137,740

The accompanying notes are an integral part of these combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENT OF CASH FLOWS
(Amounts in thousands)

	Year Ended June 30, 1999								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:									
Operating income (loss)	$ 102,899	$ 42,512	$ (144)	$ 4,585	$ 12,394	$ –	$ 689	$ –	$ 162,935
Adjustments to reconcile operating income to net cash provided by operating activities -									
Depreciation	26,750	19,637	4	1,418	4,478	–	9,439	–	61,726
Decommissioning	11,975	–	–	–	–	–	3,113	–	15,088
Advances for capacity and energy	–		1,876	–	–	–	–	–	1,876
Amortization of nuclear fuel	8,877	–	–	–	–	–	–	–	8,877
Changes in assets and liabilities:									
Accounts receivable	(304)	–	–	855	2,962	–	6,105	–	9,618
Accounts payable and accruals	8,983	4,291	(18)	203	716	–	(2,704)	–	11,471
Other	284	–	–	–	–	–	30	–	314
Net cash provided by operating activities	159,464	66,440	1,718	7,061	20,550	–	16,672	–	271,905
Cash flows from noncapital financing activities:									
Advances from participants	–	–	–	–	–	–	–	4,287	4,287
Cash flows from capital and related financing activities:									
Additions to plant, net	(10,733)	40	–	–	–	–	(1,069)	–	(11,762)
Debt interest payments	(48,290)	(53,472)	(1,562)	(5,205)	(15,771)	(16,511)	(11,574)	–	(152,385)
Proceeds from sale of bonds	55,972	–	–	–	–	–	–	–	55,972
Payment for defeasance of revenue bonds	(59,250)	–	–	–	–	–	–	–	(59,250)
Principal payments on debt	(32,015)	(21,970)	(550)	–	–	–	(6,540)	–	(61,075)
Decommissioning fund	(10,683)	–	–	–	–	–	–	–	(10,683)
Payment for bond issue costs	(765)	–	–	–	–	–	–	–	(765)
Net cash used for capital and related financing activities	(105,764)	(75,402)	(2,112)	(5,205)	(15,771)	(16,511)	(19,183)	–	(239,948)
Cash flows from investing activities:									
Interest received on investments	9,208	7,190	378	1,871	5,599	18,778	2,291	1,056	46,371
Purchases of investments	(315,216)	(89,286)	(7,738)	(31,722)	(106,904)	(2,263)	(12,805)	(21,765)	(587,699)
Proceeds from sale/maturity of investments	213,947	70,304	6,080	30,232	98,277	–	8,833	16,818	444,491
Net cash provided by (used for) investing activities	(92,061)	(11,792)	(1,280)	381	(3,028)	16,515	(1,681)	(3,891)	(96,837)
Net increase (decrease) in cash and cash equivalents	(38,361)	(20,754)	(1,674)	2,237	1,751	4	(4,192)	396	(60,593)
Cash and cash equivalents at beginning of year	85,792	51,863	2,690	2,676	7,906	76	18,509	7,979	177,491
Cash and cash equivalents at end of year	$ 47,431	$ 31,109	$ 1,016	$ 4,913	$ 9,657	$ 80	$ 14,317	$ 8,375	$ 116,898

The accompanying notes are an integral part of these combined financial statements.

Note 1 – Organization and Purpose

The Southern California Public Power Authority (the Authority), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participants consist of ten Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

The Authority has interests in the following projects:

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency (IPA), to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS) which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles (LADWP), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project (IPP).

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation (USBR) on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project (HU).

Mead-Phoenix and Mead-Adelanto Projects – As of December 17, 1991, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project (Mead-Phoenix), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component.

As of December 17, 1991, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project (Mead-Adelanto), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund (Note 3) and commercial operations commenced in April 1996. LADWP serves as the operations manager of Mead-Adelanto.

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3 and related common facilities, of the San Juan Generating Station (SJGS) from Century Power Corporation. Unit 3, a 488 megawatt unit, is one unit of a four-unit coal-fired power generating station in New Mexico.

Projects' Stabilization Fund – In fiscal 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits. This fund is not a project-related fund, therefore, it is not governed by any project Indenture of Trust.

Participant Ownership Interests – The Authority's participants may elect to participate in the projects. As of June 30, 2000 and 1999, the members have the following participation percentages in the Authority's interest in the projects:

Participants	Palo Verde	Southern Transmission System	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan
City of Los Angeles	67.0%	59.5%		24.8%	35.7%	
City of Anaheim		17.6%	42.6%	24.2%	13.5%	
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%	
Imperial Irrigation District	6.5%					51.0%
City of Vernon	4.9%					
City of Azusa	1.0%		4.2%	1.0%	2.2%	14.7%
City of Banning	1.0%		2.1%	1.0%	1.3%	9.8%
City of Colton	1.0%		3.2%	1.0%	2.6%	14.7%
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%	
City of Glendale	4.4%	2.3%		14.8%	11.1%	9.8%
City of Pasadena	4.4%	5.9%		13.8%	8.6%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The Authority has entered into power sales and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output or transmission service, as applicable. The participants are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and

debt service. The contracts cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding. The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

Note 2 - Summary of Significant Accounting Policies

The financial statements of the Authority are presented in conformity with generally accepted accounting principles applicable to governmental utilities. The Authority complies with all applicable pronouncements of the Governmental Accounting Standards Board (GASB). In accordance with GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting,* the Authority also complies with Financial Accounting Standards Board statements which do not conflict with GASB pronouncements. The Authority's records are also generally in conformity with accounting principles prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by either of these regulatory bodies.

The Authority's interests in generation and transmission projects are jointly-owned with other utilities. Each joint plant participant, including the Authority, is responsible for financing its share of construction and operating costs. The financial statements reflect the Authority's interest in each jointly-owned project.

Use of Estimates – The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility plant – The Authority's share of construction and betterment costs associated with PVNGS, STS, Mead-Phoenix, Mead-Adelanto and SJGS are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years for PVNGS, STS, Mead-Phoenix and Mead-Adelanto and twenty-one years for SJGS.

Nuclear fuel – Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each entity with nuclear operations, including the participants in PVNGS, $1 per megawatt hour of nuclear generation. The Authority records this charge as a current year expense. See Note 5 for information about spent nuclear fuel disposal.

Nuclear decommissioning – Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Authority's interest in PVNGS is estimated to be $104.9 million in 1998 dollars ($402.2 million in 2022 dollars, assuming a 6% estimated annual inflation rate). This estimate is based on an updated site specific study prepared by an independent consultant in 1998. The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant through annual charges to expense which amounted to $12.4 and $12.0 million in fiscal 2000 and 1999. The decommissioning liability is included as a component of accumulated depreciation and was $135.7 and $123.3 million at June 30, 2000 and 1999, respectively.

The Authority contributes to external trusts set up in accordance with the Arizona Nuclear Power Plant participation agreement and Nuclear Regulatory Commission requirements. As of June 30, 2000, decommissioning funds totaled approximately $77.4 million, including approximately $1.5 million of interest receivable.

Demolition and site reclamation – Demolition and site reclamation of SJGS, which involves restoring the site to a "green" condition is projected to commence subsequent to the year 2014. Based upon the most recent study performed by an independent engineering firm, the Authority's share of the estimated demolition and site reclamation costs is $18.7 million in 1992 dollars. The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant through annual charges to expense of $3.1 million. The demolition liability is included as a component of accumulated depreciation and totaled $21.8 and $18.7 million at June 30, 2000 and 1999, respectively.

As of June 30, 2000, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

Investments – Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities. These investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of operations. Gains and losses realized on the sale of investments are generally determined using the specific identification method.

The Bond Indentures for the six projects and the Multiple Project Fund require the use of trust funds to account for the Authority's receipts and disbursements. Cash and investments held in these funds are restricted to specific purposes as stipulated in the Bond Indentures.

Advances for capacity and energy – Advance payments to USBR for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity.

Cash and cash equivalents – Cash and cash equivalents include cash and investments with original maturities of 90 days or less.

Unamortized debt expenses – Debt premiums, discounts and issue expenses are deferred and amortized to expense over the lives of the related debt issues. Losses on refundings related to bonds redeemed by refunding bonds are amortized over the shorter of the life of the refunding bonds or the remaining term of bonds

refunded. Losses on early extinguishment of debt are recognized immediately.

Arbitrage rebate – The unused proceeds from the issuance of Multiple Project Revenue Bonds have been invested in taxable financial instruments. The excess of interest income over expense associated with the bonds, if any, is payable to the IRS within five years of the date of the bond offering and each consecutive five years thereafter. The Authority made a payment of $3.8 million at the end of the initial rebate period during fiscal year 1995.

In October 1992, $103.6 million and $285.0 million of the Multiple Project Revenue Bonds were transferred to the Mead-Phoenix Project and the Mead-Adelanto Project, respectively. In March 1994, a portion of the transferred bonds were refunded through the issuance of $51.8 million and $174.0 million of Mead-Phoenix Project Revenue Bonds and Mead-Adelanto Revenue Bonds, respectively. The partial refunding within five years of the original issuance triggered a recalculation of the arbitrage yield, reducing the Multiple Project Fund's rebate liability. At June 30, 2000, cumulative savings due to the rebate calculation amounted to $10.6 million. As a result, the Multiple Project Fund has recorded liabilities of $2.8 million and $7.8 million to the Mead-Phoenix Project and Mead-Adelanto Projects, respectively.

As of June 30, 2000, the Authority had no arbitrage rebate payable. The next rebate payment to the IRS, if any, is due in fiscal year 2005.

Revenues – Revenues consist of billings to participants for the sales of electric energy and of transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the property.

In September 1998, the Palo Verde participants approved a board resolution authorizing the Authority to bill the participants $65 million annually through June 30, 2004, to pay for increased debt service costs as a result of a refunding completed in October 1997. In addition, the participants resolved to transfer any overbillings, renewal and replacement excess funds or surplus amounts through June 30, 2004 into the Palo Verde reserve account. Amounts on deposit in the reserve account are intended to be used to enhance the competitiveness of the Palo Verde Project, at the discretion of the board of directors. Funds held in the reserve account as a result of this resolution totaled $13.2 million and $4.1 million as of June 30, 2000 and 1999, respectively.

Reclassifications – Certain prior period amounts have been reclassified to conform to the current presentation.

Note 3 – Long-Term Debt

Long-term debt outstanding at June 30, 2000 consists of revenue bonds and subordinate refunding bonds due serially in varying annual amounts through 2023. The revenue bonds were issued to finance the purchase and construction of the Authority's share of each of the projects. The subordinate refunding bonds were issued to advance refund specified revenue bonds. The Multiple Project Revenue Bonds were issued on August 1, 1989 to finance acquisition of ownership interests in one or more projects expected to be undertaken within five years after issuance. In October 1992, $103.6 million and $285.0 million of these bonds were transferred to the Mead-Phoenix Project and the Mead-Adelanto Project, respectively.

In accordance with the bond indentures, the revenue bonds and subordinate refunding bonds are special, limited obligations of the Authority. The bonds issued by each project are payable solely from and secured solely by interests in the issuing project as follows:

- Proceeds from the sale of bonds
- All revenues, incomes, rents and receipts attributable to the issuing project and related interest on securities held under the bond indentures
- All funds established by the indentures

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the power and transmission sales agreements with the participants.

At the option of the Authority, all outstanding Power Project Revenue Bonds and Subordinate Refunding Term Bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A and portions of the 1989A, 1992A, 1992B and 1993A Series bonds issued by the Palo Verde Project; the 1996 Subordinate Refunding Series A bonds issued by the Southern Transmission System; and, a total of $153,500,000 of the outstanding Multiple Project Revenue Bonds.

Subordinate refunding bonds

Southern Transmission Project Refunding – In May 2000, the Authority completed a tender offer and purchased $106.8 million and $35.8 million par value of the STS 1992 Series A Subordinate Refunding Bonds and 1993 Series A Subordinate Refunding Bonds, respectively. The total cost of the tender was $141.5 million, of which $122.8 million was financed through the issuance of $125 million of Southern Transmission Project Revenue Bonds, 2000 Series A Subordinate Refunding Bonds. The remaining purchase price was funded through release of funds from the debt service reserve accounts and debt service accounts related to the refunded bonds. The tender is expected to reduce total debt service payments over the life of the refunding issue by approximately $37.8 million and is expected to result in present value savings of approximately $26.6 million, based on an assumed cost of 4.0% on the new bonds. The subordinate refunding bonds bear interest at a variable rate; therefore, the actual savings may vary depending on future interest rates. An increase in the average rate of the variable bonds to 5.0% would change the total net debt service savings to $13.4 million and the present value savings to $9.3 million.

This transaction resulted in a net loss for accounting purposes of $31.5 million, consisting primarily of the write-off of unamortized debt expense and costs associated with the tender program. The Authority has proportionately allocated this loss between bonds repurchased through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds was deferred and will be amortized over the life of the new bonds. The portion tendered with cash resulted in immediate recognition of a $4.3 million extraordinary loss.

The 2000 Series A Subordinate Refunding Bonds currently bear interest at a weekly rate (4.25% as of June 30, 2000). The Authority can elect to change the interest rate period of the bonds, with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day. The Authority has entered into a Standby Agreement with a commercial bank in an initial amount of $133.75 million to provide liquidity for the

variable rate bonds. The Standby Agreement expires on May 16, 2005. Bonds purchased under the agreement will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus .50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten equal semi-annual installments, commencing after the termination of the agreement.

Advance refundings – In prior years, the Authority established irrevocable escrow trusts with the proceeds from issuance of subordinate refunding bonds. These investments will be used to call specified revenue bonds at scheduled redemption dates.

Prior year defeasance of debt – In prior years, the Authority defeased specified revenue bonds by placing the proceeds from issuance of subordinate refunding bonds in irrevocable trusts to provide for all future debt service payments on the refunded bonds. The trust investments and related liability for defeased bonds are not included in the Authority's financial statements. At June 30, 2000, $812.9 million of revenue bonds outstanding are considered defeased.

Interest rate swap

In fiscal year 1991, the Authority entered into an Interest Rate Swap Agreement with a third party for the purpose of hedging against interest rate fluctuations arising from the issuance of 1991 Subordinate Refunding Series Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the third party on a fixed rate basis at 6.38%, and for the third party to make reciprocal payments based on a variable rate basis (3.00% and 3.25% at June 30, 2000 and 1999, respectively). The bonds mature in 2019.

COMBINED SCHEDULE OF LONG-TERM DEBT
AS OF JUNE 30, 2000

	Series	Date of Issue	Effective Interest Rate	Maturities	Principal Outstanding
Palo Verde Project Revenue and Refunding Bonds	1987A	02/11/87	6.90%	2017	$ 40,140
	1989A	02/15/89	7.20%	2000 to 2015	157,160
	1992A	01/01/92	6.00%	2000	820
	1992B	01/01/92	6.00%	2000 to 2004	41,970
	1992C	01/01/92	6.00%	2000 to 2002	1,795
	1993A	03/01/93	5.50%	2000 to 2004	26,145
	1996A	02/13/96	4.40%	2000 to 2004	60,890
	1996B	02/29/96	4.40%	2008 to 2009	58,870
	1996C	08/22/96	4.20%	2016 to 2017	89,570
	1997A	10/09/97	4.30%	2000 to 2004	24,890
	1997B	10/09/97	6.90%	2017	345,675
	1999A	03/31/99	5.00%	2000 to 2004	49,705
					897,630
Southern Transmission System Project Revenue and Refunding Bonds	1988A	11/22/88	7.20%	2002 to 2006	57,565
	1991A	04/17/91	6.40%	2000 to 2019	288,700
	1992 Comp 1, 2, 4	07/20/92	6.10%	2000 to 2021	25,848
	1992 Comp 3	07/20/92	6.10%	2000 to 2021	306,678
	1993A	07/01/93	5.40%	2000 to 2023	62,080
	1996A	09/12/96	4.90%	2000 to 2006	33,965
	1996B	09/12/96	4.30%	2019 to 2023	121,065
	1998A	06/04/98	4.60%	2000 to 2011	76,565
	2000A	05/17/00	4.13%	2010 to 2023	125,000
					1,097,466
Hoover Uprating Project Revenue and Refunding Bonds	1991	08/01/91	6.20%	2000 to 2017	29,361
Multiple Project Revenue Bonds					
Mead-Phoenix Project	1989	01/04/90	7.10%	2000 to 2020	36,640
Mead-Adelanto Project	1989	01/04/90	7.10%	2000 to 2020	100,760
Multiple Project	1989	01/04/90	7.10%	2000 to 2020	253,700
					391,100
Mead-Phoenix Project Revenue Bonds	1994A	03/01/94	5.30%	2006 to 2020	51,834
Mead-Adelanto Project Revenue Bonds	1994A	03/01/94	5.30%	2006 to 2020	173,955
San Juan Project Revenue Bonds	1993	06/01/93	5.60%	2000 to 2020	211,700
Total principal amount					2,853,046
Total unamortized debt-related costs					(457,223)
Long-term debt due within one year					(138,280)
Total long-term debt, net					$ 2,257,543

Unamortized debt-related costs are as follows (amounts in thousands):

	Loss on refunding	Discount	Total
Unamortized debt-related costs:			
Palo Verde Project	$ 91,947	$ 72,977	$ 164,924
Southern Transmission System Project	167,604	59,565	227,169
Hoover Uprating Project	1,836	3,120	4,956
Mead-Phoenix Project	6,584	3,587	10,171
Mead-Adelanto Project	18,105	10,786	28,891
Multiple Project Fund	–	13,594	13,594
San Juan Project	–	7,518	7,518
	$ 286,076	$ 171,147	$ 457,223

Long-term debt maturities are as follows (amounts in thousands):

Fiscal Year Ending	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Total
2001	$ 43,675	$ 24,555	$ 615	$ 14,850	$ 41,645	$ 5,800	$ 7,140	$ 138,280
2002	45,105	19,210	650	1,710	3,895	6,200	7,480	84,250
2003	47,395	29,715	1,110	–	–	6,600	7,845	92,665
2004	49,190	30,255	1,220	–	–	7,100	8,230	95,995
2005	51,800	28,130	1,300	–	–	7,600	8,640	97,470
Thereafter	660,465	965,601	24,466	71,914	229,175	220,400	172,365	2,344,386
	$ 897,630	$ 1,097,466	$ 29,361	$ 88,474	$ 274,715	$ 253,700	$ 211,700	$2,853,046

Fair Value – The fair value of the Authority's long-term debt (including the current portion) is approximately $2.8 billion and $3.0 billion at June 30, 2000 and 1999, respectively. Management has estimated fair value based on the quoted market prices for the same or similar issues or on the current average rates offered to the Authority for debt of approximately the same remaining maturities, net of the effect of a related interest rate swap agreement.

Note 4 – Costs Recoverable From Future Billings To Participants

Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. The difference between billings and the Authority's expenses calculated in accordance with generally accepted accounting principles are deferred as costs recoverable in future periods. It is intended that the deferred amounts will be recovered through billings for repayment of principal on the related bonds.

Costs recoverable from future billings to participants are comprised of the following (in thousands):

	June 30, 1999	Fiscal 2000 Activity	June 30, 2000
GAAP items not included in billings to participants:			
Depreciation of plant	$ 565,555	$ 61,699	$ 627,254
Nuclear fuel amortization	19,548	–	19,548
Decommissioning expense	103,331	7,466	110,797
Amortization of bond discount, debt issue costs, and loss on refundings	416,925	46,992	463,917
Interest expense	42,927	3,059	45,986
Bond requirements included in billings to participants:			
Operations and maintenance, net of investment income	(112,712)	(2,127)	(114,839)
Costs of acquisition of capacity	(18,350)	1,069	(17,281)
Billings to amortize costs recoverable	(115,410)	(65,000)	(180,410)
Reduction in debt service billings due to transfer of excess funds	72,098		72,098
Principal repayments	(454,145)	(83,563)	(537,708)
Other	(54,292)	(659)	(54,951)
	$ 465,475	$ (31,064)	$ 434,411

NOTE 5: Commitments and Contingencies

In June 2000, the Authority received $2.4 million from the State of California as its share of the settlement of a class action lawsuit against a financial institution regarding improprieties in their trust department. The money will be credited to the projects that used the trustee services during the period in question, with $2.3 million allocated to the Southern Transmission System Project. These funds were credited to the participants' accounts and will be available for distribution in fiscal 2001.

Deregulation – In September 1996, Assembly Bill 1890 (the Bill) was given final approval. The Bill, which provides for broad deregulation of the power generation industry in California, requires the participation of the state's investor-owned utilities. Consumer-owned utilities can participate on a voluntary basis but must hold public hearings as part of their decision making process. The Bill, which was supported by the Authority, authorizes the collection of a transition charge for generation when a consumer-owned utility opens its service area to competition and participates in the independent transmission system established by the legislation. The Bill also mandates the collection of a public benefit charge from all electric utility customers in the state. Although these funds (approximately 2.85% of gross revenues) must be spent on renewable resources, conservation, research and development, or low income rate subsidies, the governing authority of each consumer-owned utility controls actual expenditures.

Nuclear spent fuel and waste disposal – Under the Nuclear Waste Policy Act, the Department of Energy (DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but the DOE has announced that such a repository now cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

Arizona Public Service (APS), the operating agent, has capacity in existing fuel storage pools at PVNGS which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of PVNGS through 2002, and believes it could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. The Authority currently estimates that it will incur $23.6 million (in 1998 dollars) over the life of PVNGS for its share of the costs related to the on-site interim storage of spent nuclear fuel. During fiscal 1999, the Authority expensed approximately $7 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned prior to fiscal 1999. The Authority began accruing for these costs in fiscal 1999 as a component of fuel expense as the fuel is burned. APS currently believes that spent fuel storage or disposal methods will be available for use by PVNGS to allow its continued operation beyond 2002.

The Price-Anderson Act (the "Act") requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to $8.9 billion per incident. Participants in the Palo Verde Nuclear Generating Station currently insure potential claims and liability through commercial insurance with a $200 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to $88 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million, per incident, per year. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $5.2 million, limited to payments of $591,000 per incident, per year.

Other legal matters – The Authority is involved in various legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position of the Authority or the respective separate projects.

NOTE 6: Subsequent Event (Unaudited)

On October 17, 2000, an agreement was reached on the principles of a new long-term fuel sourcing and pricing plan between the participants of SJGS and its coal supplier. The agreement authorizes the supplier to develop an underground longwall mine to replace production from two existing surface mines. To amend the contract, the Authority is required to make a $10.3 million payment in 2003. As a result, during fiscal 2001, the Authority will record an expense equal to the present value of this payment. The new underground mine will result in significantly reduced costs of coal supplied to SJGS through 2017, the term of the new contract.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SUPPLEMENTAL FINANCIAL INFORMATION
INDEX

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Debt Service Fund	Debt Service Reserve Fund	Decom-missioning Trust Fund	Deposit Installment	Deposit Reserve Installment	Escrow Account	General Reserve Account	Issue Account	Operating Account	Reserve & Contingency	Revenue Fund	Total
Balance at June 30, 1999	$ 49,204	$ 33,274	$ 65,759	$ 6,161	$ 999	$ 87,563	$ 62	$ 31,857	$ 29,325	$ 22,950	$ 5	$ 327,159
Additions:												
Investment earnings	525	2,069	3,925	23	55	–	3	892	1,457	1,333	72	10,354
Discount on investment purchases	1,273	–	36	83	–	–	–	529	232	258	11	2,422
Distribution of investment earnings	(1,777)	(2,069)	–	(106)	(54)	–	(3)	(1,413)	(1,689)	(1,509)	8,618	(2)
Revenue from power sales	–	–	–	–	–	–	–	–	–	–	183,314	183,314
Funds transferred for refundings	–	–	–	–	–	–	–	–	–	–	–	0
Distribution of revenues	33,977	–	8,004	–	–	–	110,211	–	36,695	3,083	(191,970)	0
Transfers to escrow for refundings	–	–	–	–	–	–	–	(38,088)	–	–	–	(38,088)
Transfer from escrow for principal and interest payments	108,222	–	–	–	–	–	–	9,551	–	–	–	117,773
Other	(4,078)	–	–	–	–	50,410	(110,211)	97,939	(288)	4,366	(50)	38,088
Total	138,142	–	11,965	–	1	50,410	–	69,410	36,407	7,531	(5)	313,861
Deductions:												
Construction expenditures	–	–	–	–	–	–	–	–	–	3,529	–	3,529
Operating expenditures	–	–	3	–	–	–	–	285	25,407	–	–	25,695
Fuel costs	–	–	–	–	–	–	–	–	8,587	–	–	8,587
Payment of principal	25,960	–	–	–	–	–	–	14,655	–	–	–	40,615
Interest paid – non-escrow	7,762	–	–	–	–	–	–	35,255	–	–	–	43,017
Premium and interest paid on investment purchases	10	–	42	–	–	–	–	1	–	–	–	53
Payment of principal and interest – escrow bonds	107,790	–	–	–	–	–	–	9,551	–	–	–	117,341
Total	141,522	–	45	–	–	–	–	59,747	33,994	3,529	–	238,837
Balance at June 30, 2000	$ 45,824	$ 33,274	$ 77,679	$ 6,161	$ 1,000	$ 137,973	$ 62	$ 41,520	$ 31,738	$ 26,952	$ –	$ 402,183

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,911 and $2,186 at June 30, 2000 and 1999, unrealized gain on investment of $6,564 and $5,510 at June 30, 2000 and 1999, and $86 and $98 held in the revolving fund at June 30, 2000 and 1999, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Debt Service Fund	Debt Service Reserve Fund	Escrow Fund	General Reserve Fund	Issue Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 1999	$ 959	$ 11,126	$ 19,096	$ 81	$ 127,654	$ 7,183	$ –	$ 166,099
Additions:								
Investment earnings	67	658	–	21	7,131	289	117	8,283
Distribution of investment earnings	(67)	(658)	–	(21)	(7,131)	(289)	8,166	–
Revenue from transmission sales	–	–	–	–	–	–	76,952	76,952
Distribution of revenue	–	–	–	414	76,370	8,448	(85,232)	–
Transfer from escrow for principal and interest payments	23,875	–	–	–	–	–	–	23,875
Transfer to escrow fund required by refunding bonds issuance	–	–	–	–	–	–	–	–
Gain on sale of investments	–	–	–	–	1,120	–	–	1,120
Bond proceeds	–	–	125,000	–	–	–	–	125,000
Other transfers	–	–	12,166	2,298	(16,568)	4,535	–	2,431
Total	23,875	–	137,166	2,712	60,922	12,983	3	237,661
Deductions:								
Operating expenses	–	–	–	–	–	13,386	–	13,386
Debt issue cost	–	–	–	–	2,057	–	–	2,057
Payment of principal	–	–	–	–	23,585	–	–	23,585
Interest paid	–	–	–	–	42,629	–	–	42,629
Payment of principal and interest on escrow bonds	23,875	–	–	–	–	–	–	23,875
Premium and interest paid on investment purchases	2	(5)	–	–	(6)	–	–	(9)
Other disbursements	–	–	141,458	–	11,383	–	–	152,841
Total	23,877	(5)	141,458	–	79,648	13,386	–	258,364
Balance at June 30, 2000	$ 957	$ 11,131	$ 14,804	$ 2,793	$ 108,928	$ 6,780	$ 3	$ 145,396

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $397 and $489 at June 30, 2000 and 1999, respectively, unrealized gain on investment of $8,050 and $7,815 at June 30, 2000 and 1999, respectively, and $38 held in the revolving fund at both June 30, 2000 and 1999.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	General Reserve Fund	Operating Fund	Total
Balance at June 30, 1999	$ 851	$ 3,084	$ 2,230	$ 1,388	$ 7,553
Additions:					
Investment earnings	30	154	111	59	354
Discount on investment purchases	–	–	–	1	1
Distribution of investment earnings	(30)	(154)	(111)	295	–
Revenue from power sales	–	–	–	1,951	1,951
Distribution of revenues	1,776	–	–	(1,776)	–
Miscellaneous transfers	331	–	–	(331)	–
Total	2,107	–	–	199	2,306
Deductions:					
Operating expenses	–	–	–	267	267
Payment of principal	580	–	–	–	580
Interest paid	1,529	–	–	–	1,529
Payment for defeasance of revenue bonds	–	–	–	–	–
Payment of principal and interest on escrow bonds	–	–	–	–	–
Premium and interest paid on investment purchases	–	–	–	–	–
Bond issue costs	–	–	–	–	–
Total	2,109	–	–	267	2,376
Balance at June 30, 2000	$ 849	$ 3,084	$ 2,230	$ 1,320	$ 7,483

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $57 and $71 at June 30, 2000 and 1999, unrealized loss on investment of $20 and $69 at June 30, 2000 and 1999, and $26 and $24 held in the revolving fund at June 30, 2000 and 1999, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Escrow Account	Operating Fund	Reserve & Contigency Fund	Revenue Fund	Surplus Fund	Total
Balance at June 30, 1999	$ 498	$ 4,942	$ 5,915	$ 13,440	$ 80	$ 865	$ –	$ 36	$ 25,776
Additions:									
Investment earnings	343	164	435	756	5	45	6	102	1,856
Distribution of investment earnings	–	569	(435)	–	–	(42)	8	(100)	–
Transmission revenue	–	–	–	–	–	–	7,287	–	7,287
Transfer of revenues	–	6,236	–	–	1,208	26	(7,467)	(3)	–
Other transfers	236	880	–	(868)	184	3	166	–	601
Total	579	7,849	–	(112)	1,397	32	–	(1)	9,744
Deductions:									
Construction expenditures	–	–	–	–	–	13	–	–	13
Operating expenses	–	–	–	–	1,310	–	–	–	1,310
Payment of principal	–	2,160	–	–	–	–	–	–	2,160
Interest paid	–	5,103	–	–	–	–	–	–	5,103
Premium and interest paid on investment purchases	–	1	–	113	–	–	–	–	114
Other disbursements	–	–	–	–	–	–	–	–	–
Total	–	7,264	–	113	1,310	13	–	–	8,700
Balance at June 30, 2000	$ 1,077	$ 5,527	$ 5,915	$ 13,215	$ 167	$ 884	$ –	$ 35	$ 26,820

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $315 and $683 at June 30, 2000 and 1999, unrealized gain (loss) on investment of $36 and ($40) at June 30, 2000 and 1999, and $14 and $12 held in the revolving fund at June 30, 2000 and 1999, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Escrow Account	Operating Fund	Reserve & Contigency Fund	Revenue Fund	Surplus Fund	Total
Balance at June 30, 1999	$ 993	$ 14,620	$ 16,267	$ 37,794	$ 100	$ 6,300	$ –	$ 84	$ 76,158
Additions:									
Investment earnings	1,022	589	1,196	2,129	6	97	14	292	5,345
Distribution of investment earnings	–	1,568	(1,196)	–	–	(96)	14	(290)	–
Transmission revenue	–	–	–	–	–	–	18,570	–	18,570
Distribution of revenues	–	17,340	–	–	1,383	48	(18,690)	(81)	–
Other transfers	–	2,474	–	(2,443)	–	–	92	–	123
Total	1,022	21,971	–	(314)	1,389	49	–	(79)	24,038
Deductions:									
Interest paid	–	15,568	–	–	–	–	–	–	15,568
Construction expenditures	–	–	–	–	–	–	–	–	–
Payment of principal	–	5,940	–	–	–	–	–	–	5,940
Premium and interest paid on investment purchases	–	–	–	289	–	–	–	–	289
Operating expenses	–	–	–	–	1,442	–	–	–	1,442
Total	–	21,508	–	289	1,442	–	–	–	23,239
Balance at June 30, 2000	$ 2,015	$ 15,083	$ 16,267	$ 37,191	$ 47	$ 6,349	$ –	$ 5	$ 76,957

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $1,043 and $1,989 at June 30, 2000 and 1999, unrealized loss on investment of $107 and $99 at June 30, 2000 and 1999, and $14 and $10 held in the revolving fund at June 30, 2000 and 1999, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MULTIPLE PROJECT FUND
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Proceeds Account	Debt Service Account	Earnings Account	Total
Balance at June 30, 1999	$ 247,727	$ –	$ 9,500	$ 257,227
Additions:				
Investment earnings	18,222	–	540	18,762
Transfer of investment earnings to earnings account	(18,208)	–	18,208	–
Transfer to debt service account	–	21,370	(21,730)	–
Total	14	21,370	(2,982)	18,762
Deductions:				
Interest paid	–	16,330	–	16,330
Payment of principal	–	5,400	–	5,400
Total	–	21,730	–	21,730
Balance at June 30, 2000	$ 247,741	$ –	$ 6,518	$ 254,259

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $9,344 and $9,450 at June 30, 2000 and 1999, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2000

(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Revenue Fund	Total
Balance at June 30, 1999	$ 121	$ 8,731	$ 18,016	$ 5,827	$ 7,458	$ –	$ 40,153
Additions:							
Investment earnings	3	89	287	276	217	53	925
Distribution of investment earnings	–	(283)	(1,067)	(415)	(422)	2,187	–
Discount on investment purchases	–	185	780	139	206	4	1,314
Revenue from power sales	–	–	–	–	–	57,412	57,412
Distribution of revenues	–	18,024	–	38,176	1,212	(57,412)	–
Other transfers	–	–	–	2,258	–	(2,242)	16
Total	3	18,015	–	40,434	1,213	2	59,667
Deductions:							
Administrative expenditures	124	–	–	39,416	1,649	–	41,189
Interest paid	–	11,196	–	–	–	–	11,196
Premium and interest on investment purchases	–	(7)	–	–	–	–	(7)
Principal payment	–	6,825	–	–	–	–	6,825
Total	124	18,014	–	39,416	1,649	–	59,203
Balance at June 30, 2000	$ –	$ 8,732	$ 18,016	$ 6,845	$ 7,022	$ 2	$ 40,617

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $93 and $204 at June 30, 2000 and 1999, unrealized gain on investment of $44 and $41 at June 30, 2000 and 1999, and $22 and $18 held in the revolving fund at June 30, 2000 and 1999, respectively.

City of Anaheim

Customers - Retail 108,075
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 1,028,333
Purchased 2,508,166
Total 3,536,499
Total Revenues (000s) $279,195
Operating Costs (000s) $225,701

City of Azusa

Customers Served 14,678
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 366,024
Sales
Retail 233,213
Wholesale 132,811
Total Revenues (000s) $30,118
Operating Costs (000s) $26,927

City of Banning

Customers Served 9,836
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 135,119
Total 135,119
Total Revenues (000s) $15,709
Operating Costs (000s) $15,828

City of Burbank

Customers Served 51,712
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 106,631
Purchased 1,068,006
Total 1,174,637
Total Revenues (000s) $109,252
Operating Costs (000s) $100,595

City of Colton

Customers Served 17,346
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 301,506
Total 301,506
Total Revenues (000s) $28,713
Operating Costs (000s) $29,742

City of Glendale

Customers Served 84,370
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 234,009
Purchased 965,833
Total 1,199,842
Total Revenues (000s) $139,027
Operating Costs (000s) $123,704

Imperial Irrigation District

Customers Served 95,066
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 1,038,774
Purchased 1,750,984
Total 2,789,758
Total Revenues (000s) $209,203
Operating Costs (000s) $189,132

Los Angeles Department of Water and Power

Customers Served 1,433,400
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 16,234,100
Purchased 14,810,026
Total 31,044,026
Total Revenues (000s) $2,396,137
Operating Costs (000s) $1,846,774

City of Pasadena

Customers Served 58,389
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 233,723
Purchased 1,126,135
Total 1,359,858
Total Revenues (000s) $178,834*
Operating Costs (000s) $131,706**

*Includes:
Other Non-Generating Revenue $130,696
Non-Operating Revenues ..... $ 8,008
**Includes:
Non-Operating Expenses $17,558

City of Riverside

Customers Served 93,147
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 341,991
Purchased 2,086,282
Total 2,428,273
Total Revenues (000s) $188,638
Operating Costs (000s) $177,775

City of Vernon

Customers Served 2,045
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 2,137
Purchased 1,219,833
Total 1,210,989
Total Revenues (000s) $62,613
Operating Costs (000s) $69,196

Southern California
Public Power Authority
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Website: www.scppa.org

PINNACLE WEST CAPITAL CORPORATION
ANNUAL REPORT 2000

ABOUT THE COVER AND THIS ANNUAL REPORT

This year, the company asked internationally-known artist Brad Holland to illustrate key concepts that have contributed to our success. These concepts include vision, shareholder value, competitive advantage and operational excellence.

C04

OUR BUSINESSES

	APS	Pinnacle West Energy	APS energy Services	SunCor	El Dorado Investment Company
Our Business	Arizona Public Service (APS) is Arizona's largest supplier of electricity. The business – made up of the transmission planning and operations, customer service, economic development, and pricing and regulatory departments – serves a rapidly growing market throughout Arizona.	Pinnacle West Energy* is Pinnacle West's competitive generation affiliate. Pinnacle West Energy is currently building and buying unregulated generation and generation-related assets in the western United States.	APS Energy Services is Pinnacle West's competitive retail energy services affiliate. APS Energy Services is providing energy in open markets, and energy efficiency services such as lighting and cooling efficiency for industrial and commercial customers in the West.	SunCor Development Company is a Phoenix-based real estate development company with a diverse range of projects in the Southwest. SunCor designs and builds many multifaceted projects including master-planned communities, commercial properties and golf properties.	El Dorado is a venture capital and investment firm that invests in and develops innovative companies offering energy-related technologies and services.
2000 – A Look Back	Managed volatile wholesale power market Reduced customer electric rates for sixth time in seven years Handled record volume – 3.3 million calls – in call center Delivered reliable power in one of the fastest growing regions of the country Completed largest construction workload in company history by putting 760 miles of wire in the air and ground	Palo Verde Nuclear Generating Station – ninth consecutive year as nation's number one power producer Achieved highest coal unit capacity factor – 83 percent – since 1993 Achieved highest ever production in megawatt-hours – 2.2 million – from gas/oil units Completed shortest refueling outages yet at Palo Verde Nuclear Generating Station – 31 days for Unit 3 and 33 days for Unit 2 Broke ground on two expansion projects in Arizona – 650 megawatts at West Phoenix Power Plant and more than 2,000 megawatts at Redhawk Power Plant	Actively shaped and influenced development of competitive markets in the West Became the first energy service provider to serve competitive electricity in APS and Salt River Project territories Signed largest energy services contracts in Arizona, with Arizona State University and University of Arizona Structured contract, signed customers, and began construction on largest district cooling services project in Arizona	Achieved record earnings of $11 million Completed first home and homesite sales at Coral Canyon in St. George, Utah; and Hidden Hills in Scottsdale, Ariz. Completed due diligence and set foundation for 1,800-acre community, StoneRidge in Prescott Valley, Ariz. Formed joint venture to develop high-profile Hayden Ferry Lakeside mixed-use project in Tempe, Ariz. Acquired majority interest in Club West Golf Club in Phoenix's Sonoran Hills	Achieved sixth consecutive year of profitability Paid cumulative dividends to Pinnacle West totalling $65 million over six-year period
2001 and Beyond	Grow revenue and earnings while improving margins through cost control Add customers while managing issues related to rapid growth Utilize new technology to improve service, productivity and efficiency Provide value to retail customers through continued price reductions	Continue disciplined expansion in high-growth western areas Combine operational excellence with profitability focus Explore partnerships with strategic advantages Tailor operating incentives to market opportunities Develop a balanced generation portfolio	Continue influencing development of competitive retail markets Grow revenue and earnings Adapt to changing markets at a faster pace than the competition Complete construction of downtown Phoenix district cooling plant in summer 2001	Continue new product design and efficiency improvements in homebuilding division Diversify property portfolio by increasing income-property holdings Achieve geographic diversification by increasing sales in New Mexico and Utah Remain committed to high quality developments and customer satisfaction	Convert high-tech venture capital investments to cash Focus on energy-related investments

** Includes APS' existing generation to represent our total generation group*


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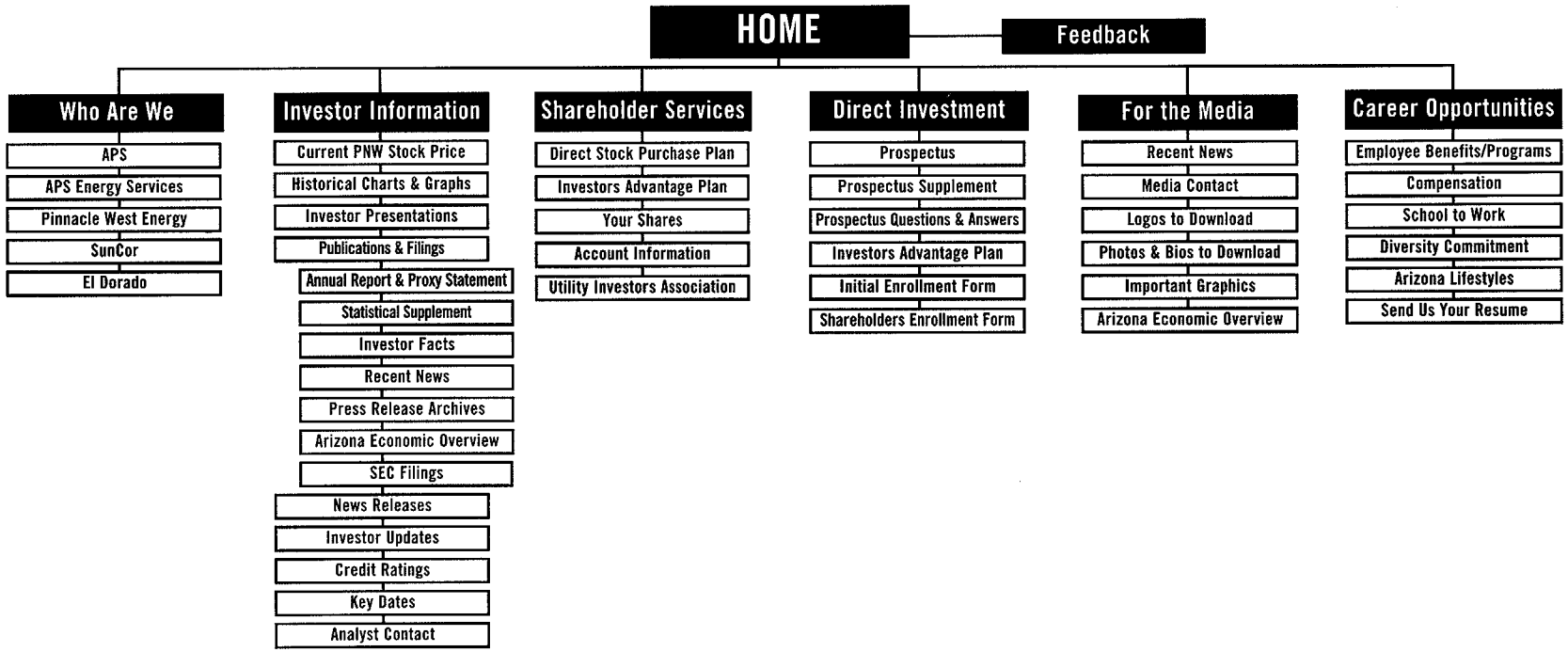
www.pinnaclewest.com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PINNACLE WEST *is a Phoenix-based company with consolidated assets of $7.1 billion and annual revenues of $3.7 billion. Through our subsidiaries, we generate, sell and deliver electricity and energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate properties.*

FINANCIAL HIGHLIGHTS

(dollars in thousands, except per share amounts)	*2000*	*1999*	*1998*	Selected Growth Rates *2000 vs. 1999*	*1999 vs. 1998*
INCOME HIGHLIGHTS					
Operating revenues	$ 3,690,175	$ 2,423,353	$ 2,130,586	52.3%	13.7%
Income from continuing operations	$ 302,332	$ 269,772	$ 242,892	12.1%	11.1%
BALANCE SHEET HIGHLIGHTS					
Total assets	$ 7,149,151	$ 6,608,506	$ 6,824,546	8.2%	(3.2%)
Common stock equity	$ 2,382,714	$ 2,205,733	$ 2,163,351	8.0%	2.0%
PER SHARE HIGHLIGHTS					
Earnings per share from continuing operations – diluted	$ 3.56	$ 3.17	$ 2.85	12.3%	11.2%
Dividends declared per share	$ 1.425	$ 1.325	$ 1.225	7.5%	8.2%
Book value per share – year-end	$ 28.09	$ 26.00	$ 25.50	8.0%	2.0%
STOCK PERFORMANCE					
Stock price per share – year-end	$ 47 5/8	$ 30 9/16	$ 42 3/8		
Stock price appreciation	55.8%	(27.9%)	—		
Total return	62.2%	(25.1%)	2.8%		
Market capitalization – year-end	$ 4,039,788	$ 2,592,462	$ 3,594,457	55.8%	(27.9%)

TO OUR SHAREHOLDERS:

Pinnacle West had a great year in 2000. We produced excellent results under conditions which tested our workforce, our knowledge of the western grid, our resiliency to market fluctuations and our ability to anticipate and act. We met these challenges and our shareholders were rewarded. Sighting on the future remains key. However, as this year's cover suggests, predictive tools have limitations, even those with wide-angle lenses. This is why we insist on preparing for a variety of outcomes.

REAL EARNINGS, REAL ASSETS, REAL GROWTH

In the year 2000, power supplies tightened in the West, and wholesale power prices soared. Natural gas also reached new levels of price and volatility. These conditions collapsed the recently created California energy market, and a new structure is slowly evolving. Anticipating the ultimate resolution to this situation is beyond mere planning tools and expertise.

While these events swirled around us, we increased earnings by 12 percent while lowering customer prices for the sixth time in seven years. Starting in 1994, APS has decreased electric prices a total of 11.4 percent. While others in the West are reacting to crises, we're preparing for the next round of competition, in both the market and regulatory arenas, to provide future value to our shareholders. That's a competitive advantage.

Last year, APS experienced strong customer growth of 3.7 percent, about three times the national average. We also increased the number of customers served per employee, as we did throughout the 1990s when we doubled that number.

Not only are we adding more customers, our customers are more satisfied. In 2000, our customer satisfaction rating rose significantly, and we expect to continue to improve in 2001.

Rapid customer growth and high prices on the wholesale power market didn't stop us from delivering reliable power – and we're working to make sure it never does. We've kept pace with growth and market volatility by planning for and building the distribution and transmission infrastructure needed to serve our customers.

On the generation side, we're meeting new demand growth through our unregulated subsidiary, Pinnacle West Energy. We broke ground on two major generation expansion projects and produced another year of outstanding performance from our fossil and nuclear units.

Increasingly efficient performance from our power plants, due to the employees who run them, helped us meet high demand from our customers, and allowed us to participate in the wholesale market.

Our cash flow is among the strongest in the industry – based on per share cash from operations – and allows us the flexibility to expand generation. Over the next five years, we will be financing a majority of our growth from internal sources and plan to maintain investment-grade credit ratings for our corporate-level securities.

Although the current power market is volatile and the regulatory environment is unsettled, we're confident of who we are, where we are, and where we're headed.

William J. Post, *Chairman*

A FOCUS ON RISK MANAGEMENT

Last year's results prove we can achieve the agility demanded by our changing industry. That means emphasizing the importance of risk management for the entire corporate enterprise.

Our approach to risk management includes buying and selling power, but there's more to it. We limit our risks by emphasizing and strengthening our areas of expertise while pursuing growth opportunities that make sense.

At the holding company level, our power trading and marketing group is adeptly balancing the market risks between delivery and supply. Unlike many utilities, we have not had a "fuel adjustment clause" to manage fuel risk since 1988. We've turned this apparent negative into a positive by fine-tuning the risk management skills needed to thrive in a competitive marketplace.

Our subsidiaries have been doing business in the West for a long time. We know the area, we know the people, we know the challenges. As we said last year, there are places we won't go. Instead, we will use our foundation and our planning capability to capture the benefits of customer growth on all sides of our business.

GROWING AND BUILDING

With APS, our regulated subsidiary, we will increasingly capture the benefits of customer growth with a regulatory Settlement Agreement that allows us to meet future customer needs while benefiting our shareholders.

We focus intensely on the total business, which means generation as much as delivery. As new units at our West Phoenix and Redhawk plants are energized and we build or buy additional generation, we expect Pinnacle West Energy to be a source of earnings growth for our company.

Pinnacle West Energy has received approvals to build and is already in various stages of construction for 2,800 megawatts of new gas-fired capacity. We remain committed to growing our generation business, and capturing the advantages of our geographic location. But there are limits to the price we'll pay for growth. We're striving to balance new capacity with anticipated load growth, while maintaining a solid capital structure.

We are moving forward with plans to transfer generation assets and employees from APS to Pinnacle West Energy. As authorized by the Settlement Agreement, we will transfer our existing generation operations to Pinnacle West Energy by the end of 2002.

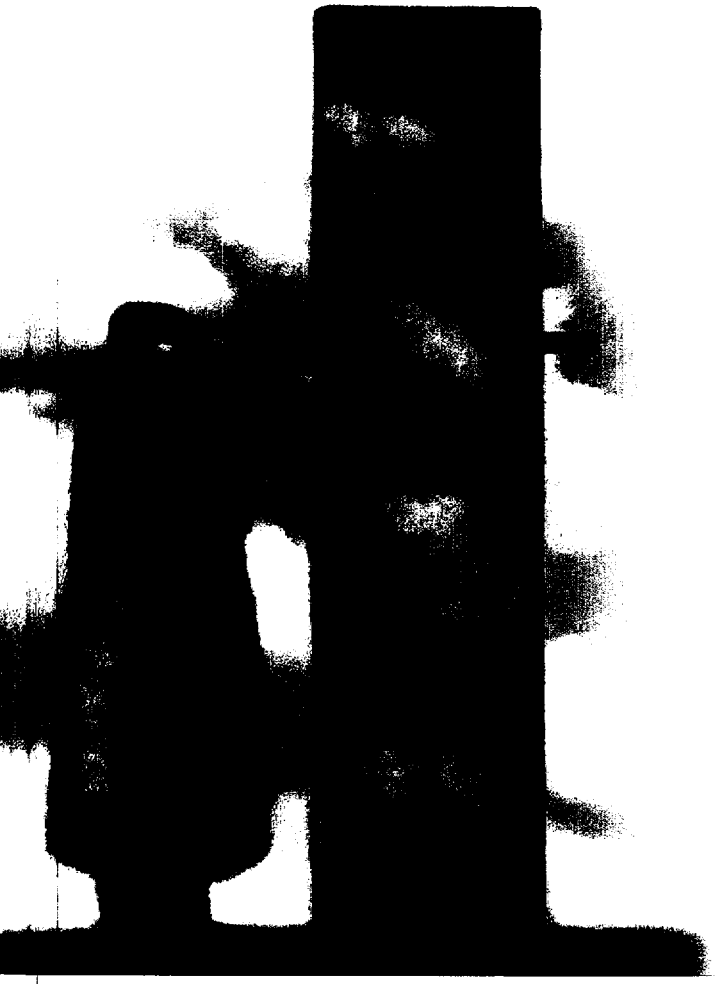
APS Energy Services, our competitive sales subsidiary, responds to opportunities to provide energy services

OUR SUCCESS LAST YEAR STEMS FROM OUR FIRM CONVICTION THAT WE MUST REMAIN NIMBLE IN OUR RESPONSE TO ALL EVENTS – EXPECTED AND UNEXPECTED.

and commodity energy to customers in Arizona, California and other Western states. APS Energy Services focuses on opportunities to provide these services while maintaining a positive gross margin.

SunCor, our real estate development subsidiary, increased its net income by 90 percent in 2000. SunCor has developed a number of renowned master-planned communities and golf properties in Arizona, New Mexico and Utah.

El Dorado, our investment subsidiary, had a standout performance in 1999 when it brought in strong returns, but last year's performance reflects the fading of tech stocks. El Dorado's future investments will focus on opportunities in the energy sector.

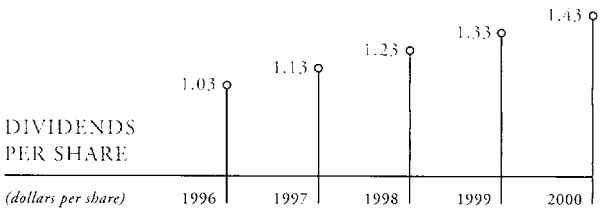


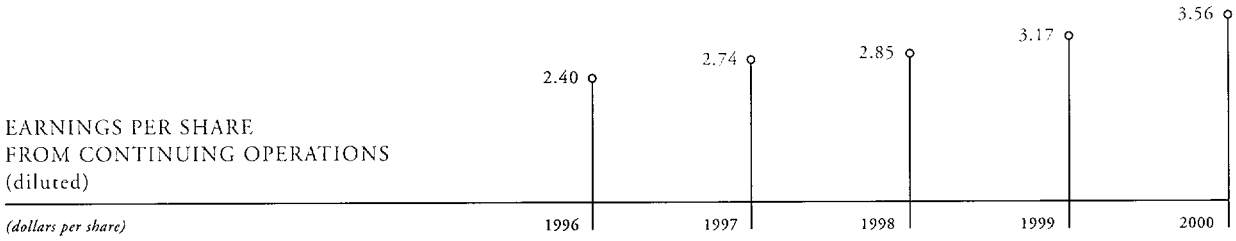
All our businesses are positioned to build long-term shareholder value. For Pinnacle West, this means continuing to outperform our peers. We are in the top quartile of utility companies in shareholder return over the last five-year period, and our goal is to be there for the long term. This proves just how serious we are about shareholder value.

We've averaged earnings increases from continuing operations of 9.4 percent per year for the last five years. That puts us in the top 10 percent of U.S. electric utilities. Over time this long-term earnings growth is reflected in our stock price, which considerably outperformed the S&P 500 Index last year and has outperformed the utility index over the last one- and five-year periods.

ANOTHER LOOK AT REGULATION

In Arizona, we talked and worked with our customers, legislators and regulators to create a workable competitive transition plan. It's working. However, we can't ignore the interconnected nature of the





western electric grid. As one of the largest machines made by man, it has inherent characteristics that are unforgiving and demanding. It must serve markets that require reliable energy at low cost, all under the umbrella of a growing patchwork of regulation.

In California, electric outages have rebalanced priorities. Short-term solutions will have long-term impact, and political objectives can stretch scientific reality only so far. Most important, changes in this industry will not be tolerated if they significantly reduce reliability or increase prices.

The California crisis has validated our approach to competition: Electric prices are important. Retail customer choice may not be as vital as the "obligation to serve." Customer reliability is our job, and managing risk for our shareholders is fundamental to solid performance.

If deregulation is dead in the West, it's in part because it never started. However, the injection, and I believe growth, of competition is real and the playing field will be in both the market and regulatory arenas. Playing this long-term, multi-faceted and regional game is something we're equipped and ready to do. And it's how we intend to produce superior results for our shareholders.

OUR EXPECTATIONS

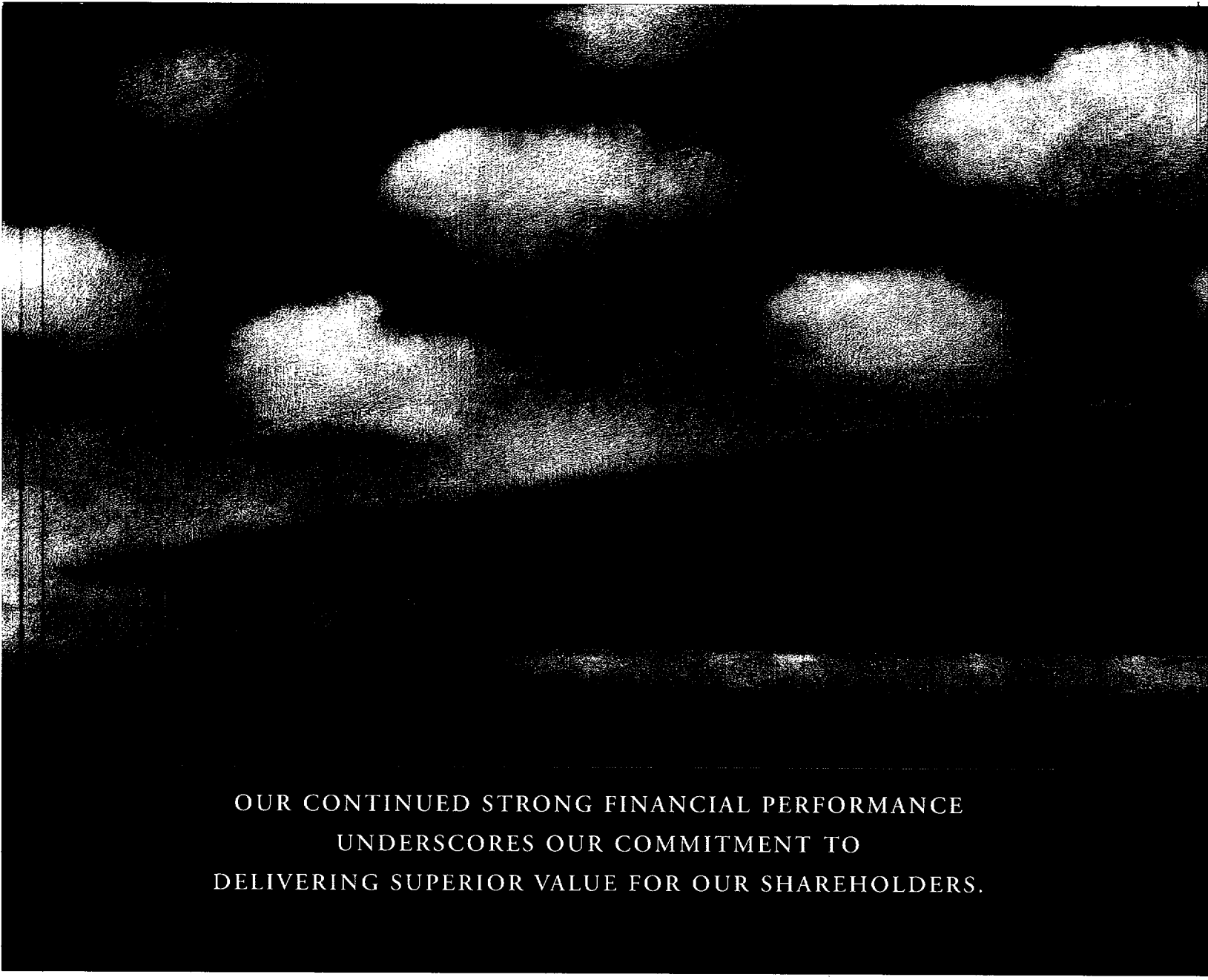
After our first full year with a new corporate structure and a new regulatory environment, Pinnacle West is a strong company – operationally, strategically and financially.

Our future rests with the men and women of our company who have worked hard to achieve success in the midst of uncertainty. We've cleared several hurdles without breaking stride. Together, we face more uncertainty, more change and more opportunity. I look forward to it.

We're committed to creating customer satisfaction and shareholder value. If we don't meet our customers' expectations, that's our fault. It's our job to respond to changing markets, find future opportunities, and continue to make more money for our shareholders.

I'm convinced we're more than up to the challenge.

William J. Post, *Chairman*



FINANCIAL PERFORMANCE

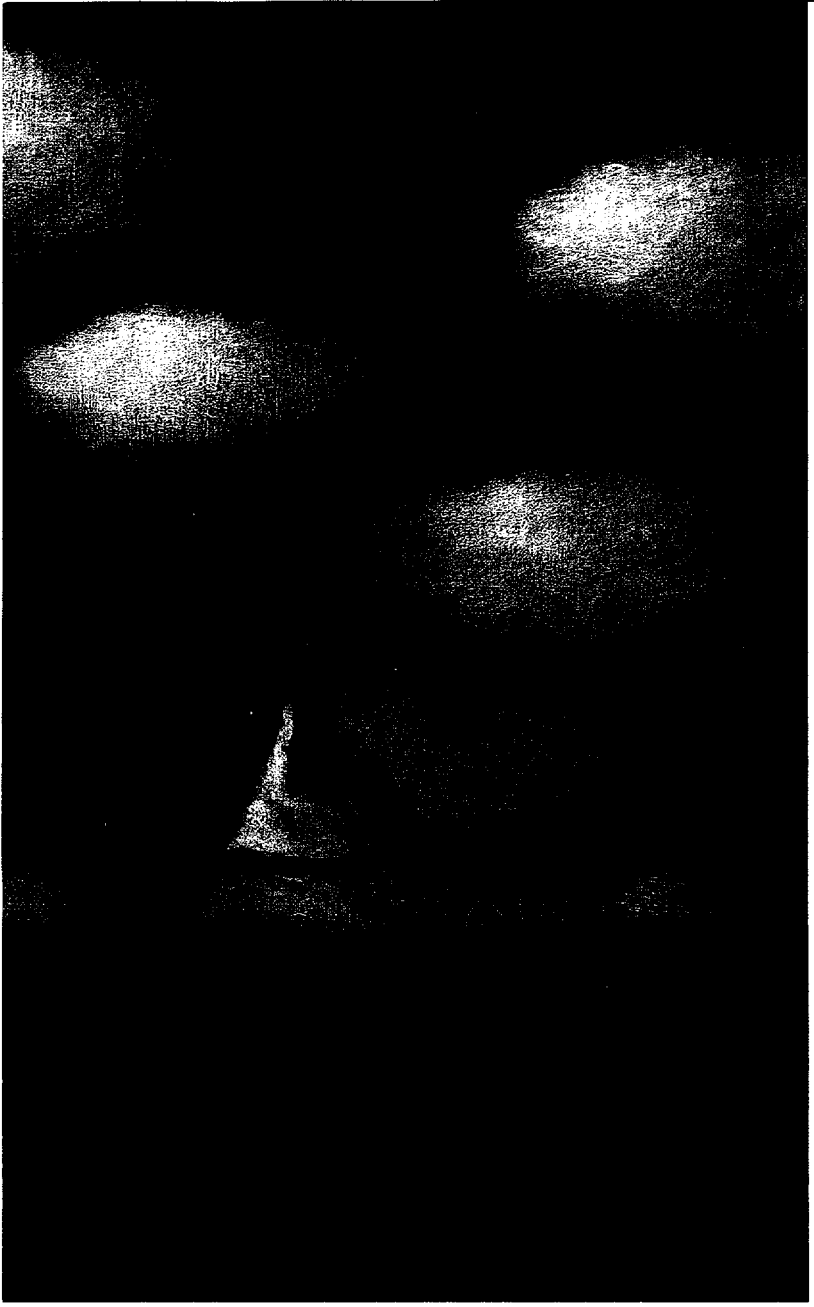
Coming off a very strong financial performance in 1999, our expectations were high for 2000. We weren't disappointed.

In 2000, during a time when the nation's economy was slowing, the Pinnacle West stock price increased 56 percent and earnings from continuing operations per diluted share grew 12 percent.

We also further differentiated ourselves by increasing our indicated annual dividend to $1.50 per share. This represented a 7 percent increase in a year when the electric utility industry posted an overall average *decrease* of 4 percent.

Income from continuing operations in 2000 increased to $302.3 million or $3.56 per diluted share of common stock. These results compare with $269.8 million or $3.17 per diluted share in 1999 – a good year in its own right. These results were accomplished largely through increased sales activity in retail and western U.S. wholesale power markets.

Improved results from our real estate operations also added to our earnings growth. These positive factors



more than offset the completion of the amortization of our investment tax credits at the end of 1999, the effects of electricity price decreases and lower earnings from El Dorado.

The five-year span of 1996 through 2000 was one of steady earnings growth for Pinnacle West.

- Total return on Pinnacle West stock for the five-year period was 96 percent (an average of 14.4 percent a year) compared with an overall industry five-year return of 79 percent (12.4 percent annually on average).

- Our earnings from continuing operations per diluted share grew an average of 9.4 percent a year over the five-year period, ranking in the top 10 percent of electric utilities nationwide.

- The five-year growth of our dividend ranked second among U.S. electric utilities that paid dividends throughout the period – averaging 8.4 percent a year compared with an average annual decrease of one percent for the industry.

Looking forward, we have opportunities to build upon our earnings growth. However, volatile western U.S. energy markets and associated market restructuring could impact future energy costs and prices. With this in mind, we will continue to focus on managing the risks related to our energy needs.

While the financial future cannot be predicted, we feel confident we can achieve our goal of providing long-term superior total returns for our shareholders through a combination of earnings and dividend growth while staying financially strong and flexible.

REGULATORY AND INDUSTRY ISSUES

Our approach to industry regulation is essentially based on two questions – Is it good for customers? Is it good for shareholders?

In 1999, we negotiated a Settlement Agreement with the Arizona Corporation Commission (ACC) that carefully balances customer and shareholder interests during a period of transition to retail competition. Under this agreement, all customers can choose their retail energy supplier beginning in 2001. Customers who remain with APS will receive a series of price reductions totalling 7.5 percent through 2003.

Our shareholders also benefit from the 1999 Settlement Agreement which provides performance-based ratemaking for APS – our electricity delivery

IN 2000, THE COMPANY DISTINGUISHED ITSELF BOTH FINANCIALLY AND OPERATIONALLY.

company – while allowing us to retain and add to our generation portfolio in the West through Pinnacle West Energy.

The merits of the existing APS Settlement Agreement are substantial and have allowed us to maintain high levels of reliability for our customers, while providing benefits of competition to all APS customers in the form of lower prices.

The agreement allows for a responsible transition to competition that balances the interests of customers and shareholders. However, there are outstanding legal challenges to various aspects of the ACC competition rules and the 1999 Settlement Agreement. We do not believe these challenges will affect our Settlement Agreement with the ACC.

Depending on how the energy situation in California develops, Arizona's deregulated environment may be further impacted at the national level by the Federal Energy Regulatory Commission (FERC) or Congress. Any actions that foster robust and liquid wholesale markets in the West should benefit Arizona electric customers and allow Pinnacle West to continue successfully pursuing our competitive business strategies.

Formation of Regional Transmission Organizations (RTOs) – which the FERC has strongly encouraged but has not mandated – will affect wholesale generation transactions and transmission. APS and other utilities in the Southwest have submitted plans to FERC for an RTO known as Desert Star. While a number of issues remain, Desert Star participants have agreed on fundamental concepts. The current and planned market structures would allow long-term purchase agreements and would not force utilities to buy through a state-run power exchange.

DELIVERY AND GENERATION

Our strategy for delivery and generation is simple yet aggressive. We will continue to serve our regulated customers through our electric energy supplier, APS, and provide electric power to our customers primarily from our own generation.

Our strategy involves managing our enterprise-wide energy risk through our marketing and trading group. This group is a fulcrum for our businesses, helping to optimize the results of delivery and generation by purchasing wholesale power to serve our retail electricity customers, and selling available output from our generating facilities and other energy resources.

Our marketing and trading group's performance in 2000 was integral to our company's earnings growth. Our electric revenues grew by approximately $1.2 billion in 2000 – a 54 percent increase over 1999. Our fuel and purchase power costs also increased dramatically – rising to $1 billion. The marketing and trading group displayed foresight, versatility and a unique ability to manage this growth.

The energy needs of our delivery business are currently met through a combination of our existing generation facilities and long-term purchase power agreements. However, when the electricity demands

of our customers exceed our long-term resources, particularly during the hot summer months, marketing and trading supplements our existing resources with short-term wholesale purchases and hedging techniques.

These hedging techniques ensure we have enough energy for our customers, and limit our exposure to volatile wholesale prices. In mid-2000, our hedging efforts allowed us to manage the costs of power and natural gas supplies during times when other electric utilities in the West suffered from high and volatile prices. Similar hedges have been substantially put in place for the summers of 2001 through 2003.

This group also manages the risks related to our wholesale buying and selling counterparties. As the California energy crisis developed, careful scrutiny of counterparties helped us control our exposure to problems that affected others in that market.

Delivery

In 2000, for the sixth time in seven years, APS reduced prices to customers. By 2004, residential and small business electric prices will have decreased 16 percent over a 10-year period.

While steadily reducing our prices, we've also set ourselves apart by maintaining high levels of reliability and avoiding rolling blackouts like those that plagued northern California in late 2000 and early 2001. We've been significantly enhancing our transmission and distribution infrastructure while responding to the unprecedented customer growth of the past decade.

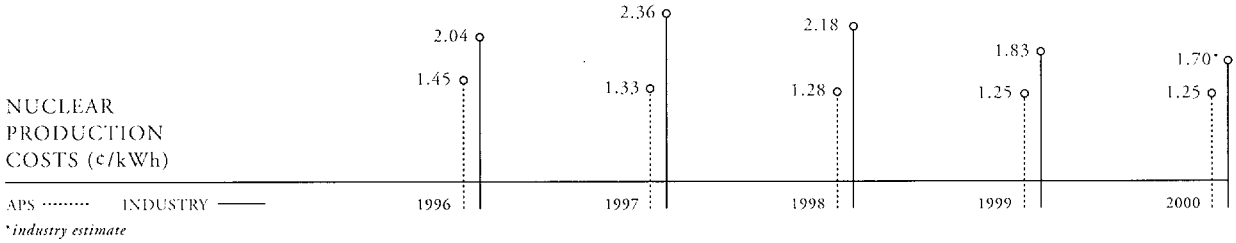
Over the last 10 years, APS has added more than 240,000 new customers, an average growth rate of 3.5 percent. Last year we grew by 3.7 percent, nearly three times the national average. To meet the growing energy needs of our customers, we're making significant investments in our delivery system to ensure a safe, reliable supply of energy.

MANAGING THE RISKS OF A VOLATILE POWER MARKET HAS BECOME CENTRAL TO THE SUCCESS OF OUR COMPANY. WE MANAGE THESE RISKS BY REMAINING AGILE AND PLANNING FOR MULTIPLE OUTCOMES.

Throughout our delivery company, we have formed teams to find specific ways to improve our service and customer satisfaction. This effort is paying off with improved customer satisfaction ratings.

We have continued to increase our profitability by serving more customers more efficiently through new technology. For example: our state-of-the-art call center has won multiple awards and was recently ranked in the top three among utilities included in a nationwide, independent benchmarking study.

We also can serve customers better and more cost effectively through our Internet site, aps.com. This recently redesigned site has been made simpler to use and more convenient by asking customers how they want to do business with APS. We listened, and now our customers can pay bills, check the status of their accounts and keep up with the latest industry information online.



Generation

Our generation group distinguished itself last year by setting new standards in productivity and efficiency. We produced more energy from our power plants than ever before – a total of 24.1 million megawatt-hours – 7.3 percent more than the previous record. Our fossil generation fleet achieved its best capacity factor ever, including the greatest annual capacity factor from our smaller gas and oil units. Overall base-load capacity factor was 87 percent, with an 83 percent rating for the coal units and 93 percent for our three Palo Verde nuclear units.

The last decade was one of ongoing performance improvement at Palo Verde. Few achievements were more impressive than the steady reduction in average refueling time.

From 1990 to 1999, the average refueling time decreased from 151 days to 37. Last year we became even more efficient, as average refueling time was decreased another 15.6 percent to 32 days.

Our outstanding generation performance and productivity enabled us to maintain reliability in 2000, protecting our company from the potential of tight power supplies and high wholesale prices. Extra generation supply – produced for the most part from our peaking units – allowed our marketing and trading group to sell a significant amount of energy at favorable wholesale prices.

UNREGULATED BUSINESSES

Pinnacle West Energy

Unlike many utility companies that sold their power stations, we embrace generation as a core business. Last year – in its first full year as our competitive generation subsidiary – Pinnacle West Energy began construction on projects that will eventually add nearly 2,800 megawatts of new gas-fired capacity, and began exploring the feasibility of underground gas storage.

The 2,800 megawatts of new capacity consists of six highly efficient combined-cycle units at two sites. These include two new units at our existing West Phoenix plant. The 120-megawatt West Phoenix

AT PINNACLE WEST, WE AIM TO STAND APART FROM OUR INDUSTRY PEERS. WE'VE DONE SO WITH RECORD CUSTOMER GROWTH, EARNINGS AND PRODUCTIVITY.

Unit 4 is scheduled to meet an in-service date of June 2001. The 530-megawatt West Phoenix Unit 5 is scheduled to begin operation in mid-2003.

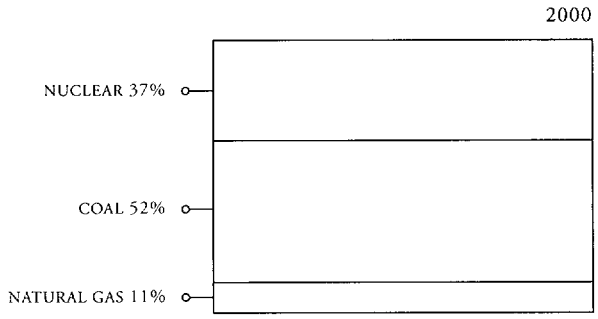
The new Redhawk power plant, located near our Palo Verde Nuclear Generating Station and its region-serving transmission switchyard, is expected to consist of four 530-megawatt units. Construction began on Units 1 and 2 in December of 2000, and commercial operation is scheduled for mid-2002. We received the first combustion turbine for this project in the first quarter of 2001 and expect to energize the new switchyard near the end of the year.

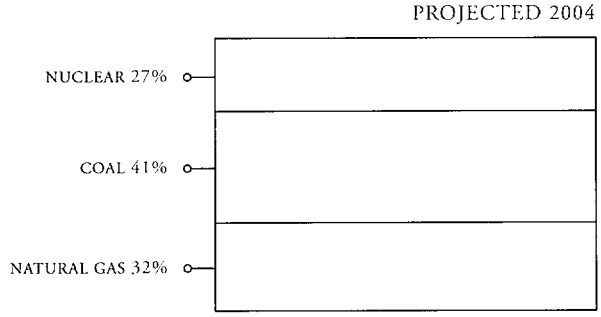
Pinnacle West Energy is exploring the feasibility of developing an underground natural gas storage facility west of Phoenix. Test drilling to confirm geological studies is under way. Such a facility could provide protection from price spikes and supply interruptions for our new plants. This facility could also provide a business opportunity in supplying gas storage capacity to other companies.

By summer 2001, we will add more than 500 megawatts of generating capacity from our new West Phoenix unit as well as some leased portable units and the reactivation of existing units. A portion of this added capacity has been several years in the planning, but some is being added as a precaution against unforeseen increases in demand. As we expand our gas-fired capacity, we will achieve a desirable balance among the three major fuels – nuclear, coal and natural gas.

By completing new units at West Phoenix and Redhawk and building or buying additional generation, we expect Pinnacle West Energy to be a major earnings growth engine.

GENERATION MIX



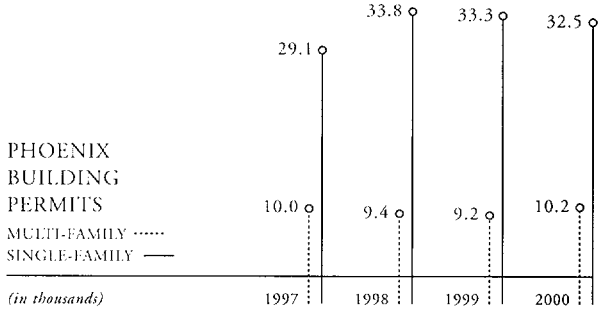


CREATING A COMPETITIVE ADVANTAGE, SATISFYING OUR CUSTOMERS AND PRODUCING SHAREHOLDER VALUE ARE THE ULTIMATE GOALS OF ALL PINNACLE WEST BUSINESSES.

APS Energy Services

This subsidiary distinguishes itself from other energy services companies with its emphasis on profitable transactions and its agility when responding to market conditions. APS Energy Services sells commodity energy and energy-related products and services designed to solve the customer's business challenges and tailored to each customer's individual demands and energy use patterns. We expect positive gross margins in all customer relationships, which means we do not attempt to buy market share and will leave markets that are not profitable.

APS Energy Services seeks a workable, competitive market wherever it does business, so one of its major thrusts is shaping market rules so customers can be offered real choices. Among the Pinnacle West family of companies, APS Energy Services is most concerned with competitive and strategic positioning and advocacy of a competitive market. This provides market opportunity not only for APS Energy Services, but also for Pinnacle West Energy because it profits from more competitive markets as well.



SunCor

SunCor's diversification into four development areas – master-planned communities, homebuilding, golf courses and commercial development – makes it unique. Where most development companies concentrate on only a few types of development, SunCor can respond to market changes by shifting concentration among four areas.

SunCor's strategy is simple – develop and sell its existing properties supplemented by selected new development opportunities. This enables the company to capture profit all along the value chain. Last year the company generated $11 million in earnings, an increase of $5 million over 1999.

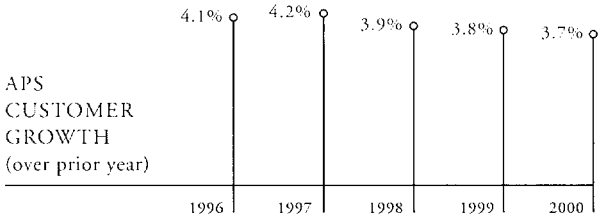
El Dorado Investment

El Dorado, our investment subsidiary, is in the process of harvesting its venture capital investments – which are primarily related to technology – as quickly as prudent. Through its investment in a technology venture capital limited partnership, El Dorado recorded significant "paper" gains in late 1999 and early 2000, but was impacted by the quick decline of the technology sector in mid-to-late 2000. Our investment in this partnership was approximately $7 million at the end of 2000. Any future investments by this subsidiary are expected to focus on opportunities related to the energy business.

COMMITMENT, CUSTOMERS, COMMUNITY

Whatever the eventual short-term resolution of the energy problems in California and other areas of the West, it is clear that major investment in generation and transmission infrastructure will be required. In Arizona, where customer growth has been three to four times the national average, we already have embarked on new investment in both areas.

As we invest in the electric infrastructure that serves our communities, we also invest in the communities themselves. Pinnacle West and its subsidiaries embrace the theory that good corporate citizenship is essential to business success. We want the areas we serve to grow, prosper and experience greater success for having Pinnacle West as a community partner.



We are a recognized industry leader by an independent, third party evaluation for our superior environmental performance. Among the utility companies listed in the S&P 500, Pinnacle West ranked in the top 10 percent for environmental performance. Living and working in Arizona, with its sensitive desert environment, we have built our environmental awareness and commitment along with our customer base.

People count on us every day. They rely on the power we produce and deliver, and they count on us to be a good neighbor. That's how we like it. For 115 years, community and industry leadership are goals that have gone hand in hand for our company. That's a tradition we intend to continue.

2000 FINANCIAL STATEMENTS

SELECTED CONSOLIDATED DATA

(dollars in thousands, except per share amounts)	2000	1999	1998	1997	1996
OPERATING RESULTS					
Operating revenues					
Electric	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272
Real estate	158,365	130,169	124,188	116,473	99,488
Income from continuing operations	$ 302,332	$ 269,772	$ 242,892	$ 235,856	$ 211,059(a)
Discontinued operations	—	38,000(d)	—	—	(9,539)(b)
Extraordinary charge – net of income tax	—	(139,885)(e)	—	—	(20,340)(c)
Net income	$ 302,332	$ 167,887	$ 242,892	$ 235,856	$ 181,180
COMMON STOCK DATA					
Book value per share – year-end	$ 28.09	$ 26.00	$ 25.50	$ 23.90	$ 22.51
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 3.57	$ 3.18	$ 2.87	$ 2.76	$ 2.41(a)
Discontinued operations	—	0.45	—	—	(0.11)
Extraordinary charge	—	(1.65)	—	—	(0.23)
Net income – basic	$ 3.57	$ 1.98	$ 2.87	$ 2.76	$ 2.07
Continuing operations – diluted	$ 3.56	$ 3.17	$ 2.85	$ 2.74	$ 2.40(a)
Net income – diluted	$ 3.56	$ 1.97	$ 2.85	$ 2.74	$ 2.06
Dividends declared per share	$ 1.425	$ 1.325	$ 1.225	$ 1.125	$ 1.025
Indicated annual dividend rate – year-end	$ 1.50	$ 1.40	$ 1.30	$ 1.20	$ 1.10
Average common shares outstanding – basic	84,732,544	84,717,135	84,774,218	85,502,909	87,441,515
Average common shares outstanding – diluted	84,935,282	85,008,527	85,345,946	86,022,709	88,021,920
TOTAL ASSETS	$ 7,149,151	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 1,955,083	$ 2,206,052	$ 2,048,961	$ 2,244,248	$ 2,372,113
Other liabilities	2,811,354	2,196,721	2,516,993	2,407,572	2,428,180
	4,766,437	4,402,773	4,565,954	4,651,820	4,800,293
Minority interests					
Non-redeemable preferred stock of APS	—	—	85,840	142,051	165,673
Redeemable preferred stock of APS	—	—	9,401	29,110	53,000
Common stock equity	2,382,714	2,205,733	2,163,351	2,027,436	1,970,323
Total liabilities and equity	$ 7,149,151	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289

(a) Includes an after-tax charge of $18.9 million ($0.22 per share) for a voluntary severance program and about $12 million ($0.13 per share) of income tax benefits related to capital loss carryforwards.
(b) Charges, net of tax, associated with the settlement of a legal matter related to MeraBank, A Federal Savings Bank.
(c) Charges associated with the repayment or refinancing of the parent company's high-coupon debt.
(d) Tax benefit stemming from the resolution of income tax matters related to MeraBank, A Federal Savings Bank.
(e) Charges associated with a regulatory disallowance.

(dollars in thousands, except per share amounts)	*2000*	*1999*	*1998*	*1997*	*1996*
ELECTRIC OPERATING REVENUES					
Residential	$ 880,468	$ 805,173	$ 766,378	$ 746,937	$ 721,877
Commercial	771,909	733,038	699,016	687,988	678,130
Industrial	146,088	159,329	172,296	164,696	162,324
Irrigation	6,498	7,374	7,288	8,706	9,448
Other	10,719	11,708	10,644	11,842	13,078
Total retail	1,815,682	1,716,622	1,655,622	1,620,169	1,584,857
Wholesale	1,594,541	506,877	300,698	226,828	98,560
Transmission for others	14,766	11,348	11,058	10,295	10,240
Miscellaneous services	106,821	58,337	39,020	21,261	24,615
Total electric operating revenues	$ 3,531,810	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272
ELECTRIC SALES (MWh)					
Residential	9,780,680	8,774,822	8,310,689	7,970,309	7,541,440
Commercial	10,057,707	9,543,853	8,697,397	8,524,882	8,233,762
Industrial	2,511,292	2,561,349	3,279,430	3,123,283	3,039,357
Irrigation	87,073	99,669	84,640	112,363	121,775
Other	97,772	94,877	90,927	86,090	84,362
Total retail	22,534,524	21,074,570	20,463,083	19,816,927	19,020,696
Wholesale	21,997,357	15,693,834	10,317,391	9,233,573	3,367,234
Total electric sales	44,531,881	36,768,404	30,780,474	29,050,500	22,387,930
ELECTRIC CUSTOMERS -END OF YEAR					
Residential	762,574	735,359	708,215	680,478	654,602
Commercial	90,273	86,707	83,506	81,246	78,178
Industrial	3,286	3,183	3,084	3,192	3,055
Irrigation	371	754	710	764	841
Other	965	932	895	851	828
Total retail	857,469	826,935	796,410	766,531	737,504
Wholesale	67	73	67	50	48
Total electric customers	857,536	827,008	796,477	766,581	737,552

See "Financial Review" on pages 20-29 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS STOCK SYMBOL: PNW

2000	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE	*1999*	HIGH	LOW	CLOSE	DIVIDENDS PER SHARE(a)
1st Quarter	$ 32.31	$ 26.25	$ 28.19	$ 0.350	1st Quarter	$ 43.38	$ 35.94	$ 36.38	$ 0.325
2nd Quarter	35.88	27.88	33.88	0.350	2nd Quarter	42.94	36.25	40.25	0.650
3rd Quarter	51.31	33.81	50.89	0.350	3rd Quarter	41.31	34.69	36.38	—
4th Quarter	52.22	40.89	47.63	0.375	4th Quarter	38.13	30.19	30.56	0.350

(a) Dividends for the 3rd quarter of 1999 were declared in June 1999.

FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: Arizona Public Service Company (APS), Pinnacle West Energy Corporation (Pinnacle West Energy), APS Energy Services Company, Inc. (APS Energy Services), SunCor Development Company (SunCor), and El Dorado Investment Company (El Dorado) including:

- the changes in our earnings from 1999 to 2000 and from 1998 to 1999;
- the effects of regulatory agreements on our results and outlook;
- our capital needs and resources;
- major factors that affect our financial outlook; and
- our management of market risks.

OVERVIEW OF OUR BUSINESS

Pinnacle West owns all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;
- APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;
- SunCor, which is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which is primarily a venture capital and investment firm.

OUR BUSINESS STRATEGIES

Our business strategies are linked to the strong growth characteristics of Arizona and the western regional market. We are committed to the West and are pursuing the following primary strategies:

- Continuing focus on customer value provided by APS, our regulated "energy delivery" company;
- Expanding our interests in competitively efficient generation assets in the West through Pinnacle West Energy by developing new plants, increasing our ownership share of plants that we already operate and partially own, and buying plants from other utilities;
- Aggressively managing costs, with an emphasis on the reduction of variable costs per generating unit (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; and
- Managing energy activities, including:
  - continuing expansion of wholesale operations;
  - managing commodity price risk; and
  - providing sufficient capacity, energy, and ancillary services to reliability meet obligations to our regulated service customers.

BUSINESS SEGMENTS

As we discuss below in greater detail, APS' 1999 Settlement Agreement with the Arizona Corporation Commission (ACC) authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. We have internally organized our operations into the following two principal business segments, determined by products, services, and regulatory environment:

- The electricity delivery business segment, which consists of the transmission and distribution of electricity and wholesale activities; and
- The generation business segment, which consists of our generation activities.

See "Business Segments" in Note 18 for more information about our business segments. In general, we have structured our discussion below based on existing legal entities rather than the operating segments defined by the new organizational structure because we continue to analyze these matters internally by legal entity. The "Results of Operations," for example, primarily reflect the results of APS' operations because APS currently owns substantially all of our assets and produces substantially all of our profits.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 35. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

The following is a summary of net income for 2000, 1999, and 1998:

(dollars in millions)	*2000*	*1999*	*1998*
APS	$ 307	$ 267	$ 246
Pinnacle West Energy	(2)	—	—
APS Energy Services	(13)	(9)	—
SunCor	11	6	45
El Dorado	2	11	5
Parent Company	(3)	(5)	(53)
Income from Continuing Operations	302	270	243
Income Tax Benefit from Discontinued Operations	—	38	—
Extraordinary Charge – Net of Income Taxes of $94	—	(140)	—
Net Income	$ 302	$ 168	$ 243

2000 Compared with 1999

Our 2000 consolidated net income was $302 million compared with $168 million in 1999. Our 2000 net income increased $134 million over 1999 primarily because of a $140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting increase in our 2000 net income was partially offset by a $38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased $32 million, or 12%, over 1999 primarily because of increases in wholesale and retail electric sales and in real estate profits. These positive factors more than offset decreases resulting from the completion of investment tax credit (ITC) amortization in 1999, reductions in retail electricity prices, lower earnings from El Dorado, and miscellaneous factors. See "Regulatory Agreements" below and Note 3 for information on the price reductions. See "Regulatory Agreements" below and Note 4 for additional information about ITC amortization.

In 2000, electric operating revenues increased $1.2 billion primarily because of:

- increased wholesale revenues ($1.1 billion);
- increases in the number of retail electricity customers and the average amount of electricity used by customers ($97 million); and
- weather impacts ($33 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail electricity prices ($28 million).

The increase in wholesale revenues resulted primarily from higher prices and increased activity in western United States wholesale power markets. These revenues were accompanied by increases in purchased power and fuel expense of $1.0 billion.

Fuel and purchased power expenses were also higher because of higher retail sales volumes and increased prices.

The increase in real estate profits resulted from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses, which primarily related to customer growth, was substantially offset by $20 million of non-recurring items recorded in 1999.

Net other income and expense decreased $11 million primarily because of a decrease in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

1999 Compared with 1998

Our 1999 consolidated net income was $168 million compared with $243 million in 1998. Our 1999 net income decreased $75 million from 1998 primarily because of a $140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting decrease in our 1999 net income was partially offset by a $38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations increased $27 million, or 11%, over 1998 primarily because of increases in retail electricity revenues and lower financing costs. These positive factors more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See "Regulatory Agreements" below and Note 3 for additional information about the price reductions.

In 1999, electric operating revenues increased $287 million primarily because of:

- increased wholesale revenues ($219 million);
- increases in retail electricity customers and the average amount of electricity used by customers ($81 million); and
- miscellaneous factors ($9 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail prices ($22 million).

The increase in wholesale revenues resulted from higher prices and increased activity in western United States wholesale markets. The revenues were accompanied by an increase in purchased power expenses. Although these activities contributed positively to earnings in both periods, the contribution in 1999 was lower than in 1998.

Operations and maintenance expenses increased $27 million primarily because of $20 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were partially offset by lower employee benefit costs.

Net other income and expense increased $10 million primarily because of an increase in the market value of El Dorado's

investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

Regulatory Agreements

Regulatory agreements approved by the ACC affect the results of APS' operations. The following discussion focuses on three agreements approved by the ACC, each of which included retail electricity price reductions:

- The 1999 Settlement Agreement to implement retail electric competition;
- A 1996 agreement that accelerated the amortization of APS' regulatory assets; and
- A 1994 settlement that accelerated the amortization of APS' deferred ITCs.

1999 Settlement Agreement

As part of the 1999 Settlement Agreement, APS agreed to reduce retail electricity prices for standard, full offer service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease required by the 1996 regulatory agreement (see below). For customers having loads three megawatts or greater, standard offer rates will be reduced in annual increments that total 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. APS recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 income statement.

Under the 1996 Regulatory Agreement, APS was recovering substantially all of its regulatory assets through accelerated amortization over an eight-year period that would have ended June 30, 2004. For more details, see Note 1. The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

1999	2000	2001	2002	2003	1/1-6/30 2004	Total
$164	$158	$145	$115	$86	$18	$686

See Note 3 and "Business Outlook – Electric Competition (Retail)" below for additional information regarding the 1999 Settlement Agreement.

1996 Regulatory Agreement

As part of the 1996 regulatory agreement, APS reduced its retail electricity prices by 3.4% effective July 1, 1996. This reduction decreased annual revenue by about $49 million annually ($29 million after income taxes). APS also agreed to share future cost savings with its customers during the term of this agreement, which resulted in the following additional retail price reductions:

- $18 million annually ($11 million after income taxes), or 1.2%, effective July 1, 1997;
- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998; and
- $11 million annually ($7 million after income taxes), or 0.7%, effective July 1, 1999 (as noted above, this reduction was included in the July 1, 1999 price reduction under the 1999 Settlement Agreement).

1994 Rate Settlement

As part of a 1994 rate settlement, APS accelerated amortization of substantially all of its ITCs over a five-year period that ended on December 31, 1999. The amortization of ITCs decreased annual consolidated income tax expense by about $24 million. Beginning in 2000, no further benefits were reflected in income tax expense related to the acceleration of the ITCs (see Note 4).

CAPITAL NEEDS AND RESOURCES

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the period ended December 31, 2000 and estimated capital expenditures for the next three years:

	(actual)	(estimated)		
(dollars in millions)	*2000*	*2001*	*2002*	*2003*
APS				
Delivery	$ 285	$ 337	$ 293	$ 294
Existing Generation (a)	187	118	108	—
	472	455	401	294
Pinnacle West Energy (b)				
Generation Expansion	193	659	129	132
Existing Generation (a)	—	—	—	122
	193	659	129	254
SunCor (c)	50	75	23	14
Other (d)	—	21	9	9
Total	$ 715	$1,210	$ 562	$ 571

(a) Pursuant to the 1999 Settlement Agreement, APS is required to move its generating assets and competitive services no later than December 31, 2002.

(b) Does not include the Southern California Edison (SCE) purchase agreements. See Note 12 and "Capital Resources and Cash Requirements – Pinnacle West Energy" below.

(c) Consists primarily of capital expenditures for land development and retail and office building construction.

(d) Primarily APS Energy Services.

Capital Resources and Cash Requirements

Pinnacle West (Parent Company)

During the past three years, our primary cash needs were for:

- dividends to our shareholders;
- equity infusions into our subsidiaries, including $200 million invested in APS from 1996 through 1999 as part of the 1996 regulatory agreement (see Note 3) and $193 million invested in Pinnacle West Energy for 2000 capital expenditures;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

Over the next three years, we anticipate that our cash needs will fall into these same categories, although we expect our equity infusions into Pinnacle West Energy to continue as it invests in additional generating facilities (see below) until it begins to finance its own construction needs.

Our primary sources of cash are dividends from our subsidiaries and external financing. For the years 1998 through 2000, total dividends from subsidiaries were $596 million which included $510 million from APS, $50 million from SunCor, and $36 million from El Dorado.

Our long-term debt at December 31, 2000 was $238 million compared to $106 million at December 31, 1999. We have a $250 million line of credit, under which we had $188 million of borrowings outstanding at December 31, 2000. Our debt repayment requirements for the next three years are approximately: $213 million in 2001, zero in 2002, and $25 million in 2003.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. APS pays for its capital requirements with cash from operations and, to the extent necessary, external financing.

During the period from 1998 through 2000, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2001 through 2003, as well.

See the table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. In general, most of APS' projected capital expenditures are for:

- expanding transmission and distribution capabilities to serve growing customer needs;
- upgrading existing utility property; and
- environmental purposes.

During 2000, APS redeemed approximately $357 million of long-term debt, including premiums, with cash from operations and from the issuance of long- and short-term debt. APS' long-term debt redemption requirements for the next three years are approximately: $380 million in 2001; $125 million in 2002; and zero in 2003. APS made optional redemptions of about $13 million of long-term debt in February 2001. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2000, APS had credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 2000, APS had about $82 million of commercial paper and no long-term bank borrowings outstanding.

APS' long-term debt was $2.1 billion at December 31, 2000 and 1999.

Although provisions in APS' first mortgage bond indenture and ACC financing orders establish maximum amounts of additional first mortgage bonds that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Pinnacle West Energy

Pinnacle West Energy has announced plans to build up to 2,800 megawatts (MW) of generating capacity from 2001-2006 at an estimated cost of about $1.3 billion.

Site	MW
West Phoenix 4	120
West Phoenix 5	530
Redhawk 1	530
Redhawk 2	530
Redhawk 3	530
Redhawk 4	530
TOTAL	2,770

As discussed in greater detail below, Pinnacle West Energy has also announced plans to purchase Nevada Power Company's (NPC) Harry Allen Power Station and SCE's interest in the Palo Verde Nuclear Generating Station (Palo Verde).

Pinnacle West Energy is also considering additional expansion, which may result in additional expenditures.

Pinnacle West Energy expects to fund its capital requirements through internally generated cash, debt issued directly by Pinnacle West Energy, and capital infusions from the parent company's internally generated cash and external financing.

Pinnacle West Energy is currently planning a 650 MW expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units, near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW West Phoenix Unit 5

in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is currently scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately $65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including the Federal Energy Regulatory Commission (FERC) and the Nevada Public Utility Commission (NPUC). The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada recently requested that the NPUC reexamine NPC's divestiture of generation assets. The timing and result of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original $300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for $250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APS Energy Services funded its cash requirements with cash infusions from the parent company.

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the Capital Expenditures Table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements from internally generated cash and external financings.

As of December 31, 2000, SunCor had a $120 million line of credit, under which $110 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2001; $37 million in 2002; and $74 million in 2003.

El Dorado does not have any capital requirements over the next three years. El Dorado intends to focus on the realization of the value of its existing investments. El Dorado's future investments are expected to be limited to opportunities related to the energy sector.

APS Energy Services' capital expenditures and other cash requirements will be funded from cash invested by the parent company.

ACCOUNTING MATTERS

We adopted a new standard on accounting for derivatives in 2001. As a result, in January 2001 we recognized a $3 million after-tax loss in net income as a cumulative effect of a change in accounting principles and a $64 million after-tax gain reflected in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges. There are still several unresolved issues related to the application of certain provisions of this new standard as it relates to the electric utility industry. The ultimate resolution of these issues by the Financial Accounting Standards Board (FASB) could result in a material impact to our financial statements and increased volatility in future net income and comprehensive income. See Note 2 for further information. Also, see Note 2 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements. As a result of the 1999 Settlement Agreement (see "Regulatory Agreements" above and Note 3), we discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance ($140 million after income taxes) as an extraordinary charge on the 1999 income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

BUSINESS OUTLOOK

This section describes several major factors affecting our financial outlook.

Competition and Industry Restructuring

Electric Competition (Wholesale)

The National Energy Policy Act of 1992 (1992 Energy Act) and the FERC's subsequent rulemaking activities have established the regulatory framework to open the wholesale electricity market to competition. The 1992 Energy Act amended provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to a competitive wholesale market. The 1992 Energy Act permits utilities to participate in the development of independent electric generating plants for electricity sales to wholesale customers, and also permits the FERC to order transmission access for third parties to transmission facilities owned by another entity. The 1992 Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers. Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including us, with opportunities to sell and deliver electricity at market-based prices.

Electric Competition (Retail)

On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona (the Rules). Among other things, the Rules require most utilities, including APS, to transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. The Rules require the transfer to take place by January 1, 2001, absent a waiver. APS received a waiver in the 1999 Settlement Agreement to allow the transfer of its competitive generation assets and services to affiliates no later than December 31, 2002. Accordingly, we plan to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard offer customers under rates that have been approved by the ACC. These rates are fixed until July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last year, have been volatile. At various times prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects these market conditions to continue in 2001. We believe we have adequately supplemented our current generation portfolio with power purchased through contracts and hedging techniques that limit exposure to the volatile spot wholesale power market. However, in the event of shortfalls due to unforeseen increases in load demand or generation outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

As discussed in Note 3, the 1999 Settlement Agreement authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. APS intends to move its generation assets to Pinnacle West Energy within that timeframe. Following its receipt of these generation assets, Pinnacle West Energy expects to sell its power at wholesale to our power marketing division (Power Marketing). Power Marketing, in turn, is expected to sell power to APS and to non-affiliated power purchasers. APS is expected to meet fifty percent of its energy needs under a power purchase agreement with Power Marketing. As required by the Rules, APS will acquire the remaining fifty percent of its energy needs through a competitive bid process in which Power Marketing may participate. We believe that these arrangements will allow us to manage APS' exposure to the wholesale power market during the period within which APS' rates are fixed, as discussed in the preceding paragraph.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. Several rural electric cooperatives and the Arizona Consumers Council, a private non-profit public interest group (represented by the Arizona Center for Law in the Public Interest, also a private non-profit public interest organization) have filed court challenges to the Rules. Although these actions do not directly challenge the divestiture provisions of the Rules, they do raise fundamental constitutional issues concerning the ability of the ACC to permit the forces of competition to determine retail electric prices.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement.

The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review.

On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

Neither party challenging the 1999 Settlement Agreement has raised issues regarding the 1999 Settlement Agreement that could not be remedied by the ACC if the Arizona Court of Appeals remands the 1999 Settlement Agreement to the ACC. However, it is impossible to predict with certainty exactly what the ACC would do in the event the order approving the 1999 Settlement Agreement were invalidated, either in whole or in part. Even aside from the pending litigation, the ACC retains continuing jurisdiction over all orders issued by it and can attempt to "rescind, alter or amend" such order under appropriate circumstances and upon notice and hearing.

In May 1998, a law was enacted by the Arizona legislature to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for additional information about the Rules, the 1999 Settlement Agreement, the ongoing litigation related to each, and for legislative developments.

As a result of the foregoing matters, as well as energy market developments, particularly in California (see "California Energy Market Issues" below), electric utility restructuring is in a state of flux in the western United States and around the country.

Generation Expansion

See "Capital Needs and Resources – Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

California Energy Market Issues

SCE and PG&E Corp. (PG&E) have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the California Power Exchange (PX) and California Independent System Operator (ISO).

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon the financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Capital Resources and Cash Requirements – Pinnacle West Energy" above for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Factors Affecting Operating Revenues

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona, and from competitive retail and wholesale bulk power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged 3.8% a year for the three years 1998 through 2000; we currently expect customer growth to average 3.5% to 4% a year for 2001 through 2003. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 4.5% a year in 2001 through 2003, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard offer customers that will switch to unbundled service.

Wholesale activities will be affected by electricity prices and costs of available fuel and purchased power in the western United States, as well as competitive market conditions and regulatory and legislative changes in various state and federal jurisdictions. These factors have significantly affected our wholesale power activities and their resultant earnings contributions over the last several years. We cannot predict future contributions from wholesale activities.

Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply. Such activities are currently not material to our consolidated financial results.

Other Factors Affecting Future Financial Results

Fuel and purchased power costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, our power plant performance, prevailing market prices, and our hedging program for managing such costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, inflation, and other factors.

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 1 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement. Also, see Note 1 regarding current depreciation rates.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally generated cash flow.

The annual earnings contribution from our real estate subsidiary, SunCor, is expected to remain modest over the next several years. SunCor's earnings were $5 million (excluding the effects of a $40 million deferred tax asset transfer) in 1998, $6 million in 1999, and $11 million in 2000.

El Dorado, our investment subsidiary, is affected by market conditions related to its investments. See Note 1 for a discussion of recent events affecting El Dorado's financial results and its outlook. Historical results are not necessarily indicative of future performance for El Dorado. El Dorado's strategies focus on realization of the value of its existing investments. Any future investments are expected to be in the energy business.

Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

MARKET RISKS

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

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 13). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2000 and December 31, 1999. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2000 and December 31, 1999.

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 2000

	Short-Term		Variable Long-Term		Fixed Long-Term	
(dollars in thousands)	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2001	6.64%	$ 82,775	7.23%	$ 438,203	6.63%	$ 25,266
2002	—	—	8.62%	36,890	8.13%	125,000
2003	—	—	8.61%	73,578	6.89%	25,443
2004	—	—	8.87%	268	6.17%	205,000
2005	—	—	8.89%	294	7.28%	400,000
Years thereafter	—	—	4.13%	483,790	7.47%	610,813
Total		$ 82,775		$ 1,033,023		$ 1,391,522
Fair Value		$ 82,775		$ 1,033,023		$ 1,422,014

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1999

	Short-Term		Variable Long-Term		Fixed Long-Term	
(dollars in thousands)	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2000	5.33%	$ 38,300	10.25%	$ 87	5.79%	$ 114,711
2001	—	—	7.00%	336,117	6.70%	27,488
2002	—	—	8.47%	64,085	8.13%	125,000
2003	—	—	5.51%	50,118	6.87%	25,000
2004	—	—	10.25%	130	6.17%	205,000
Years thereafter	—	—	3.19%	479,727	7.87%	900,483
Total		$ 38,300		$ 930,264		$ 1,397,682
Fair Value		$ 38,300		$ 930,264		$ 1,366,968

Commodity Price Risk

Pinnacle West's Energy Risk Management Committee (the ERMC) has established risk management guidelines to monitor and manage commodity price risks. The ERMC is chaired by Pinnacle West's Vice President of Finance and is comprised of senior executives.

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements. In accordance with Emerging Issues Task Force (EITF) 98-10, "Accounting for contracts involved in energy trading and risk management activities," such trading positions are marked to market. These trading activities are part of our wholesale activities and are reflected in the wholesale revenues and expenses.

As of December 31, 2000, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would have decreased the fair market value of these contracts by approximately $29 million compared to a $6 million decrease that would have been realized as of December 31, 1999. The increase in this exposure over 1999 is a result of the increased volume of hedge positions and increased prices in this portfolio. This analysis does not include the favorable impact this same hypothetical price move would have had on certain underlying physical exposures being hedged with the commodity derivative portfolio.

We are exposed to losses in the event of non-performance or non-payment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regional economic and market conditions, including the California energy situation, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the stock market (particularly the technology sector in which El Dorado is currently invested) and the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

REPORT OF MANAGEMENT AND INDEPENDENT AUDITORS' REPORT

REPORT OF MANAGEMENT

The primary responsibility for the integrity of our financial information rests with management, which has prepared the accompanying financial statements and related information. This information was prepared in accordance with generally accepted accounting principles as appropriate in the circumstances, and based on management's best estimates and judgments. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal control. A limiting factor in all systems of internal control is that the cost of the system should not exceed the benefits to be derived. Management believes that our system provides the appropriate balance between such costs and benefits.

Periodically the internal control system is reviewed by both our internal auditors and our independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis. By letter dated February 21, 2001, to the Audit Committee, our independent auditors confirmed that they are independent accountants with respect to us, within the meaning of the Securities Act and the requirements of the Independence Standards Board.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that our systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chairman and
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona

February 9, 2001

CONSOLIDATED STATEMENTS OF INCOME

YEAR ENDED DECEMBER 31,

(dollars in thousands, except per share amounts)	2000	1999	1998
OPERATING REVENUES			
Electric	$ 3,531,810	$ 2,293,184	$ 2,006,398
Real estate	158,365	130,169	124,188
Total	3,690,175	2,423,353	2,130,586
OPERATING EXPENSES			
Fuel and purchased power	1,934,783	796,109	545,297
Operations and maintenance	450,809	446,777	419,433
Real estate operations	134,422	119,516	115,331
Depreciation and amortization (Note 1)	394,410	385,568	379,679
Taxes other than income taxes	99,780	96,606	103,718
Total	3,014,204	1,844,576	1,563,458
OPERATING INCOME	675,971	578,777	567,128
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	—	(1,016)	(9,703)
Net other income and expense	(186)	10,793	609
Total	(186)	9,777	(9,094)
INCOME BEFORE INTEREST AND INCOME TAXES	675,785	588,554	558,034
INTEREST EXPENSE			
Interest charges	171,239	162,381	169,145
Capitalized interest	(21,638)	(11,664)	(18,596)
Total	149,601	150,717	150,549
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	526,184	437,837	407,485
INCOME TAXES (NOTE 4)	223,852	168,065	164,593
INCOME FROM CONTINUING OPERATIONS	302,332	269,772	242,892
Income tax benefit from discontinued operations	—	38,000	—
Extraordinary charge – net of income taxes of $94,115	—	(139,885)	—
NET INCOME	$ 302,332	$ 167,887	$ 242,892
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,733	84,717	84,774
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	84,935	85,009	85,346
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (NOTE 16)			
Continuing operations – basic	$ 3.57	$ 3.18	$ 2.87
Net income – basic	3.57	1.98	2.87
Continuing operations – diluted	3.56	3.17	2.85
Net income – diluted	3.56	1.97	2.85
DIVIDENDS DECLARED PER SHARE	$ 1.425	$ 1.325	$ 1.225

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

(dollars in thousands)	2000	1999
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 10,363	$ 20,705
Customer and other receivables – net	513,822	244,599
Accrued utility revenues	74,566	72,919
Materials and supplies (at average cost)	71,966	69,977
Fossil fuel (at average cost)	19,405	21,869
Deferred income taxes (Note 4)	5,793	8,163
Other current assets	97,998	60,562
Total current assets	793,913	498,794
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	371,323	344,293
Other assets (Note 13)	318,249	267,458
Total investments and other assets	689,572	611,751
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,809,566	7,546,314
Less accumulated depreciation and amortization	3,188,302	3,026,194
Total	4,621,264	4,520,120
Construction work in progress	464,540	209,281
Nuclear fuel, net of amortization of $61,256 and $66,357	47,389	49,114
Net utility plant	5,133,193	4,778,515
DEFERRED DEBITS		
Regulatory assets (Notes 3 and 4)	469,867	613,729
Other deferred debits	62,606	105,717
Total deferred debits	532,473	719,446
TOTAL ASSETS	$ 7,149,151	$ 6,608,506

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

DECEMBER 31,

(dollars in thousands)	2000	1999
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 375,805	$ 186,524
Accrued taxes	89,246	70,510
Accrued interest	42,954	33,253
Short-term borrowings (Note 5)	82,775	38,300
Current maturities of long-term debt (Note 6)	463,469	114,798
Customer deposits	26,189	26,098
Other current liabilities	110,860	26,007
Total current liabilities	1,191,298	495,490
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	1,955,083	2,206,052
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,143,040	1,183,855
Unamortized gain – (Note 10)	68,636	73,212
Other	408,380	444,164
Total deferred credits and other	1,620,056	1,701,231
COMMITMENTS AND CONTINGENCIES (NOTES 3, 12 AND 13)		
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 2000 and 1999	1,532,831	1,537,449
Retained earnings	849,883	668,284
Total common stock equity	2,382,714	2,205,733
TOTAL LIABILITIES AND EQUITY	$ 7,149,151	$ 6,608,506

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31,

(dollars in thousands)	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 302,332	$ 269,772	$ 242,892
Items not requiring cash			
Depreciation and amortization	394,410	385,568	379,679
Nuclear fuel amortization	30,083	31,371	32,856
Deferred income taxes – net	(8,973)	(17,413)	41,262
Deferred investment tax credit	740	(23,514)	(23,516)
Other – net	478	(12,476)	1,190
Changes in current assets and liabilities			
Customer and other receivables – net	(269,223)	(10,723)	(50,369)
Accrued utility revenues	(1,647)	(5,179)	(9,181)
Materials, supplies and fossil fuel	475	(8,794)	(2,797)
Other current assets	(37,436)	(12,968)	(6,186)
Accounts payable	193,502	28,193	34,386
Accrued taxes	18,736	12,591	(22,090)
Accrued interest	9,701	1,387	(1,108)
Other current liabilities	89,714	15,047	(5,235)
(Increase) decrease in land held	(25,937)	(12,542)	33,405
Other – net	2,605	(4,720)	(39,350)
Net Cash Flow Provided By Operating Activities	699,560	635,600	605,838
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(658,608)	(343,448)	(319,142)
Capitalized interest	(21,638)	(11,664)	(18,596)
Other – net	(41,761)	(16,143)	(2,144)
Net Cash Flow Used For Investing Activities	(722,007)	(371,255)	(339,882)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	651,000	607,791	148,229
Short-term borrowings – net	44,475	(140,530)	48,080
Dividends paid on common stock	(120,733)	(112,311)	(103,849)
Repayment of long-term debt	(558,019)	(510,693)	(286,314)
Redemption of preferred stock	—	(96,499)	(75,517)
Other – net	(4,618)	(11,936)	(3,531)
Net Cash Flow Provided By (Used For) Financing Activities	12,105	(264,178)	(272,902)
NET CASH FLOW	(10,342)	167	(6,946)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	20,705	20,538	27,484
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 10,363	$ 20,705	$ 20,538

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEAR ENDED DECEMBER 31,

(dollars in thousands)	2000	1999	1998
Retained earnings at beginning of year	$ 668,284	$ 612,708	$ 473,665
Net income	302,332	167,887	242,892
Common stock dividends	(120,733)	(112,311)	(103,849)
Retained earnings at end of year	$ 849,883	$ 668,284	$ 612,708

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor, and El Dorado. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS, our major subsidiary and Arizona's largest electric utility, provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our unregulated generation operations. APS Energy Services was formed in 1998 and sells energy and energy-related products and services in competitive retail markets in the western United States. SunCor is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. El Dorado is primarily a venture capital and investment firm.

Accounting Records

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in our financial statements.

During 1997, the EITF of the FASB issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 3 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pre-tax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

1999	2000	2001	2002	2003	1/1-6/30 2004	Total
$164	$158	$145	$115	$86	$18	$686

The majority of our remaining regulatory assets relate to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note).

The balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (for additional generation information see Note 18):

(dollars in thousands)	DECEMBER 31, 2000	1999
Electric plant in service and held for future use	$ 3,856,600	$ 3,817,919
Accumulated depreciation and amortization	(1,693,079)	(1,664,782)
Construction work in progress	304,992	87,819
Nuclear fuel, net of amortization	47,389	49,114

Utility Plant and Depreciation

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

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

We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a proposed accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis. For the years 1998 through 2000 the rates, as prescribed by our regulators, ranged from a low of 3.33% to a high of 20%. The weighted-average rate was 3.40% for 2000, 3.34% for 1999, and 3.32% for 1998. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. The partnership adjusts the value of its investments at the end of each fiscal quarter. The value of El Dorado's investment in the partnership is determined by various factors beyond our control, including equity market conditions. Most of the partnership's investments are in technology-related companies whose share prices are highly volatile.

Prior to June 2000, we recorded our share of the earnings from the partnership, as the partnership adjusted the value of its investment, on a one-quarter lag. This procedure was followed due to time constraints in obtaining and analyzing such results for inclusion in our consolidated financial statements on a current basis. In the second quarter of 2000, we requested a distribution of our share of the investments held by the partnership, and we adjusted our investment to reflect the current market value.

An amendment to the partnership agreement resulted in El Dorado receiving a distribution, subject to certain sales restrictions, of securities representing substantially all of El Dorado's investment in the partnership. We began accounting for the securities as available for sale with changes in fair value recorded in other comprehensive income. Gains and losses from the ultimate sale of such securities will be reflected in our net earnings.

The book value of El Dorado's investment in the partnership was approximately $7 million at December 31, 2000 and $21 million at December 31, 1999.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plants. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 6.62% for 2000, 6.65% for 1999, and 6.88% for 1998.

Revenues

We record electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel

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

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal and Note 13 for information on nuclear decommissioning costs.

Income Taxes

We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to the parent company.

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Derivative Instruments

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements.

Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in revenue or fuel and purchased power expense as an offset to the related item being hedged when the underlying hedged physical transaction closes (deferral method).

Net gains and losses on derivatives utilized for trading are recognized in wholesale revenues on a current basis (the mark to market method). Trading positions are measured at fair value as of the balance sheet date. The net gain was $9 million for 2000 and $1 million for 1999.

Statements of Cash Flows

We consider temporary cash investments and marketable securities, with original maturities of less than 90 days, to be cash equivalents for purposes of reporting cash flows. During 2000, 1999, and 1998, we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

	YEARS ENDED DECEMBER 31,		
(dollars in millions)	*2000*	*1999*	*1998*
Interest paid	$ 132	$ 141	$ 144
Income taxes paid	219	200	165
Dividends paid on preferred stock of APS	—	1	10

2. ACCOUNTING MATTERS

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholder's equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

As a result of adopting SFAS No. 133, we recognized $118 million of derivative assets and $16 million of derivative liabilities in our balance sheet as of January 1, 2001. We recorded a $3 million after-tax loss in net income as a cumulative effect of change in accounting principles and a $64 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges.

In December 2000, the FASB's Derivatives Implementation Group (DIG) discussed whether contracts in the electric industry that have some of the characteristics of purchased and written options should qualify for the "normal purchases and sales" scope exception. The DIG did not reach a conclusion on this issue. We account for electricity contracts with characteristics of options as normal purchases and sales if it is probable that the contract will not be settled in cash and will result in the physical delivery of electricity. The DIG also discussed but did not determine whether electricity contracts subject to "bookout" should qualify for the normal exception. A bookout occurs when one party appears more than once in a contract path for the sale and purchase of energy. In that instance, the counterparties may agree that they will not schedule or deliver physical energy that originates and ends with the same counterparty, but rather will settle in cash the amounts due to or from each counterparty. We account for our non-trading electricity transactions that bookout as gross settlement with physical delivery (and eligible for the normal scope exception) if title transfers, gross cash payment is made, and the transaction retains both performance and credit risk. Trading contracts are measured at fair value (mark to market) as discussed in Note 1.

Our accounting is reflective of the non-storability of our product and the lack of predictability of the demand for electricity at any point in time. If the FASB or DIG ultimately provides us with contrary guidance, we may be required to mark our non-trading electricity contracts to their fair market values each reporting period, which could have a material impact on our financial statements and add significant net income and comprehensive income volatility that would not be reflective of the nature of our business. If these agreements are required to be treated as derivative instruments, a cumulative effect of a change in accounting principles would be applied in the quarter following final resolution of the issues.

In 1999 we adopted EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. The effects of adopting EITF 98-10 were not material to our 1999 financial statements.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB issued a revised exposure draft in February 2000 and we are evaluating the impacts.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

1999 SETTLEMENT AGREEMENT. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

The following are the major provisions of the 1999 Settlement Agreement, as approved:

- APS has reduced, and will reduce, rates for standard offer service for customers with loads less than three MW in a series of annual retail electric price reductions of 1.5% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the 1999 Settlement Agreement, there was a retail price decrease of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000. For customers having loads three MW or greater, standard offer rates will be reduced in varying annual increments that total 5% in the years 1999 through 2002.
- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There will be a moratorium on retail price changes for standard offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition rules, system benefits costs in excess of the levels included in current rates, and costs associated with the "provider of last resort" and standard offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the electric competition rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after

mitigation and exclusive of regulatory assets, are at least $533 million net present value. APS will not be allowed to recover $183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value through a competitive transition charge (CTC) that will remain in effect through December 31, 2004, at which time it will terminate. Any over/under-recovery due to sales volume variances will be credited/debited against the costs subject to recovery under the adjustment clause described above.

- APS will form a separate corporate affiliate or affiliates and transfer to such affiliate(s) its generating assets and competitive services at book value as of the date of transfer, which transfer shall take place no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.
- When the 1999 Settlement Agreement approved by the ACC is no longer subject to judicial review, APS will move to dismiss all of its litigation pending against the ACC as of the date APS entered into the 1999 Settlement Agreement. To protect its rights, APS has several lawsuits pending on ACC orders relating to stranded cost recovery and the adoption and amendment of the ACC's electric competition rules, which would be voluntarily dismissed at the appropriate time under this provision.

As discussed in Note 1 above, we have discontinued the application of SFAS No. 71 for our generation operations.

RETAIL ELECTRIC COMPETITION RULES. On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona. Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. On December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery, the adoption or amendment of the Rules, and the certification of competitive electric service providers.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review. The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access was available to all APS retail customers.
- Electric service providers that get Certificates of Convenience and Necessity from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for non-competitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its generation and other competitive assets and services to affiliates no later than December 31, 2002. See "1999 Settlement Agreement" above for a discussion of the planned timing of the transfer.

1996 REGULATORY AGREEMENT. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows:

(dollars in millions)

Annual Electric Revenue Decrease	Percentage Decrease	Effective Date
$49	3.4%	July 1, 1996
$18	1.2%	July 1, 1997
$17	1.1%	July 1, 1998
$11	0.7%	July 1, 1999(a)

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse $200 million of common equity into APS in annual payments of $50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

LEGISLATION. In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;
- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and
- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one MW (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

General

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position it to compete in the new regulatory environment.

Federal

The 1992 Energy Act and recent rulemakings by FERC have promoted increased competition in the wholesale energy markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills will undoubtedly be introduced during the current congressional session. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2001 and beyond. These bills and other bills are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any comprehensive restructuring of the electric utility industry can occur.

4. INCOME TAXES

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

APS has recorded a regulatory asset related to income taxes on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS amortizes this amount as the differences reverse. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate its amortization of the regulatory asset for income taxes over an eight-year period that will end June 30, 2004 (see Note 1). We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income. The components of income tax expense for continuing operations are:

	YEAR ENDED DECEMBER 31,		
(dollars in thousands)	*2000*	*1999*	*1998*
Current			
Federal	$ 189,779	$ 171,491	$ 105,922
State	42,306	37,501	40,621
Total current	232,085	208,992	146,543
Deferred	(8,973)	(17,413)	41,566
ITC amortization	740	(23,514)	(23,516)
Total expense	$ 223,852	$ 168,065	$ 164,593

The following chart compares pretax income at the 35% federal income tax rate to income tax expense:

(dollars in thousands)	YEAR ENDED DECEMBER 31, 2000	1999	1998
Federal income tax expense at 35% statutory rate	$ 184,164	$ 153,243	$ 142,620
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	12,328	14,575	17,848
Preferred stock dividends of APS	—	356	3,396
ITC amortization	740	(23,514)	(23,516)
State income tax net of federal income tax benefit	23,555	23,030	22,764
Other	3,065	375	1,481
Income tax expense	$ 223,852	$ 168,065	$ 164,593

The components of the net deferred income tax liability were as follows:

(dollars in thousands)	YEAR ENDED DECEMBER 31, 2000	1999
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 27,056	$ 29,446
Other	89,416	133,748
Total deferred tax assets	116,472	163,194
DEFERRED TAX LIABILITIES		
Plant-related	1,081,637	1,104,769
Regulatory asset for income taxes	172,082	234,117
Total deferred tax liabilities	1,253,719	1,338,886
Accumulated deferred income taxes – net	$ 1,137,247	$ 1,175,692

Investment Tax Credit

Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our ITCs over a five-year period (1995-1999).

Income Tax Benefit From Discontinued Operations

In 1999, the income tax benefit from discontinued operations for $38 million resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $250 million at December 31, 2000 and $350 million at December 31, 1999, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 2000 and 1999 for these lines of credit ranged from 0.09% to 0.125% per annum. APS had no long-term bank borrowings at December 31, 2000 and $50 million outstanding at December 31, 1999.

APS' commercial paper borrowings outstanding were $82 million at December 31, 2000 and $38 million at December 31, 1999. The weighted average interest rate on commercial paper borrowings was 6.64% for the year ended December 31, 2000 and 5.33% for the year ended December 31, 1999.

By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had a revolving line of credit of $250 million at December 31, 2000 and 1999. The commitment fees were 0.15% in 2000 and 0.10% in 1999. Outstanding amounts at December 31, 2000 were $188 million and at December 31, 1999 were $56 million.

SunCor had revolving lines of credit totalling $120 million at December 31, 2000 and $100 million at December 31, 1999. The commitment fees were 0.125% in 2000 and 1999. SunCor had $110 million outstanding at December 31, 2000 and $94 million outstanding at December 31, 1999.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plants; APS also has unsecured debt; SunCor's debt is collateralized by interests in certain real property; Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt outstanding at December 31, 2000 and December 31, 1999:

(dollars in thousands)	Maturity Dates (a)	Interest Rates	YEAR ENDED DECEMBER 31, 2000	1999
APS				
First mortgage bonds	2000	5.75%	$ —	$ 100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	80,000
	2020	10.25%	—	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	70,650
	2024	8.75%	121,668	121,668
	2025	8%	33,075	47,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,993)	(5,860)
Pollution control bonds	2024-2034	Adjustable rate(b)	476,860	476,860
Funds held in trust account for certain pollution control bonds			—	(1,236)
Collateralized loan	2000	5.375%-6.125%	—	10,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	—
Floating rate notes	2001	Adjustable rate(c)	250,000	250,000
Senior notes (d)	2006	6.75%	83,695	83,695
Debentures	2025	10%	—	75,000
Bank loans	2003	Adjustable rate(e)	—	50,000
Capitalized lease obligation	2000	7.48%(f)	—	7,199
Capitalized lease obligation	2001-2003	7.75%	709	—
			2,057,174	2,112,111
SUNCOR				
Revolving credit	2002-2003	(g)	110,000	94,000
Notes payable	2001-2006	(h)	8,163	3,404
Bonds payable	2039	5.85%	5,215	5,335
			123,378	102,739
PINNACLE WEST				
Revolving credit	2001	(i)	188,000	56,000
Senior notes	2001-2003	(j)	50,000	50,000
			238,000	106,000
Total long-term debt			2,418,552	2,320,850
Less current maturities			463,469	114,798
Total long-term debt less current maturities			$1,955,083	$2,206,052

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) The weighted-average rate for the year ended December 31, 2000 was 4.06% and for December 31, 1999 was 3.15%. Changes in short-term interest rates would affect the costs associated with this debt.
(c) The weighted-average rate for the year ended December 31, 2000 was 7.33% and for December 31, 1999 was 6.8525%.
(d) APS currently has outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. APS' payments of principal, premium, and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.
(e) The weighted-average rate for the year ended December 31, 2000 was 6.53% and for December 31, 1999 was 5.5%. Changes in short-term interest rates would affect the costs associated with this debt. At December 31, 2000, we had no long-term bank borrowings outstanding.
(f) Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined cycle plant that was sold and leased back. The capital lease was paid off early and the related asset was purchased in December 2000 (See Note 10).
(g) The weighted-average rate at December 31, 2000 was 8.61% and at December 31, 1999 was 8.51%. Interest for 2000 and 1999 was based on LIBOR plus 2% or prime plus 0.5%.
(h) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
(i) The weighted-average rate at December 31, 2000 was 7.51% and at December 31, 1999 was 6.825%. Interest for 2000 was based on LIBOR plus 0.75% and interest for 1999 was based on LIBOR plus 0.33%.
(j) Includes two series of notes: $25 million at 6.62% due 2001, and $25 million at 6.87% due 2003.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2005:

- $463 million in 2001;
- $162 million in 2002;
- $99 million in 2003;
- $205 million in 2004; and
- $400 million in 2005.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2000.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock. Preferred stock balances of APS at December 31, 2000 and 1999 were zero. Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 2000 are as follows:

(dollars in thousands)	Number of Shares	Par Value Amount
Balance, December 31, 1997	291,098	$ 29,110
Retirements		
$10.00 Series U	(197,087)	(19,709)
Balance, December 31, 1998	94,011	9,401
Retirements		
$10.00 Series U	(94,011)	(9,401)
Balance, December 31, 1999	—	—
Balance, December 31, 2000	—	$ —

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 2000 is as follows:

(dollars in thousands)	Number of Shares	Amount
Balance, December 31, 1997	84,824,947	$ 1,553,771
Common stock expense	—	(3,128)(a)
Balance, December 31, 1998	84,824,947	1,550,643
Common stock expense	—	(13,194)(a)
Balance, December 31, 1999	84,824,947	1,537,449
Common stock expense	—	(4,618)
Balance, December 31, 2000	84,824,947	$ 1,532,831

(a) Including premiums and expenses of preferred stock issues of APS.

9. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plans

Through 1999, Pinnacle West and its subsidiaries each sponsored defined benefit pension plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single pension plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under these plans based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 2000 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- $2 million in 2000;
- $4 million in 1999; and
- $11 million in 1998.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others:

(dollars in thousands)	*2000*	*1999*	*1998*
Service cost - benefits earned during the period	$ 24,955	$ 24,982	$ 24,817
Interest cost on projected benefit obligation	58,361	52,905	51,524
Expected return on plan assets	(77,231)	(68,335)	(54,513)
Amortization of:			
Transition asset	(3,227)	(3,226)	(3,226)
Prior service cost	2,078	2,078	2,078
Net actuarial gain	(1,633)	—	—
Net periodic pension cost	$ 3,303	$ 8,404	$ 20,680

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the balance sheets:

(dollars in thousands)	*2000*	*1999*
Funded status – pension plan assets more than (less than) projected benefit obligation	$ (20,730)	$ 37,275
Unrecognized net transition asset	(16,781)	(20,008)
Unrecognized prior service cost	18,558	20,636
Unrecognized net actuarial gains	(23,816)	(101,153)
Net pension liability recognized in the balance sheets	$ (42,769)	$ (63,250)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)	2000	1999
Projected pension benefit obligation at beginning of year	$ 742,638	$ 731,305
Service cost	24,955	24,982
Interest cost	58,361	52,905
Benefit payments	(30,568)	(29,694)
Actuarial (gains)/losses	540	(36,860)
Projected pension benefit obligation at end of year	$ 795,926	$ 742,638

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)	2000	1999
Fair value of pension plan assets at beginning of year	$ 779,913	$ 690,271
Actual return on plan assets	1,851	93,977
Employer contributions	24,000	25,359
Benefit payments	(30,568)	(29,694)
Fair value of pension plan assets at end of year	$ 775,196	$ 779,913

We made the assumptions below to calculate the pension liability:

	2000	1999
Discount rate	7.75%	7.75%
Rate of increase in compensation levels	4.25%	4.25%
Expected long-term rate of return on assets	10.00%	10.00%

Employee Savings Plan Benefits

Through 1999, Pinnacle West and its subsidiaries each sponsored defined contribution savings plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single defined contribution savings plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. In a defined contribution plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of approximately $4 million for 2000, 1999, and 1998.

Postretirement Plans

We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- $ 3 million for 2000
- $ 7 million for 1999 and
- $ 9 million for 1998.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others:

(dollars in thousands)	2000	1999	1998
Service cost - benefits earned during the period	$ 8,613	$ 8,939	$ 7,890
Interest cost on accumulated benefit obligation	19,315	17,366	15,763
Expected return on plan assets	(22,381)	(18,454)	(12,001)
Amortization of:			
Transition obligation	7,698	7,698	7,698
Net actuarial gains	(7,983)	(5,117)	(2,952)
Net periodic postretirement benefit cost	$ 5,262	$ 10,432	$ 16,398

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

(dollars in thousands)	2000	1999
Funded status – postretirement plan assets more than (less than) projected benefit obligation	$ (14,851)	$ 25,549
Unrecognized net obligation at transition	92,446	100,145
Unrecognized net actuarial gains	(81,280)	(128,309)
Net postretirement amount recognized in the balance sheets	$ (3,685)	$ (2,615)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 2000 and 1999:

(dollars in thousands)	2000	1999
Accumulated postretirement benefit obligation at beginning of year	$ 231,989	$ 237,679
Service cost	8,613	8,939
Interest cost	19,315	17,366
Benefit payments	(8,905)	(8,761)
Actuarial (gains) losses	12,994	(23,234)
Accumulated postretirement benefit obligation at end of year	$ 264,006	$ 231,989

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 2000 and 1999:

(dollars in thousands)	2000	1999
Fair value of postretirement plan assets at beginning of year	$ 257,538	$ 213,410
Actual return on plan assets	(4,436)	42,975
Employer contributions	4,958	9,914
Benefit payments	(8,906)	(8,761)
Fair value of postretirement plan assets at end of year	$ 249,154	$ 257,538

We made the assumptions below to calculate the postretirement liability:

	2000	*1999*
Discount rate	7.75%	7.75%
Expected long-term rate of return on assets – after tax	8.77%	8.77%
Initial health care cost trend rate – under age 65	7.00%	7.00%
Initial health care cost trend rate – age 65 and over	6.00%	6.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

The following table shows the effect of a 1% increase or decrease in the health care cost trend rate:

(dollars in millions)	1% increase	1% decrease
Effect on 2000 cost of postretirement benefits other than pensions	$ 5	$ (4)
Effect on the accumulated postretirement benefit obligation at December 31, 2000	43	(34)

10. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain of approximately $140 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2001-2015.

In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 2000 was $33 million.

In December 2000, APS purchased Units 1, 2, and 3 of West Phoenix Power Plant. These units were previously reflected as a capital lease.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Total lease expense was $58 million in 2000, $52 million in 1999, and $55 million in 1998.

Estimated future minimum lease commitments, are approximately $67 million for each of the years 2001 to 2005 and $663 million thereafter.

11. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at December 31, 2000. APS' share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

(dollars in thousands)	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,824,480	$ 814,693	$ 7,414
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	571,573	265,571	29,593
Four Corners Steam Generating Station Units 4 and 5	15.0%	152,717	75,797	—
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	231,509	99,623	4,899
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	73,382	40,023	686
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	67,987	22,813	—
Navajo Southern System	31.4%(b)	27,290	17,804	55
Palo Verde – Yuma 500KV System	23.9%(b)	9,712	3,844	1
Four Corners Switchyards	27.5%(b)	3,071	1,925	—
Phoenix – Mead System	17.1%(b)	36,418	2,681	—
Palo Verde – Estrella 500KV system	50.0%(b)	—	—	610

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

12. COMMITMENTS AND CONTINGENCIES

Litigation

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Power Service Agreement

APS is a party to a power service agreement with Citizens Communications Company (Citizens) under which APS supplies Citizens with power. By letter dated March 7, 2001, Citizens advised APS that it believes APS has overcharged Citizens by over $50 million under the agreement since the summer of 2000. APS believes that its charges to Citizens under the agreement are fully in accordance with the terms of the agreement and APS will vigorously defend any contrary claims raised by Citizens.

Palo Verde Nuclear Generating Station

Pursuant to the Nuclear Waste Policy Act of 1982, the DOE must accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The United States Nuclear Regulatory Commission (NRC) requires operators of nuclear power reactors to enter into spent fuel disposal contracts with the DOE. Under the Nuclear Waste Policy Act of 1982, the DOE was to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998. The DOE has announced that such a permanent repository cannot be completed before 2010, and that it does not intend to begin accepting spent fuel prior to that date.

In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision precluding the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision, a number of utilities filed damages actions against DOE in the court of Federal Claims. In decisions that became final in December 2000, the United States Court of Appeals for the Federal Circuit held that utilities do not have to exhaust the DOE administrative claims before filing lawsuits for damages against the DOE in the court of Federal Claims.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent

fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates that it will incur $113 million (in 2000 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2000, APS had recorded a liability and regulatory asset of $40 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel And Purchased Power Commitments

APS is a party to various fuel and purchased power contracts with terms expiring from 2001 through 2021 that include required purchase provisions. APS estimates its contract requirements to be approximately $277 million in 2001; $145 million in 2002; $90 million in 2003; $83 million in 2004; and $55 million in 2005. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit APS to decrease its required purchases under certain circumstances.

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $58 million at December 31, 2000 and is included in deferred credits-other in the Balance Sheet.

A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 2000 was about $32 million.

California Energy Market Issues

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Generation Expansion" below for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Construction Program

Consolidated capital expenditures in 2001 are estimated at:

(dollars in millions)		*2001*
APS	$	455
Pinnacle West Energy		659
SunCor		75
Other		21
Total	$	1,210

Generation Expansion

Pinnacle West Energy has announced plans to build and acquire up to 2,800 MW of generating capacity from 2001-2006 at an estimated cost of about $1.3 billion.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW Unit 5 in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately $65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including FERC and the NPUC. The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada has recently requested that the NPUC reexamine the divestiture of generation. The timing and results of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original $300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for it's Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for $250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11 million for nuclear decommissioning expense in each of the years 2000, 1999, and 1998. APS estimates it will cost about $1.8 billion ($493 million in 2000 dollars) to decommission its share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decommissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations. The trust accounts are reported in investments and other assets on the Consolidated Balance Sheets at their market value of $205 million at December 31, 2000 and $176 million at December 31, 1999. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

See Note 2 for a proposed accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

14. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2000 and 1999 is as follows:

(dollars in thousands, except per share amounts)	2000			
QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 446,228	$ 720,174	$ 1,567,960	$ 797,448
Real Estate	41,889	36,374	39,396	40,706
Operating Income (a)	$ 96,271	$ 201,153	$ 256,001	$ 122,546
Net income	$ 54,070	$ 89,901	$ 116,049	$ 42,312
Earnings per average common share outstanding				
Net income – basic	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Net income – diluted	$ 0.64	$ 1.06	$ 1.37	$ 0.50
Dividends declared per share	$ 0.35	$ 0.35	$ 0.35	$ 0.375

(dollars in thousands, except per share amounts)	1999			
QUARTER ENDED	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 413,983	$ 511,434	$ 867,630	$ 500,137
Real Estate	24,533	32,697	26,640	46,299
Operating Income (a)	$ 91,599	$ 148,968	$ 240,294	$ 97,916
Income from continuing operations	$ 30,690	$ 68,702	$ 125,579	$ 44,801
Income tax benefit from discontinued operations	—	—	38,000	—
Extraordinary charge – net of income tax	—	—	(139,885)	—
Net income	$ 30,690	$ 68,702	$ 23,694	$ 44,801
Earnings (loss) per average common share outstanding				
Continuing operations – basic	$ 0.36	$ 0.81	$ 1.48	$ 0.53
Discontinued operations – basic	—	—	0.45	—
Extraordinary charge – basic	—	—	(1.65)	—
Net income – basic	$ 0.36	$ 0.81	$ 0.28	$ 0.53
Continuing operations – diluted	$ 0.36	$ 0.81	$ 1.48	$ 0.53
Discontinued operations – diluted	—	—	0.45	—
Extraordinary charge – diluted	—	—	(1.65)	—
Net income – diluted	$ 0.36	$ 0.81	$ 0.28	$ 0.53
Dividends declared per share (b)	$ 0.325	$ 0.65	$ —	$ 0.35

(a) Electric revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(b) Dividends for the quarter ending September 30, 1999 were declared in June 1999.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2000 and 1999 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2000 and 1999 fair values of such investments, which we determine by using quoted market values, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.42 billion on December 31, 2000, with an estimated fair value of $2.48 billion. On December 31, 1999, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.31 billion, with an estimated fair value of $2.29 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

The following table presents earnings per average common share outstanding (EPS):

	2000	*1999*	*1998*
Basic EPS:			
Continuing operations	$ 3.57	$ 3.18	$ 2.87
Discontinued operations	—	0.45	—
Extraordinary charge	—	(1.65)	—
Net income	$ 3.57	$ 1.98	$ 2.87
Diluted EPS:			
Continuing operations	$ 3.56	$ 3.17	$ 2.85
Discontinued operations	—	0.45	—
Extraordinary charge	—	(1.65)	—
Net income	$ 3.56	$ 1.97	$ 2.85

Dilutive stock options increased average common shares outstanding by 202,738 shares in 2000, 291,392 shares in 1999, and 571,728 shares in 1998. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,935,282 shares in 2000, 85,008,527 shares in 1999, and 85,345,946 shares in 1998.

Options to purchase 517,614 shares of common stock were outstanding at December 31, 2000 but were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted EPS were 506,734 at December 31, 1999 and 244,200 at December 31, 1998.

17. STOCK-BASED COMPENSATION

Pinnacle West offers two stock incentive plans for our and our subsidiaries' officers and key employees.

The plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

The awards outstanding under the incentive plans at December 31, 2000 approximate 1,569,171 non-qualified stock options, 193,992 shares of restricted stock, and no incentive stock options, stock appreciation rights or dividend equivalents.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective beginning in 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value of options granted (fair value method). We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees."

If we had recorded compensation expense based on the fair value method, our net income and earnings per share would have been reduced to the following pro forma amounts:

(dollars in thousands)	2000	1999	1998
Net income			
As reported	$ 302,332	$ 167,887	$ 242,892
Pro forma (fair value method)	$ 301,102	$ 166,913	$ 242,177
Earnings per share – basic			
As reported	$ 3.57	$ 1.98	$ 2.87
Pro forma (fair value method)	$ 3.55	$ 1.97	$ 2.86

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	2000	1999	1998
Risk-free interest rate	5.81%	5.68%	4.54%
Dividend yield	3.48%	3.33%	3.03%
Volatility	32.00%	20.50%	18.80%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 2000, 1999, and 1998 and changes during the years ending on those dates:

(dollars in thousands)	2000 Shares	2000 Weighted Average Exercise Price	1999 Shares	1999 Weighted Average Exercise Price	1998 Shares	1998 Weighted Average Exercise Price
Outstanding at beginning of year	1,441,124	$ 33.45	1,563,512	$ 27.95	1,554,631	$ 24.38
Granted	451,450	43.28	458,450	35.95	244,200	46.78
Exercised	(283,819)	20.90	(516,838)	18.19	(217,317)	23.09
Forfeited	(39,584)	39.86	(64,000)	40.36	(18,002)	33.42
Outstanding at end of year	1,569,171	37.55	1,441,124	33.45	1,563,512	27.95
Options exercisable at year-end	831,537	34.37	835,381	29.69	1,106,165	22.04
Weighted average fair value of options granted during the year		11.81		7.05		8.15

The following table summarizes information about our stock option plans at December 31, 2000:

Exercise Prices Per Share	Options Outstanding	Weighted Average Remaining Contract Life (Years)	Options Exercisable
$10.06	7,000	.50	7,000
15.75	10,000	.90	10,000
17.68	4,900	1.10	4,900
18.13	14,000	1.50	14,000
19.00	58,618	3.90	58,618
19.56	15,000	1.90	15,000
22.13	33,250	3.00	33,250
23.25	14,000	2.50	14,000
27.16	20,000	9.20	5,000
27.44	84,918	4.90	84,918
31.44	87,335	5.90	87,335
34.66	327,113	8.90	118,124
36.56	5,000	8.80	2,083
39.75	170,636	7.00	170,636
41.00	70,000	8.10	44,722
44.03	431,450	9.90	11,985
46.78	215,951	7.90	149,966
$10.06 – $46.78	1,569,171		831,537

18. BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment) which consist of the transmission and distribution of electricity and wholesale activities (delivery business segment) and the generation of electricity (generation business segment). The other amounts include activity relating to the parent company and other subsidiaries including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Financial data for the business segments is provided as follows:

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 2000

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 990,415	$ 3,531,810	$ 158,365	$ (990,415)	$ 3,690,175
Operating expense	600,389	2,871,329	138,677	(990,415)	2,619,980
Operating margin	390,026	660,481	19,688	—	1,070,195
Depreciation and amortization	125,220	263,446	5,744	—	394,410
Interest	41,808	96,081	11,712	—	149,601
Pretax margin	222,998	300,954	2,232	—	526,184
Income taxes	87,828	134,692	1,332	—	223,852
Earnings for common stock	$ 135,170	$ 166,262	$ 900	$ —	$ 302,332
Total assets	$ 2,606,046	$ 4,068,510	$ 474,595	$ —	$ 7,149,151
Capital expenditures	$ 379,761	$ 285,455	$ 49,949	$ —	$ 715,165

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1999

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 853,755	$ 2,292,798	$ 130,555	$ (853,755)	$ 2,423,353
Operating expense	522,925	1,672,169	106,876	(853,755)	1,448,215
Operating margin	330,830	620,629	23,679	—	975,138
Depreciation and amortization	121,683	260,374	3,511	—	385,568
Interest and preferred stock dividend requirements	40,753	101,855	9,125	—	151,733
Pretax margin	168,394	258,400	11,043	—	437,837
Income taxes	47,976	111,512	8,577	—	168,065
Income tax benefit from discontinued operations – PNW	—	—	38,000	—	38,000
Extraordinary charge – net of income tax of $94,115	—	(139,885)	—	—	(139,885)
Earnings for common stock	$ 120,418	$ 7,003	$ 40,466	$ —	$ 167,887
Total assets	$ 2,342,291	$ 3,795,846	$ 470,369	$ —	$ 6,608,506
Capital expenditures	$ 110,798	$ 241,469	$ 126,581	$ —	$ 478,848

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1998

(dollars in thousands)	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 858,340	$ 2,006,398	$ 124,188	$ (858,340)	$ 2,130,586
Operating expense	522,696	1,414,753	104,061	(858,340)	1,183,170
Operating margin	335,644	591,645	20,127	—	947,416
Depreciation and amortization	135,406	241,168	3,105	—	379,679
Interest and preferred stock dividend requirements	37,045	108,670	14,537	—	160,252
Pretax margin	163,193	241,807	2,485	—	407,485
Income taxes	49,969	109,487	5,137	—	164,593
Earnings for common stock	$ 113,224	$ 132,320	$ (2,652)	$ —	$ 242,892
Total assets	$ 2,399,560	$ 3,993,740	$ 431,246	$ —	$ 6,824,546
Capital expenditures	$ 85,767	$ 241,638	$ 73,133	$ —	$ 400,538

BOARD OF DIRECTORS

PAMELA GRANT
(62) 1980*
Civic Leader
Committees:
Human Resources, Chairman
Audit

MARTHA O. HESSE
(58) 1991
President, Hesse Gas Company
Committees:
Audit, Chairman
Finance and Operating

THE REV. BILL JAMIESON, JR.
(57) 1991
President, Institute for Servant Leadership of Asheville, North Carolina
Committee:
Human Resources

ROY A. HERBERGER, JR.
(58) 1992
President, Thunderbird, The American Graduate School of International Management
Committees:
Finance and Operating, Chairman
Human Resources

ROBERT G. MATLOCK
(67) 1993
Management Consultant
R.G. Matlock & Associates, Inc.
Committee:
Human Resources

WILLIAM J. POST
(50) 1994
Chairman of the Board & Chief Executive Officer
Committee:
Finance and Operating

HUMBERTO S. LOPEZ
(55) 1995
President, HSL Properties, Inc.
Committee:
Audit

MICHAEL L. GALLAGHER
(56) 1997
Chairman Emeritus
Gallagher & Kennedy, P.A.
Committee:
Human Resources

BRUCE J. NORDSTROM
(51) 1997
Certified Public Accountant, Nordstrom and Associates, P.C.
Committee:
Audit

JACK E. DAVIS
(54) 1998
President

EDDIE BASHA
(63) 1999
Chairman of the Board, Basha's
Committee:
Audit

KATHRYN L. MUNRO
(52) 1999
Chairman, BridgeWest L.L.C.
Committee:
Finance and Operating

** The year in which the individual first joined the Board of a Pinnacle West company.*

OFFICERS

PINNACLE WEST

William J. Post
(50) 1973*
Chairman of the Board &
Chief Executive Officer

Jack E. Davis
(54) 1973
President

Armando B. Flores
(57) 1991
Executive Vice President,
Corporate Business Services

Robert S. Aiken
(44) 1986
Vice President, Federal Affairs

John G. Bohon
(55) 1971
Vice President, Corporate Services &
Human Resources

Edward Z. Fox
(47) 1995
Vice President, Communications,
Environment & Safety

Chris N. Froggatt
(43) 1986
Vice President & Controller

Nancy C. Loftin
(47) 1985
Vice President & General Counsel

Michael V. Palmeri
(42) 1982
Vice President, Finance

Martin L. Shultz
(56) 1979
Vice President, Government Affairs

Faye Widenmann
(52) 1978
Vice President & Secretary

Barbara M. Gomez
(46) 1978
Treasurer

ARIZONA PUBLIC SERVICE

William J. Post
Chairman of the Board &
Chief Executive Officer

Michael V. Palmeri
Vice President, Finance

Faye Widenmann
Vice President & Secretary

Nancy C. Loftin
Vice President & General Counsel

Barbara M. Gomez
Treasurer

Jack E. Davis
President,
Energy Delivery & Sales

Jan H. Bennett
(53) 1967
Vice President, Customer Service

William L. Stewart
(57) 1994
President, Generation

James M. Levine
(51) 1989
Executive Vice President,
Generation

Gregg R. Overbeck
(54) 1990
Senior Vice President,
Nuclear Generation

John R. Denman
(58) 1964
Vice President, Fossil Generation

William E. Ide
(54) 1977
Vice President,
Nuclear Production

David Mauldin
(51) 1990
Vice President, Nuclear
Engineering & Support

PINNACLE WEST ENERGY

William L. Stewart
President

Ajoy K. Banerjee
(55) 1999
Vice President, Generation Expansion

Ajit P. Bhatti
(55) 1973
Vice President, Generation Planning

APS ENERGY SERVICES

Vicki G. Sandler
(44) 1982
President, Energy Services

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

John C. Ogden
(55) 1972
President & Chief Executive Officer

Geoffrey L. Appleyard
(47) 1987
Vice President & Chief Financial Officer

Duane S. Black
(48) 1989
Vice President & Chief Operating Officer

Jay T. Ellingson
(51) 1992
Vice President, Development –
Palm Valley

Steven Gervais
(45) 1987
Vice President & General Counsel

Margaret E. Kirch
(51) 1988
Vice President,
Commercial Development

Thomas A. Patrick
(47) 1995
Vice President, Golf Operations

EL DORADO INVESTMENT

William J. Post
Chairman of the Board,
President and CEO

** The year in which the individual was first employed within the Pinnacle West group of companies.*

SHAREHOLDER INFORMATION

CORPORATE HEADQUARTERS
Street address:
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004

Mailing address:
P.O. Box 52133
Phoenix, Arizona 85072-2133

Main telephone number: (602) 250-1000

ANNUAL MEETING OF SHAREHOLDERS
Wednesday, May 23, 2001
10:30 a.m.
The Orpheum Theatre
203 West Adams Street
Phoenix, Arizona 85003

STOCK LISTING
Ticker symbol: PNW on New York Stock Exchange and Pacific Stock Exchange
Newspaper financial listings: PinWst

FORM 10-K
Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available to shareholders upon written request, without charge. Write: Office of the Secretary.

INVESTORS ADVANTAGE PLAN
Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping, reduced brokerage commissions and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling the Company at the toll-free number listed on this page, at the corporate Web site, or by writing to:

Pinnacle West Capital Corporation
Shareholder Department
P.O. Box 52133
Phoenix, AZ 85072-2133

CORPORATE WEB SITE
www.pinnaclewest.com

TRANSFER AGENTS AND REGISTRAR
Common Stock
Pinnacle West Capital Corporation
Stock Transfer Department
P.O. Box 52134
Phoenix, Arizona 85072-2134
Or:
400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004
Telephone: (602) 379-2519

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION
Shareholder Department
Toll-free: (800) 457-2983

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1995-2000 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

INVESTOR RELATIONS CONTACT
Rebecca L. Hickman
Director, Investor Relations
P.O. Box 53999 Station 9998
Phoenix, Arizona 85072-3999
Telephone: (602) 250-5668
Fax: (602) 250-2789

STATEWIDE ASSOCIATION FOR UTILITY INVESTORS
The Arizona Utility Investors Association represents the interests of investors in Arizona utilities. If interested, send your name and address to:

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067
(602) 257-9200
www.auia.org

IMPORTANT NOTICE FOR SHAREHOLDERS:
Pinnacle West now posts quarterly results and other important information on its Web site (www.pinnaclewest.com). If you would like to receive news by regular mail, fax or e-mail, let us know by mail or phone at the addresses and numbers listed on this page. Also, let us know if you would like to be kept abreast of legislative and regulatory activities at the state and federal levels which could impact investor-owned utilities.

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