APS

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10 CFR 50.71(b)

102-04483-AKK/SAB/CJJ
September 13, 2000

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-37
Washington, DC 20555-0001

Dear Sirs:

Subject: **Palo Verde Nuclear Generating Station (PVNGS)**
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Submittal of 1999 Annual Financial Reports

Pursuant to 10 CFR 50.71(b), enclosed please find copies of the 1999 Annual Financial Reports for the Participants who jointly own PVNGS. These Participants are Arizona Public Service Company, Salt River Project, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Southern California Public Power Authority, and Los Angeles Department of Water and Power. No commitments are being made to the NRC by this letter.

If you have any questions, please contact Scott A. Bauer at (623) 393-5978.

Sincerely,

Angela K Krainik

AKK/SAB/CJJ/kg

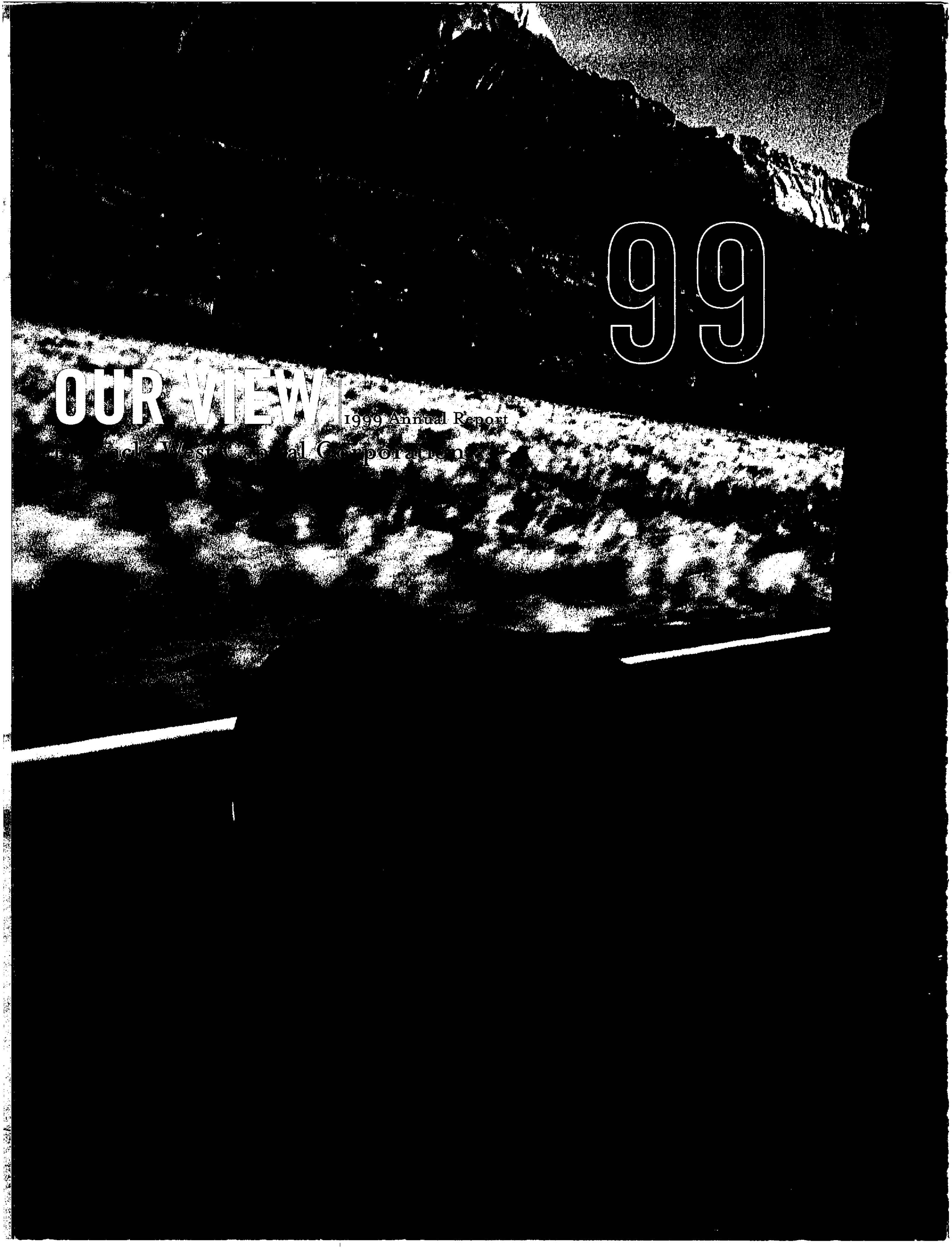
Enclosures

cc: E. W. Merschoff (all w/enclosure)
M. B. Fields
J. H. Moorman

ENCLOSURE

PALO VERDE NUCLEAR GENERATING STATION

1999 ANNUAL FINANCIAL REPORTS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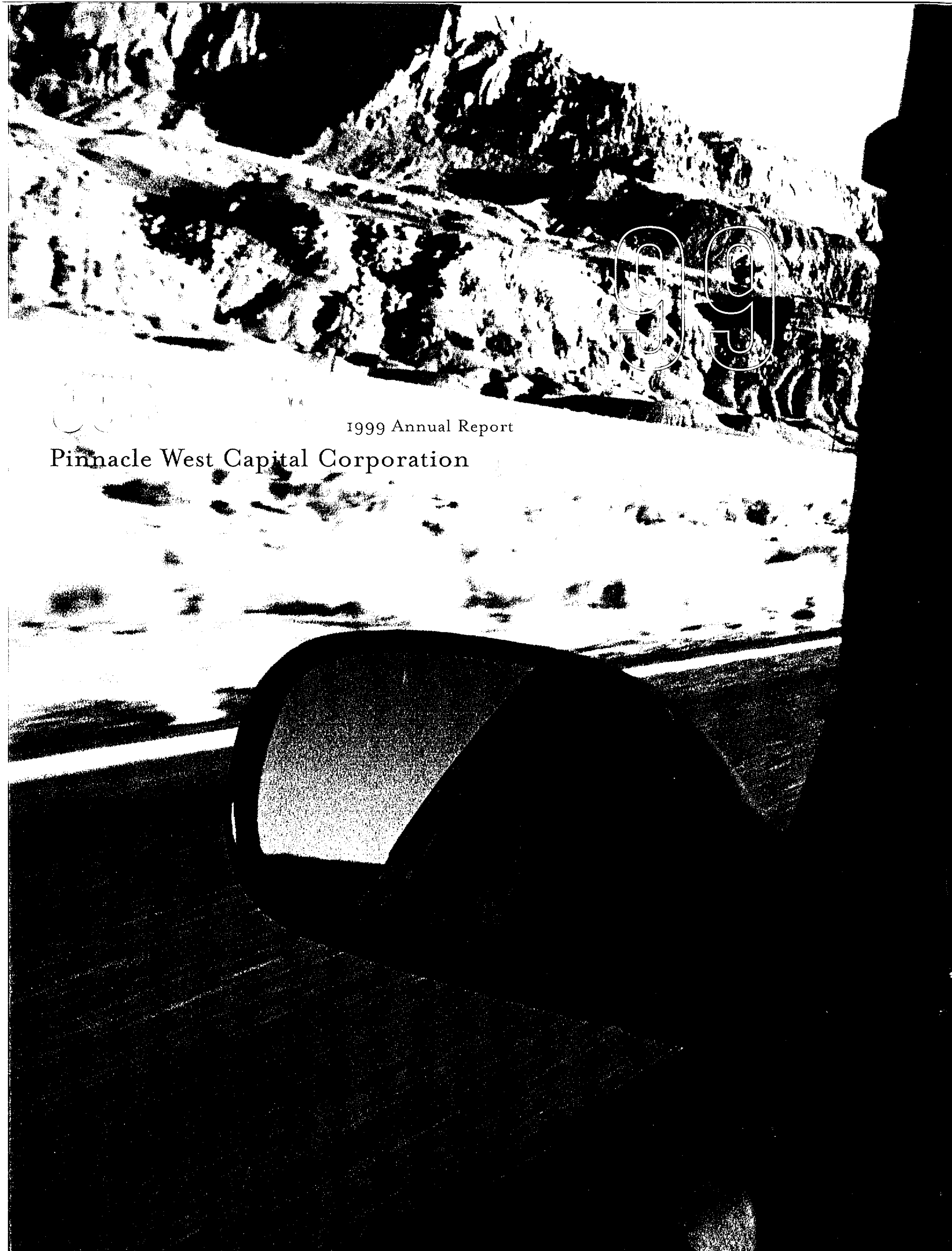
OUR VIEW
1999 Annual Report
Pinnacle West Capital Corporation



1999 Annual Report

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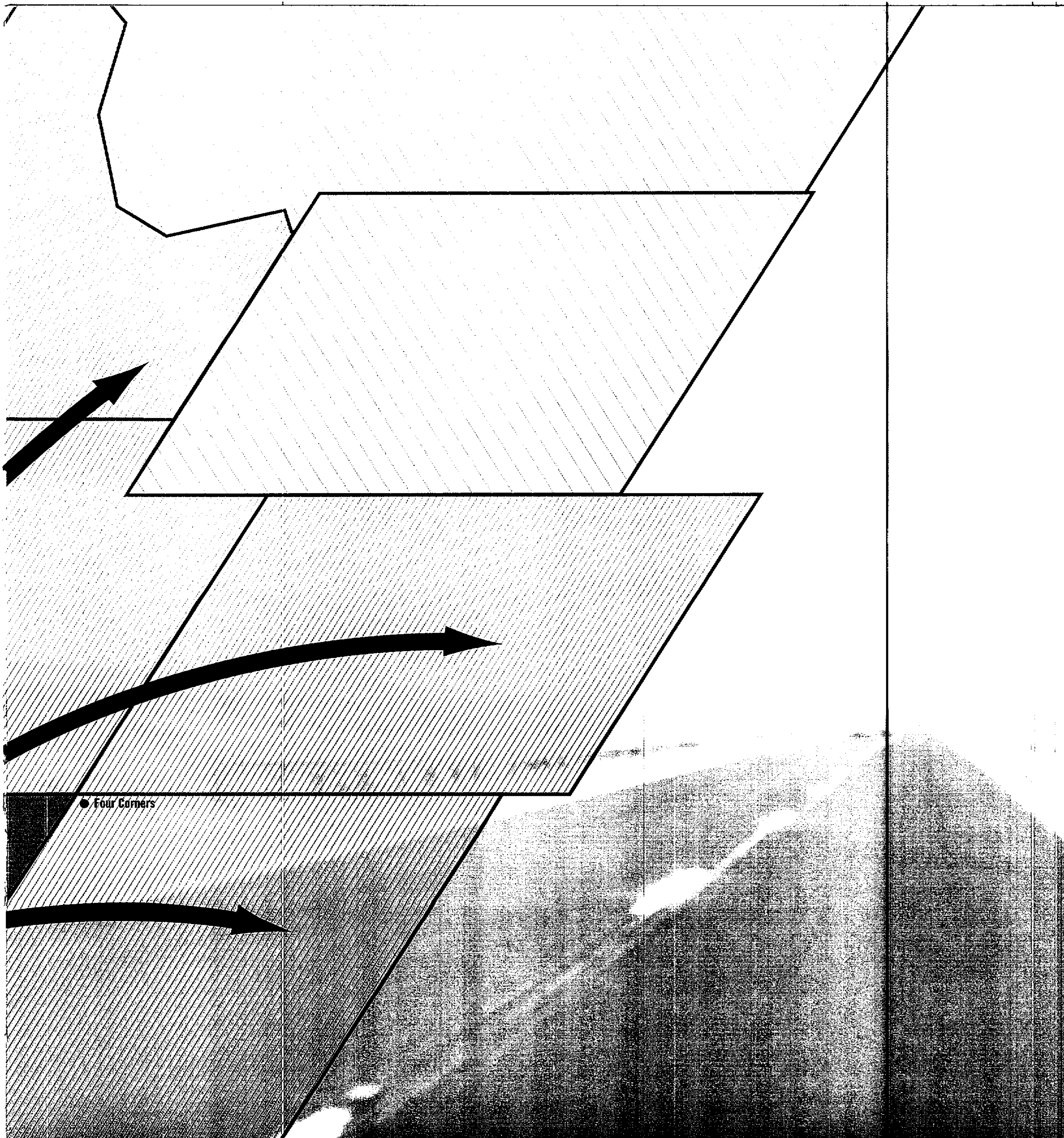
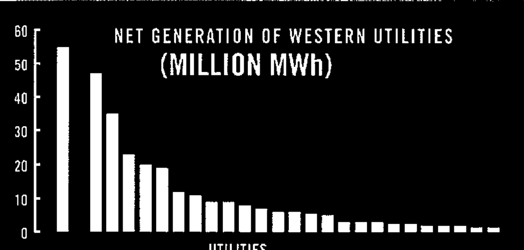
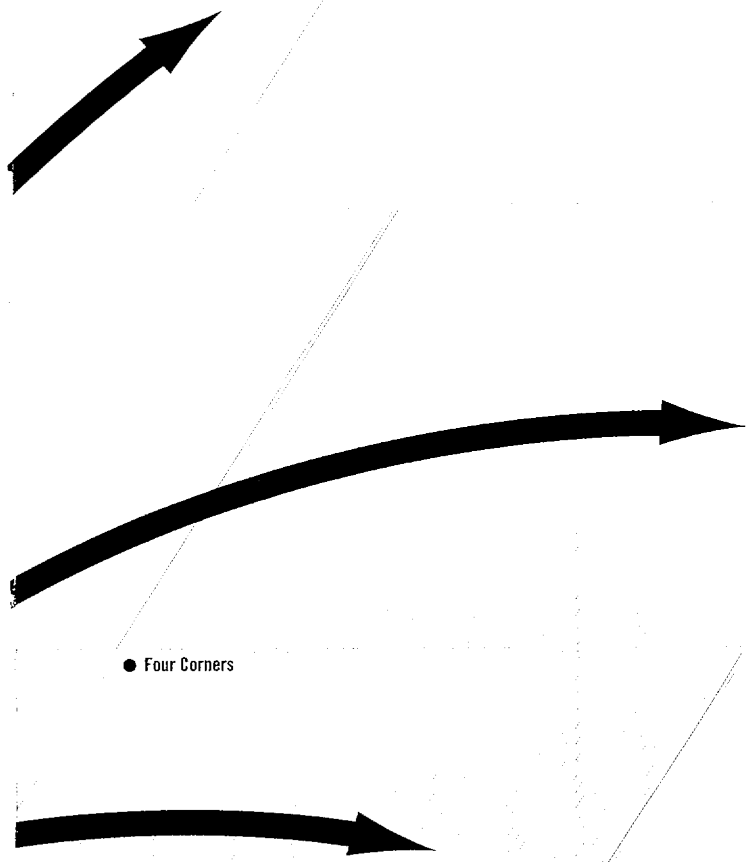
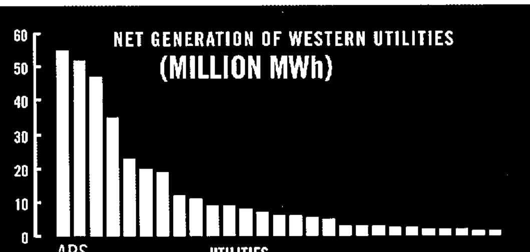




THE SECOND LARGEST GENERATION PORTFOLIO IN THE WEST

SOME OF THE LOWEST PRODUCTION COSTS IN THE WEST





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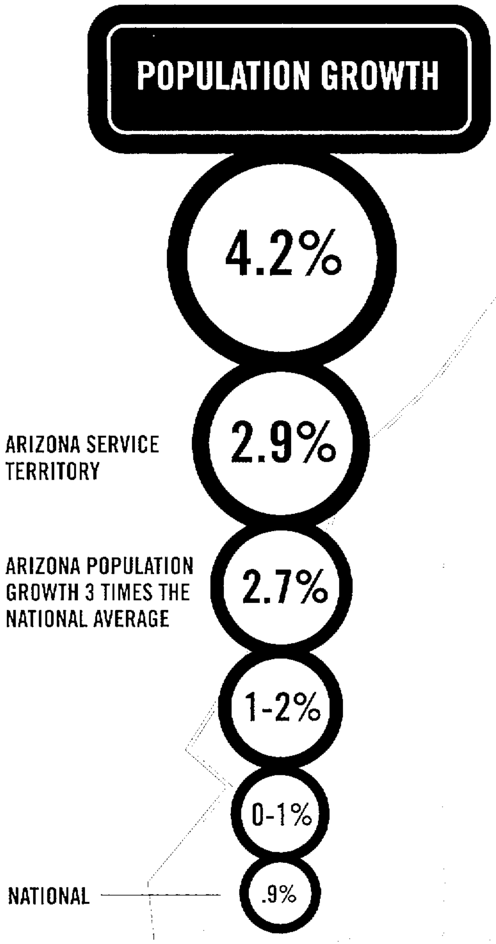
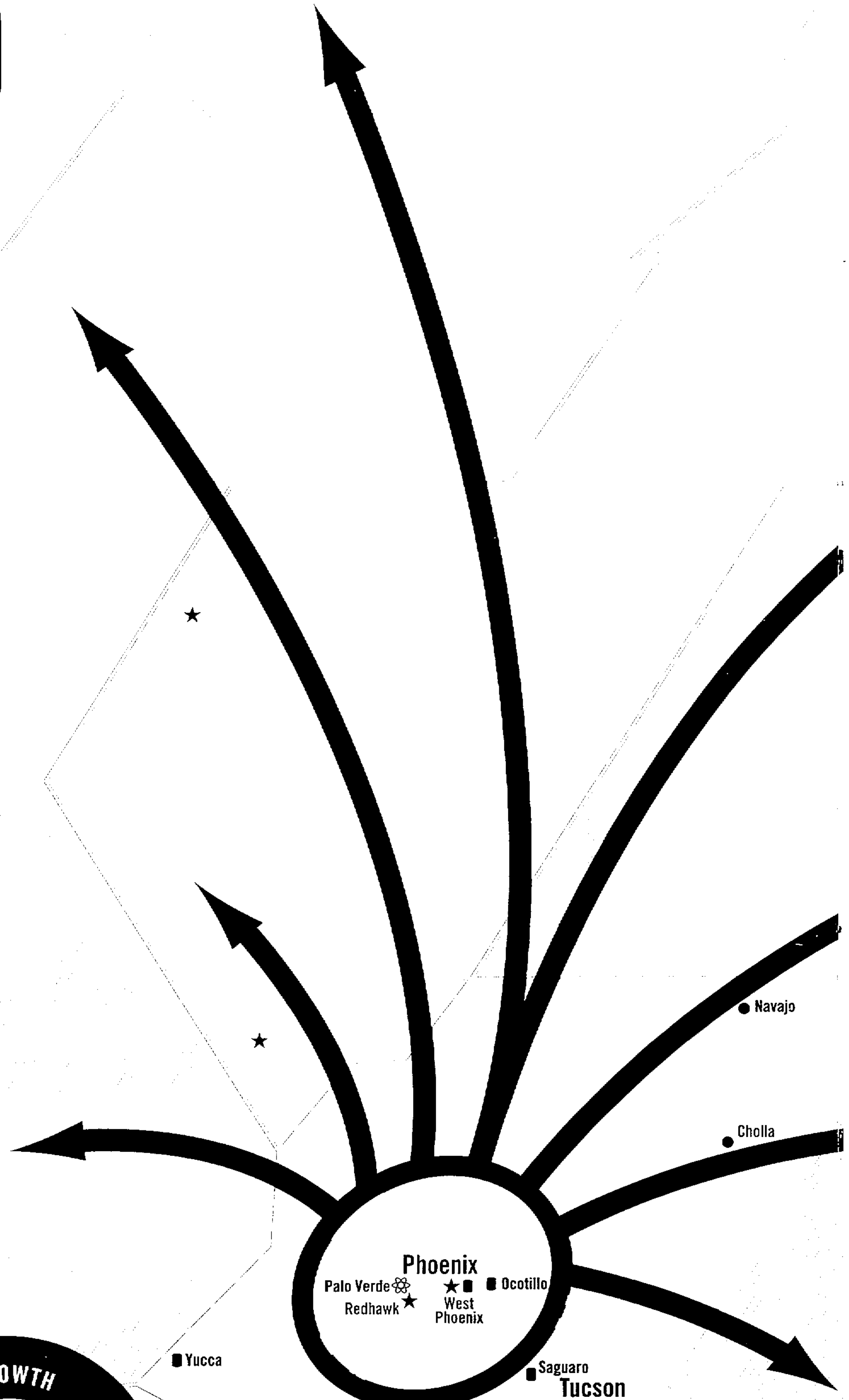
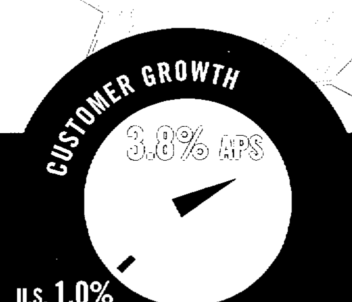




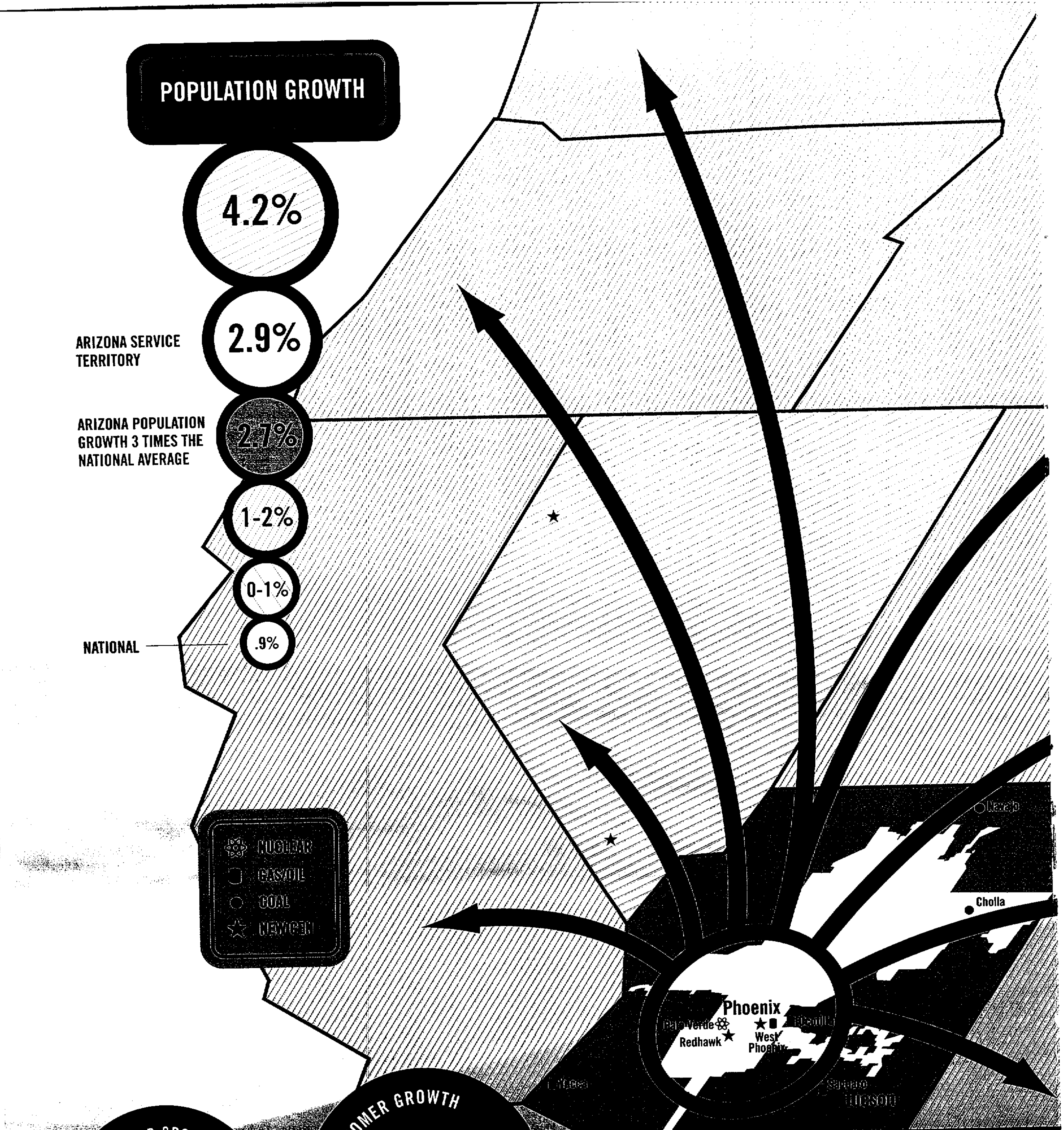
REGIONAL PEAK LOAD GROWTH 2 TIMES THE NATIONAL AVERAGE



CUSTOMER GROWTH 4 TIMES THE NATIONAL AVERAGE

OUR VIEW

FROM THE MOST ACTIVE TRADING HUB IN THE WEST



PEAK LOAD GROWTH

3.8% SOUTHWEST

U.S. 1.9%

REGIONAL PEAK LOAD GROWTH 2 TIMES THE NATIONAL AVERAGE

CUSTOMER GROWTH

3.8% APS

U.S. 1.0%

CUSTOMER GROWTH 4 TIMES THE NATIONAL AVERAGE

OUR VIEW

FROM THE MOST ACTIVE TRADING HUB IN THE WEST

Pinnacle West has outperformed the electric utility industry and is positioned to capture the benefits of the fast-growing markets in the western United States.

COMPETITIVE ADVANTAGES

- We focus on the area we know – the West. Unique to companies our size and in our region, we can engage in both electricity production and delivery.
- Our cash flow, which ranks in the top 10 percent in the industry, provides financial flexibility to support our future growth.
- Our low power production costs position us well competitively. Our nuclear production costs are among the lowest in the nation and our overall average production costs are below regional averages and those of new technologies.

GROWTH

- In 1999, our customer base grew 3.8 percent compared with an electric utility industry growth rate of about one percent. Economic forecasts project our growth advantage to continue.
- Our settlement agreement allows price-cap regulation and deregulation of generation, both creating the potential for strong earnings growth.
- Our announced expansion plan will increase our generating capability by about 3,000 megawatts, placing us among the largest generation owners in the West.

VALUE

- Over the past five years, our earnings per share – after eliminating non-recurring items to clarify the underlying trend – grew at an average annual rate of 10 percent.
- During the same period, our total return to shareholders was 85 percent, more than one and a half times the electric utility industry average.

FINANCIAL HIGHLIGHTS (dollars in thousands, except per share amounts)

	1999	1998	1997	Selected Growth Rates 1999 vs. 1998	1998 vs. 1997
INCOME HIGHLIGHTS					
Operating Revenues	$ 2,423,353	$ 2,130,586	$ 1,995,026	13.7%	6.8%
Income from Continuing Operations	$ 269,772	$ 242,892	$ 235,856	11.1%	3.0%
BALANCE SHEET HIGHLIGHTS					
Total Assets	$ 6,608,506	$ 6,824,546	$ 6,850,417	(3.2)%	(0.4)%
Common Stock Equity	$ 2,205,733	$ 2,163,351	$ 2,027,436	2.0%	6.7%
PER SHARE HIGHLIGHTS					
Earnings Per Share from Continuing Operations – Diluted	$ 3.17	$ 2.85	$ 2.74	11.2%	4.0%
Dividends Paid Per Share	$ 1.325	$ 1.225	$ 1.125	8.2%	8.9%
Book Value Per Share – Year-End	$ 26.00	$ 25.50	$ 23.90	2.0%	6.7%
STOCK PERFORMANCE					
Stock Price Per Share – Year-End	$ 30 9/16	$ 42 3/8	$ 42 3/8	(27.9)%	—
Stock Price Appreciation (decrease)	(27.9)%	—	33.5%		
Total Return	(25.1)%	2.8%	38.0%		
Market Capitalization – Year-End	$ 2,592,462	$ 3,594,457	$ 3,594,457	(27.9)%	—

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Pinnacle West is a Phoenix-based company with consolidated assets of $6.6 billion and annual revenues of $2.4 billion. Through our subsidiaries, we generate, sell and deliver electricity, and we sell 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 projects.

To Our Shareholders:

As this year's annual report cover suggests, we're looking ahead, and we see a firm direction for our future. In our view, the old utility industry with its regulatory uncertainties is rapidly receding in the rearview mirror.

What We've Done

We've resolved our regulatory past with a new, performance-based compact. This settlement, which was approved by the Arizona Corporation Commission (ACC) in October 1999, brings competition to Arizona, gives customers a series of price reductions, settles transition and stranded cost issues and allows us to move our generation assets to an unregulated subsidiary by 2002 or sooner.

We've thought long and hard about our competitive position in a restructured utility industry. We've concluded that we don't know gas pipelines or gas production, and we got out of gas distribution a long time ago. We don't know the U.K. or Southeast Asia or South America. So we won't go there.

What we do know is electricity production and delivery in our part of the United States. And we have the benefit – somewhat unique to companies our size and operating in our region – of being authorized to engage in both. With knowledge of growing western power markets, the cash flow from distribution, the earnings potential of unregulated production and the rules of the competitive game in Arizona finally established, we strongly believe we are well positioned:

- Our bottom-line focus will be even more relentless, bolstered by our regulatory settlement that allows us to retain our cost savings for shareholders.
- Top-line revenue should continue to grow, propelled by dynamic population growth in the Southwest.
- As the second-largest generation operator in the West, we're building and plan to buy additional generation facilities in the western markets that we know well.
- Strong cash flow will fund all of our customer growth and much of our generation growth plan. Generation growth is being undertaken with a goal of maintaining investment-grade credit quality in our securities at the corporate level.

Our cash flow is among the strongest in the electric utility industry. This discretionary cash flow provides flexibility for us to fund customer growth, invest in unregulated businesses, increase the dividend or reduce debt. Based on cash coverage of dividends, we rank in the top 10 percent of the industry.

Throughout the 90s, we improved productivity, doubling the number of customers served per employee. We reduced our actual cost per kilowatt-hour below 1985 levels. We became an outstanding generation performer. We reduced debt, and gained a solid financial footing. We've replaced all of our legacy computer technology, and our focus is on the future of today's core business.

Despite our stop-and-go regulatory environment of the past few years, retail competition has finally begun in Arizona and will be available to all customers in 2001. We worked aggressively to achieve a settlement agreement with representatives from many customer and industry groups to get competition under way and expand the wholesale generation market.

With this settlement in place, we can speak with greater clarity about our strategies and confidently execute them.

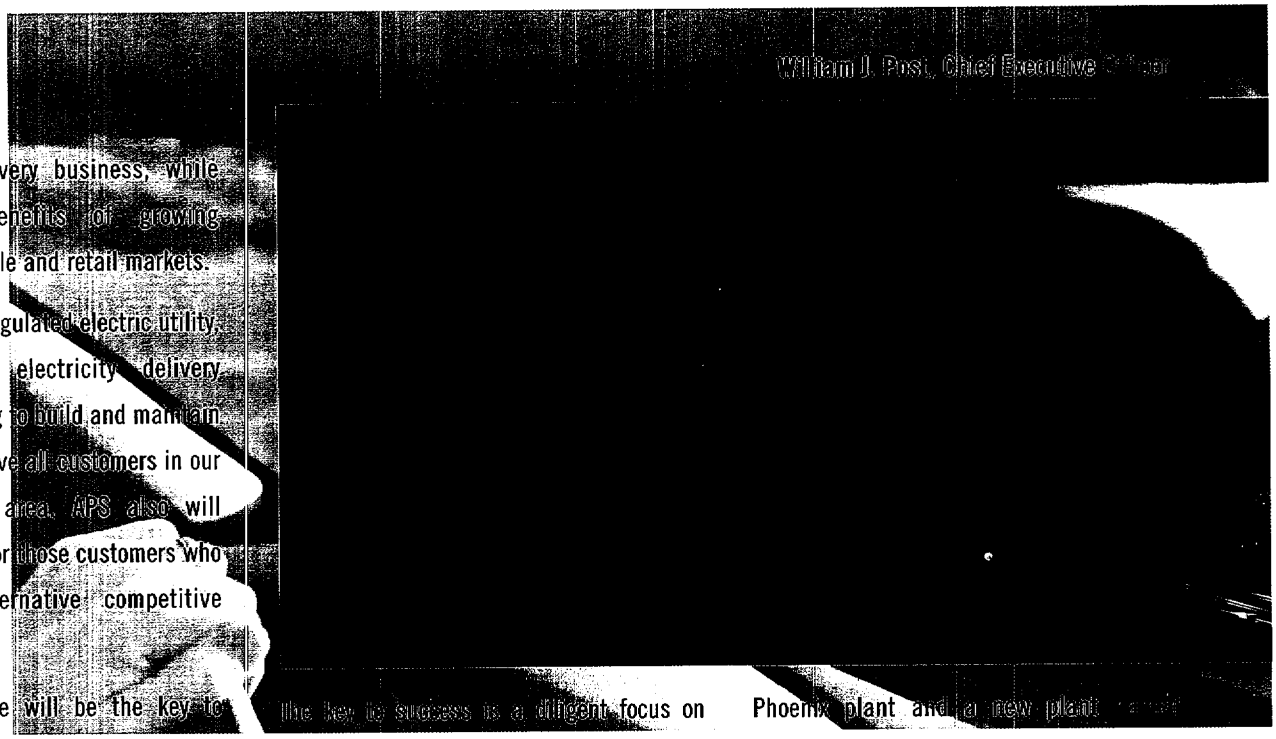
Where We're Going

In our view, the future is full of possibility and as wide open as the vistas pictured throughout this report.

We have a capable team. We're building and planning to buy more of the right assets, and we're dedicated to providing outstanding customer service. We intend to capitalize on the intrinsic high growth in

Our company sits right at a major energy hub in the West – with strong load growth and an expanding wholesale market.

William J. Post, Chief Executive Officer



our regulated delivery business, while capturing the benefits of growing competitive wholesale and retail markets.

Delivery APS, our regulated electric utility, will become an electricity delivery company, continuing to build and maintain the "wires" that serve all customers in our regulated service area. APS also will provide electricity for those customers who don't choose alternative competitive energy suppliers.

Outstanding service will be the key to retaining customers. We will achieve high customer satisfaction while focusing on cost management. We're using new technology to improve service and productivity, as measured by customers served per employee and cost per kilowatt-hour.

We've made a strong commitment to technology because we recognize that information and knowledge drive our business. We've invested more than $200 million in productivity-enhancing systems to help us extract the maximum value from our assets. While the typical shareholder may not think of us as a technology company, we do.

Our strategy for the electricity delivery business is to expand our current customer base while improving margins through relentless cost control.

Generation For generation, the goals are to operate competitively efficient generating plants, maximize output, minimize production costs per unit of output and move our product to market as profitably as possible.

The key to success is a diligent focus on operational efficiency, cost management and continuous improvement, combined with disciplined expansion of generation holdings and innovative power marketing. Our ability to add new generation and to transfer existing generation to a new unregulated subsidiary, Pinnacle West Energy, will let us take advantage of a growing competitive western wholesale market.

We have a number of competitive strengths in the generation business that make us confident we can grow this business profitably:

- We already are the second-largest operator of generation assets in the West. For us, generation is a core business.
- We have an enviable record as a nuclear, coal and gas plant operator.
- We can use our regional market knowledge to site new plants and use our assets to attract partners and obtain assets outside Arizona.

In 1999, we announced two new major gas-fired generating projects totaling about 2,800 megawatts – additions at our West Phoenix plant and a new plant named "Redhawk" to be built near Palo Verde.

The Redhawk site is especially desirable because an extensive transmission system linked to some of the fastest-growing markets in the nation converges at Palo Verde, making it a major trading hub for western power markets. It already provides a settlement site for NYMEX futures contracts and a source of daily spot market quotes.

By moving quickly to build our new plants, we have taken a disciplined stake in the future growth of Arizona, the Southwest and the whole interconnected western electricity market. This strategy is already taking shape. In March 2000, we announced that Houston-based Reliant Energy will partner with us on the first two Redhawk units, and we will join with them on two power plant projects in Nevada. These projects represent Pinnacle West Energy's first generation venture outside Arizona – but within the West, where we intend to stay.

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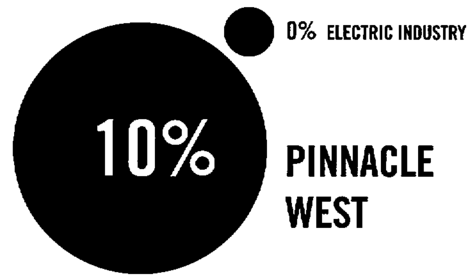
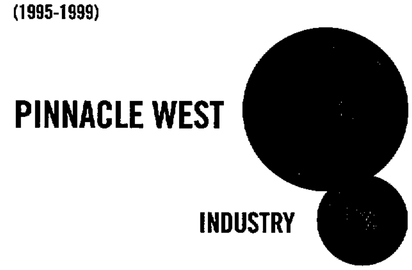
DIVIDEND GROWTH
(1995-1999)



EARNINGS PER SHARE GROWTH
(1995-1999)



We're also interested in increasing our ownership share of plants we already operate and partly own, including the Palo Verde nuclear station. We can increase our revenues and earnings by expanding our ownership share in plants that we've already shown can operate at the highest levels.

APS Energy Services Our competitive sales subsidiary expands our retail offerings by selling unregulated power and related services tailored to the customers' individual demands and energy-use patterns.

Our strategy is to target selected customers and customer groups that we can serve profitably with electric energy and demand-management technologies and services. We require positive gross margins from each customer relationship, whether commodity only, services only, or both.

SunCor and El Dorado Our real estate subsidiary, SunCor Development, and our investment subsidiary, El Dorado, almost doubled their combined earnings contribution in 1999. We look for increases again this year if the markets for real estate and technology-related stock remain strong.

Issues Along Our Way

We're aware of several challenges on the road to a new business environment and continuing growth.

Legal Challenges Recently filed lawsuits raise issues about specific parts of our settlement agreement. We believe that these narrow issues will be resolved without significant impact.

The legal challenges also raise Arizona Constitutional issues about allowing competitive markets to set electricity prices. These constitutional issues are unique to Arizona, were favorably decided by lower courts in past utility cases and were considered by the ACC and us in proceeding as we did. Nevertheless, it is possible that a political solution, in the form of a constitutional amendment to facilitate a competitive market in electricity, may be appropriate to remove any legal uncertainty.

Given the broad support for the settlement agreement among the intervenors, and the appeal of a competitive market to Arizona's political leadership, we think a favorable vote on such an amendment is achievable.

Size Our view is that profitability is more important than size, and our focus on growing generation is to target areas with faster-than-average population and load growth.

Strong economic growth in the western United States – and particularly in Arizona – gives us the opportunity to continue superior earnings growth without taking inordinate expansion risks such as offshore investments and convergence strategies.

We believe that operating in the West – a region in which we have proven skills and knowledge – will provide superior growth opportunities.

Power Marketing and Risk Management Our power marketing group provides key cost and risk management services for our businesses. This group buys power for our regulated customers, acquires energy for our retail energy services business and will sell the output from our unregulated generation company. Balancing our customers' needs and hedging market risks are crucial tasks that our power marketing group manages while adding to the bottom line.

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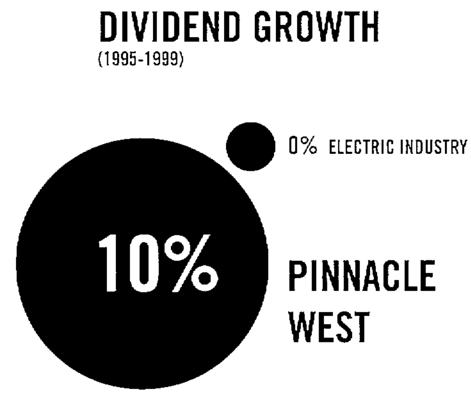

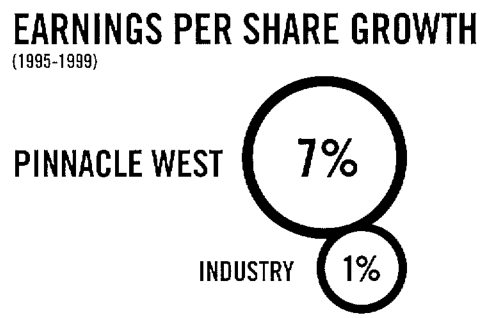

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We recognize that risks are different in an unregulated marketplace than they were in the regulated environment. Since 1988, we have managed the risk of buying fuel and purchased power without an adjustment clause, which many electric utilities have relied on extensively for more than a decade. While this situation may have been viewed negatively in the past, we think our experience in risk management provides confidence that we can manage this aspect of our business and readily adapt to more volatile competitive power markets.

The risk of overbuilding merchant generation is often mentioned and is one that we take seriously. Our plans for generation expansion are disciplined and conservative for the following reasons.

First, the Southwest is currently a net importer of power and is continuing to grow rapidly. Second, although other companies have announced plans for new facilities in Arizona, we believe that timing and execution will give us an early entrant advantage.

Our view is that managing the inherent risk in a competitive wholesale market is critical for all our energy businesses. Strong risk management tools, experienced risk managers and detailed western market knowledge have been and will continue to be our trademarks in this area.

Wholesale Markets and Transmission The Federal Energy Regulatory Commission (FERC) recognizes the importance of wholesale markets and is requiring all transmission-owning utilities to join a regional transmission organization (RTO) or to explain the barriers to forming an RTO. We are working with other western utilities to develop Desert Star, an independent system operator, but conflicting geographic and ownership interests, particularly differences between government-owned and investor-owned utilities, make it difficult to predict the eventual outcome of this effort.

Current western wholesale markets are "thin" and driven more by regulated utilities selling excess generation than by the wholesale sales of all energy distributed for the ultimate consumer. Future expansion of the wholesale market to include a higher proportion of all sales will depend on the region's continued movement to competition, transmission structure, regulatory intervention in evolving competitive markets and new power plant construction. The development of a liquid wholesale market is pre-conditional to a fully competitive retail market. Our settlement lets us participate in this new, growing market while providing a means to deal with regulated sales should a liquid wholesale market not develop.

Value for You

Making money for our shareholders ultimately depends on earnings and dividends. Our earnings over the past five years have grown at an average annual rate of almost seven times the industry growth of one percent. If we eliminate non-recurring items, as Wall Street analysts often do, our average growth was more than 10 percent.

Our highest priority is to provide you with long-term value that we believe comes from financial performance. In our view, value is the ability to continue making money for our shareholders through financial results.

We're proud of our performance in 1999 but dissatisfied that it is not reflected in our current stock price. Despite earnings growth for the past five years that far exceeds the electric utility average, our price earnings ratio is below the utility average.

Our earnings, dividend growth and strong cash flow set a very high standard – one we expect to continue. Our strategies are designed to produce financial results that will attract those who invest not only in electric utilities but other industries as well.

I realize that this year's letter to you is longer than usual, but I felt that it was critical for you to know how we intend to deliver value to you. It's our overriding purpose, and we will continue to outperform our industry. We are very excited about our future and believe that the strategy I have outlined is a firm formula for success.

William J. Post

William J. Post, Chief Executive Officer

OVERVIEW Our defining objective is to provide superior total returns to our shareholders through a combination of earnings and dividend growth, while maintaining financial strength and flexibility.

Financial Performance

From a financial perspective, 1999 was very strong. Earnings per share from continuing operations grew more than 11 percent. Dividends increased 7.7 percent to an indicated annual rate of $1.40 per share as of year-end. We redeemed all of APS' preferred stock and reduced our outstanding debt by a total of $132 million.

Income from continuing operations in 1999 was $269.8 million or $3.17 per diluted share of common stock, compared with $242.9 million or $2.85 per share in 1998. The year-to-year comparison was positively affected by 3.8 percent electricity customer growth, about three times the national average. The comparison also benefited from higher contributions from our non-regulated subsidiaries and lower financing costs. These earnings improvements were partially offset by the effects of two electricity price decreases and increased utility operations and maintenance expense.

Cost management remains high on our agenda. The increase in utility operations and maintenance expense was comprised almost entirely of non-recurring costs totaling approximately $20 million ($12 million after income taxes) including certain environmental and other items that are not expected in future cost levels.

Net income for 1999 of $167.9 million or $1.97 per share included an extraordinary charge for a regulatory disallowance and an income tax benefit from discontinued operations. We recorded the extraordinary charge of $139.9 million after income taxes, or $1.65 per share, in the third quarter as a part of the APS settlement approved by the Arizona Corporation Commission (ACC).

Our expected results from core operations, combined with the outlook in our non-utility businesses, provide us the opportunity for earnings growth in 2000 despite our completion of the amortization of investment tax credits at the end of 1999, which amounted to $0.28 per share of common stock.

Market Area Economy

In 1999, the population in Arizona grew 2.9 percent, or about three times the national average. Job growth was 3.5 percent. The unemployment rate was 4.2 percent. APS' calculated peak electricity load, adjusted for weather, grew 214 megawatts or 4.4 percent.

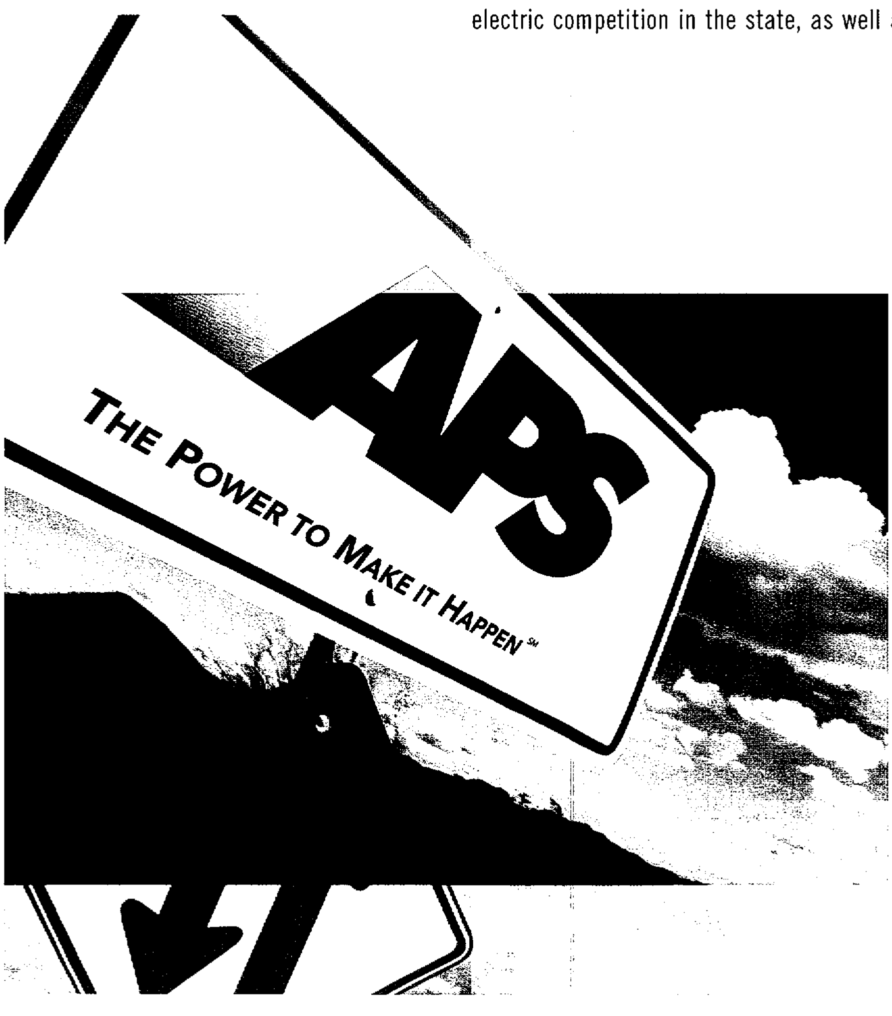
In the Southwest, electricity demand is expected to grow 50 percent faster than for the nation as a whole. In recent years (1995-99), peak loads in the region have grown 3.8 percent annually, which compares favorably with national averages of 1.9 percent.

Continuing strong economic growth is projected for Arizona and the West. Over the next two years, Arizona's population is expected to grow by an annual average rate of more than 2.6 percent, while the West's is slated to increase by about 1.7 percent a year.

Electric Industry Restructuring and Regulatory Issues

In our view, the transition of the electricity supply industry from regulated monopolies to customer-oriented competitors will provide significant opportunities for our company.

In 1999, the ACC approved rules for retail electric competition in the state, as well as a settlement agreement for APS (see details in Note 3 of Notes to Consolidated Financial Statements, page 35).



We realize that competition could affect our regulated electricity sales, however, it also provides opportunities. In the next several years, we don't expect it to significantly impact our financial results. Beyond that, we expect to enhance returns for our shareholders by participating in the deregulating wholesale electricity markets and by adding customers in markets opening to retail competition.

The settlement agreement opened our retail service area to the first phase of competition in October 1999, allowing many of our customers to choose their electricity suppliers. All of our customers will have the opportunity to choose their electricity suppliers beginning in 2001.

The settlement gives us the opportunity to recover all of our regulatory assets and most of our other stranded costs. It also allows us to improve our competitiveness by reducing electricity prices for our customers as much as 7.5 percent from 1999 through 2003.

Electric industry restructuring in Arizona also is affected by ever-changing legislators and regulators. Two of the three seats on the ACC will be on the election ballot in November 2000. Referenda are being considered in the Arizona Legislature to increase the number of commissioners on the ACC through amendment of the state constitution.

Some other issues to be resolved include:

- Establishment of transmission entities – such as regional transmission organizations, independent system operators (ISOs) and transmission companies – that provide equal access to transmission
- Development of a liquid, robust wholesale market structure that truly provides open access to electricity generators and marketers
- Enactment of federal legislation, including issues related to government-owned utilities and the transmission system
- Resolution of market power and other antitrust issues

REGULATED ELECTRICITY BUSINESS

Delivery

The regulated delivery side of our business will focus on retaining our customer base through a combination of excellent service and fair prices. For the fifth year in a row, APS reduced its prices for customers. By 2004, we will have reduced prices for our residential and small business customers by 16 percent over a 10-year period.

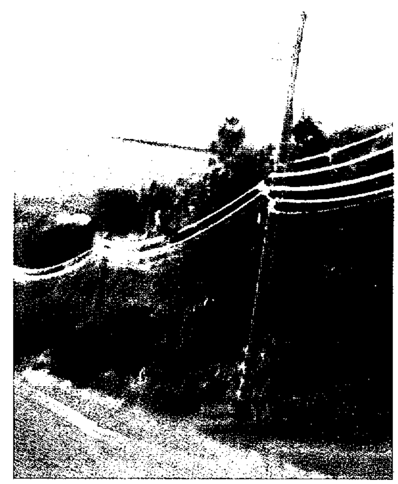
Our main goal is to serve more customers, better and more economically. We are relentless about improving customer service, and we're setting new standards of excellence. We're doing this even while serving more customers with fewer people.

One key to continuing cost reductions and service improvement will be a well-trained workforce using advanced technologies. New computer systems put powerful tools at our employees' fingertips allowing us to serve customers faster and better and to save money and time. As just a start, customers now can request turn-on or turn-off of electric service through our award-winning website.

Customers will increasingly do business from an internet site. We believe this will be true for electric service as well. We're proud that our site – APS Online – was chosen by Andersen Consulting as one of the top 10 in a study of 144 utility websites.

We see ourselves as a technology company. For example, one of our computer engineers designed an innovative circuit board to strengthen a system that restores power automatically. Without this circuit board, the system sometimes had to be reset manually. This design is the kind of innovation that saves money and improves service.

We have strengthened the infrastructure of our business by continuing to invest in transmission and distribution facilities to ensure we maintain reliable electric service, an overarching mission that we take very seriously. Due to the large growth in our service area, our regulated delivery business is one of the larger construction companies in Arizona. To minimize costs in this area, we aggressively apply new technologies to coordinate teams, tighten supply chains and reduce inventories.

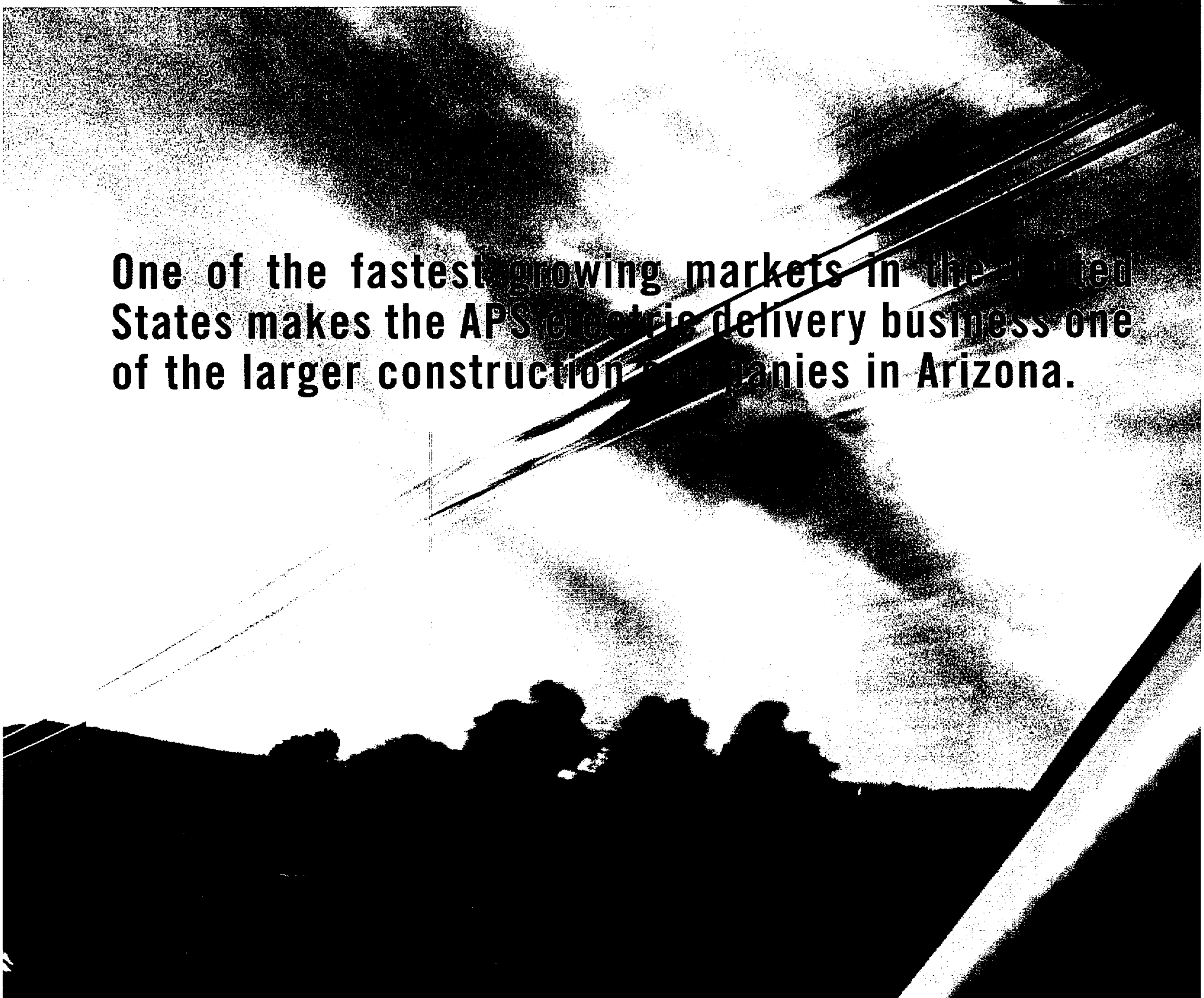


One of the fastest growing markets in the United States makes the APS electric delivery business one of the larger construction companies in Arizona.

Generation

Over the past decade, we have built an impressive record of outstanding generation performance. We continued this tradition in 1999.

For the fifth year in a row, Palo Verde generated more power than any other single power station in the United States. In 1999, the plant achieved a 93 percent capacity factor and produced more than 30.4 billion kilowatt-hours of electricity - both new plant records. The station also earned a third consecutive "1" rating from the Institute of Nuclear Power Operations, placing us among an elite group of nuclear stations in the United States with superior safety and operating achievements. Palo Verde has shown nearly continuous improvement in output during the 1990s from 20.6 million megawatt-hours in 1990 to 30.4 million in 1999.



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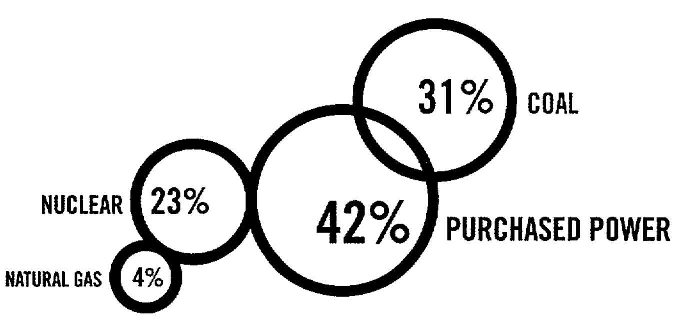
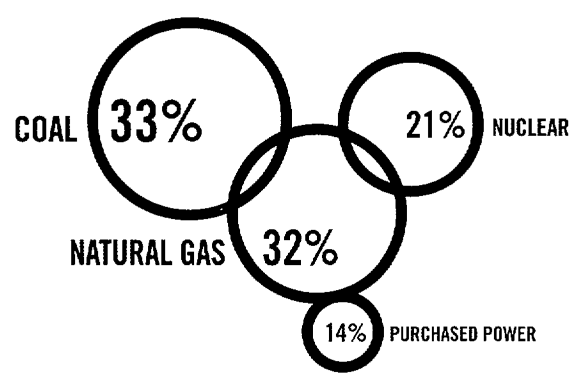
1999 ENERGY MIX



2005 PROJECTED ENERGY MIX



For the fifth year in a row, Palo Verde generated more power than any other single power station in the United States.

As a result of a decade of shortening refueling outage durations, improving performance and controlling costs, Palo Verde now ranks consistently among the lowest-cost nuclear plants. In 1999, it ranked fifth in production costs among the nation's nuclear plants.

Our fossil units also performed at record levels in 1999. We achieved a 79.2 percent capacity factor, the best since 1994. Availability at our gas and hydro units reached 98 percent. Through fossil heat-rate improvements in 1999, we achieved $2.5 million in fuel-cost savings.

At APS generation, we put great emphasis on safety, and we are especially proud of the safety records at our West Phoenix, Ocotillo and Yucca gas-fired power plants, which extended their safety runs without a lost-time accident to 18, 17 and 15 years, respectively.

Cost management remains a central focus. Generation costs must continue their downward slope to meet price reduction targets while continuing to increase earnings.

We have achieved significant savings in coal fuel costs in the past couple of years by renegotiating contracts and by seeking alternative suppliers at one plant that previously had only one supplier. In 1999, we used coal from seven different mines at our Cholla plant, requiring impressive materials handling and supply-chain management. This fuel diversity will make it easier to manage fuel costs in the future.

Through heat rate improvements, increased capacity factors and fuel cost savings, we have steadily improved our competitive position in the western generation market.

Transmission and Market Structure

In 1997, APS began working with other western utilities to form the Desert Star ISO. Desert Star, as contemplated, is an independent organization of transmission-owning utilities that will be responsible for maintaining reliable and economic operation of an open access transmission system in Arizona, New Mexico and parts of Nevada and Texas.

While discussions continue on Desert Star, we are working with other transmission providers in Arizona to establish an independent system administrator (ISA). This ISA will assure equal access to transmission facilities in Arizona, resolve conflicts in transmission schedules and assure reliable operation of the system while Desert Star is developed and awaits FERC approval for operation.

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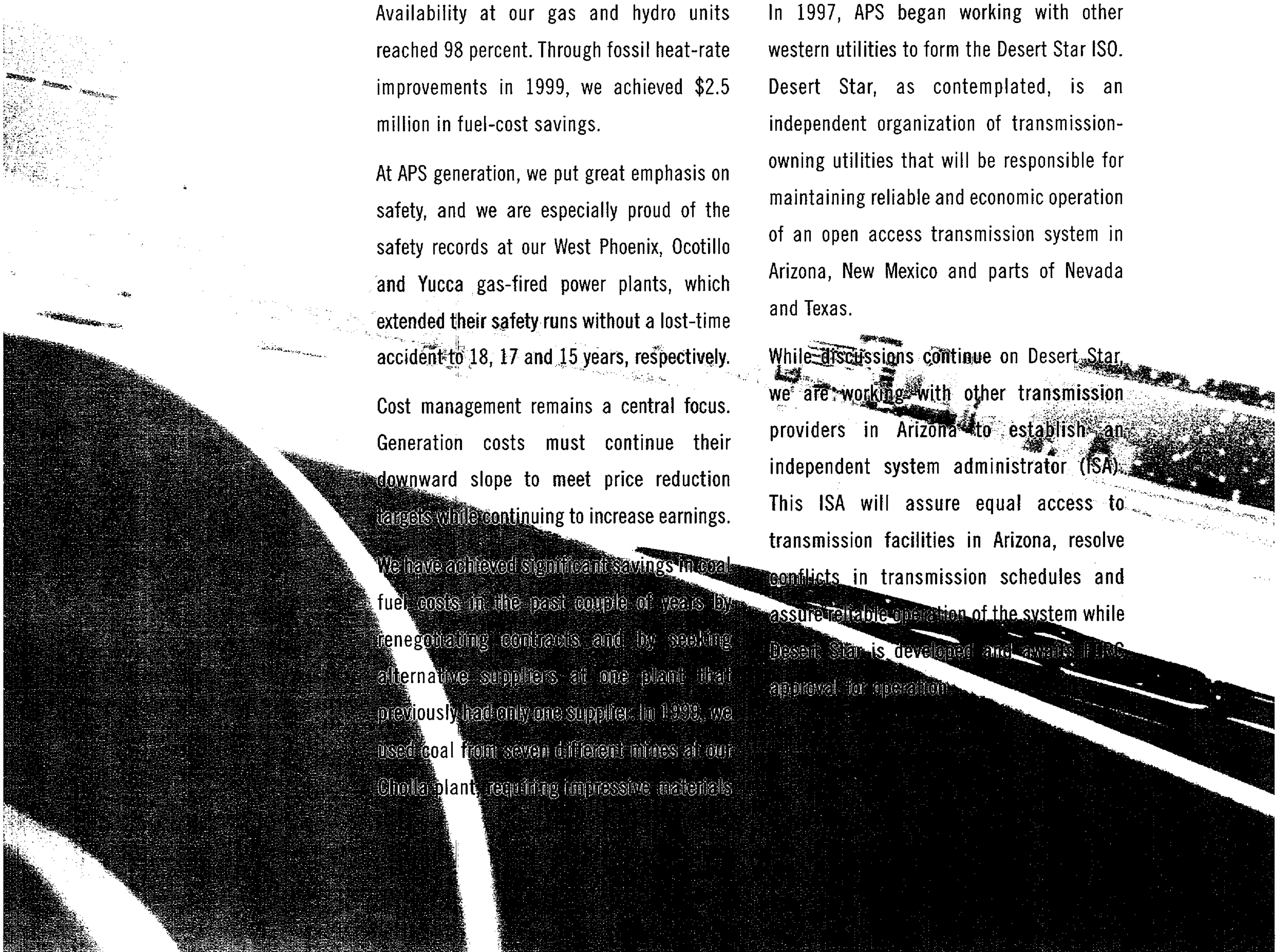


Power Marketing

Our power marketing group has continued to increase its presence in the growing competitive western markets. This steady growth largely has been accomplished through a conservative strategy backed by a significant asset position in the western electricity generating market.

APS has gained considerable experience in marketing generation as the second-largest operator of generation in the West. As the competitive market develops greater sophistication, our experience positions us well to continue enhancing our ability to manage market costs and risks.

We've increased our risk-management expertise by hiring senior risk managers from oil and gas trading companies. And, we've invested in enhanced risk management software and power system computer models to simulate the daily interaction of energy markets and electric system operations.

Our exposure to procurement risks related to providing electricity to our full-service customers is limited by several factors: top-notch power production performance, favorable long-term purchased-power contracts and an actively managed purchased-power program to ensure that we are able to economically meet our customers' energy demands.

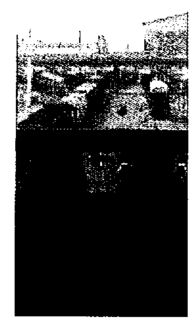
UNREGULATED BUSINESSES

Pinnacle West Energy: Competitive Generation

During 1999, we began to execute a generation growth plan that will capitalize on our competitive strengths as a power plant operator and our location in a high-growth area to take advantage of opportunities in the wholesale power markets.

Pinnacle West Energy, formed in 1999 as our competitive generation affiliate, has announced a growth strategy with about 3,000 megawatts of new gas-fired capacity in various stages of development, and has purchases of existing capacity under consideration.

In April 1999, we announced plans to build two new gas-fired generating units at our existing West Phoenix power plant site. This project consists of a 120-megawatt unit, with commercial operation planned to begin in 2001. A second, larger unit will be a 530-megawatt facility to be operational by mid-2003. These two units will cost about $330 million and will require about 200 construction workers and a permanent work force of about 12 employees.



In September, we announced a second, larger project – Redhawk Power Station, to be located near the Palo Verde nuclear station. Redhawk consists of up to four 530-megawatt units, a total of 2,120 megawatts of new combined-cycle capacity. Construction of the Redhawk station is scheduled to begin in mid-2000, with the

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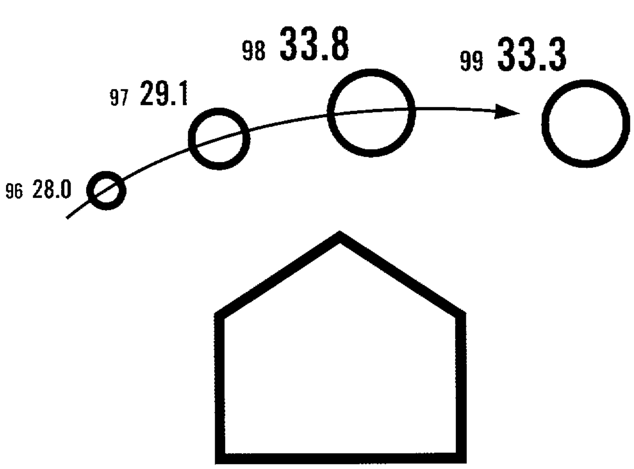
Exceptional growth has made Phoenix – the heart of the APS market – the nation's sixth largest city.



PHOENIX BUILDING PERMITS (in thousands) units coming on line in stages beginning in 2002. The four units combined are expected to cost about $1 billion, requiring about 300 workers during peak construction and up to 100 full-time employees during operations.

In 1999, we purchased the land, developed a water plan and ordered eight combustion turbines for Redhawk. In February 2000, we accomplished a major milestone for both projects when we received Certificates of Environmental Compatibility for West Phoenix and Redhawk.

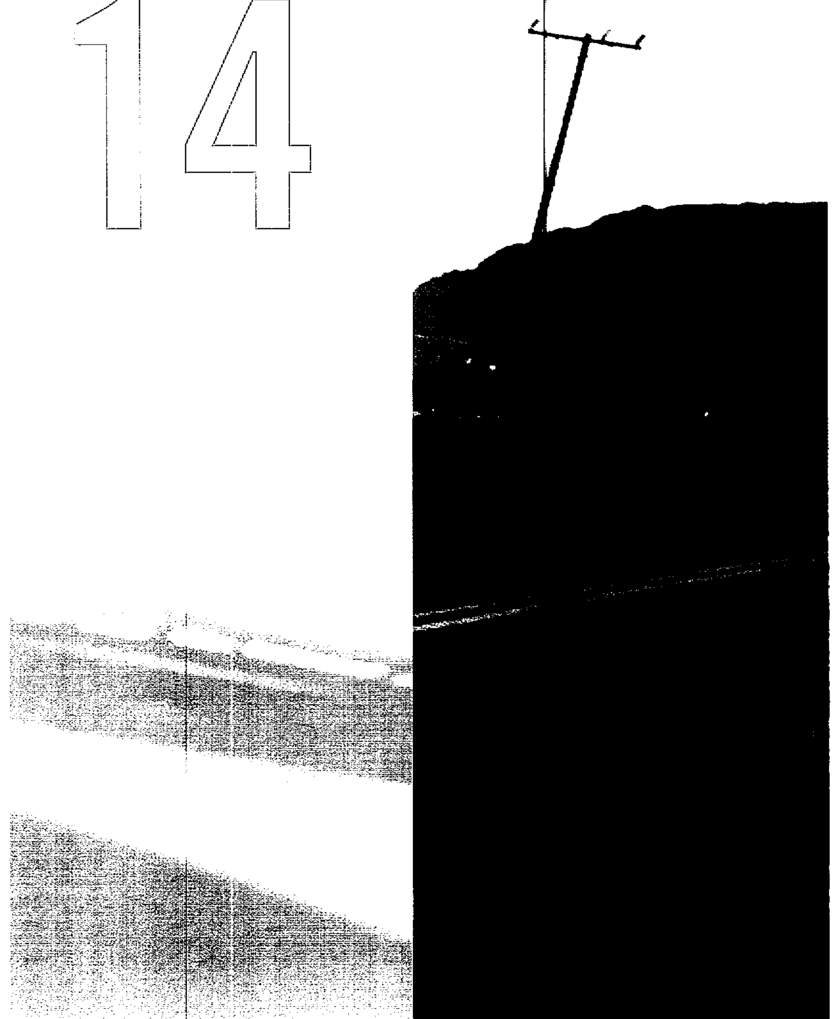
In March 2000, we entered into an agreement with Reliant Energy to equally share the first two Redhawk units. As part of that agreement, Pinnacle West Energy will have half-ownership of three 500-megawatt gas-fired units being developed in Nevada by Reliant. The Nevada plants, like our new Arizona facilities, target fast-growing areas with access to key transmission hubs.

We will consider several different paths to generation growth, including:

- New construction
- Increased ownership interests in the plants we operate
- Alliances with other utilities
- Partnership ventures

Our main objective will be to earn returns that are greater than those possible under traditional regulation.

Currently, Pinnacle West's generation is owned by APS. Under terms of the settlement agreement, the regulated generation – including Palo Verde, Four Corners, Navajo, Cholla and several smaller plants – will be transferred from APS to Pinnacle West Energy by the end of 2002 or sooner.

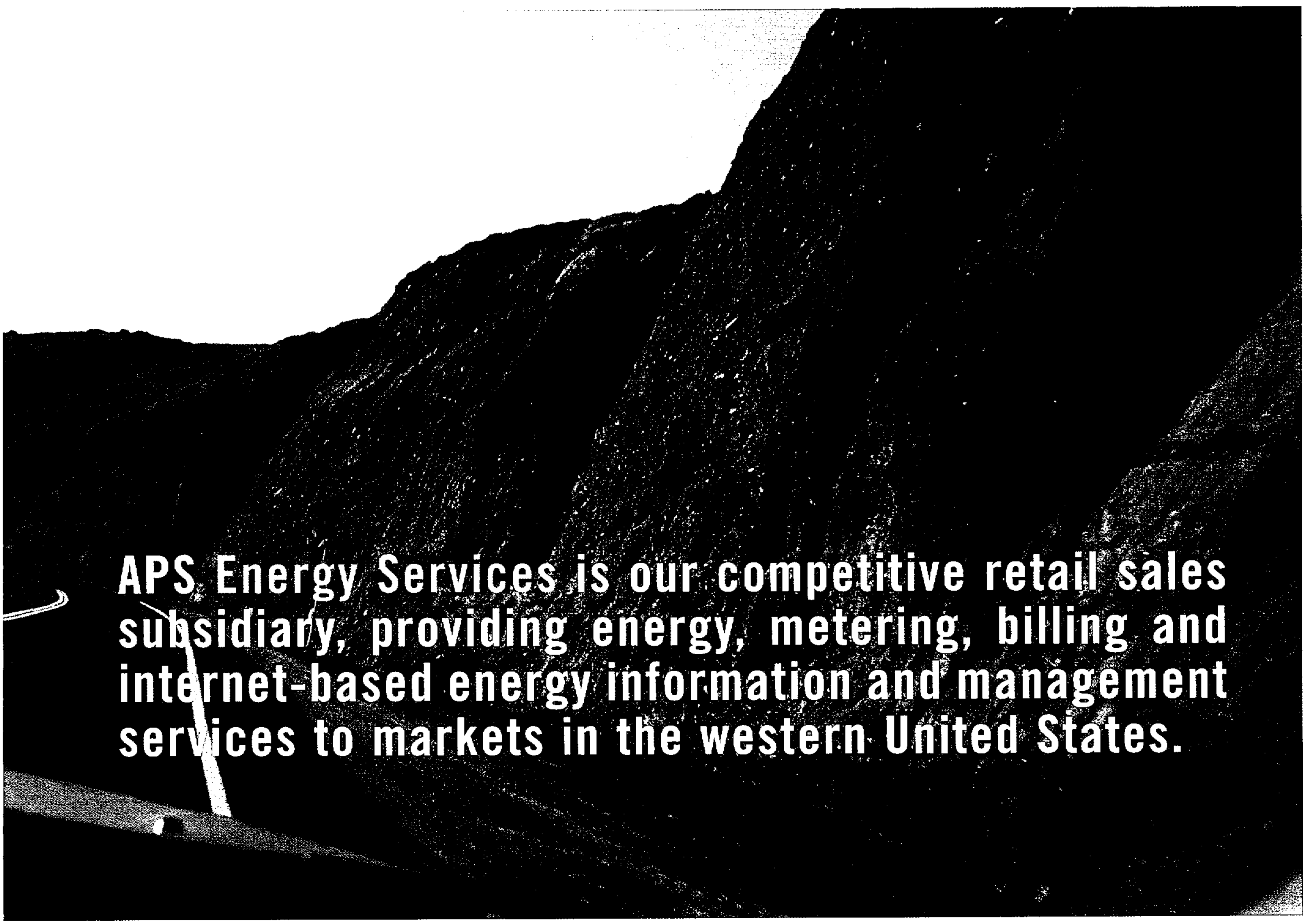


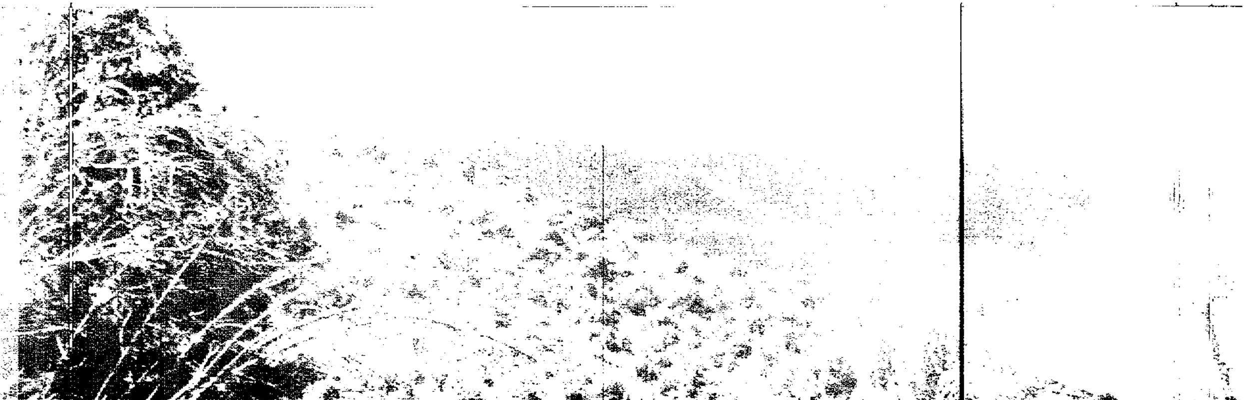
Unlike some utilities, we have chosen to retain and expand generation because it is one of our core competencies. With generation deregulated, we believe it's possible to increase earnings and bolster value for our shareholders in new ways.

Pinnacle West Energy plans to grow by targeting high-growth western markets beyond our former regulated base and by benefiting from new profit opportunities. We plan to use our assets and knowledge of physical markets to diversify and expand our geographic focus in the West.

APS Energy Services

APS Energy Services is our competitive retail sales subsidiary, providing energy, metering, billing and internet-based energy information and management services to markets in the western United States.





The 4.2-megawatt Childs-Irving facility, built in the early 1900s, will be retired, the waterway will be returned to its natural state and full flows will be returned to the stream by the end of 2004, as part of our commitment to the environment and our community.

In 1999, APS Energy Services received approval from the ACC to provide competitive electric power services in Arizona. With two years of experience in the California market, APS Energy Services enters the Arizona market with a keen understanding of customer needs in a competitive environment.

In competitive electricity markets, APS Energy Services is a company of "firsts." We were the first to serve competitive customers in California, where we've signed up customers such as Albertson's, La Quinta Inns, Texas Instruments and Earthgrains.

In Arizona, with competition in effect only a few months, we were the first company to serve customers in the electric utility service areas opened to competition. We are providing commodity and energy efficiency services to customers such as Northern Arizona University and other similar public institutions.

SunCor Development

SunCor, one of the premier real estate developers in the Southwest, had an excellent year in 1999. It contributed $6 million to consolidated earnings and, at year-end, had assets with a book value of $437 million.

SunCor's strategy is to improve overall profitability and control its risk by developing select projects in discreet stages, reflecting a disciplined development path. SunCor has provided good cash flow from dividends to the parent company – more than $136 million over the past five years.

SunCor builds planned residential communities and individual homes, develops commercial properties and manages golf courses in the fast-growing states of Arizona, New Mexico and Utah. Golden Heritage Homes, our home-building unit, sold 345 homes in 1999. About two-thirds of SunCor's assets are invested in planned communities, with the remainder invested in commercial and industrial projects.

With a greater proportion of its holdings now available to produce sales and income, we expect SunCor to show enhanced profitability.

El Dorado Investment

El Dorado earned $11 million in 1999 compared with $5 million in 1998, and paid $10 million in dividends to the parent company. These results included recognition of gains on technology stocks that went public in 1999. Assuming continued strength in this market, we could recognize further increases in 2000.

At the end of 1999, El Dorado had assets with a book value of $37 million.

Competition and Community

Our location in Arizona makes it easier for us to attract and retain talented employees and is a major benefit to our businesses.

As beneficiaries, we invest in neighborhoods and community-based organizations and encourage employee-involvement in volunteer activities. We participate with and support more than 400 community organizations.

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All of our subsidiaries take considerable pride in their commitment to employee safety and development, open communications, sound environmental practices and community outreach. Each of these areas will remain just as important in the competitive arena as they are in the regulated world. Our safety goal is zero lost-time accidents, a standard that several of our facilities maintain year after year.

We endorse the 10-point Code of Conduct adopted by the Coalition for Environmentally Responsible Economies (CERES). These CERES principles require public reporting of specific environmental achievements and goals, and we produce an *Environmental, Health and Safety Annual Report* that is available to the public upon request, as is a *Community Investment Report*.

In 1999, there were several examples of our corporate-wide commitment to responsible business practices:

APS reached an agreement with several environmental groups to accelerate decommissioning of a small but historically significant hydroelectric facility, the Childs-Irving plant in central Arizona. This 4.2-megawatt facility, built in the early 1900s, will be retired, the waterway will be returned to its natural state and full flows will be restored to the stream by the end of 2004.

SunCor opened the Sanctuary Golf Course, the first course in Arizona (and one of only 17 in the world) to receive Signature Status from the Audubon Society for its program of wildlife conservation, habitat enhancement and environmental improvement.

It is efforts like these that build both employee and community support. Community acceptance provides a key strategic advantage for smooth operation of existing plants and facilities as well as for siting of new power plants, new transmission infrastructure and new residential communities. We intend to continue earning the right to business success by supporting our communities and earning their trust.

1999 FINANCIAL STATEMENTS

SELECTED CONSOLIDATED DATA (dollars in thousands, except per share amounts)

	1999	1998	1997	1996	1995
OPERATING RESULTS					
Operating revenues					
Electric	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952
Real estate	130,169	124,188	116,473	99,488	54,846
Income from continuing operations	$ 269,772	$ 242,892	$ 235,856	$ 211,059(a)	$ 199,608
Discontinued operations	38,000(d)	—	—	(9,539)(b)	—
Extraordinary charge – net of income tax	(139,885)(e)	—	—	(20,340)(c)	(11,571)(c)
Net income	$ 167,887	$ 242,892	$ 235,856	$ 181,180	$ 188,037
COMMON STOCK DATA					
Book value per share – year-end	$ 26.00	$ 25.50	$ 23.90	$ 22.51	$ 21.49
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 3.18	$ 2.87	$ 2.76	$ 2.41(a)	$ 2.28
Discontinued operations	0.45	—	—	(0.11)	—
Extraordinary charge	(1.65)	—	—	(0.23)	(0.13)
Net income – basic	$ 1.98	$ 2.87	$ 2.76	$ 2.07	$ 2.15
Continuing operations – diluted	$ 3.17	$ 2.85	$ 2.74	$ 2.40(a)	$ 2.27
Net income – diluted	$ 1.97	$ 2.85	$ 2.74	$ 2.06	$ 2.14
Dividends declared per share	$ 1.325	$ 1.225	$ 1.125	$ 1.025	$ 0.925
Indicated annual dividend rate – year-end	$ 1.40	$ 1.30	$ 1.20	$ 1.10	$ 1.00
Average common shares outstanding – basic	84,717,135	84,774,218	85,502,909	87,441,515	87,419,300
Average common shares outstanding – diluted	85,008,527	85,345,946	86,022,709	88,021,920	87,884,226
TOTAL ASSETS	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 2,206,052	$ 2,048,961	$ 2,244,248	$ 2,372,113	$ 2,510,709
Other liabilities	2,196,721	2,516,993	2,407,572	2,428,180	2,336,695
	4,402,773	4,565,954	4,651,820	4,800,293	4,847,404
Minority interests					
Non-redeemable preferred stock of APS	—	85,840	142,051	165,673	193,561
Redeemable preferred stock of APS	—	9,401	29,110	53,000	75,000
Common stock equity	2,205,733	2,163,351	2,027,436	1,970,323	1,881,087
Total liabilities and equity	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052

(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)

	1999	1998	1997	1996	1995
ELECTRIC OPERATING REVENUES					
Residential	$ 805,173	$ 766,378	$ 746,937	$ 721,877	$ 669,762
Commercial	733,038	699,016	687,988	678,130	653,425
Industrial	159,329	172,296	164,696	162,324	156,501
Irrigation	7,374	7,288	8,706	9,448	9,596
Other	11,708	10,644	11,842	13,078	12,631
Total retail	1,716,622	1,655,622	1,620,169	1,584,857	1,501,915
Sales for resale	506,877	300,698	226,828	98,560	86,510
Transmission for others	11,348	11,058	10,295	10,240	9,390
Miscellaneous services	58,337	39,020	21,261	24,615	17,137
Net electric operating revenues	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952
ELECTRIC SALES (MWh)					
Residential	8,774,822	8,310,689	7,970,309	7,541,440	6,848,905
Commercial	9,543,853	8,697,397	8,524,882	8,233,762	7,768,289
Industrial	2,561,349	3,279,430	3,123,283	3,039,357	2,933,459
Irrigation	99,669	84,640	112,363	121,775	119,580
Other	94,877	90,927	86,090	84,362	78,478
Total retail	21,074,570	20,463,083	19,816,927	19,020,696	17,748,711
Sales for resale	15,693,834	10,317,391	9,233,573	3,367,234	2,720,704
Total electric sales	36,768,404	30,780,474	29,050,500	22,387,930	20,469,415
ELECTRIC CUSTOMERS - END OF YEAR					
Residential	735,359	708,215	680,478	654,602	625,352
Commercial	86,707	83,506	81,246	78,178	75,105
Industrial	3,183	3,084	3,192	3,055	2,913
Irrigation	754	710	764	841	837
Other	932	895	851	828	786
Total retail	826,935	796,410	766,531	737,504	704,993
Sales for resale	73	67	50	48	39
Total electric customers	827,008	796,477	766,581	737,552	705,032

See "Financial Review" on pages 22-29 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS stock symbol: PNW

1999	High	Low	Close	Dividends Per Share(a)	1998	High	Low	Close	Dividends Per Share(a)
1st Quarter	43 3/8	35 15/16	36 3/8	$ 0.325	1st Quarter	45	39 3/8	44 7/16	$ 0.300
2nd Quarter	42 15/16	36 1/4	40 1/4	$ 0.650	2nd Quarter	46 3/16	42	45	$ 0.600
3rd Quarter	41 5/16	34 11/16	36 3/8	$ —	3rd Quarter	45 9/16	40 1/16	44 13/16	$ —
4th Quarter	38 1/8	30 3/16	30 9/16	$ 0.350	4th Quarter	49 1/4	41 5/8	42 3/8	$ 0.325

(a) Dividends for the 3rd quarter of 1999 and 1998 were declared in June.

FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: APS, SunCor, El Dorado, APS Energy Services, and Pinnacle West Energy, including:

- the changes in our earnings from 1998 to 1999 and from 1997 to 1998
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results and outlook
- our capital needs and resources – for APS and our other operations, and
- our management of market risks.

APS, our major subsidiary and Arizona's largest electric utility, with approximately 827,000 customers, provides wholesale and retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates, sells, and delivers electricity and energy-related products and services to wholesale and retail customers in the western United States. SunCor is a developer of residential, commercial, and industrial projects on some 15,000 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio. 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. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our future unregulated generation operations.

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

1999 Compared with 1998

Our 1999 consolidated net income was $168 million compared with $243 million in 1998. The following is a summary:

(millions of dollars)

	1999	1998
APS	$ 267	$ 246
APS Energy Services	(9)	—
SunCor	6	45
El Dorado	11	5
Parent Company	(5)	(53)
Income from Continuing Operations	270	243
Income Tax Benefit from Discontinued Operations	38	—
Extraordinary Charge – Net of Income Taxes of $94	(140)	—
Net Income	$ 168	$ 243

The income tax benefit from discontinued operations resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

The extraordinary charge related to a regulatory disallowance which resulted from APS' comprehensive Settlement Agreement that was approved by the Arizona Corporation Commission (ACC) in September 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the regulatory disallowance and the Settlement Agreement.

APS' earnings before extraordinary charge increased $21 million – a 9% increase – over 1998 earnings primarily because of increases in the number of customers and in the average amount of electricity used by customers and lower financing costs. These positive impacts more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See Note 3 for additional information about the price reductions.

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

- increased power marketing and trading revenues ($219 million)
- increases in the number of 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 power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power 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.

APS' utility operations and maintenance expenses increased $18 million primarily because of $19 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were more than offset by lower employee benefit costs and movement of certain marketing functions to APS Energy Services in early 1999.

APS Energy Services recorded a loss of $9 million in 1999, its first year of operations. Income tax benefits related to the loss are recorded at the parent company. In 1999, the loss consisted primarily of operating expenses, which were partially offset by revenues as new markets began to open for retail electricity competition.

Our real estate subsidiary, SunCor Development, reported earnings of $6 million in 1999 compared with $45 million in 1998. SunCor's 1998 earnings included $37 million related to the recording of a deferred tax asset by SunCor in connection with its intercompany tax sharing agreement with Pinnacle West. Income taxes related to SunCor's pretax income are now being recorded by SunCor. Prior to 1998, the income tax effects related to SunCor's income and losses were not recorded at SunCor due to net operating losses. On an after-tax basis and excluding the effects of the deferred tax asset, SunCor's contributions to consolidated earnings were $6 million in 1999 and $5 million in 1998 – a significant percentage increase in net income from operations for the real estate subsidiary.

El Dorado Investment Company, our investment subsidiary, reported earnings of $11 million in 1999 compared with $5 million in 1998. The improvement related primarily to the increased value of El Dorado's investment in a technology-related venture capital partnership; this investment is revalued on a quarterly basis.

1998 Compared with 1997

Our 1998 consolidated net income was $243 million compared with $236 million in 1997 – a 3.0% increase. The following is a summary:

(millions of dollars)

	1998	1997
APS	$ 246	$ 239
SunCor	45	5
El Dorado	5	8
Parent Company	(53)	(16)
Net Income	$ 243	$ 236

APS' 1998 earnings increased $7 million – a 3% increase over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, the prior year's benefits of the two fuel-related settlements recorded in 1997, and retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the average amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

The increase in power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power markets. The revenue increases were accompanied by an increase in purchased power expenses. These activities contributed positively to earnings in both periods; the contribution in 1998 was higher than in 1997.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $14 million primarily because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because APS had more plant in service.

Financing costs decreased by $16 million primarily because of lower amounts of outstanding debt and APS preferred stock.

Before the effects of recording deferred taxes under its tax sharing agreement, the earnings contribution from our real estate subsidiary, SunCor Development, increased $3 million as a result of an increase in land sales. SunCor's stand-alone net income in 1998 was $45 million, of which $37 million represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an inter-company tax allocation agreement. On a consolidated basis, Pinnacle West had already recognized the income tax benefits; therefore, there was no impact on consolidated net income in 1998.

The contribution from El Dorado, our investment subsidiary, decreased $3 million as a result of a decrease in investment sales.

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: 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 included accelerated amortization of APS' deferred investment tax credits (ITCs).

As part of the 1999 Settlement Agreement, APS reduced rates for standard offer service for customers with loads less than 3 megawatts 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 related to the 1996 regulatory agreement (see below). For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

Also, under the Settlement Agreement a regulatory disallowance removed $234 million before income taxes ($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. Before the ACC approved the 1999 Settlement 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 under the 1996 agreement. For more details, see Note 1.

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

(millions of dollars)

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

Also, 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 the 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, which was included in the July 1, 1999 1.5% price reduction under the 1999 Settlement Agreement.

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

CAPITAL NEEDS AND RESOURCES

Pinnacle West (Parent Company)

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

- dividends to our shareholders
- interest payments and
- optional and mandatory repayment of principal on our long-term debt.

In addition, as part of the 1996 agreement with the ACC, we invested $50 million annually in APS for the years 1996 through 1999. The 1999 payment was the last payment under the 1996 regulatory agreement (see Note 3). During 1997, we repurchased $80 million of common stock, reducing our shares outstanding at year-end 1997 by 2.7 million shares.

Our primary sources of cash are dividends from our subsidiaries. During 1999, APS paid $170 million in dividends to the parent. In 1999, SunCor and El Dorado declared dividends to the parent of $20 million and $10 million, respectively. Combined dividends from SunCor and El Dorado are expected to be at least $25 million annually during the next several years; however, the aggregate amount of those dividends depends somewhat on the status of the real estate and stock markets (particularly the technology sector).

Our long-term debt at December 31, 1999 was $106 million compared to $92 million at December 31, 1998. We have a $250 million line of credit, under which we had $56 million of borrowings outstanding at December 31, 1999. We do not have any principal debt repayment obligations until 2001.

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 its operations and, to the extent necessary, external financing.

As part of the 1996 regulatory agreement, APS received annual cash infusions from Pinnacle West of $50 million from 1996 through 1999. During the period from 1997 through 1999, APS paid for all of its capital expenditures with cash from its operations. APS expects to do so in 2000 through 2002 as well.

APS' capital expenditures in 1999 were $332 million. APS' projected capital expenditures for the next three years are: $384 million in 2000; $342 million in 2001; and $334 million in 2002. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

During 1999, APS redeemed about $323 million of long-term debt and $96 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. APS no longer has any outstanding preferred stock. Its long-term debt redemption requirements and payment obligations on a capitalized lease for the next three years are approximately: $115 million in 2000; $253 million in 2001; and $125 million in 2002. In addition, APS made optional redemptions of about $89 million of long-term debt in January 2000. 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, 1999, APS had credit commitments from various banks totaling about $350 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1999, APS had about $38 million of commercial paper and $50 million of long-term bank borrowings outstanding.

In February 1999, APS issued $125 million of unsecured long-term debt and in November 1999, APS issued $250 million of unsecured long-term debt.

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

We are currently planning, through Pinnacle West Energy, a 650-megawatt expansion of our West Phoenix Power Plant, and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk. Pinnacle West Energy's capital expenditures in 1999 were $21 million. Projected capital expenditures for these projects are $152 million in 2000; $240 million in 2001; and $245 million in 2002. We are also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's capital expenditures will be funded with debt proceeds, and with internally generated cash and debt proceeds from the parent company. Assuming all approvals are granted, we expect to begin construction at West Phoenix in the second quarter of 2000.

Pinnacle West Energy has signed a joint development agreement with Reliant Energy Power Generation, Inc. (Reliant) covering construction and operation of three new merchant plants. Pinnacle West Energy plans to contribute the first two units (1,060 megawatts) of the Redhawk project to the joint agreement. Construction is expected to start in the third quarter of 2000, with commercial operation scheduled in the summer of 2002. Reliant plans to contribute two new natural gas-fired projects (1,500 megawatts) in Nevada to the venture.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and their own external financings.

SunCor's capital needs consist primarily of capital expenditures for land development, retail and office building construction, and home construction. On the basis of projects now under development, SunCor expects capital needs over the next three years to be: $53 million in 2000; $43 million in 2001; and $51 million in 2002. Capital resources to meet these requirements include funds from operations and SunCor's own external financings.

As of December 31, 1999, SunCor had a $100 million line of credit, under which $94 million of borrowings were outstanding. SunCor has no principal debt repayment requirements for 2000, $30 million for 2001, and $64 million for 2002.

COMPETITION AND INDUSTRY RESTRUCTURING

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. See "Results of Operations – Regulatory Agreements" and Note 3 for additional information about APS' Settlement Agreement with the ACC related to the implementation of retail electric competition, the ACC rules that provide a framework for the introduction of retail electric competition in Arizona, and other competitive developments, including an agreement with Salt River Project.

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 a discussion of legislative developments.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. 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.

APS prepares its 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 its financial statements. As a result of the Settlement Agreement (see Note 3), APS discontinued the application of SFAS No. 71 for its generation operations. This meant that the generation assets were tested for impairment and the portion of the regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. APS determined that the generation assets were not impaired. A regulatory disallowance ($140 million after income taxes) was reported as an extraordinary charge on the income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the Settlement Agreement.

YEAR 2000 READINESS DISCLOSURE

Some companies expected to face problems on January 1, 2000 in the case that computer systems and equipment would not properly recognize calendar dates. During 1997, APS had initiated a comprehensive company-wide Year 2000 program to review and resolve all Year 2000 issues in mission critical systems in a timely manner to ensure the reliability of electric service to its customers. We have spent about $5 million to be Year 2000 ready. To date, we have not experienced any material Year 2000 related problems, and we do not anticipate any in the future.

ACCOUNTING MATTERS

We describe a new standard on accounting for derivatives in Note 2. The new standard on derivatives is effective for us in 2001. We are currently evaluating what impact it will have on our financial statements. 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.

RISK MANAGEMENT

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 the 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 and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 1999 and December 31, 1998. The interest rates presented in the table below represent the weighted average interest rates for the years ended December 31, 1999 and December 31, 1998.

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1999 (thousands of dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	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

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1998 (thousands of dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
1999	5.88%	$ 178,830	7.30%	$ 3,268	7.24%	$ 164,777
2000	—	—	7.32%	25,756	5.79%	114,711
2001	—	—	6.57%	93,472	6.70%	27,488
2002	—	—	10.25%	119	8.13%	125,000
2003	—	—	5.94%	125,131	6.87%	25,000
Years thereafter	—	—	3.43%	459,803	7.75%	1,058,963
Total		$ 178,830		$ 707,549		$ 1,515,939
Fair Value		$ 178,830		$ 707,549		$ 1,577,365

Commodity Price Risk

APS is exposed to the impact of market fluctuations in the price and distribution costs of electricity, natural gas, coal, and emissions allowances. APS employs 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 its overall risk management program, APS enters into these derivative transactions for trading and to hedge certain natural gas in storage as well as purchases and sales of electricity, fuels, and emissions allowances/credits.

As of December 31, 1999, a hypothetical adverse price movement of 10% in the market price of APS' commodity derivative portfolio would decrease the fair market value of these contracts by approximately $6 million. This analysis does not include the favorable impact this same hypothetical price move would have on the underlying position being hedged with the commodity derivative portfolio.

APS is exposed to credit losses in the event of non-performance or non-payment by counterparties. APS uses a credit management process to assess and monitor its financial exposure to counterparties. APS does not expect counterparty defaults to materially impact its financial condition, results of operations, or net cash flow.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; the strength of the stock market (particularly the technology sector) and the strength of the real estate market.

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. Such information was prepared in accordance with generally accepted accounting principles 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 accounting controls. A limiting factor in all systems of internal accounting 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 accounting 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.

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
President and
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and its subsidiaries as of December 31, 1999 and 1998 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 its subsidiaries at December 31, 1999 and 1998 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Phoenix, Arizona

February 18, 2000

CONSOLIDATED STATEMENTS OF INCOME (dollars in thousands, except per share amounts)

year ended december 31,	1999	1998	1997
OPERATING REVENUES			
Electric	$ 2,293,184	$ 2,006,398	$ 1,878,553
Real estate	130,169	124,188	116,473
Total	2,423,353	2,130,586	1,995,026
OPERATING EXPENSES			
Fuel and purchased power	796,109	545,297	443,571
Utility operations and maintenance	446,777	419,433	405,605
Real estate operations	119,516	115,331	111,628
Depreciation and amortization (Note 1)	385,568	379,679	368,285
Taxes other than income taxes	96,606	103,718	108,431
Total	1,844,576	1,563,458	1,437,520
OPERATING INCOME	578,777	567,128	557,506
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	(1,016)	(9,703)	(12,803)
Net other income and expense	10,793	609	4,569
Total	9,777	(9,094)	(8,234)
INCOME BEFORE INTEREST AND INCOME TAXES	588,554	558,034	549,272
INTEREST EXPENSE			
Interest charges	162,381	169,145	182,838
Capitalized interest	(11,664)	(18,596)	(19,703)
Total	150,717	150,549	163,135
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	437,837	407,485	386,137
INCOME TAXES (NOTE 4)	168,065	164,593	150,281
INCOME FROM CONTINUING OPERATIONS	269,772	242,892	235,856
Income tax benefit from discontinued operations	38,000	—	—
Extraordinary charge – net of income taxes of $94,115	(139,885)	—	—
NET INCOME	$ 167,887	$ 242,892	$ 235,856
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,717,135	84,774,218	85,502,909
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	85,008,527	85,345,946	86,022,709
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING			
Continuing operations – basic	$ 3.18	$ 2.87	$ 2.76
Net income – basic	1.98	2.87	2.76
Continuing operations – diluted	3.17	2.85	2.74
Net income – diluted	1.97	2.85	2.74
DIVIDENDS DECLARED PER SHARE	$ 1.325	$ 1.225	$ 1.125

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (thousands of dollars)

december 31,	1999	1998
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20,705	$ 20,538
Customer and other receivables – net	244,599	233,876
Accrued utility revenues	72,919	67,740
Materials and supplies (at average cost)	69,977	69,074
Fossil fuel (at average cost)	21,869	13,978
Deferred income taxes (Note 4)	8,163	3,999
Other current assets	60,562	47,594
Total current assets	498,794	456,799
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	344,293	331,021
Other assets (Note 13)	267,458	236,562
Total investments and other assets	611,751	567,583
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,546,314	7,265,604
Less accumulated depreciation and amortization	3,026,194	2,814,762
Total	4,520,120	4,450,842
Construction work in progress	209,281	228,643
Nuclear fuel, net of amortization of $66,357 and $68,569	49,114	51,078
Net utility plant	4,778,515	4,730,563
DEFERRED DEBITS		
Regulatory assets (Notes 3 and 4)	613,729	980,084
Other deferred debits	105,717	89,517
Total deferred debits	719,446	1,069,601
TOTAL ASSETS	$ 6,608,506	$ 6,824,546

See Notes to Consolidated Financial Statements.

(thousands of dollars)

december 31,		1999		1998
LIABILITIES AND EQUITY				
CURRENT LIABILITIES				
Accounts payable	$	186,524	$	155,800
Accrued taxes		70,510		62,520
Accrued interest		33,253		31,866
Short-term borrowings (Note 5)		38,300		178,830
Current maturities of long-term debt (Note 6)		114,798		168,045
Customer deposits		26,098		28,510
Other current liabilities		26,007		14,632
Total current liabilities		495,490		640,203
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)		2,206,052		2,048,961
DEFERRED CREDITS AND OTHER				
Deferred income taxes (Note 4)		1,183,855		1,343,536
Deferred investment tax credit (Note 4)		3,830		27,345
Unamortized gain – sale of utility plant		73,212		77,787
Other		440,334		428,122
Total deferred credits and other		1,701,231		1,876,790
COMMITMENTS AND CONTINGENCIES (NOTES 3, 12 AND 13)				
MINORITY INTERESTS (NOTE 7)				
Non-redeemable preferred stock of APS		—		85,840
Redeemable preferred stock of APS		—		9,401
COMMON STOCK EQUITY (NOTE 8)				
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 1999 and 1998		1,537,449		1,550,643
Retained earnings		668,284		612,708
Total common stock equity		2,205,733		2,163,351
TOTAL LIABILITIES AND EQUITY	$	6,608,506	$	6,824,546

CONSOLIDATED STATEMENTS OF CASH FLOWS (thousands of dollars)

year ended december 31,	1999	1998	1997
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 269,772	$ 242,892	$ 235,856
Items not requiring cash			
Depreciation and amortization	385,568	379,679	368,285
Nuclear fuel amortization	31,371	32,856	32,702
Deferred income taxes – net	(17,413)	41,262	24,809
Deferred investment tax credit	(23,514)	(23,516)	(23,518)
Other – net	(12,476)	1,190	(3,854)
Changes in current assets and liabilities			
Customer and other receivables – net	(10,723)	(50,369)	(14,270)
Accrued utility revenues	(5,179)	(9,181)	(3,089)
Materials, supplies and fossil fuel	(8,794)	(2,797)	7,793
Other current assets	(12,968)	(6,186)	(109)
Accounts payable	28,193	34,386	(54,882)
Accrued taxes	12,591	(22,090)	2,197
Accrued interest	1,387	(1,108)	(6,678)
Other current liabilities	15,047	(5,235)	(23,087)
(Increase) decrease in land held	(12,542)	33,405	33,010
Other – net	(4,720)	(39,350)	48,254
Net Cash Flow Provided By Operating Activities	635,600	605,838	623,419
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(343,448)	(319,142)	(307,876)
Capitalized interest	(11,664)	(18,596)	(19,703)
Other – net	(16,143)	(2,144)	(3,124)
Net Cash Flow Used For Investing Activities	(371,255)	(339,882)	(330,703)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	607,791	148,229	146,013
Short-term borrowings – net	(140,530)	48,080	113,850
Dividends paid on common stock	(112,311)	(103,849)	(96,160)
Repurchase and retirement of common stock	—	—	(79,997)
Repayment of long-term debt	(510,693)	(286,314)	(325,526)
Redemption of preferred stock	(96,499)	(75,517)	(47,201)
Other – net	(11,936)	(3,531)	(2,897)
Net Cash Flow Used For Financing Activities	(264,178)	(272,902)	(291,918)
NET CASH FLOW	167	(6,946)	798
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	20,538	27,484	26,686
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 20,705	$ 20,538	$ 27,484

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (thousands of dollars)

year ended december 31,	1999	1998	1997
Retained Earnings at Beginning of Year	$ 612,708	$ 473,665	$ 333,969
Net Income	167,887	242,892	235,856
Common Stock Dividends	(112,311)	(103,849)	(96,160)
Retained Earnings at End of Year	$ 668,284	$ 612,708	$ 473,665

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, SunCor, El Dorado, APS Energy Services, and Pinnacle West Energy.

APS, our major subsidiary and Arizona's largest electric utility, with approximately 827,000 customers, provides wholesale or retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates, sells, and delivers electricity and energy-related products and services to wholesale and retail customers in the western United States. SunCor is a developer of residential, commercial, and industrial projects on some 15,000 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio. 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. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our future unregulated generation operations.

Accounting Records

Our accounting records are maintained in accordance with generally accepted accounting principles (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 Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the ratemaking policies of these commissions. For regulated operations, APS prepares its 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 its financial statements.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (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.

In September 1999, the APS Settlement Agreement was approved by the ACC (see Note 3 for a discussion of the agreement). APS has discontinued the application of SFAS No. 71 for its generation operations. This means that the generation assets were tested for impairment and the portion of regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. APS determined that the generation assets were not impaired. A regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and this was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the consolidated income statement. Prior to the Settlement Agreement, under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that would have ended June 30, 2004.

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

(millions of dollars)

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

The majority of the 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:

(thousands of dollars)

december 31.	1999	1998
Electric plant in service and held for future use	$ 3,770,234	$ 3,680,482
Accumulated depreciation and amortization	(1,817,589)	(1,681,099)
Construction work in progress	87,819	107,324
Nuclear fuel, net of amortization	49,114	51,078

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service. 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 1997 through 1999 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1999 was 3.34%. APS depreciates non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Venture Capital Investments

El Dorado has investments in venture capital partnerships that account for their investments at fair value. Since El Dorado uses the equity method of accounting for its partnership interests, it must record its share of realized and unrealized gains and losses in net income.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plant. 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 6.65% for 1999, 6.88% for 1998, and 7.25% for 1997.

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, APS is 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 APS 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. In addition, Note 13 has 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.

Statements of Cash Flows

We consider temporary cash investments and marketable securities to be cash equivalents for purposes of reporting cash flows. During 1999, 1998, and 1997 we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

(millions of dollars)

years ended december 31,	1999	1998	1997
Interest paid	$ 141	$ 144	$ 163
Income taxes paid	200	165	146
Dividends paid on preferred stock of APS	1	10	13

Reclassifications

We have reclassified certain prior year amounts for comparison purposes with 1999.

2. ACCOUNTING MATTERS

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2001. 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. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

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 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

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 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the Settlement Agreement. One of the parties questioned the authority of the ACC to approve the Settlement Agreement and both parties challenged several specific provisions of the Settlement Agreement.

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

- APS will reduce rates for standard offer service for customers with loads less than 3 megawatts 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) includes the July 1, 1999 retail price decrease of approximately $11 million annually ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the Settlement Agreement, retroactive to July 1, 1999, and also will be 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 will be 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), with an additional 140 megawatts being made available to eligible non-residential customers. Unless subject to judicial or regulatory restraint, APS will open its distribution system to retail access for all customers on January 1, 2001.
- Prior to the Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 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 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 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 that 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. 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 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 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, APS has discontinued the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," for its 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 (Rules). If any of the Rules conflict with the Settlement Agreement, the terms of the Settlement Agreement govern. 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 and the adoption or amendment of the Rules, but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions. On January 14, 2000, a special action was filed requesting the Arizona Supreme Court to enjoin implementation of the Rules and decide whether the ACC can allow the competitive marketplace, rather than the ACC, to set just and reasonable rates under the Arizona Constitution. The issue of competitively set rates has been decided by lower Arizona courts in favor of the ACC in four separate lawsuits, two of which relate to telecommunications companies. The Supreme Court denied to hear the case as a special action on March 17, 2000. The lower court litigation will continue.

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.
- The Rules require each affected utility, including APS, to make available at least 20% of its 1995 system retail peak demand for competitive generation supply beginning when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever is earlier, and 100% beginning January 1, 2001. Under the Settlement Agreement, APS will provide retail access to customers representing the minimum 20% required by the ACC and an additional 140 megawatts of non-residential load in 1999, and to all customers as of January 1, 2001, or such other dates as approved by the ACC.
- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date, which for APS' customers was the approval of the Settlement Agreement. Customers may also aggregate smaller loads to meet this one megawatt requirement.
- When effective, residential customers will be phased in at 1.25% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.
- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) 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 Settlement Agreement, APS received a waiver to allow transfer of its competitive generation assets and services to affiliates no later than December 31, 2002.

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 of approximately $49 million ($29 million after income taxes), or 3.4%, effective July 1, 1996; approximately $18 million ($11 million after income taxes), or 1.2%, effective July 1, 1997; approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998; and approximately $11 million ($7 million after income taxes), or 0.7%, effective as of July 1, 1999. The July 1, 1999 rate decrease was included in the first rate reduction under the Settlement Agreement discussed above. The regulatory agreement also required the parent company to 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 megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999-2000 legislative session on certain competitive issues.

GENERAL

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, or results of operation. 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 Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills have been introduced during the 106th Congress. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2000 and beyond. These bills, other bills that 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.

AGREEMENT WITH SALT RIVER PROJECT

On April 25, 1998, APS entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The ACC approved the Agreement on February 18, 1999. The Agreement contains the following major components:

- Both parties amended the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.
- Both parties amended the Power Coordination Agreement to lower the price that APS pays Salt River Project for purchased power. During 1999, the price APS paid Salt River Project for purchased power was reduced by approximately $3 million (pretax) and we estimate the decrease to be approximately $16 million (pretax) in 2000 and lesser annual amounts through 2006.
- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal levels.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) became effective upon the introduction of competition. See "Settlement Agreement" and "ACC Rules" above.

4. INCOME TAXES

Investment Tax Credit

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

Income Tax Benefit from Discontinued Operations

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.

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:

(thousands of dollars)

year ended december 31,	1999	1998	1997
Current			
Federal	$ 171,491	$ 105,922	$ 105,818
State	37,501	40,621	43,172
Total current	208,992	146,543	148,990
Deferred	(17,413)	41,566	28,729
Change in valuation allowance	—	—	(3,920)
ITC amortization	(23,514)	(23,516)	(23,518)
Total expense	$ 168,065	$ 164,593	$ 150,281

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

(thousands of dollars)

year ended december 31,	1999	1998	1997
Federal income tax expense at 35% statutory rate	$ 153,243	$ 142,620	$ 135,148
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	14,575	17,848	14,694
Preferred stock dividends of APS	356	3,396	4,481
ITC amortization	(23,514)	(23,516)	(23,518)
State income tax net of federal income tax benefit	23,030	22,764	24,497
Change in valuation allowance	—	—	(3,400)
Other	375	1,481	(1,621)
Income tax expense	$ 168,065	$ 164,593	$ 150,281

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

(thousands of dollars)

year ended december 31,	1999	1998
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 29,446	$ 31,285
Other	133,748	127,903
Total deferred tax assets	163,194	159,188
DEFERRED TAX LIABILITIES		
Plant-related	1,104,769	1,117,253
Regulatory asset for income taxes	234,117	381,472
Total deferred tax liabilities	1,338,886	1,498,725
Accumulated deferred income taxes – net	$ 1,175,692	$ 1,339,537

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $350 million at December 31, 1999 and $400 million at December 31, 1998, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1999 and 1998 for these lines of credit ranged from 0.07% to 0.125% per annum. APS had long-term bank borrowings of $50 million outstanding at December 31, 1999 and $125 million outstanding at December 31, 1998.

APS' commercial paper borrowings outstanding were $38 million at December 31, 1999 and $179 million at December 31, 1998. The weighted average interest rate on commercial paper borrowings was 5.33% for the year ended December 31, 1999 and 5.88% for December 31, 1998. 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, 1999 and 1998. The commitment fees were 0.10% in 1999 and 1998. Outstanding amounts at December 31, 1999 were $56 million and at December 31, 1998 were $42 million.

SunCor had revolving lines of credit totalling $100 million at December 31, 1999 and $55 million at December 31, 1998. The commitment fees were 0.125% in 1999 and 1998. SunCor had $94 million outstanding at December 31, 1999 and $38 million outstanding at December 31, 1998.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant; 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, 1999 and December 31, 1998:

(thousands of dollars)

december 31,	Maturity Dates (a)	Interest Rates	1999	1998
APS				
First mortgage bonds	1999	7.625%	$ —	$ 100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	85,000
	2020	10.25%	100,550	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	91,900
	2024	8.75%	121,668	121,668
	2025	8%	47,075	88,300
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,860)	(6,482)
Pollution control bonds	2024-2034	Adjustable rate(b)	476,860	456,860
Funds held in trust account for certain pollution control bonds			(1,236)	—
Collateralized loan	1999-2000	5.375%-6.125%	10,000	20,000
Unsecured notes	2004	5.875%	125,000	—
Unsecured notes	2005	6.25%	100,000	100,000
Floating rate notes	2001	Adjustable rate(c)	250,000	—
Senior notes (d)	1999	6.72%	—	50,000
Senior notes (d)	2006	6.75%	83,695	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate(e)	50,000	125,000
Capitalized lease obligation	1999-2001	7.48%(f)	7,199	11,612
			2,112,111	2,040,918
SUNCOR				
Revolving credit	2001-2002	(g)	94,000	38,139
Bank loan	2001	(h)	—	42,061
Notes payable	1998-2006	(i)	3,404	3,888
Bonds payable	2039	5.85%	5,335	—
			102,739	84,088
PINNACLE WEST				
Revolving credit	2001	(j)	56,000	42,000
Senior notes	2001-2003	(k)	50,000	50,000
			106,000	92,000
Total long-term debt			2,320,850	2,217,006
Less current maturities			114,798	168,045
Total long-term debt less current maturities			$ 2,206,052	$ 2,048,961

(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, 1999 was 3.15% and for December 31, 1998 was 3.39%. 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, 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, 1999 was 5.5% and for December 31, 1998 was 5.94%. Changes in short-term interest rates would affect the costs associated with this debt.
(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 (see Note 10).
(g) The weighted-average rate at December 31, 1999 was 8.51% and at December 31, 1998 was 7.41%. Interest for 1999 and 1998 was based on LIBOR plus 2% or prime plus 0.5%.
(h) The weighted-average rate at December 31, 1998 was 7.76%. Interest for 1998 was based on LIBOR plus 2% or prime plus 0.5%.
(i) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75%.
(j) The weighted-average rate at December 31, 1999 was 6.825% and at December 31, 1998 was 5.66%. Interest for 1999 and 1998 was based on LIBOR plus 0.33%.
(k) 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 2004:

- $115 million in 2000
- $364 million in 2001
- $189 million in 2002
- $ 75 million in 2003 and
- $205 million in 2004.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1999.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock.

Preferred stock balances of APS at December 31, 1999 and 1998 are shown below:

(dollars in thousands, except per share amounts)	Authorized	Number of Shares Outstanding December 31, 1999	1998	Par Value Per Share	Par Value Outstanding December 31, 1999	1998
NON-REDEEMABLE:						
$1.10 preferred	160,000	—	139,030	$ 25.00	$ —	$ 3,476
$2.50 preferred	105,000	—	86,440	50.00	—	4,322
$2.36 preferred	120,000	—	32,520	50.00	—	1,626
$4.35 preferred	150,000	—	62,986	100.00	—	6,299
Serial preferred:	1,000,000					
$2.40 Series A		—	200,587	50.00	—	10,029
$2.625 Series C		—	214,895	50.00	—	10,745
$2.275 Series D		—	90,691	50.00	—	4,534
$3.25 Series E		—	304,475	50.00	—	15,224
Serial preferred:	4,000,000					
Adjustable rate						
Series Q		—	295,851	100.00	—	29,585
Total		—	1,427,475		$ —	$ 85,840
REDEEMABLE:						
Serial preferred:						
$10.00 Series U		—	94,011	$ 100.00	$ —	$ 9,401

Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 1999 are as follows:

(dollars in thousands)

	Number of Shares	Par Value Amount
Balance, December 31, 1996	530,000	$ 53,000
Retirements		
$10.00 Series U	(118,902)	(11,890)
$7.875 Series V	(120,000)	(12,000)
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	—	$ —

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 1999 is as follows:

(dollars in thousands)

	Number of Shares	Amount (a)
Balance, December 31, 1996	87,515,847	$ 1,636,354
Common stock expense – net	—	(2,586)
Common stock retired	(2,690,900)	(79,997)
Balance, December 31, 1997	84,824,947	1,553,771
Common stock expense – net	—	(3,128)
Balance, December 31, 1998	84,824,947	1,550,643
Common stock expense – net	—	(13,194)
Balance, December 31, 1999	84,824,947	$ 1,537,449

(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, 1999 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- $ 4 million in 1999
- $11 million in 1998 and
- $ 9 million in 1997.

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

(thousands of dollars)

	1999	1998	1997
Service cost – benefits earned during the period	$ 24,982	$ 24,817	$ 20,435
Interest cost on projected benefit obligation	52,905	51,524	48,402
Expected return on plan assets	(68,335)	(54,513)	(47,959)
Amortization of:			
Transition asset	(3,226)	(3,226)	(3,226)
Prior service cost	2,078	2,078	2,078
Net periodic pension cost	$ 8,404	$ 20,680	$ 19,730

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

(thousands of dollars)

	1999	1998
Funded status – pension plan assets more than (less than) projected benefit obligation	$ 37,275	$ (41,034)
Unrecognized net transition asset	(20,008)	(23,235)
Unrecognized prior service cost	20,636	22,715
Unrecognized net actuarial gains	(101,153)	(38,668)
Net pension amount recognized in the balance sheets	$ (63,250)	$ (80,222)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Projected pension benefit obligation at beginning of year	$ 731,305	$ 708,144
Service cost	24,982	24,817
Interest cost	52,905	51,524
Benefit payments	(29,694)	(29,636)
Actuarial gains	(36,860)	(23,544)
Projected pension benefit obligation at end of year	$ 742,638	$ 731,305

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Fair value of pension plan assets at beginning of year	$ 690,271	$ 619,412
Actual return on plan assets	93,977	86,527
Employer contributions	25,359	13,968
Benefit payments	(29,694)	(29,636)
Fair value of pension plan assets at end of year	$ 779,913	$ 690,271

We made the assumptions below to calculate the pension liability:

	1999	1998
Discount rate	7.75%	7.00%
Rate of increase in compensation levels	4.25%	3.50%
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 each of the last three years (1997-1999).

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:

- $ 7 million for 1999
- $ 9 million for 1998 and
- $10 million for 1997.

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

(thousands of dollars)

	1999	1998	1997
Service cost – benefits earned during the period	$ 8,939	$ 7,890	$ 7,046
Interest cost on accumulated benefit obligation	17,366	15,763	14,441
Expected return on plan assets	(18,454)	(12,001)	(8,706)
Amortization of:			
Transition asset	7,698	7,698	7,698
Net actuarial gains	(5,117)	(2,952)	(2,685)
Net periodic postretirement benefit cost	$ 10,432	$ 16,398	$ 17,794

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

(thousands of dollars)

	1999	1998
Funded status - postretirement plan assets more than (less than) projected benefit obligation	$ 25,549	$ (24,269)
Unrecognized net obligation at transition	100,145	107,842
Unrecognized net actuarial gains	(128,309)	(86,692)
Net postretirement amount recognized in the balance sheets	$ (2,615)	$ (3,119)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Accumulated postretirement benefit obligation at beginning of year	$ 237,679	$ 199,348
Service cost	8,939	7,890
Interest cost	17,366	15,763
Benefit payments	(8,761)	(10,378)
Actuarial (gains) losses	(23,234)	25,056
Accumulated postretirement benefit obligation at end of year	$ 231,989	$ 237,679

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Fair value of postretirement plan assets at beginning of year	$ 213,410	$ 151,146
Actual return on plan assets	42,975	47,284
Employer contributions	9,914	25,327
Benefit payments	(8,761)	(10,347)
Fair value of postretirement plan assets at the end of year	$ 257,538	$ 213,410

We made the assumptions below to calculate the postretirement liability:

	1999	1998
Discount rate	7.75%	7.00%
Expected long-term rate of return on assets – after tax	8.77%	8.73%
Initial health care cost trend rate – under age 65	7.00%	7.50%
Initial health care cost trend rate – age 65 and over	6.00%	6.50%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would increase by approximately $5 million and the accumulated benefit obligation as of December 31, 1999 would increase by approximately $38 million.

Assuming a 1% decrease in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would decrease by approximately $4 million and the accumulated benefit obligation as of December 31, 1999 would decrease by approximately $30 million.

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 $46 million in 2000 and approximately $49 million per year in 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, 1999 was $43 million. Lease expense was approximately $42 million in each of the years 1997 through 1999.

APS has a capital lease on a combined cycle plant, which it sold and leased back. The lease requires semiannual payments of $3 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54 million; accumulated amortization at December 31, 1999 was $51 million.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates. Miscellaneous lease expense was approximately $10 million in 1999, $13 million in 1998, and $11 million in 1997.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

(dollars in millions)

Year	
2000	$ 17
2001	19
2002	20
2003	20
2004	20
Thereafter	138
Total future commitments	$ 234

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, 1999. 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 APS	Plant In Service	Accumulated Depreciation	Construction Work In Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,829,633	$ 751,567	$ 7,220
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	572,574	240,696	17,145
Four Corners Steam Generating Station Units 4 and 5	15.0%	139,209	71,333	364
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	230,536	94,332	4,555
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	68,643	38,068	1,679
Transmission Facilities:				
ANPP 500 KV System	35.8%(b)	68,133	21,446	7
Navajo Southern System	31.4%(b)	27,364	17,550	42
Palo Verde – Yuma 500 KV System	23.9%(b)	11,728	4,388	36
Four Corners Switchyards	27.5%(b)	3,071	1,855	—
Phoenix – Mead System	17.1%(b)	36,434	1,768	—

(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.

Palo Verde Nuclear Generating Station

Under the Nuclear Waste Policy Act, 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 DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including APS. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision.

APS has capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 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. APS currently estimates that it will incur $113 million (in 1999 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, 1999, APS had recorded a liability and a regulatory asset of $37 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date. APS currently believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

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 the 29.1% interest in the three Palo Verde units, APS' 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 2000 through 2020 that include required purchase provisions. APS estimates its 2000 contract requirements to be about $177 million. 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 $57 million at December 31, 1999 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, 1999 was about $41 million.

Construction Program

Consolidated capital expenditures in 2000 are estimated at $591 million.

Generation Expansion

We are currently planning, through Pinnacle West Energy, a 650-megawatt expansion of our West Phoenix Power Plant, and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk. Pinnacle West Energy's capital expenditures in 1999 were $21 million. Projected capital expenditures for these projects are $152 million in 2000; $240 million in 2001; and $245 million in 2002. We are also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's capital expenditures will be funded with debt proceeds, and internally generated cash and debt proceeds from the parent company. Assuming all approvals are granted, we expect to begin construction at West Phoenix in the second quarter of 2000.

Pinnacle West Energy has signed a joint development agreement with Reliant Energy Power Generation, Inc. (Reliant) covering construction and operation of three new merchant plants. Pinnacle West Energy plans to contribute the first two units (1,060 megawatts) of the Redhawk project to the joint agreement. Construction is expected to start in the third quarter of 2000, with commercial operation scheduled in the summer of 2002. Reliant plans to contribute two new natural gas-fired projects (1,500 megawatts) in Nevada to the venture.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11 million for nuclear decommissioning expense in each of the years 1999, 1998, and 1997. APS estimates it will cost about $1.8 billion ($472 million in 1999 dollars) to decommission its 29.1% 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 Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" on the Consolidated Balance Sheets at their market value of $176 million at December 31, 1999 and $146 million at December 31, 1998.

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 1999 and 1998 is as follows:

(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

(dollars in thousands, except per share amounts)

1998 — Quarter Ended	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 380,423	$ 441,715	$ 740,734	$ 443,526
Real estate	34,161	28,916	18,276	42,835
Operating income (a)	$ 90,837	$ 122,605	$ 251,838	$ 101,848
Net income	$ 31,086	$ 48,997	$ 127,281	$ 35,528
Earnings per average common share outstanding				
Net income – basic	$ 0.37	$ 0.58	$ 1.50	$ 0.42
Net income – diluted	$ 0.36	$ 0.57	$ 1.49	$ 0.42
Dividends declared per share (b)	$ 0.30	$ 0.60	$ —	$ 0.325

(a) APS' utility business is 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 quarters ending September 30, 1999 and September 30, 1998 were declared in June.

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, 1999 and 1998 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 1999 and 1998 fair values of such investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.31 billion on December 31, 1999, with an estimated fair value of $2.29 billion. On December 31, 1998, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.21 billion, with an estimated fair value of $2.27 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

In 1997 we adopted SFAS No. 128, "Earnings Per Share." This statement requires the presentation of both basic and diluted earnings per share on the financial statements. The following table presents earnings per average common share outstanding (EPS):

	1999	1998	1997
Basic EPS:			
Continuing operations	$ 3.18	$ 2.87	$ 2.76
Discontinued operations	0.45	—	—
Extraordinary charge	(1.65)	—	—
Net income	$ 1.98	$ 2.87	$ 2.76
Diluted EPS:			
Continuing operations	$ 3.17	$ 2.85	$ 2.74
Discontinued operations	0.45	—	—
Extraordinary charge	(1.65)	—	—
Net income	$ 1.97	$ 2.85	$ 2.74

Dilutive stock options increased average common shares outstanding by 291,392 shares in 1999, 571,728 shares in 1998, and 519,800 shares in 1997. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 85,008,527 shares in 1999, 85,345,946 shares in 1998, and 86,022,709 shares in 1997.

Options to purchase 506,734 shares of common stock were outstanding during the last quarter of 1999 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.

17. STOCK-BASED COMPENSATION

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

The most recent 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. 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, 1999 approximate 1,441,124 non-qualified stock options, 159,837 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 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 would have been reduced to the following pro forma amounts:

(thousands of dollars)

	1999	1998	1997
Net income			
As reported	$ 167,887	$ 242,892	$ 235,856
Pro forma (fair value method)	$ 166,913	$ 242,177	$ 235,446
Net income per share – basic			
As reported	$ 1.98	$ 2.87	$ 2.76
Pro forma (fair value method)	$ 1.97	$ 2.86	$ 2.75

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation. 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:

	1999	1998	1997
Risk-free interest rate	5.68%	4.54%	5.66%
Dividend yield	3.33%	3.03%	4.50%
Volatility	20.50%	18.80%	15.63%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 1999, 1998, and 1997 and changes during the years ending on those dates:

	1999 Shares	1999 Weighted Average Exercise Price	1998 Shares	1998 Weighted Average Exercise Price	1997 Shares	1997 Weighted Average Exercise Price
Outstanding at beginning of year	1,563,512	$ 27.95	1,554,631	$ 24.38	1,739,576	$ 21.51
Granted	458,450	35.95	244,200	46.78	260,450	39.56
Exercised	(516,838)	18.19	(217,317)	23.09	(409,975)	21.60
Forfeited	(64,000)	40.36	(18,002)	33.42	(35,420)	27.10
Outstanding at end of year	1,441,124	33.45	1,563,512	27.95	1,554,631	24.38
Options exercisable at year-end	835,381	29.69	1,106,165	22.04	1,075,014	19.52
Weighted average fair value of options granted during the year		7.05		8.15		5.83

The following table summarizes information about our stock option plans at December 31, 1999:

Exercise Prices Per Share	Outstanding	Weighted Average Remaining Contract Life	Options Exercisable
$10.06	7,000	1.50	7,000
11.25	15,500	0.90	15,500
15.75	17,500	1.90	17,500
16.25	3,500	0.50	3,500
17.68	10,775	2.10	10,775
18.13	28,000	2.50	28,000
19.00	82,370	4.90	82,370
19.56	32,000	2.90	32,000
22.13	71,584	4.00	71,584
23.25	28,000	3.50	28,000
27.44	126,837	5.90	126,837
31.44	157,874	6.90	157,874
34.66	348,450	9.90	9,679
36.56	5,000	9.80	417
39.75	213,534	8.00	142,356
41.00	70,000	9.10	21,389
46.78	223,200	8.90	80,600
$10.06 – $46.78	1,441,124		835,381

18. BUSINESS SEGMENTS

Historically, we reported our operations as a single, integrated business segment. The basis of our reporting in previous years was due to APS' regulated operating environment. The ACC authorized a combined rate for supplying and delivering electricity to customers which was cost-based and was designed to recover APS' operating expenses and investment in electric utility assets and to provide a return on the investment.

As a result of the 1999 Settlement Agreement, our generation operations are now deregulated for accounting purposes. For the purposes of complying with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131), we are required to disclose information about its business segments separately. Accordingly, APS has separated identifiable expenses between the two segments and has allocated revenues and other expenses using a study that identifies the portion of its base rates related to generation and delivery. APS then used that information to develop the financial information of the business segments for each of the three years ended December 31, 1999 (or as of December 31, 1999 and 1998, with respect to assets). None of our revenues from external customers are attributed to, and none of our long-lived assets are located in, any foreign country.

Beginning in 1999, we have two principal business segments (determined by products, services, and regulatory environment) which consist of the generation of electricity (generation business segment), and the transmission and distribution of electricity (delivery business segment). The "Other" amounts include activity relating to other subsidiaries including SunCor, El Dorado, and APS Energy Services. Intercompany eliminations primarily relate to intercompany sales of electricity. Financial data for business segments is provided as follows:

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1999 (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 (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

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1997 (in thousands)

	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 803,647	$ 1,878,553	$ 116,473	$ (803,647)	$ 1,995,026
Operating expense	471,992	1,297,802	98,519	(803,647)	1,064,666
Operating margin	331,655	580,751	17,954	—	930,360
Depreciation and amortization	131,684	233,987	2,614	—	368,285
Interest and preferred stock dividend requirements	50,311	104,410	21,217	—	175,938
Pretax margin	149,660	242,354	(5,877)	—	386,137
Income taxes	44,898	108,426	(3,043)	—	150,281
Earnings for common stock	$ 104,762	$ 133,928	$ (2,834)	$ —	$ 235,856
Capital expenditures	$ 84,960	$ 217,047	$ 67,248	$ —	$ 369,255

BOARD OF DIRECTORS

RICHARD SNELL
(69) 1975*
Chairman of the Board**

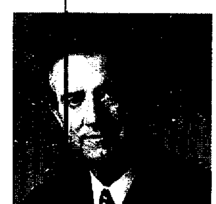
ROY A. HERBERGER, JR.
(57) 1992
President,
Thunderbird, The American Graduate School of International Management
Committees:
Audit
Finance and Planning, Chairman

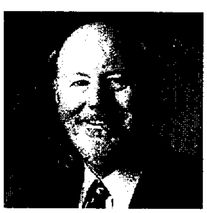
PAMELA GRANT
(61) 1980
Civic Leader
Committees:
Human Resources, Chairman
Finance and Planning

WILLIAM J. POST
(49) 1994
President & Chief Executive Officer

MARTHA O. HESSE
(57) 1991
President,
Hesse Gas Company
Committees:
Audit, Chairman
Human Resources

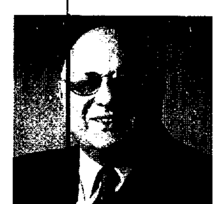
HUMBERTO S. LOPEZ
(54) 1995
President,
HSL Properties, Inc.
Committees:
Human Resources
Audit



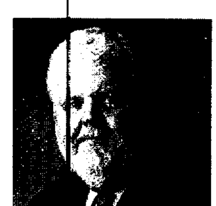


THE REV. BILL JAMIESON, JR.
(56) 1991
President,
Institute for Servant Leadership of Asheville, North Carolina
Committees:
Audit
Finance and Planning

EDDIE BASHA
(62) 1999
Chairman of the Board,
Bashas'
Committees:
Human Resources
Audit



MICHAEL L. GALLAGHER
(55) 1999
President,
Gallagher & Kennedy, P.A.
Committees:
Human Resources
Finance and Planning



* The year in which the individual first joined the Board of a Pinnacle West company.
** Retired as Chief Executive Officer February 5, 1999.

OFFICERS

PINNACLE WEST

Richard Snell
(69) 1990*
Chairman of the Board**

William J. Post
(49) 1973
President & Chief Executive Officer

Armando B. Flores
(56) 1991
Executive Vice President,
Corporate Business Services

Robert S. Aiken
(43) 1986
Vice President, Federal Affairs

John G. Bohon
(54) 1971
Vice President, Corporate Services &
Human Resources

Edward Z. Fox
(46) 1995
Vice President, Communications,
Environment & Safety

Chris N. Froggatt
(42) 1986
Vice President & Controller

James L. Kunkel
(62) 1997
Vice President

Nancy C. Loftin
(46) 1985
Vice President & General Counsel

Michael V. Palmeri
(41) 1982
Vice President, Finance

Martin L. Shultz
(55) 1979
Vice President, Government Affairs

Faye Widenmann
(51) 1978
Vice President & Secretary

Barbara M. Gomez
(45) 1978
Treasurer

ARIZONA PUBLIC SERVICE

Richard Snell
Chairman of the Board

William J. Post
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
(53) 1973
President,
Energy Delivery & Sales

Jan H. Bennett
(52) 1967
Vice President, Customer Service

William L. Stewart
(56) 1994
President, Generation

James M. Levine
(50) 1989
Executive Vice President,
Generation

Gregg R. Overbeck
(53) 1990
Senior Vice President, Nuclear Generation

John R. Denman
(57) 1964
Vice President, Fossil Generation

William E. Ide
(53) 1977
Vice President,
Nuclear Production

David Mauldin
(50) 1990
Vice President, Nuclear Engineering
& Support

PINNACLE WEST ENERGY

William L. Stewart
President

Ajoy K. Banerjee
(54) 1999
Vice President, Generation Expansion

Ajit P. Bhatti
(54) 1973
Vice President, Generation Planning

APS ENERGY SERVICES

Vicki G. Sandler
(43) 1982
Vice President, Energy Services

SUNCOR DEVELOPMENT

Richard Snell
Chairman of the Board

John C. Ogden
(54) 1972
President & Chief Executive Officer

Geoffrey L. Appleyard
(46) 1987
Vice President & Chief Financial Officer

Duane S. Black
(47) 1989
Vice President & Chief Operating Officer

Jay T. Ellingson
(50) 1992
Vice President, Development – Palm Valley

Steven Gervais
(44) 1987
Vice President & General Counsel

Margaret E. Kirch
(50) 1988
Vice President,
Commercial Development

Thomas A. Patrick
(46) 1995
Vice President, Golf Operations

EL DORADO INVESTMENT

Richard Snell
Chairman of the Board

James L. Kunkel
President

* The year in which the individual was first employed within the Pinnacle West group of companies.
** Retired as Chief Executive Officer February 5, 1999.

SHAREHOLDER INFORMATION

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

Mailing address:
P.O. Box 52132
Phoenix, Arizona 85072-2132

Main telephone number: (602) 379-2500

ANNUAL MEETING OF SHAREHOLDERS
Wednesday, May 17, 2000
10:30 a.m.
The Wigwam Resort
300 Wigwam Boulevard
Litchfield Park, Arizona 85340

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 after April 1, 2000 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 or by writing to:

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

CORPORATE WEBSITE
http://www.pinnaclewest.com

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1994-1999 will be available in April on the Company's website or by writing to the Investor Relations Department.

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

BankBoston N.A.
c/o EquiServe
P.O. Box 8040
Boston, Massachusetts 02266-8040
Telephone: (781) 575-3120

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION
Shareholder Department telephone number
(toll-free): 1-800-457-2983

INVESTOR RELATIONS CONTACT
Rebecca L. Hickman
Director, Investor Relations
Telephone: (602) 250-5668
Fax: (602) 250-5640

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
Web: 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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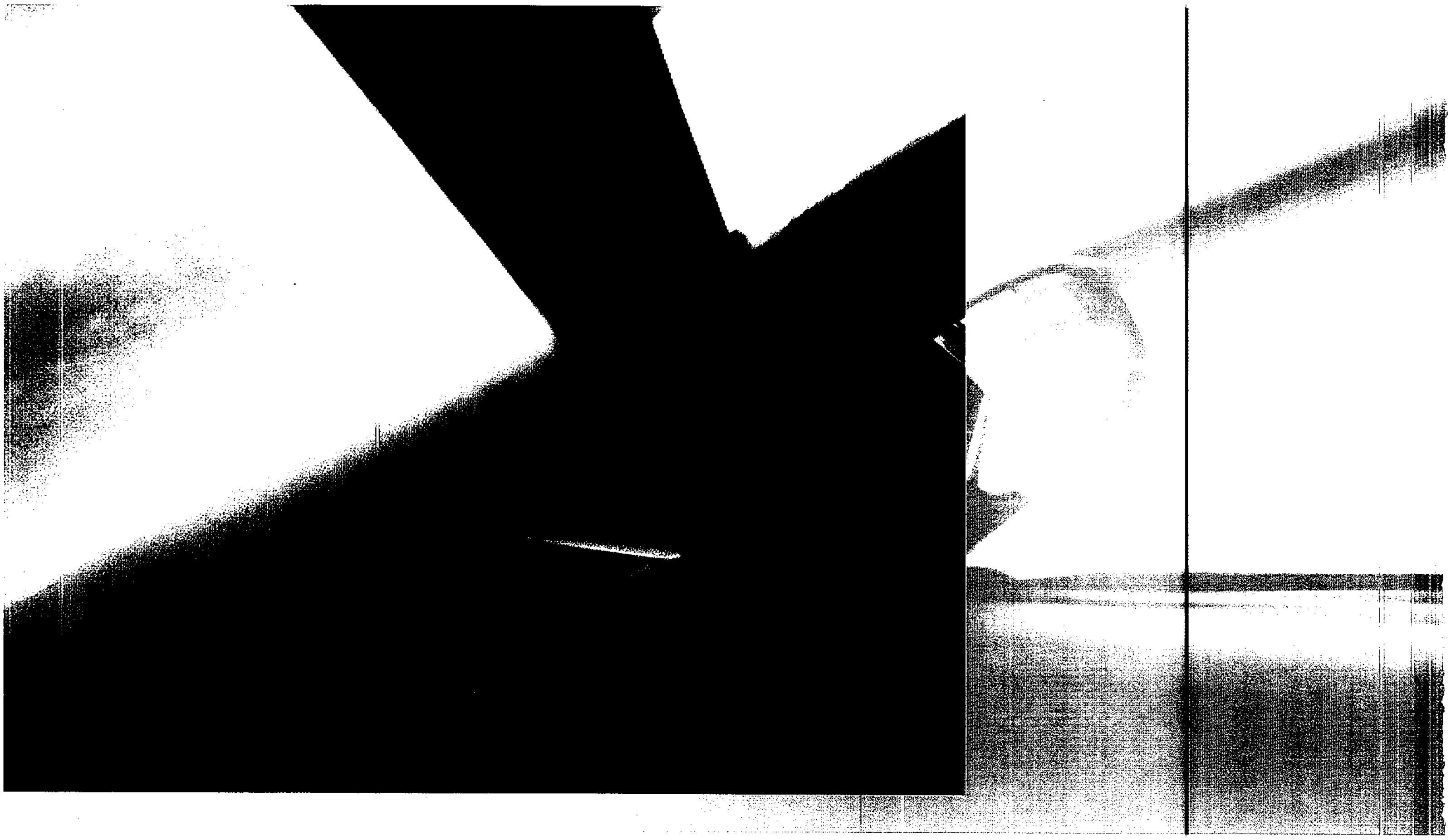


PINNACLE WEST
CAPITAL CORPORATION

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1999

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number 1-8962.

Pinnacle West Capital Corporation

(Exact name of registrant as specified in its charter)

ARIZONA (State or other jurisdiction of incorporation or organization)	86-0512431 (I.R.S. Employer Identification No.)
400 East Van Buren Street, Suite 700 Phoenix, Arizona 85004 (Address of principal executive offices, including zip code)	(602) 379-2500 (Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	New York Stock Exchange Pacific Stock Exchange

Title of Each Class of Voting Stock	Shares Outstanding as of March 27, 2000	Aggregate Market Value of Shares Held by Non-affiliates as of March 27, 2000
Common Stock, No Par Value	84,722,640	$2,271,625,785(a)

(a) Computed by reference to the closing price on the composite tape on March 27, 2000, as reported by the Wall Street Journal.

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

Yes X No __

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

Documents Incorporated By Reference

Portions of the registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 17, 2000 are incorporated by reference into Part III hereof.

TABLE OF CONTENTS

GLOSSARY

ACC — Arizona Corporation Commission

ACC Staff — Staff of the Arizona Corporation Commission

AFUDC — Allowance for Funds Used During Construction

ANPP — Arizona Nuclear Power Project, also known as Palo Verde

APS — Arizona Public Service Company

APSES — APS Energy Services Company, Inc.

CC&N — Certificate of convenience and necessity

Cholla — Cholla Power Plant

Cholla 4 — Unit 4 of the Cholla Power Plant

Company — Pinnacle West Capital Corporation

El Dorado — El Dorado Investment Company

EPA — United States Environmental Protection Agency

FASB — Financial Accounting Standards Board

FERC — Federal Energy Regulatory Commission

Four Corners — Four Corners Power Plant

GAAP — Generally accepted accounting principles

ITC — Investment tax credit

kW — Kilowatt, one thousand watts

kWh — Kilowatt-hour, one thousand watts per hour

MW — Megawatt hours, one million watts

MWh — Megawatt hours, one million watts per hour

NGS — Navajo Generating Station

NRC — Nuclear Regulatory Commission

Palo Verde — Palo Verde Nuclear Generating Station

Pinnacle West Energy — Pinnacle West Energy Corporation

SEC — Securities and Exchange Commission

Salt River Project — Salt River Project Agricultural Improvement and Power District

SunCor — SunCor Development Company

PART I

ITEM 1. BUSINESS

The Company

General

We were incorporated in 1985 under the laws of the State of Arizona and are engaged, through our subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Our principal executive offices are located at 400 East Van Buren Street, Suite 700, Phoenix, Arizona 85004 (telephone 602-379-2500).

At December 31, 1999, we employed about 7,534 people, including the employees of our subsidiaries. Of these employees, 6,234 were employees of our major subsidiary, APS, and employees assigned to joint projects of APS where APS serves as a project manager, and about 1,300 were our employees and employees of our other subsidiaries.

Our other subsidiaries, in addition to APS, include SunCor, El Dorado, APS Energy Services and Pinnacle West Energy. See "Business of SunCor Development Company," "Business of El Dorado Investment Company," "Business of APS Energy Services Company, Inc.," and "Business of Pinnacle West Energy Corporation" in this Item for further information regarding these businesses.

This document contains "forward-looking statements" that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; the strength of the stock market (particularly the technology sector) and the strength of the real estate market. See "Business of Arizona Public Service Company -- Competition" for a discussion of some of these factors.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

Following is a discussion of the business of APS, our major subsidiary.

General

APS was incorporated in 1920 under the laws of Arizona and is engaged principally in serving electricity in the State of Arizona. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000). We own all of the outstanding shares of APS' common stock.

APS is Arizona's largest electric utility, with 827,000 customers. APS provides wholesale or retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area. During 1999, no single purchaser or user of energy accounted for more than 2% of total electric revenues. See Note 18 of Notes to Financial Statements for a discussion of business segments. At December 31, 1999, APS employed 6,234 people, which includes employees assigned to joint projects where APS is project manager.

Competition

Retail

The ACC has regulatory authority over APS in matters relating to retail electric rates, the issuance of securities, and the transaction of business with affiliated parties. See Note 3 of Notes to Financial Statements in Item 8 for a discussion of the electric industry restructuring in Arizona, including APS' 1999 Settlement Agreement, ACC rules for the introduction of retail electric competition, and Arizona legislative initiatives. See also "Financial Review - Competition and Industry Restructuring" in Item 7. In addition to the introduction of competition pursuant to the Settlement Agreement and the ACC rules, APS is subject to varying degrees of competition in certain territories adjacent to or within areas that APS serves that are also currently served by other utilities in its region (such as Tucson Electric Power Company, Southwest Gas Corporation, and Citizens Utility Company) as well as cooperatives, municipalities, electrical districts, and similar types of governmental organizations (principally Salt River Project).

APS faces competitive challenges from low-cost hydroelectric power and natural gas fuel, as well as the access of some utilities to preferential low-priced federal power and other subsidies. In addition, some customers, particularly industrial and large commercial, may own and operate facilities to generate their own electric energy requirements. Such facilities may be operated by the customers themselves or by other entities engaged for such purpose.

Wholesale

APS competes with other utilities, power marketers, and independent power producers in the sale of electric capacity and energy in the wholesale market. APS expects that competition to sell capacity will remain vigorous. APS' rates for wholesale power sales and transmission services are subject to regulation by the FERC. During 1999, approximately 23% of its electric operating revenues resulted from such sales and charges.

The National Energy Policy Act of 1992 has promoted increased competition in the wholesale electric power markets. The Energy Act reformed provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, the Energy Act permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers and other third parties can sell at wholesale to customers wherever located. The Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

Effective July 9, 1996, a FERC decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with access to transmission facilities comparable to the transmission owners' access for wholesale transactions, establishes information requirements, and provides for recovery of certain wholesale stranded costs. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states, unless a state lacks authority to impose rates to recover such costs, in which case FERC will consider doing so. APS has filed a revised open access tariff in accordance with this decision. APS does not believe that this decision will have a material adverse impact on its results of operations or financial position.

Regulatory Assets

APS' major regulatory assets are deferred income taxes and rate synchronization cost deferrals. As a result of APS' September 1999 Settlement Agreement, APS has discontinued the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," for its generation operations. This means that regulatory assets, unless reestablished as recoverable through ongoing regulated cash flows, were eliminated and the generation assets were tested for impairment. APS determined that the generation assets were not impaired. Prior to the Settlement Agreement, under a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that would have ended June 30, 2004. See Notes 1, 3, and 4 of Notes to Financial Statements in Item 8 for additional information.

Competitive Strategies

APS is pursuing strategies to maintain and enhance its competitive position. These strategies include (i) cost management, with an emphasis on the reduction of variable costs (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; (ii) a focus on APS' core business through customer service, distribution system reliability, business segmentation, and the anticipation of market opportunities; (iii) an emphasis on good regulatory relationships; (iv) asset maximization (e.g., higher capacity factors and lower forced outage rates); (v) strengthening its capital structure and financial condition; (vi) leveraging core competencies into related areas, such as energy management products and services; and (vii) operating a trading floor and implementing a risk management program to provide for more stability of prices and the ability to retain or grow incremental margins through more competitive pricing and risk management. Underpinning APS' competitive strategies are the strong growth characteristics of its service territory. As competition in the electric utility industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position it to compete effectively in a more competitive, restructured industry.

Generating Fuel and Purchased Power

1999 Energy Mix

APS' sources of energy during 1999 were: coal – 29.9%; nuclear – 22.4%; purchased power – 43.2%; gas – 4.4%; and other – 0.1%.

Coal Supply

Leases NGS and Four Corners are located on the Navajo Reservation and held under easements granted by the federal government as well as leases from the Navajo Nation. See "Properties- Plant Sites Leased from the Navajo Nation" in Item 2. Most of the coal for Cholla is supplied by a coal supplier who mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government, and private landholders. Remaining coal requirements are purchased on the spot market. All of the coal for Four Corners is purchased from a coal supplier with a long-term lease of coal reserves owned by the Navajo Nation. The coal for NGS comes from a supplier with a long-term lease with the Navajo Nation and the Hopi Tribe. See Note 12 of Notes to Financial Statements in Item 8 for information regarding our obligation for coal mine reclamation.

Contracts Cholla presently has sufficient coal under current contracts to ensure a reliable fuel supply through 2005. Portions of the fuel supply are bid on the spot market to take advantage of competitive pricing options. Following expiration of current contracts, there are numerous competitive fuel supply options available to ensure continuous plant operation. Cholla also has certain requirements for low sulfur coal and the current supplier is expected to continue to provide most of Cholla's low sulfur coal requirements through the current contract. There are sufficient reserves of low sulfur coal available from other suppliers to ensure the continued operation of Cholla for its useful life. The sulfur content of coal at Cholla for 1999 was 0.47%. Average prices paid for all coal supplied from reserves dedicated under existing contracts were slightly lower than, but comparable to, 1998. For the years remaining on the contracts after 2000, prices will be reduced.

Four Corners is a mine-mouth operation which is under contract for coal through 2004. There are options to extend the contract through the plant site lease expiration in 2017. The sulfur content of Four Corners coal for 1999 was 0.77%, and the units are equipped with scrubbers. The average price paid for all coal supplied under the existing contract was slightly lower than, but comparable to, 1998. The Four Corners lease waives, until July 2001, the requirement that APS, as well as its fuel supplier, pay certain taxes to the Navajo Nation. In September 1997, a settlement agreement was finalized between the coal supplier, the Navajo Nation, and Four Corners participants, which settled certain issues in the lease regarding the obligation of the fuel supplier to pay taxes prior to the expiration of tax waivers in 2001. Pursuant to this agreement, the coal supplier currently pays a possessory interest tax to the Navajo Nation, which is contractually reimbursed by participants. The parties also agreed to investigate alternative contractual arrangements and business relationships before 2001 in an effort to permit the electricity generated at Four Corners to be priced competitively. APS anticipates that additional taxes will be levied by the Navajo Nation upon the expiration of the tax waivers; however, APS cannot currently predict the outcome of this matter or the amount of the additional taxes.

NGS is under contract with its coal supplier through 2011, with options to extend through the plant site lease. The sulfur content of coal at NGS for 1999 was 0.53%, and the units are equipped with scrubbers. Average price paid for coal supplied in 1999 under the existing contract was lower than, but comparable to, 1998. The NGS lease waives certain taxes through the lease expiration in 2019. The lease provides for the potential to renegotiate the coal royalty in 2007 and 2017, which may impact the fuel price.

Natural Gas Supply

APS is a party to contracts with a number of natural gas suppliers that allow it to purchase natural gas in the method it determines to be most economic. Currently, APS is purchasing the majority of its natural gas requirements from numerous companies under these contracts. APS' natural gas supply is transported pursuant to a firm transportation service contract with El Paso Natural Gas Company. APS continues to analyze the market to determine the most favorable source and method of meeting its natural gas requirements.

Nuclear Fuel Supply

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

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

The Palo Verde participants have made contractual arrangements to obtain quantities of uranium concentrates anticipated to be sufficient to meet operational requirements through 2002. Existing contracts and options could be utilized to meet approximately 88% of requirements in 2003, 88% of requirements in 2004, 49% of requirements in 2005, and 16% of requirements in 2006 and beyond. Spot purchases on the uranium market will be made, as appropriate, in lieu of any uranium that might be obtained through contractual options.

The Palo Verde participants have contracted for uranium conversion services. Existing contracts and options could be utilized to meet approximately 70% of requirements in 2000, 75% of requirements in 2001 and 80% of requirements in 2002. The Palo Verde participants have an enrichment services contract and an enriched uranium product contract that furnish enrichment services required for the operation of the three Palo Verde units through 2003. In addition, existing contracts will provide fuel assembly fabrication services until at least 2015 for each Palo Verde unit.

Spent Nuclear Fuel and Waste Disposal. Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987, the United States Department of Energy ("DOE") is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The NRC, pursuant to the Waste Act, requires operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository. DOE has announced that such a repository now cannot be completed before 2010. In July 1996, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) ruled that the DOE has an obligation to start disposing of spent nuclear fuel no later than January 31, 1998. By way of letter dated December 17, 1996, DOE informed APS and other contract holders that DOE anticipates that it would be unable to begin acceptance of spent nuclear fuel for disposal in a repository or interim storage facility by January 31, 1998. In November 1997, the D.C. Circuit issued a Writ of Mandamus precluding DOE from excusing its own delay on the grounds that DOE has not yet prepared a permanent repository or interim storage facility. On May 5, 1998, the D.C. Circuit issued a ruling refusing to order DOE to begin moving spent nuclear fuel. See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of interim spent fuel storage costs.

Several bills have been introduced in Congress contemplating the construction of a central interim storage facility; however, there is resistance to certain features of these bills both in Congress and the Administration.

Facility funding is a further complication. While all nuclear utilities pay into a so-called nuclear waste fund an amount calculated on the basis of the output of their respective plants, the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes). According to DOE spokespersons, the fund may now be at a level less than needed to achieve a 2010 operational date for a permanent repository. No funding will be available for a central interim facility until one is authorized by Congress.

APS has storage capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002. Construction of a new facility for on-site dry storage of spent fuel is underway. Once this facility is completed and approvals are granted, APS believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

A new low-level waste facility was built in 1995 on-site which could store an amount of waste equivalent to ten years of normal operation at Palo Verde. Although some low-level waste has been stored on-site, 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 believes that scientific and financial aspects of the issues of spent fuel and low-level waste storage and disposal can be resolved satisfactorily. However, APS also acknowledges that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which APS is less able to predict.

Purchased Power Agreements

In addition to that available from its own generating capacity (see "Properties" in Item 2), APS purchases electricity from other utilities under various arrangements. One of the most important of these is a long-term contract with Salt River Project. This contract may be canceled by Salt River Project on three years' notice and requires Salt River Project to make available, and APS to pay for, certain amounts of electricity. The amount of electricity is based in large part on customer demand within certain areas now served by APS pursuant to a related territorial agreement. The generating capacity available to APS pursuant to the contract was 316 MW January through May 1999, and starting June 1999 changed to 302 MW. In 1999, APS received approximately 1,056,200 MWh of energy under the contract and paid about $43.9 million for capacity availability and energy received. See Note 3 of Notes to Financial Statements for a discussion of amendments to this contract and other agreements with Salt River Project.

In September 1990, APS entered into a thirty year agreement under which APS and PacifiCorp engage in one-for-one seasonal capacity exchanges. APS receives electricity from PacifiCorp during APS' summer peak season. APS will have 480 MW of generating capacity available to it under the agreements until 2020. In 1999, APS had 480 MW of generating capacity available from PacifiCorp and APS received approximately 572,382 MWh of energy under the capacity exchange.

Construction Program

During the years 1997 through 1999, APS incurred approximately $962 million in capital expenditures. Utility capital expenditures for the years 2000 through 2002 are expected to be primarily for expanding transmission and distribution capabilities to meet customer growth, upgrading existing facilities, and for environmental purposes. Capitalized expenditures, including expenditures for environmental control facilities, for the years 2000 through 2002 have been estimated as follows:

(Millions of Dollars)

By Year		**By Major Facilities**	
2000	$384	Production	$255
2001	342	Transmission and Distribution	691
2002	334	General	114
Total	$ 1,060	Total	$ 1,060

The amounts for 2000 through 2002 exclude capitalized interest costs and include capitalized property taxes and about $30-$35 million each year for nuclear fuel. APS conducts a continuing review of its construction program.

Mortgage Replacement Fund Requirements

So long as any of APS' first mortgage bonds are outstanding, APS is required for each calendar year to deposit with the trustee under its mortgage cash in a formularized amount related to net additions to its mortgaged utility plant. APS may satisfy all or any part of this "replacement fund" requirement by utilizing redeemed or retired bonds, net property additions, or property retirements. For 1999, the replacement fund requirement amounted to approximately $143 million. Certain of the bonds APS has issued under the mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash APS deposits in the replacement fund. This is subject in many cases to a period of time after the original issuance of the bonds during which they may not be so redeemed.

Environmental Matters

EPA Environmental Regulation

Clean Air Act. APS is subject to a number of requirements under the Clean Air Act. Pursuant to the Clean Air Act, the EPA adopted regulations that address visibility impairment in certain federally-protected areas which can be reasonably attributed to specific sources. In September 1991, the EPA issued a final rule that limited sulfur dioxide emissions at NGS. One NGS unit had to comply with this rule in 1997, one in 1998, and the last unit in 1999. Salt River Project is the NGS operating agent. Salt River Project estimates a capital cost of $430 million and annual operations and maintenance costs of approximately $14 million for all three units, for NGS to meet these requirements. APS is required to fund 14% of these expenditures. About all of these capital costs have been incurred.

The Clean Air Act also addresses, among other things:

- "acid rain,"
- visibility in certain specified areas,
- hazardous air pollutants and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Clean Air Act establishes a system of sulfur dioxide emissions "allowances." Each existing utility unit is granted a certain number of "allowances." For Phase II plants, which include APS' plants, allowances will be required beginning in the year 2000 to operate the plants. Based on EPA allowance allocations, APS has sufficient allowances to permit continued operation of its plants at current levels without installing additional equipment.

The Clean Air Act also requires the EPA to set nitrogen oxides emissions limitations. These limitations require certain plants to install additional pollution control equipment. In December 1996, the EPA issued rules for nitrogen oxides emissions limitations that would have required APS to install additional pollution control equipment at Four Corners by January 1, 2000. On February 14, 1997, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. APS alleged that the EPA improperly classified Four Corners Unit 4 in these rules, thereby subjecting Unit 4 to a more stringent emission limitation. Arizona Public Service Company v. United States Environmental Protection Agency, No. 97-1091. In February 1998, the Court vacated the Unit 4 emission limitation and remanded the issue to EPA for reconsideration. In December 1999, EPA's direct final rule, which classified Four Corners Unit 4 as APS had proposed, became final. APS does not currently expect this rule to have a material impact on its financial position or results of operations.

With respect to protection of visibility in certain specified areas, the Clean Air Act requires the EPA to conduct a study concerning visibility impairment in those areas and to identify sources contributing to such impairment. Interim findings of this study indicate that any beneficial effect on visibility as a result of the Clean Air Act would be offset by expected population and industry growth. The Clean Air Act also requires EPA to establish a "Grand Canyon Visibility Transport Commission" to complete a study on visibility impairment in the "Golden Circle of National Parks" in the Colorado Plateau. NGS, Cholla, and Four Corners are located near the Golden Circle of National Parks. The Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA.

On April 22, 1999, the EPA announced final regional haze rules. These new regulations require states to submit, by 2008, implementation plans containing requirements to eliminate all man-made emissions causing visibility impairment in certain specified areas, including the Golden Circle of National Parks in the Colorado Plateau. The 2008 implementation plans must also include consideration and potential application of best available retrofit technology ("BART") for major stationary sources which came into operation between August 1962 and August 1977, such as the Navajo Generating Station, Cholla Power Plant and Four Corners Power Plant. The nine western states and tribes that participated in the Grand Canyon Visibility Transport Commission process will have the option to follow an alternate implementation plan and schedule for areas considered by the Commission. Under this option, those states and tribes would submit implementation plans by 2003, which would incorporate the emission reduction scheme adopted in the Commission's recommendations and application of BART by 2018, possibly using an emission trading program. Any states and tribes that implement this option will also have to submit revised implementation plans in 2008 to address visibility in certain specified areas that were not considered by the Commission. Because Arizona and the Navajo Nation have the discretion to choose between the national or Commission options and a variety of pollution controls to meet the requirements of the regional haze rules, the actual impact on APS cannot be determined at this time.

Also, in July 1997, EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to the rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard. These standards were challenged and the court determined that EPA's promulgation of the standards violated the constitutional prohibition on delegation of legislative power. The court remanded the ozone standard, vacated the coarse particulate matter standard, and invited the parties to brief the court on vacating or remanding the fine particulate matter standard. APS cannot currently predict EPA's response to this decision. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, APS currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, APS does not currently expect these rules to have a material adverse effect on its financial position or results of operations.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the Clean Air Act requires two studies. The results of the first study indicated an impact from mercury emissions from such units in certain unspecified areas. The EPA has not yet stated whether or not mercury emissions limitations will be imposed. Secondly, the EPA will complete a general study by December 2000 concerning the necessity of regulating hazardous air pollutant emissions from such units under the Clean Air Act. Because APS cannot speculate as to the ultimate requirements by the EPA, APS cannot currently estimate the capital expenditures, if any, which may be required as a result of these studies.

Certain aspects of the Clean Air Act may require APS to make related expenditures, such as permit fees. APS does not expect any of these to have a material impact on its financial position or results of operations.

Federal Implementation Plan. In September 1999, the EPA proposed a Federal Implementation Plan ("FIP") to set air quality standards at certain power plants, including the Navajo Generating Station and the Four Corners Power Plant. The comment period on this proposal ended in November 1999. The FIP is similar to current Arizona regulation of NGS and New Mexico regulation of Four Corners, with minor modifications. APS does not currently expect FIP to have a material impact on its financial position or results of operations.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who generated, transported, or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often jointly and severally, liable for the cost of any necessary remediation of the substances. The EPA had previously advised APS that the EPA considers APS to be a PRP in the Indian Bend Wash Superfund Site, South Area. Our Ocotillo Power Plant is located in this area. APS is in the process of conducting an investigation to determine the extent and scope of contamination at the plant site. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, APS does not expect this matter to have a material impact on its financial position or results of operations.

Manufactured Gas Plant Sites. APS is currently investigating properties which APS now owns or which were at one time owned by APS or its corporate predecessors, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present
- such materials constitute an environmental or health risk and
- APS has any responsibility for remedial action.

Where appropriate, APS has begun remediation of certain of these sites. APS does not expect these matters to have a material adverse effect on its financial position or results of operations.

Purported Navajo Environmental Regulation

Four Corners and NGS are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. APS is the Four Corners operating agent. APS owns a 100% interest in Four Corners Units 1, 2, and 3, and a 15% interest in Four Corners Units 4 and 5. APS owns a 14% interest in NGS Units 1, 2, and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Acts"). Pursuant to the Acts, the Navajo Nation Environmental Protection Agency is authorized to promulgate regulations covering air quality, drinking water, and pesticide activities, including those that occur at Four Corners and NGS. By separate letters dated October 12 and October 13, 1995, the Four Corners participants and the NGS participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Acts apply to operations of Four Corners and NGS. On October 17, 1995, the Four Corners participants and the NGS participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that

- their respective leases and federal easements preclude the application of the Acts to the operations of Four Corners and NGS and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners and NGS.

On October 18, 1995, the Navajo Nation and the Four Corners and NGS participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. APS cannot currently predict the outcome of this matter.

In February 1998, the EPA promulgated regulations specifying those provisions of the Clean Air Act for which it is appropriate to treat Indian tribes in the same manner as states. The EPA indicated that it believes that the Clean Air Act generally would supersede pre-existing binding agreements that may limit the scope of tribal authority over reservations. On April 10, 1998, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 98-1196. On February 19, 1999, the EPA promulgated regulations setting forth the EPA's approach to issuing Federal operating permits to covered stationary sources on Indian reservations. On April 15, 1999, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 99-1146.

Water Supply

Assured supplies of water are important for APS' generating plants. At the present time, APS has adequate water to meet its needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions in recent years.

Both groundwater and surface water in areas important to APS' operations have been the subject of inquiries, claims, and legal proceedings which will require a number of years to resolve. APS is one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from its allocation to offset the loss.

A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. APS' rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde is potentially at issue in this action. As project manager of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Three of APS' less-utilized power plants are also located within the geographic area subject to the summons. APS' claims dispute the court's jurisdiction over its groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. The Arizona Supreme Court recently issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. APS and other parties have petitioned the U.S. Supreme Court for review of this decision. Another issue important to the claims is pending on appeal to the Arizona Supreme Court. No trial date concerning APS' water rights claims has been set in this matter.

APS has also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). APS' groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. APS' claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. The parties are in the process of settlement negotiations with respect to this matter. No trial date concerning APS' water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, APS expects that the described litigation will not have a material adverse impact on its financial position or results of operations.

BUSINESS OF SUNCOR DEVELOPMENT COMPANY

SunCor was incorporated in 1965 under the laws of the State of Arizona and is engaged primarily in the acquisition, ownership, development, operation, and sale of land and other real property, including homes and commercial buildings. The principal executive offices of SunCor are located at 3838 North Central, Suite 1500, Phoenix, Arizona 85012 (telephone 602-285-6800). SunCor and its subsidiaries, excluding SunCor Resort & Golf Management, Inc. ("Resort Management"), employ approximately 140 persons. Resort Management, which manages the Wigwam Resort and Country Club (the "Wigwam"), employs between 620 and 750 persons at the Wigwam, depending on the Wigwam's operating season. In addition, Resort Management operates four golf courses and three family entertainment operations, which together employ about 350 people.

SunCor's assets consist primarily of land and improvements and other real estate investments. SunCor's major asset is the Palm Valley project, which consists of over 7,000 acres and is located west of Phoenix in the area of Goodyear/Litchfield Park, Arizona ("Palm Valley"). SunCor has completed the master plan for development of Palm Valley. There has been significant residential and commercial development at Palm Valley by SunCor and by other developers that have acquired land from SunCor or entered into joint ventures with SunCor. Development at Palm Valley currently includes residential communities, including a retirement community, with golf courses, hotels, restaurants, commercial and retail outlets, a hospital, and assisted-care facilities.

Other SunCor projects under development include seven master-planned communities and four commercial projects. The four commercial projects and four of the master-planned communities are located in the Phoenix area. Other master-planned communities are located near Sedona, Arizona, St. George, Utah, and Santa Fe, New Mexico. Several of the master-plan and commercial projects are joint ventures with other developers, financial partners, or landowners.

For the past three years, SunCor's operating revenues were about: 1999, $130.2 million; 1998, $125.4 million; and 1997, $123.6 million. For those same periods, SunCor's net income was about: 1999, $6.1 million; 1998, $44.7 million; and 1997, $5.3 million. About $37.2 million of SunCor's 1998 net income represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, there was no impact to consolidated net income. SunCor's capital needs consist primarily of capital expenditures for land development and home construction for SunCor's homebuilding subsidiary, Golden Heritage Homes, Inc. On the basis of projects now under development, SunCor expects capital needs over the next three years to be 2000, $53 million; 2001, $43 million; and 2002, $51 million.

At December 31, 1999, SunCor had total assets of about $437 million. See Note 6 of Notes to the Consolidated Financial Statements in Item 8 for information regarding SunCor's long-term debt. SunCor intends to continue its focus on real estate development in homebuilding and the development of residential, commercial, and industrial projects.

BUSINESS OF EL DORADO DEVELOPMENT COMPANY

El Dorado was incorporated in 1983 under the laws of the State of Arizona and is engaged principally in the business of making equity investments in other companies. El Dorado's short-term goal is to convert its venture capital portfolio to cash as quickly and as advantageously as possible. On a long-term basis, we may use El Dorado, when appropriate, as our subsidiary for new ventures that are strategic to our principal business of generating, distributing, and marketing electricity. El Dorado's offices are located at 400 East Van Buren Street, Suite 800, Phoenix, Arizona 85004 (telephone 602-379-2589).

At December 31, 1999, El Dorado had an investment in a venture capital partnership at a carrying amount of $21.3 million. In addition, El Dorado had a 54% interest in a privately held company and limited partnership interests in two professional sports teams.

For the past three years, El Dorado's net income was: $11.5 million in 1999, $4.5 million in 1998, and $8.2 million in 1997. At December 31, 1999, El Dorado had total assets of $36.6 million.

BUSINESS OF APS ENERGY SERVICES COMPANY, INC.

APS Energy Services was incorporated in 1998 under the laws of the State of Arizona and is engaged principally in the business of selling unregulated power and related services. APS Energy Services' principal offices are located at 400 East Van Buren Street, Station 8103, Phoenix, Arizona 85004 (telephone (602) 250-5000).

BUSINESS OF PINNACLE WEST ENERGY CORPORATION

Pinnacle West Energy Corporation was incorporated in 1999 under the laws of the State of Arizona and is engaged principally in the business of the development and production of wholesale energy. Pinnacle West Energy is the subsidiary through which we intend to conduct our future unregulated generation operations. Pinnacle West Energy's principal offices are located at 400 North Fifth Street, Station 8987, Phoenix, Arizona 85004 (telephone (602) 250-4145).

Pinnacle West Energy's capital expenditures in 1999 were $21 million. Projected capital expenditures are $152 million in 2000; $240 million in 2001; and $245 million in 2002.

ITEM 2. PROPERTIES

Accredited Capacity

APS' present generating facilities have an accredited capacity as follows:

	Capacity(kW)
Coal:	
Units 1, 2, and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2, and 3 at Cholla Plant	615,000
14% owned Units 1, 2, and 3 at the Navajo Plant	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	435,000(1)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
	1,183,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Other	5,600
Total	3,986,900

(1) West Phoenix steam units (108,300 kW) are currently mothballed.

Reserve Margin

APS' 1999 peak one-hour demand on its electric system was recorded on August 24, 1999 at 4,934,700 kW, compared to the 1998 peak of 5,027,000 kW recorded on July 16. Taking into account additional capacity then available to APS under traditional long-term purchase power contracts as well as APS' own generating capacity, APS' capability of meeting system demand on August 24, 1999, amounted to 4,754,600 kW, for an installed reserve margin of (4.4%). The power actually available to APS from its resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 1999 peak amounted to 3,587,100 kW, for a margin of (27.5%). Firm purchases, including short-term seasonal purchases, totaling 1,643,000 kW were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 9.1%.

Plant Sites Leased from Navajo Nation

Leases NGS and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. These are long term agreements with options to extend, and we do not believe that the risk with respect to enforcement of these easements and leases is material. The majority of coal contracted for use in these plants and certain associated transmission lines are also located on Indian reservations. See "Generating Fuel and Purchased Power — Coal Supply" in Item 1.

Tax and Royalty See "Generating Fuel and Purchased Power – Coal Supply" in Item 1 for a discussion of changes in the amount of royalty payments and expiration of tax waivers under the NGS and Four Corners leases.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 10 of Notes to Consolidated Financial Statements in Item 8 for a discussion of three sale and leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize APS, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

The NRC recently amended its rules on financial assurance requirements for the decommissioning of nuclear power plants. The amended rules became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. APS currently relies on the external sinking fund mechanism to meet the NRC financial assurance requirements for its interests in Palo Verde Units 1, 2, and 3. The decommissioning costs of Palo Verde Units 1, 2, and 3 are currently included in ACC jurisdictional rates. ACC rules regarding the introduction of retail electric competition in Arizona (see Note 3 of Notes to Consolidated Financial Statements) currently provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow APS to maintain its external sinking fund mechanism. See Note 2 of Notes to Consolidated Financial Statements in Item 8 for additional information about nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters

See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Consolidated Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Other Information Regarding Properties

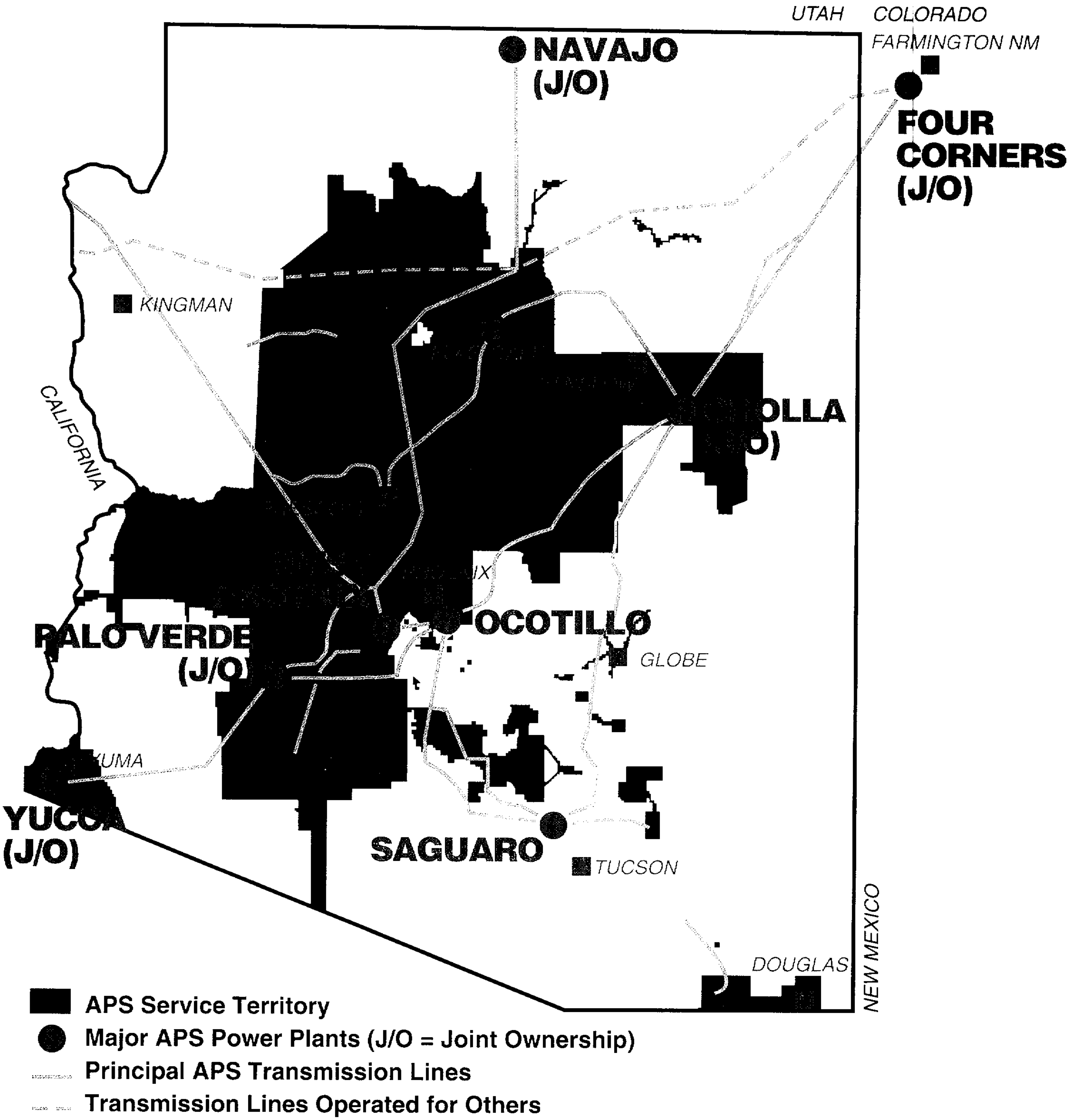
See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of APS' power plants.

See "Construction Program" in Item 1 and "Financial Review — Capital Needs and Resources" in Item 7 for a discussion of APS' construction plans.

See Notes 6, 10, and 11 of Notes to Consolidated Financial Statements in Item 8 with respect to property of the Company not held in fee or held subject to any major encumbrance.

Information Regarding Properties of SunCor

See "Business of SunCor Development Company" for information regarding SunCor's properties.


UTAH
COLORADO
FARMINGTON NM
NAVAJO (J/O)
FOUR CORNERS (J/O)
KINGMAN
CALIFORNIA
PALO VERDE (J/O)
OCOTILLO
GLOBE
SAGUARO
TUCSON
DOUGLAS
NEW MEXICO
APS Service Territory
Major APS Power Plants (J/O = Joint Ownership)
Principal APS Transmission Lines
Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

APS In June 1999, the Navajo Nation served Salt River Project with a lawsuit naming Salt River Project, several Peabody Coal Company entities ("Peabody"), Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo and Mohave Generating Stations. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS. APS is a 14% owner of Navajo Generating Station, which Salt River Project operates. The suit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands" arising out of the [primary coal lease]. Salt River Project has advised APS that it denies all charges and will vigorously defend itself. Because the litigation is in preliminary stages, APS cannot currently predict the outcome of this matter.

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See "Regulatory Matters" in Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of competition and the rules regarding the introduction of retail electric competition in Arizona and related litigation. In December 1999, APS filed a lawsuit to protect its legal rights regarding the rules, and in the complaint APS asked the Court for (i) a judgment vacating the retail electric competition rules, (ii) a declaratory judgment that the rules are unlawful because, among other things, they were entered into without proper legal authorization, and (iii) a permanent injunction barring the ACC from enforcing or implementing the rules and from promulgating any other regulations without lawful authority. Arizona Public Service Company v. Arizona Corporation Commission, CV99-21907. On August 28, 1998, APS filed two lawsuits to protect its legal rights under the stranded cost order and in its complaints the Company asked the Court to vacate and set aside the order. Arizona Public Service Company v. Arizona Corporation Commission, CV 98-15728. Arizona Public Service Company v. Arizona Corporation Commission, 1-CA-CC-98-0008.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

SUPPLEMENTAL ITEM.
EXECUTIVE OFFICERS OF THE REGISTRANT

Our executive officers are as follows:

Name	Age at March 1, 2000	Position(s) at March 1, 2000
Robert S. Aiken	43	Vice President, Federal Affairs
John G. Bohon	54	Vice President, Corporate Services & Human Resources
Jack E. Davis	53	President, APS Energy Delivery & Sales
Armando B. Flores	56	Executive Vice President, Corporate Business Services
Edward Z. Fox	46	Vice President, Communications, Environment & Safety
Chris N. Froggatt	42	Vice President & Controller
Barbara M. Gomez	45	Treasurer
James L. Kunkel	62	Vice President
James M. Levine	50	Executive Vice President, APS Generation
Nancy C. Loftin	46	Vice President & General Counsel
Michael V. Palmeri	41	Vice President, Finance
William J. Post	49	President and Chief Executive Officer(1)
Martin L. Shultz	55	Vice President, Government Affairs
Richard Snell	69	Chairman of the Board of Directors (1)
William L. Stewart	56	President, APS Generation
Faye Widenmann	51	Vice President and Secretary

(1) member of the Board of Directors

The executive officers of the Company are elected no less often than annually and may be removed by the Board of Directors at any time. The terms served by the named officers in their current positions and the principal occupations (in addition to those stated in the table) of such officers for the past five years have been as follows:

Mr. Aiken was elected to his present position in July 1999. Prior to that time he was the Company's Manager, Federal Affairs (November 1986–July 1999).

Mr. Bohon was elected to his present position in July 1999. Prior to that time he was Vice President, Corporate Services and Human Resources of APS (October 1998–July 1999), Vice President, Procurement of APS (April 1997–October 1998) and Director, Corporate Services of APS (December 1989–April 1997).

Mr. Davis was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Commercial Operations of APS (September 1996–October 1998) and Vice President, Generation and Transmission of APS (June 1993–September 1996). Mr. Davis is a director of APS.

Mr. Flores was elected to his present position in July 1999. Prior to that time, he was Executive Vice President, Corporate Business Services of APS (October 1998–July 1999), Senior Vice President, Corporate Business Services of APS (September 1996–October 1998) and Vice President, Human Resources of APS (December 1991–September 1996).

Mr. Fox was elected to his present position in July 1999. Prior to that time he was Vice President, Environmental/Health/Safety and New Technology Ventures of APS (October 1995–July 1999), Director, Arizona Department of Environmental Quality and Chairman, Wastewater Management Authority of Arizona (July 1991–September 1995).

Mr. Froggatt was elected to his present position in July 1999. Prior to that time he was Controller of APS (July 1997–July 1999) and Director, Accounting Services of APS (December 1992–July 1997).

Ms. Gomez was elected to her present position in August 1999. Prior to that time, she was Manager, Treasury Operations of APS (1997–1999) and Manager, Financial Planning of APS (1994–1997). She was also elected Treasurer of APS in October 1999.

Mr. Kunkel was elected Vice President effective December 15, 1997. Prior to December 1997, he was a partner with the accounting firm PricewaterhouseCoopers, successor to Coopers & Lybrand, in both their Los Angeles and Phoenix offices. Mr. Kunkel is also a director of Aztar Corporation.

Mr. Levine was elected to his present position in July 1999. Prior to that time he was Senior Vice President, Nuclear Generation of APS (September 1996–July 1999) and Vice President, Nuclear Production of APS (September 1989–September 1996).

Ms. Loftin was elected to her present position in July 1999. She was elected to the positions of Vice President and Chief Legal Counsel of APS in September 1996. Prior to that time, she was Secretary of APS (since April 1987) and Corporate Counsel of APS (since February 1989). She was also elected Vice President and General Counsel of APS in July 1999.

Mr. Palmeri was elected to his present position in August 1999. Prior to that time he was Treasurer of APS and Pinnacle West (July 1997–September 1999), Assistant Treasurer of Pinnacle West (February 1994–July 1997) and Manager of Finance of Pinnacle West (June 1990–February 1994). He also was elected Vice President, Finance of APS in October 1999.

Mr. Post was elected President effective August, 1999, and Chief Executive Officer effective February 1999. He has served as an officer of the Company since 1995 in the following capacities: from August 1999 to present as President and Chief Executive Officer; from February 1999 to August 1999 as Chief Executive Officer; from February 1997 to February 1999 as President; and from June 1995 to February 1997 as Executive Vice President. In October 1998, he resigned as President and maintained the position of Chief Executive Officer of APS. He was APS' Chief Operating Officer (September 1994–February 1997), as well as a Senior Vice President of APS since June 1993. Mr. Post is also a director of APS and Blue Cross-Blue Shield of Arizona.

Mr. Shultz was elected to his current position in July 1999. Prior to that time he held the position of Director of Government Relations for APS (1988–July 1999).

Mr. Snell has been Chairman of the Board of the Company and Chairman of the Board of APS since February 1990. Until February 1999, he was also Chief Executive Officer of the Company, and until February 1997, he was President of the Company. Mr. Snell is also a director of Aztar Corporation and Central Newspapers, Inc.

Mr. Stewart was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Generation of APS (September 1996–October 1998) and Executive Vice President, Nuclear of APS (May 1994–September 1996). Mr. Stewart is a director of APS.

Ms. Widenmann was elected to her current position in July 1999. Prior to that time, she held the position of Secretary (since 1985) and Vice President of Corporate Relations and Administration (since November 1986). She was also elected Vice President and Secretary of APS in July 1999.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED SECURITY HOLDER MATTERS

Our common stock is publicly held and is traded on the New York and Pacific Stock Exchanges. At the close of business on March 27, 2000, our common stock was held of record by approximately 42,645 shareholders.

The chart below sets forth the common stock price ranges on the composite tape, as reported in the Wall Street Journal for 1999 and 1998. The chart also sets forth the dividends declared during each of the four quarters for 1999 and 1998.

Common Stock Price Ranges and Dividends

1999	High	Low	Dividend Per Share[(a)]
1st Quarter	43 3/8	35 15/16	$ .325
2nd Quarter	42 15/16	36 1/4	.650
3rd Quarter	41 5/16	34 11/16	---
4th Quarter	38 1/8	30 3/16	.350
1998			
1st Quarter	45	39 3/8	$ .300
2nd Quarter	46 3/16	42	.600
3rd Quarter	45 9/16	40 1/16	---
4th Quarter	49 1/4	41 5/8	.325

(a) Dividends for the third quarter of 1999 and 1998 were declared in June.

ITEM 6. SELECTED CONSOLIDATED DATA (dollars in thousands, except per share amounts)

	1999	1998	1997	1996	1995
OPERATING RESULTS					
Operating revenues					
Electric	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952
Real estate	130,169	124,188	116,473	99,488	54,846
Income from continuing operations	$ 269,772	$ 242,892	$ 235,856	$ 211,059(a)	$ 199,608
Discontinued operations	38,000(d)	—	—	(9,539)(b)	—
Extraordinary charge – net of income tax	(139,885)(e)	—	—	(20,340)(c)	(11,571)(c)
Net income	$ 167,887	$ 242,892	$ 235,856	$ 181,180	$ 188,037
COMMON STOCK DATA					
Book value per share – year-end	$ 26.00	$ 25.50	$ 23.90	$ 22.51	$ 21.49
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 3.18	$ 2.87	$ 2.76	$ 2.41(a)	$ 2.28
Discontinued operations	0.45	—	—	(0.11)	—
Extraordinary charge	(1.65)	—	—	(0.23)	(0.13)
Net income – basic	$ 1.98	$ 2.87	$ 2.76	$ 2.07	$ 2.15
Continuing operations – diluted	$ 3.17	$ 2.85	$ 2.74	$ 2.40(a)	$ 2.27
Net income – diluted	$ 1.97	$ 2.85	$ 2.74	$ 2.06	$ 2.14
Dividends declared per share	$ 1.325	$ 1.225	$ 1.125	$ 1.025	$ 0.925
Indicated annual dividend rate – year-end	$ 1.40	$ 1.30	$ 1.20	$ 1.10	$ 1.00
Average common shares outstanding – basic	84,717,135	84,774,218	85,502,909	87,441,515	87,419,300
Average common shares outstanding – diluted	85,008,527	85,345,946	86,022,709	88,021,920	87,884,226
TOTAL ASSETS	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 2,206,052	$ 2,048,961	$ 2,244,248	$ 2,372,113	$ 2,510,709
Other liabilities	2,196,721	2,516,993	2,407,572	2,428,180	2,336,695
	4,402,773	4,565,954	4,651,820	4,800,293	4,847,404
Minority interests					
Non-redeemable preferred stock of APS	—	85,840	142,051	165,673	193,561
Redeemable preferred stock of APS	—	9,401	29,110	53,000	75,000
Common stock equity	2,205,733	2,163,351	2,027,436	1,970,323	1,881,087
Total liabilities and equity	$ 6,608,506	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052

(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)

	1999	1998	1997	1996	1995
ELECTRIC OPERATING REVENUES					
Residential	$ 805,173	$ 766,378	$ 746,937	$ 721,877	$ 669,762
Commercial	733,038	699,016	687,988	678,130	653,425
Industrial	159,329	172,296	164,696	162,324	156,501
Irrigation	7,374	7,288	8,706	9,448	9,596
Other	11,708	10,644	11,842	13,078	12,631
Total retail	1,716,622	1,655,622	1,620,169	1,584,857	1,501,915
Sales for resale	506,877	300,698	226,828	98,560	86,510
Transmission for others	11,348	11,058	10,295	10,240	9,390
Miscellaneous services	58,337	39,020	21,261	24,615	17,137
Net electric operating revenues	$ 2,293,184	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952
ELECTRIC SALES (MWh)					
Residential	8,774,822	8,310,689	7,970,309	7,541,440	6,848,905
Commercial	9,543,853	8,697,397	8,524,882	8,233,762	7,768,289
Industrial	2,561,349	3,279,430	3,123,283	3,039,357	2,933,459
Irrigation	99,669	84,640	112,363	121,775	119,580
Other	94,877	90,927	86,090	84,362	78,478
Total retail	21,074,570	20,463,083	19,816,927	19,020,696	17,748,711
Sales for resale	15,693,834	10,317,391	9,233,573	3,367,234	2,720,704
Total electric sales	36,768,404	30,780,474	29,050,500	22,387,930	20,469,415
ELECTRIC CUSTOMERS - END OF YEAR					
Residential	735,359	708,215	680,478	654,602	625,352
Commercial	86,707	83,506	81,246	78,178	75,105
Industrial	3,183	3,084	3,192	3,055	2,913
Irrigation	754	710	764	841	837
Other	932	895	851	828	786
Total retail	826,935	796,410	766,531	737,504	704,993
Sales for resale	73	67	50	48	39
Total electric customers	827,008	796,477	766,581	737,552	705,032

See "Financial Review" on pages 22-29 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS stock symbol: PNW

1999	High	Low	Close	Dividends Per Share(a)	1998	High	Low	Close	Dividends Per Share(a)
1st Quarter	43 3/8	35 15/16	36 3/8	$ 0.325	1st Quarter	45	39 3/8	44 7/16	$ 0.300
2nd Quarter	42 15/16	36 1/4	40 1/4	$ 0.650	2nd Quarter	46 3/16	42	45	$ 0.600
3rd Quarter	41 5/16	34 11/16	36 3/8	$ —	3rd Quarter	45 9/16	40 1/16	44 13/16	$ —
4th Quarter	38 1/8	30 3/16	30 9/16	$ 0.350	4th Quarter	49 1/4	41 5/8	42 3/8	$ 0.325

(a) Dividends for the 3rd quarter of 1999 and 1998 were declared in June.

ITEM 7. FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: APS, SunCor, El Dorado, APS Energy Services, and Pinnacle West Energy, including:

- the changes in our earnings from 1998 to 1999 and from 1997 to 1998
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results and outlook
- our capital needs and resources – for APS and our other operations, and
- our management of market risks.

APS, our major subsidiary and Arizona's largest electric utility, with approximately 827,000 customers, provides wholesale and retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates, sells, and delivers electricity and energy-related products and services to wholesale and retail customers in the western United States. SunCor is a developer of residential, commercial, and industrial projects on some 15,000 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio. 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. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our future unregulated generation operations.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 37. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

1999 Compared with 1998

Our 1999 consolidated net income was $168 million compared with $243 million in 1998. The following is a summary:

(millions of dollars)

	1999	1998
APS	$ 267	$ 246
APS Energy Services	(9)	—
SunCor	6	45
El Dorado	11	5
Parent Company	(5)	(53)
Income from Continuing Operations	270	243
Income Tax Benefit from Discontinued Operations	38	—
Extraordinary Charge – Net of Income Taxes of $94	(140)	—
Net Income	$ 168	$ 243

The income tax benefit from discontinued operations resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

The extraordinary charge related to a regulatory disallowance which resulted from APS' comprehensive Settlement Agreement that was approved by the Arizona Corporation Commission (ACC) in September 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the regulatory disallowance and the Settlement Agreement.

APS' earnings before extraordinary charge increased $21 million – a 9% increase – over 1998 earnings primarily because of increases in the number of customers and in the average amount of electricity used by customers and lower financing costs. These positive impacts more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See Note 3 for additional information about the price reductions.

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

- increased power marketing and trading revenues ($219 million)
- increases in the number of 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 power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power 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.

APS' utility operations and maintenance expenses increased $18 million primarily because of $19 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were more than offset by lower employee benefit costs and movement of certain marketing functions to APS Energy Services in early 1999.

APS Energy Services recorded a loss of $9 million in 1999, its first year of operations. Income tax benefits related to the loss are recorded at the parent company. In 1999, the loss consisted primarily of operating expenses, which were partially offset by revenues as new markets began to open for retail electricity competition.

Our real estate subsidiary, SunCor Development, reported earnings of $6 million in 1999 compared with $45 million in 1998. SunCor's 1998 earnings included $37 million related to the recording of a deferred tax asset by SunCor in connection with its intercompany tax sharing agreement with Pinnacle West. Income taxes related to SunCor's pretax income are now being recorded by SunCor. Prior to 1998, the income tax effects related to SunCor's income and losses were not recorded at SunCor due to net operating losses. On an after-tax basis and excluding the effects of the deferred tax asset, SunCor's contributions to consolidated earnings were $6 million in 1999 and $5 million in 1998 – a significant percentage increase in net income from operations for the real estate subsidiary.

El Dorado Investment Company, our investment subsidiary, reported earnings of $11 million in 1999 compared with $5 million in 1998. The improvement related primarily to the increased value of El Dorado's investment in a technology-related venture capital partnership; this investment is revalued on a quarterly basis.

1998 Compared with 1997

Our 1998 consolidated net income was $243 million compared with $236 million in 1997 – a 3.0% increase. The following is a summary:

(millions of dollars)

	1998	1997
APS	$ 246	$ 239
SunCor	45	5
El Dorado	5	8
Parent Company	(53)	(16)
Net Income	$ 243	$ 236

APS' 1998 earnings increased $7 million – a 3% increase over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, the prior year's benefits of the two fuel-related settlements recorded in 1997, and retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the average amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

The increase in power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power markets. The revenue increases were accompanied by an increase in purchased power expenses. These activities contributed positively to earnings in both periods; the contribution in 1998 was higher than in 1997.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $14 million primarily because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because APS had more plant in service.

Financing costs decreased by $16 million primarily because of lower amounts of outstanding debt and APS preferred stock.

Before the effects of recording deferred taxes under its tax sharing agreement, the earnings contribution from our real estate subsidiary, SunCor Development, increased $3 million as a result of an increase in land sales. SunCor's stand-alone net income in 1998 was $45 million, of which $37 million represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, Pinnacle West had already recognized the income tax benefits; therefore, there was no impact on consolidated net income in 1998.

The contribution from El Dorado, our investment subsidiary, decreased $3 million as a result of a decrease in investment sales.

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: 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 included accelerated amortization of APS' deferred investment tax credits (ITCs).

As part of the 1999 Settlement Agreement, APS reduced rates for standard offer service for customers with loads less than 3 megawatts 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 related to the 1996 regulatory agreement (see below). For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

Also, under the Settlement Agreement a regulatory disallowance removed $234 million before income taxes ($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. Before the ACC approved the 1999 Settlement 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 under the 1996 agreement. For more details, see Note 1.

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

(millions of dollars)

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

Also, 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 the 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, which was included in the July 1, 1999 1.5% price reduction under the 1999 Settlement Agreement.

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

CAPITAL NEEDS AND RESOURCES

Pinnacle West (Parent Company)

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

- dividends to our shareholders
- interest payments and
- optional and mandatory repayment of principal on our long-term debt.

In addition, as part of the 1996 agreement with the ACC, we invested $50 million annually in APS for the years 1996 through 1999. The 1999 payment was the last payment under the 1996 regulatory agreement (see Note 3). During 1997, we repurchased $80 million of common stock, reducing our shares outstanding at year-end 1997 by 2.7 million shares.

Our primary sources of cash are dividends from our subsidiaries. During 1999, APS paid $170 million in dividends to the parent. In 1999, SunCor and El Dorado declared dividends to the parent of $20 million and $10 million, respectively. Combined dividends from SunCor and El Dorado are expected to be at least $25 million annually during the next several years; however, the aggregate amount of those dividends depends somewhat on the status of the real estate and stock markets (particularly the technology sector).

Our long-term debt at December 31, 1999 was $106 million compared to $92 million at December 31, 1998. We have a $250 million line of credit, under which we had $56 million of borrowings outstanding at December 31, 1999. We do not have any principal debt repayment obligations until 2001.

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 its operations and, to the extent necessary, external financing.

As part of the 1996 regulatory agreement, APS received annual cash infusions from Pinnacle West of $50 million from 1996 through 1999. During the period from 1997 through 1999, APS paid for all of its capital expenditures with cash from its operations. APS expects to do so in 2000 through 2002 as well.

APS' capital expenditures in 1999 were $332 million. APS' projected capital expenditures for the next three years are: $384 million in 2000; $342 million in 2001; and $334 million in 2002. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

During 1999, APS redeemed about $323 million of long-term debt and $96 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. APS no longer has any outstanding preferred stock. Its long-term debt redemption requirements and payment obligations on a capitalized lease for the next three years are approximately: $115 million in 2000; $253 million in 2001; and $125 million in 2002. In addition, APS made optional redemptions of about $89 million of long-term debt in January 2000. 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, 1999, APS had credit commitments from various banks totaling about $350 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1999, APS had about $38 million of commercial paper and $50 million of long-term bank borrowings outstanding.

In February 1999, APS issued $125 million of unsecured long-term debt and in November 1999, APS issued $250 million of unsecured long-term debt.

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

We are currently planning, through Pinnacle West Energy, a 650-megawatt expansion of our West Phoenix Power Plant, and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk. Pinnacle West Energy's capital expenditures in 1999 were $21 million. Projected capital expenditures for these projects are $152 million in 2000; $240 million in 2001; and $245 million in 2002. We are also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's capital expenditures will be funded with debt proceeds, and with internally generated cash and debt proceeds from the parent company. Assuming all approvals are granted, we expect to begin construction at West Phoenix in the second quarter of 2000.

Pinnacle West Energy has signed a joint development agreement with Reliant Energy Power Generation, Inc. (Reliant) covering construction and operation of three new merchant plants. Pinnacle West Energy plans to contribute the first two units (1,060 megawatts) of the Redhawk project to the joint agreement. Construction is expected to start in the third quarter of 2000, with commercial operation scheduled in the summer of 2002. Reliant plans to contribute two new natural gas-fired projects (1,500 megawatts) in Nevada to the venture.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and their own external financings.

SunCor's capital needs consist primarily of capital expenditures for land development, retail and office building construction, and home construction. On the basis of projects now under development, SunCor expects capital needs over the next three years to be: $53 million in 2000; $43 million in 2001; and $51 million in 2002. Capital resources to meet these requirements include funds from operations and SunCor's own external financings.

As of December 31, 1999, SunCor had a $100 million line of credit, under which $94 million of borrowings were outstanding. SunCor has no principal debt repayment requirements for 2000, $30 million for 2001, and $64 million for 2002.

COMPETITION AND INDUSTRY RESTRUCTURING

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. See "Results of Operations – Regulatory Agreements" and Note 3 for additional information about APS' Settlement Agreement with the ACC related to the implementation of retail electric competition, the ACC rules that provide a framework for the introduction of retail electric competition in Arizona, and other competitive developments, including an agreement with Salt River Project.

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 a discussion of legislative developments.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. 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.

APS prepares its 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 its financial statements. As a result of the Settlement Agreement (see Note 3), APS discontinued the application of SFAS No. 71 for its generation operations. This meant that the generation assets were tested for impairment and the portion of the regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. APS determined that the generation assets were not impaired. A regulatory disallowance ($140 million after income taxes) was reported as an extraordinary charge on the income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the Settlement Agreement.

YEAR 2000 READINESS DISCLOSURE

Some companies expected to face problems on January 1, 2000 in the case that computer systems and equipment would not properly recognize calendar dates. During 1997, APS had initiated a comprehensive company-wide Year 2000 program to review and resolve all Year 2000 issues in mission critical systems in a timely manner to ensure the reliability of electric service to its customers. We have spent about $5 million to be Year 2000 ready. To date, we have not experienced any material Year 2000 related problems, and we do not anticipate any in the future.

ACCOUNTING MATTERS

We describe a new standard on accounting for derivatives in Note 2. The new standard on derivatives is effective for us in 2001. We are currently evaluating what impact it will have on our financial statements. 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.

RISK MANAGEMENT

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 the 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 and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 1999 and December 31, 1998. The interest rates presented in the table below represent the weighted average interest rates for the years ended December 31, 1999 and December 31, 1998.

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1999 (thousands of dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	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

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1998 (thousands of dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
1999	5.88%	$ 178,830	7.30%	$ 3,268	7.24%	$ 164,777
2000	—	—	7.32%	25,756	5.79%	114,711
2001	—	—	6.57%	93,472	6.70%	27,488
2002	—	—	10.25%	119	8.13%	125,000
2003	—	—	5.94%	125,131	6.87%	25,000
Years thereafter	—	—	3.43%	459,803	7.75%	1,058,963
Total		$ 178,830		$ 707,549		$ 1,515,939
Fair Value		$ 178,830		$ 707,549		$ 1,577,365

Commodity Price Risk

APS is exposed to the impact of market fluctuations in the price and distribution costs of electricity, natural gas, coal, and emissions allowances. APS employs 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 its overall risk management program, APS enters into these derivative transactions for trading and to hedge certain natural gas in storage as well as purchases and sales of electricity, fuels, and emissions allowances/credits.

As of December 31, 1999, a hypothetical adverse price movement of 10% in the market price of APS' commodity derivative portfolio would decrease the fair market value of these contracts by approximately $6 million. This analysis does not include the favorable impact this same hypothetical price move would have on the underlying position being hedged with the commodity derivative portfolio.

APS is exposed to credit losses in the event of non-performance or non-payment by counterparties. APS uses a credit management process to assess and monitor its financial exposure to counterparties. APS does not expect counterparty defaults to materially impact its financial condition, results of operations, or net cash flow.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; the strength of the stock market (particularly the technology sector) and the strength of the real estate market.

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.

ITEM 7 A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Financial Review" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND
FINANCIAL STATEMENT SCHEDULE

See Note 14 of Notes to Financial Statements for the selected quarterly financial data required to be presented in this Item.

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. Such information was prepared in accordance with generally accepted accounting principles 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 accounting controls. A limiting factor in all systems of internal accounting 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 accounting 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.

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
President and
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and its subsidiaries as of December 31, 1999 and 1998 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 its subsidiaries at December 31, 1999 and 1998 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Phoenix, Arizona

February 18, 2000

CONSOLIDATED STATEMENTS OF INCOME (dollars in thousands, except per share amounts)

year ended december 31,	1999	1998	1997
OPERATING REVENUES			
Electric	$ 2,293,184	$ 2,006,398	$ 1,878,553
Real estate	130,169	124,188	116,473
Total	2,423,353	2,130,586	1,995,026
OPERATING EXPENSES			
Fuel and purchased power	796,109	545,297	443,571
Utility operations and maintenance	446,777	419,433	405,605
Real estate operations	119,516	115,331	111,628
Depreciation and amortization (Note 1)	385,568	379,679	368,285
Taxes other than income taxes	96,606	103,718	108,431
Total	1,844,576	1,563,458	1,437,520
OPERATING INCOME	578,777	567,128	557,506
OTHER INCOME (EXPENSE)			
Preferred stock dividend requirements of APS	(1,016)	(9,703)	(12,803)
Net other income and expense	10,793	609	4,569
Total	9,777	(9,094)	(8,234)
INCOME BEFORE INTEREST AND INCOME TAXES	588,554	558,034	549,272
INTEREST EXPENSE			
Interest charges	162,381	169,145	182,838
Capitalized interest	(11,664)	(18,596)	(19,703)
Total	150,717	150,549	163,135
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	437,837	407,485	386,137
INCOME TAXES (NOTE 4)	168,065	164,593	150,281
INCOME FROM CONTINUING OPERATIONS	269,772	242,892	235,856
Income tax benefit from discontinued operations	38,000	—	—
Extraordinary charge – net of income taxes of $94,115	(139,885)	—	—
NET INCOME	$ 167,887	$ 242,892	$ 235,856
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,717,135	84,774,218	85,502,909
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	85,008,527	85,345,946	86,022,709
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING			
Continuing operations – basic	$ 3.18	$ 2.87	$ 2.76
Net income – basic	1.98	2.87	2.76
Continuing operations – diluted	3.17	2.85	2.74
Net income – diluted	1.97	2.85	2.74
DIVIDENDS DECLARED PER SHARE	$ 1.325	$ 1.225	$ 1.125

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (thousands of dollars)

december 31,	1999	1998
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20,705	$ 20,538
Customer and other receivables – net	244,599	233,876
Accrued utility revenues	72,919	67,740
Materials and supplies (at average cost)	69,977	69,074
Fossil fuel (at average cost)	21,869	13,978
Deferred income taxes (Note 4)	8,163	3,999
Other current assets	60,562	47,594
Total current assets	498,794	456,799
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	344,293	331,021
Other assets (Note 13)	267,458	236,562
Total investments and other assets	611,751	567,583
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,546,314	7,265,604
Less accumulated depreciation and amortization	3,026,194	2,814,762
Total	4,520,120	4,450,842
Construction work in progress	209,281	228,643
Nuclear fuel, net of amortization of $66,357 and $68,569	49,114	51,078
Net utility plant	4,778,515	4,730,563
DEFERRED DEBITS		
Regulatory assets (Notes 3 and 4)	613,729	980,084
Other deferred debits	105,717	89,517
Total deferred debits	719,446	1,069,601
TOTAL ASSETS	$ 6,608,506	$ 6,824,546

See Notes to Consolidated Financial Statements.

(thousands of dollars)

december 31,	1999	1998
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 186,524	$ 155,800
Accrued taxes	70,510	62,520
Accrued interest	33,253	31,866
Short-term borrowings (Note 5)	38,300	178,830
Current maturities of long-term debt (Note 6)	114,798	168,045
Customer deposits	26,098	28,510
Other current liabilities	26,007	14,632
Total current liabilities	495,490	640,203
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,206,052	2,048,961
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,183,855	1,343,536
Deferred investment tax credit (Note 4)	3,830	27,345
Unamortized gain – sale of utility plant	73,212	77,787
Other	440,334	428,122
Total deferred credits and other	1,701,231	1,876,790
COMMITMENTS AND CONTINGENCIES (NOTES 3, 12 AND 13)		
MINORITY INTERESTS (NOTE 7)		
Non-redeemable preferred stock of APS	—	85,840
Redeemable preferred stock of APS	—	9,401
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 1999 and 1998	1,537,449	1,550,643
Retained earnings	668,284	612,708
Total common stock equity	2,205,733	2,163,351
TOTAL LIABILITIES AND EQUITY	$ 6,608,506	$ 6,824,546

CONSOLIDATED STATEMENTS OF CASH FLOWS (thousands of dollars)

year ended december 31,		1999		1998		1997
CASH FLOWS FROM OPERATING ACTIVITIES						
Income from continuing operations	$	269,772	$	242,892	$	235,856
Items not requiring cash						
Depreciation and amortization		385,568		379,679		368,285
Nuclear fuel amortization		31,371		32,856		32,702
Deferred income taxes – net		(17,413)		41,262		24,809
Deferred investment tax credit		(23,514)		(23,516)		(23,518)
Other – net		(12,476)		1,190		(3,854)
Changes in current assets and liabilities						
Customer and other receivables – net		(10,723)		(50,369)		(14,270)
Accrued utility revenues		(5,179)		(9,181)		(3,089)
Materials, supplies and fossil fuel		(8,794)		(2,797)		7,793
Other current assets		(12,968)		(6,186)		(109)
Accounts payable		28,193		34,386		(54,882)
Accrued taxes		12,591		(22,090)		2,197
Accrued interest		1,387		(1,108)		(6,678)
Other current liabilities		15,047		(5,235)		(23,087)
(Increase) decrease in land held		(12,542)		33,405		33,010
Other – net		(4,720)		(39,350)		48,254
Net Cash Flow Provided By Operating Activities		635,600		605,838		623,419
CASH FLOWS FROM INVESTING ACTIVITIES						
Capital expenditures		(343,448)		(319,142)		(307,876)
Capitalized interest		(11,664)		(18,596)		(19,703)
Other – net		(16,143)		(2,144)		(3,124)
Net Cash Flow Used For Investing Activities		(371,255)		(339,882)		(330,703)
CASH FLOWS FROM FINANCING ACTIVITIES						
Issuance of long-term debt		607,791		148,229		146,013
Short-term borrowings – net		(140,530)		48,080		113,850
Dividends paid on common stock		(112,311)		(103,849)		(96,160)
Repurchase and retirement of common stock		—		—		(79,997)
Repayment of long-term debt		(510,693)		(286,314)		(325,526)
Redemption of preferred stock		(96,499)		(75,517)		(47,201)
Other – net		(11,936)		(3,531)		(2,897)
Net Cash Flow Used For Financing Activities		(264,178)		(272,902)		(291,918)
NET CASH FLOW		167		(6,946)		798
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR		20,538		27,484		26,686
CASH AND CASH EQUIVALENTS AT END OF YEAR	$	20,705	$	20,538	$	27,484

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (thousands of dollars)

year ended december 31,	1999	1998	1997
Retained Earnings at Beginning of Year	$ 612,708	$ 473,665	$ 333,969
Net Income	167,887	242,892	235,856
Common Stock Dividends	(112,311)	(103,849)	(96,160)
Retained Earnings at End of Year	$ 668,284	$ 612,708	$ 473,665

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, SunCor, El Dorado, APS Energy Services, and Pinnacle West Energy.

APS, our major subsidiary and Arizona's largest electric utility, with approximately 827,000 customers, provides wholesale or retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates, sells, and delivers electricity and energy-related products and services to wholesale and retail customers in the western United States. SunCor is a developer of residential, commercial, and industrial projects on some 15,000 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio. 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. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our future unregulated generation operations.

Accounting Records

Our accounting records are maintained in accordance with generally accepted accounting principles (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 Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the ratemaking policies of these commissions. For regulated operations, APS prepares its 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 its financial statements.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (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.

In September 1999, the APS Settlement Agreement was approved by the ACC (see Note 3 for a discussion of the agreement). APS has discontinued the application of SFAS No. 71 for its generation operations. This means that the generation assets were tested for impairment and the portion of regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. APS determined that the generation assets were not impaired. A regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and this was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the consolidated income statement. Prior to the Settlement Agreement, under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that would have ended June 30, 2004.

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

(millions of dollars)

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

The majority of the 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:

(thousands of dollars)

december 31,	1999	1998
Electric plant in service and held for future use	$ 3,770,234	$ 3,680,482
Accumulated depreciation and amortization	(1,817,589)	(1,681,099)
Construction work in progress	87,819	107,324
Nuclear fuel, net of amortization	49,114	51,078

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service. 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 1997 through 1999 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1999 was 3.34%. APS depreciates non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Venture Capital Investments

El Dorado has investments in venture capital partnerships that account for their investments at fair value. Since El Dorado uses the equity method of accounting for its partnership interests, it must record its share of realized and unrealized gains and losses in net income.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plant. 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 6.65% for 1999, 6.88% for 1998, and 7.25% for 1997.

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, APS is 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 APS 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. In addition, Note 13 has 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.

Statements of Cash Flows

We consider temporary cash investments and marketable securities to be cash equivalents for purposes of reporting cash flows. During 1999, 1998, and 1997 we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

(millions of dollars)

years ended december 31,	1999	1998	1997
Interest paid	$ 141	$ 144	$ 163
Income taxes paid	200	165	146
Dividends paid on preferred stock of APS	1	10	13

Reclassifications

We have reclassified certain prior year amounts for comparison purposes with 1999.

2. ACCOUNTING MATTERS

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2001. 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. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

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 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

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 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the Settlement Agreement. One of the parties questioned the authority of the ACC to approve the Settlement Agreement and both parties challenged several specific provisions of the Settlement Agreement.

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

- APS will reduce rates for standard offer service for customers with loads less than 3 megawatts 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) includes the July 1, 1999 retail price decrease of approximately $11 million annually ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the Settlement Agreement, retroactive to July 1, 1999, and also will be 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 will be 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), with an additional 140 megawatts being made available to eligible non-residential customers. Unless subject to judicial or regulatory restraint, APS will open its distribution system to retail access for all customers on January 1, 2001.
- Prior to the Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 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 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 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 that 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. 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 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 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, APS has discontinued the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," for its 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 (Rules). If any of the Rules conflict with the Settlement Agreement, the terms of the Settlement Agreement govern. 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 and the adoption or amendment of the Rules, but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions. On January 14, 2000, a special action was filed requesting the Arizona Supreme Court to enjoin implementation of the Rules and decide whether the ACC can allow the competitive marketplace, rather than the ACC, to set just and reasonable rates under the Arizona Constitution. The issue of competitively set rates has been decided by lower Arizona courts in favor of the ACC in four separate lawsuits, two of which relate to telecommunications companies. The Supreme Court denied to hear the case as a special action on March 17, 2000. The lower court litigation will continue.

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.
- The Rules require each affected utility, including APS, to make available at least 20% of its 1995 system retail peak demand for competitive generation supply beginning when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever is earlier, and 100% beginning January 1, 2001. Under the Settlement Agreement, APS will provide retail access to customers representing the minimum 20% required by the ACC and an additional 140 megawatts of non-residential load in 1999, and to all customers as of January 1, 2001, or such other dates as approved by the ACC.
- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date, which for APS' customers was the approval of the Settlement Agreement. Customers may also aggregate smaller loads to meet this one megawatt requirement.
- When effective, residential customers will be phased in at 1.25% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.
- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) 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 Settlement Agreement, APS received a waiver to allow transfer of its competitive generation assets and services to affiliates no later than December 31, 2002.

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 of approximately $49 million ($29 million after income taxes), or 3.4%, effective July 1, 1996; approximately $18 million ($11 million after income taxes), or 1.2%, effective July 1, 1997; approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998; and approximately $11 million ($7 million after income taxes), or 0.7%, effective as of July 1, 1999. The July 1, 1999 rate decrease was included in the first rate reduction under the Settlement Agreement discussed above. The regulatory agreement also required the parent company to 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 megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999-2000 legislative session on certain competitive issues.

GENERAL

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, or results of operation. 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 Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills have been introduced during the 106th Congress. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2000 and beyond. These bills, other bills that 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.

AGREEMENT WITH SALT RIVER PROJECT

On April 25, 1998, APS entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The ACC approved the Agreement on February 18, 1999. The Agreement contains the following major components:

- Both parties amended the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.
- Both parties amended the Power Coordination Agreement to lower the price that APS pays Salt River Project for purchased power. During 1999, the price APS paid Salt River Project for purchased power was reduced by approximately $3 million (pretax) and we estimate the decrease to be approximately $16 million (pretax) in 2000 and lesser annual amounts through 2006.
- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal levels.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) became effective upon the introduction of competition. See "Settlement Agreement" and "ACC Rules" above.

4. INCOME TAXES

Investment Tax Credit

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

Income Tax Benefit from Discontinued Operations

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.

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:

(thousands of dollars)

year ended december 31,	1999	1998	1997
Current			
Federal	$ 171,491	$ 105,922	$ 105,818
State	37,501	40,621	43,172
Total current	208,992	146,543	148,990
Deferred	(17,413)	41,566	28,729
Change in valuation allowance	—	—	(3,920)
ITC amortization	(23,514)	(23,516)	(23,518)
Total expense	$ 168,065	$ 164,593	$ 150,281

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

(thousands of dollars)

year ended december 31,	1999	1998	1997
Federal income tax expense at 35% statutory rate	$ 153,243	$ 142,620	$ 135,148
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	14,575	17,848	14,694
Preferred stock dividends of APS	356	3,396	4,481
ITC amortization	(23,514)	(23,516)	(23,518)
State income tax net of federal income tax benefit	23,030	22,764	24,497
Change in valuation allowance	—	—	(3,400)
Other	375	1,481	(1,621)
Income tax expense	$ 168,065	$ 164,593	$ 150,281

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

(thousands of dollars)

year ended december 31,	1999	1998
DEFERRED TAX ASSETS		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 29,446	$ 31,285
Other	133,748	127,903
Total deferred tax assets	163,194	159,188
DEFERRED TAX LIABILITIES		
Plant-related	1,104,769	1,117,253
Regulatory asset for income taxes	234,117	381,472
Total deferred tax liabilities	1,338,886	1,498,725
Accumulated deferred income taxes – net	$ 1,175,692	$ 1,339,537

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $350 million at December 31, 1999 and $400 million at December 31, 1998, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1999 and 1998 for these lines of credit ranged from 0.07% to 0.125% per annum. APS had long-term bank borrowings of $50 million outstanding at December 31, 1999 and $125 million outstanding at December 31, 1998.

APS' commercial paper borrowings outstanding were $38 million at December 31, 1999 and $179 million at December 31, 1998. The weighted average interest rate on commercial paper borrowings was 5.33% for the year ended December 31, 1999 and 5.88% for December 31, 1998. 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, 1999 and 1998. The commitment fees were 0.10% in 1999 and 1998. Outstanding amounts at December 31, 1999 were $56 million and at December 31, 1998 were $42 million.

SunCor had revolving lines of credit totalling $100 million at December 31, 1999 and $55 million at December 31, 1998. The commitment fees were 0.125% in 1999 and 1998. SunCor had $94 million outstanding at December 31, 1999 and $38 million outstanding at December 31, 1998.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant; 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, 1999 and December 31, 1998:

(thousands of dollars)

december 31,	Maturity Dates (a)	Interest Rates	1999	1998
APS				
First mortgage bonds	1999	7.625%	$ —	$ 100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	85,000
	2020	10.25%	100,550	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	91,900
	2024	8.75%	121,668	121,668
	2025	8%	47,075	88,300
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,860)	(6,482)
Pollution control bonds	2024-2034	Adjustable rate(b)	476,860	456,860
Funds held in trust account for certain pollution control bonds			(1,236)	—
Collateralized loan	1999-2000	5.375%-6.125%	10,000	20,000
Unsecured notes	2004	5.875%	125,000	—
Unsecured notes	2005	6.25%	100,000	100,000
Floating rate notes	2001	Adjustable rate(c)	250,000	—
Senior notes (d)	1999	6.72%	—	50,000
Senior notes (d)	2006	6.75%	83,695	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate(e)	50,000	125,000
Capitalized lease obligation	1999-2001	7.48%(f)	7,199	11,612
			2,112,111	2,040,918
SUNCOR				
Revolving credit	2001-2002	(g)	94,000	38,139
Bank loan	2001	(h)	—	42,061
Notes payable	1998-2006	(i)	3,404	3,888
Bonds payable	2039	5.85%	5,335	—
			102,739	84,088
PINNACLE WEST				
Revolving credit	2001	(j)	56,000	42,000
Senior notes	2001-2003	(k)	50,000	50,000
			106,000	92,000
Total long-term debt			2,320,850	2,217,006
Less current maturities			114,798	168,045
Total long-term debt less current maturities			$ 2,206,052	$ 2,048,961

(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, 1999 was 3.15% and for December 31, 1998 was 3.39%. 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, 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, 1999 was 5.5% and for December 31, 1998 was 5.94%. Changes in short-term interest rates would affect the costs associated with this debt.
(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 (see Note 10).
(g) The weighted-average rate at December 31, 1999 was 8.51% and at December 31, 1998 was 7.41%. Interest for 1999 and 1998 was based on LIBOR plus 2% or prime plus 0.5%.
(h) The weighted-average rate at December 31, 1998 was 7.76%. Interest for 1998 was based on LIBOR plus 2% or prime plus 0.5%.
(i) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75%.
(j) The weighted-average rate at December 31, 1999 was 6.825% and at December 31, 1998 was 5.66%. Interest for 1999 and 1998 was based on LIBOR plus 0.33%.
(k) 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 2004:

- $115 million in 2000
- $364 million in 2001
- $189 million in 2002
- $ 75 million in 2003 and
- $205 million in 2004.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1999.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock.

Preferred stock balances of APS at December 31, 1999 and 1998 are shown below:

(dollars in thousands, except per share amounts)		Number of Shares Outstanding December 31,			Par Value Outstanding December 31,	
	Authorized	1999	1998	Par Value Per Share	1999	1998
NON-REDEEMABLE:						
$1.10 preferred	160,000	—	139,030	$ 25.00	$ —	$ 3,476
$2.50 preferred	105,000	—	86,440	50.00	—	4,322
$2.36 preferred	120,000	—	32,520	50.00	—	1,626
$4.35 preferred	150,000	—	62,986	100.00	—	6,299
Serial preferred:	1,000,000					
$2.40 Series A		—	200,587	50.00	—	10,029
$2.625 Series C		—	214,895	50.00	—	10,745
$2.275 Series D		—	90,691	50.00	—	4,534
$3.25 Series E		—	304,475	50.00	—	15,224
Serial preferred:	4,000,000					
Adjustable rate						
Series Q		—	295,851	100.00	—	29,585
Total		—	1,427,475		$ —	$ 85,840
REDEEMABLE:						
Serial preferred:						
$10.00 Series U		—	94,011	$ 100.00	$ —	$ 9,401

Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 1999 are as follows:

(dollars in thousands)

	Number of Shares	Par Value Amount
Balance, December 31, 1996	530,000	$ 53,000
Retirements		
$10.00 Series U	(118,902)	(11,890)
$7.875 Series V	(120,000)	(12,000)
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	—	$ —

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 1999 is as follows:

(dollars in thousands)

	Number of Shares	Amount (a)
Balance, December 31, 1996	87,515,847	$ 1,636,354
Common stock expense – net	—	(2,586)
Common stock retired	(2,690,900)	(79,997)
Balance, December 31, 1997	84,824,947	1,553,771
Common stock expense – net	—	(3,128)
Balance, December 31, 1998	84,824,947	1,550,643
Common stock expense – net	—	(13,194)
Balance, December 31, 1999	84,824,947	$ 1,537,449

(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, 1999 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- $ 4 million in 1999
- $11 million in 1998 and
- $ 9 million in 1997.

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

(thousands of dollars)

	1999	1998	1997
Service cost – benefits earned during the period	$ 24,982	$ 24,817	$ 20,435
Interest cost on projected benefit obligation	52,905	51,524	48,402
Expected return on plan assets	(68,335)	(54,513)	(47,959)
Amortization of:			
Transition asset	(3,226)	(3,226)	(3,226)
Prior service cost	2,078	2,078	2,078
Net periodic pension cost	$ 8,404	$ 20,680	$ 19,730

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

(thousands of dollars)

	1999	1998
Funded status – pension plan assets more than (less than) projected benefit obligation	$ 37,275	$ (41,034)
Unrecognized net transition asset	(20,008)	(23,235)
Unrecognized prior service cost	20,636	22,715
Unrecognized net actuarial gains	(101,153)	(38,668)
Net pension amount recognized in the balance sheets	$ (63,250)	$ (80,222)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Projected pension benefit obligation at beginning of year	$ 731,305	$ 708,144
Service cost	24,982	24,817
Interest cost	52,905	51,524
Benefit payments	(29,694)	(29,636)
Actuarial gains	(36,860)	(23,544)
Projected pension benefit obligation at end of year	$ 742,638	$ 731,305

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Fair value of pension plan assets at beginning of year	$ 690,271	$ 619,412
Actual return on plan assets	93,977	86,527
Employer contributions	25,359	13,968
Benefit payments	(29,694)	(29,636)
Fair value of pension plan assets at end of year	$ 779,913	$ 690,271

We made the assumptions below to calculate the pension liability:

	1999	1998
Discount rate	7.75%	7.00%
Rate of increase in compensation levels	4.25%	3.50%
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 each of the last three years (1997-1999).

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:

- $ 7 million for 1999
- $ 9 million for 1998 and
- $10 million for 1997.

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

(thousands of dollars)

	1999	1998	1997
Service cost – benefits earned during the period	$ 8,939	$ 7,890	$ 7,046
Interest cost on accumulated benefit obligation	17,366	15,763	14,441
Expected return on plan assets	(18,454)	(12,001)	(8,706)
Amortization of:			
Transition asset	7,698	7,698	7,698
Net actuarial gains	(5,117)	(2,952)	(2,685)
Net periodic postretirement benefit cost	$ 10,432	$ 16,398	$ 17,794

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

(thousands of dollars)

	1999	1998
Funded status - postretirement plan assets more than (less than) projected benefit obligation	$ 25,549	$ (24,269)
Unrecognized net obligation at transition	100,145	107,842
Unrecognized net actuarial gains	(128,309)	(86,692)
Net postretirement amount recognized in the balance sheets	$ (2,615)	$ (3,119)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Accumulated postretirement benefit obligation at beginning of year	$ 237,679	$ 199,348
Service cost	8,939	7,890
Interest cost	17,366	15,763
Benefit payments	(8,761)	(10,378)
Actuarial (gains) losses	(23,234)	25,056
Accumulated postretirement benefit obligation at end of year	$ 231,989	$ 237,679

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 1999 and 1998:

(thousands of dollars)

	1999	1998
Fair value of postretirement plan assets at beginning of year	$ 213,410	$ 151,146
Actual return on plan assets	42,975	47,284
Employer contributions	9,914	25,327
Benefit payments	(8,761)	(10,347)
Fair value of postretirement plan assets at the end of year	$ 257,538	$ 213,410

We made the assumptions below to calculate the postretirement liability:

	1999	1998
Discount rate	7.75%	7.00%
Expected long-term rate of return on assets – after tax	8.77%	8.73%
Initial health care cost trend rate – under age 65	7.00%	7.50%
Initial health care cost trend rate – age 65 and over	6.00%	6.50%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would increase by approximately $5 million and the accumulated benefit obligation as of December 31, 1999 would increase by approximately $38 million.

Assuming a 1% decrease in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would decrease by approximately $4 million and the accumulated benefit obligation as of December 31, 1999 would decrease by approximately $30 million.

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 $46 million in 2000 and approximately $49 million per year in 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, 1999 was $43 million. Lease expense was approximately $42 million in each of the years 1997 through 1999.

APS has a capital lease on a combined cycle plant, which it sold and leased back. The lease requires semiannual payments of $3 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54 million; accumulated amortization at December 31, 1999 was $51 million.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates. Miscellaneous lease expense was approximately $10 million in 1999, $13 million in 1998, and $11 million in 1997.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

(dollars in millions)

Year	
2000	$ 17
2001	19
2002	20
2003	20
2004	20
Thereafter	138
Total future commitments	$ 234

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, 1999. 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 APS	Plant In Service	Accumulated Depreciation	Construction Work In Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,829,633	$ 751,567	$ 7,220
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	572,574	240,696	17,145
Four Corners Steam Generating Station Units 4 and 5	15.0%	139,209	71,333	364
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	230,536	94,332	4,555
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	68,643	38,068	1,679
Transmission Facilities:				
ANPP 500 KV System	35.8%(b)	68,133	21,446	7
Navajo Southern System	31.4%(b)	27,364	17,550	42
Palo Verde – Yuma 500 KV System	23.9%(b)	11,728	4,388	36
Four Corners Switchyards	27.5%(b)	3,071	1,855	—
Phoenix – Mead System	17.1%(b)	36,434	1,768	—

(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.

Palo Verde Nuclear Generating Station

Under the Nuclear Waste Policy Act, 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 DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including APS. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision.

APS has capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 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. APS currently estimates that it will incur $113 million (in 1999 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, 1999, APS had recorded a liability and a regulatory asset of $37 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date. APS currently believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

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 the 29.1% interest in the three Palo Verde units, APS' 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 2000 through 2020 that include required purchase provisions. APS estimates its 2000 contract requirements to be about $177 million. 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 $57 million at December 31, 1999 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, 1999 was about $41 million.

Construction Program

Consolidated capital expenditures in 2000 are estimated at $591 million.

Generation Expansion

We are currently planning, through Pinnacle West Energy, a 650-megawatt expansion of our West Phoenix Power Plant, and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk. Pinnacle West Energy's capital expenditures in 1999 were $21 million. Projected capital expenditures for these projects are $152 million in 2000; $240 million in 2001; and $245 million in 2002. We are also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's capital expenditures will be funded with debt proceeds, and internally generated cash and debt proceeds from the parent company. Assuming all approvals are granted, we expect to begin construction at West Phoenix in the second quarter of 2000.

Pinnacle West Energy has signed a joint development agreement with Reliant Energy Power Generation, Inc. (Reliant) covering construction and operation of three new merchant plants. Pinnacle West Energy plans to contribute the first two units (1,060 megawatts) of the Redhawk project to the joint agreement. Construction is expected to start in the third quarter of 2000, with commercial operation scheduled in the summer of 2002. Reliant plans to contribute two new natural gas-fired projects (1,500 megawatts) in Nevada to the venture.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11 million for nuclear decommissioning expense in each of the years 1999, 1998, and 1997. APS estimates it will cost about $1.8 billion ($472 million in 1999 dollars) to decommission its 29.1% 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 Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" on the Consolidated Balance Sheets at their market value of $176 million at December 31, 1999 and $146 million at December 31, 1998.

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 1999 and 1998 is as follows:

(dollars in thousands, except per share amounts)

Quarter Ended	1999 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

(dollars in thousands, except per share amounts)

Quarter Ended	1998 March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 380,423	$ 441,715	$ 740,734	$ 443,526
Real estate	34,161	28,916	18,276	42,835
Operating income (a)	$ 90,837	$ 122,605	$ 251,838	$ 101,848
Net income	$ 31,086	$ 48,997	$ 127,281	$ 35,528
Earnings per average common share outstanding				
Net income – basic	$ 0.37	$ 0.58	$ 1.50	$ 0.42
Net income – diluted	$ 0.36	$ 0.57	$ 1.49	$ 0.42
Dividends declared per share (b)	$ 0.30	$ 0.60	$ —	$ 0.325

(a) APS' utility business is 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 quarters ending September 30, 1999 and September 30, 1998 were declared in June.

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, 1999 and 1998 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 1999 and 1998 fair values of such investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.31 billion on December 31, 1999, with an estimated fair value of $2.29 billion. On December 31, 1998, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.21 billion, with an estimated fair value of $2.27 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

In 1997 we adopted SFAS No. 128, "Earnings Per Share." This statement requires the presentation of both basic and diluted earnings per share on the financial statements. The following table presents earnings per average common share outstanding (EPS):

	1999	1998	1997
Basic EPS:			
Continuing operations	$ 3.18	$ 2.87	$ 2.76
Discontinued operations	0.45	—	—
Extraordinary charge	(1.65)	—	—
Net income	$ 1.98	$ 2.87	$ 2.76
Diluted EPS:			
Continuing operations	$ 3.17	$ 2.85	$ 2.74
Discontinued operations	0.45	—	—
Extraordinary charge	(1.65)	—	—
Net income	$ 1.97	$ 2.85	$ 2.74

Dilutive stock options increased average common shares outstanding by 291,392 shares in 1999, 571,728 shares in 1998, and 519,800 shares in 1997. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 85,008,527 shares in 1999, 85,345,946 shares in 1998, and 86,022,709 shares in 1997.

Options to purchase 506,734 shares of common stock were outstanding during the last quarter of 1999 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.

17. STOCK-BASED COMPENSATION

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

The most recent 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. 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, 1999 approximate 1,441,124 non-qualified stock options, 159,837 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 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 would have been reduced to the following pro forma amounts:

(thousands of dollars)

	1999	1998	1997
Net income			
As reported	$ 167,887	$ 242,892	$ 235,856
Pro forma (fair value method)	$ 166,913	$ 242,177	$ 235,446
Net income per share – basic			
As reported	$ 1.98	$ 2.87	$ 2.76
Pro forma (fair value method)	$ 1.97	$ 2.86	$ 2.75

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation. 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:

	1999	1998	1997
Risk-free interest rate	5.68%	4.54%	5.66%
Dividend yield	3.33%	3.03%	4.50%
Volatility	20.50%	18.80%	15.63%
Expected life (months)	60	60	60

The following table is a summary of the status of our stock option plans as of December 31, 1999, 1998, and 1997 and changes during the years ending on those dates:

	1999 Shares	1999 Weighted Average Exercise Price	1998 Shares	1998 Weighted Average Exercise Price	1997 Shares	1997 Weighted Average Exercise Price
Outstanding at beginning of year	1,563,512	$ 27.95	1,554,631	$ 24.38	1,739,576	$ 21.51
Granted	458,450	35.95	244,200	46.78	260,450	39.56
Exercised	(516,838)	18.19	(217,317)	23.09	(409,975)	21.60
Forfeited	(64,000)	40.36	(18,002)	33.42	(35,420)	27.10
Outstanding at end of year	1,441,124	33.45	1,563,512	27.95	1,554,631	24.38
Options exercisable at year-end	835,381	29.69	1,106,165	22.04	1,075,014	19.52
Weighted average fair value of options granted during the year		7.05		8.15		5.83

The following table summarizes information about our stock option plans at December 31, 1999:

Exercise Prices Per Share	Outstanding	Weighted Average Remaining Contract Life	Options Exercisable
$10.06	7,000	1.50	7,000
11.25	15,500	0.90	15,500
15.75	17,500	1.90	17,500
16.25	3,500	0.50	3,500
17.68	10,775	2.10	10,775
18.13	28,000	2.50	28,000
19.00	82,370	4.90	82,370
19.56	32,000	2.90	32,000
22.13	71,584	4.00	71,584
23.25	28,000	3.50	28,000
27.44	126,837	5.90	126,837
31.44	157,874	6.90	157,874
34.66	348,450	9.90	9,679
36.56	5,000	9.80	417
39.75	213,534	8.00	142,356
41.00	70,000	9.10	21,389
46.78	223,200	8.90	80,600
$10.06 – $46.78	1,441,124		835,381

18. BUSINESS SEGMENTS

Historically, we reported our operations as a single, integrated business segment. The basis of our reporting in previous years was due to APS' regulated operating environment. The ACC authorized a combined rate for supplying and delivering electricity to customers which was cost-based and was designed to recover APS' operating expenses and investment in electric utility assets and to provide a return on the investment.

As a result of the 1999 Settlement Agreement, our generation operations are now deregulated for accounting purposes. For the purposes of complying with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131), we are required to disclose information about its business segments separately. Accordingly, APS has separated identifiable expenses between the two segments and has allocated revenues and other expenses using a study that identifies the portion of its base rates related to generation and delivery. APS then used that information to develop the financial information of the business segments for each of the three years ended December 31, 1999 (or as of December 31, 1999 and 1998, with respect to assets). None of our revenues from external customers are attributed to, and none of our long-lived assets are located in, any foreign country.

Beginning in 1999, we have two principal business segments (determined by products, services, and regulatory environment) which consist of the generation of electricity (generation business segment), and the transmission and distribution of electricity (delivery business segment). The "Other" amounts include activity relating to other subsidiaries including SunCor, El Dorado, and APS Energy Services. Intercompany eliminations primarily relate to intercompany sales of electricity. Financial data for business segments is provided as follows:

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1999 (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 (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

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1997 (in thousands)

	Generation	Delivery	Other	Eliminations	Total
Operating revenues	$ 803,647	$ 1,878,553	$ 116,473	$ (803,647)	$ 1,995,026
Operating expense	471,992	1,297,802	98,519	(803,647)	1,064,666
Operating margin	331,655	580,751	17,954	—	930,360
Depreciation and amortization	131,684	233,987	2,614	—	368,285
Interest and preferred stock dividend requirements	50,311	104,410	21,217	—	175,938
Pretax margin	149,660	242,354	(5,877)	—	386,137
Income taxes	44,898	108,426	(3,043)	—	150,281
Earnings for common stock	$ 104,762	$ 133,928	$ (2,834)	$ —	$ 235,856
Capital expenditures	$ 84,960	$ 217,047	$ 67,248	$ —	$ 369,255

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions (a)	Balance at end of Period
		(Thousands of Dollars)			
		YEAR ENDED DECEMBER 31, 1999			
Real Estate Valuation Reserves	$ 15,000	$ ---	$ ---	$ 7,000	$ 8,000
		YEAR ENDED DECEMBER 31, 1998			
Real Estate Valuation Reserves	$ 23,000	$ ---	$ ---	$ 8,000	$ 15,000
		YEAR ENDED DECEMBER 31, 1997			
Real Estate Valuation Reserves	$ 41,000	$ ---	$ ---	$ 18,000	$ 23,000

(a) Represents pro-rata allocations for sale of land.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Reference is hereby made to "Election of Directors" and to "General – Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 17, 2000 (the "2000 Proxy Statement") and to the Supplemental Item --- "Executive Officers of the Registrant" in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to the fourth and fifth paragraphs under the heading "The Board and its Committees," to "Executive Compensation," to "Human Resources Committee Report," to "Stock Performance Comparisons" and to "Executive Benefit Plans" in the 2000 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Reference is hereby made to "Certain Securities Ownership" in the 2000 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Reference is hereby made to "Executive Benefit Plans – Employment and Severance Arrangements" and to "General-Business Relationship" in the 2000 Proxy Statement.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements

See the Index to Consolidated Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

Exhibit No.		*Description*
10.1[a]	—	2000 Management Variable Incentive Plan (Pinnacle West)
10.2[a]	—	2000 Senior Management Variable Incentive Plan (Pinnacle West)
10.3[a]	—	2000 Officer Variable Incentive Plan (Pinnacle West)
10.4[a]	—	2000 Management Variable Incentive Plan (APS)
10.5[a]	—	2000 Senior Management Variable Incentive Plan (APS)
10.6[a]	—	2000 Officers Variable Incentive Plan (APS)
10.7[a]	—	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan
10.8[a]	—	Fourth Amendment dated December 28, 1999 to the Arizona Public Service Company Directors Deferred Compensation Plan
10.9[a]	—	Letter Agreement dated December 13, 1999 between APS and William L. Stewart
10.10[a]	—	Second Amendment effective January 1, 2000 to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan
10.11[a]	—	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation Stock Option and Incentive Plan
10.12[a]	—	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan
10.13[a]	—	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 7, 1999
10.14[a]	—	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996
10.15[a]	—	First Amendment dated December 7, 1999 to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans

10.16[a]	—	Letter Agreement dated July 28, 1995 between Arizona Public Service Company and Armando B. Flores
10.17[a]	—	Letter Agreement dated October 3, 1997 between Arizona Public Service Company and James M. Levine
21	—	Subsidiaries of the Company
23.1	—	Consent of Deloitte & Touche LLP
27.1	—	Financial Data Schedule

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.1	Articles of Incorporation, restated as of July 29, 1988	19.1 to the Company's September 1988 Form 10-Q Report	1-8962	11-14-88
3.2	Bylaws, amended as of December 15, 1999	4.1 to the Company's Registration Statement on Form S-8 No. 333-95035	1-8962	1-20-00
4.1	Mortgage and Deed of Trust Relating to APS' First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to APS' August 1, 1993 Form 8-K Report	1-4473	9-27-93
4.5	Fifty-second Supplemental Indenture	4.1 to APS' September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to APS' Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94
4.7	Fifty-fourth Supplemental Indenture	4.1 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.8	Fifty-fifth Supplemental Indenture	4.8 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS' total assets	4.1 to APS' 1993 Form 10-K Report	1-4473	3-30-94
4.10	Indenture dated as of January 1, 1995 among APS and The Bank of New York, as Trustee	4.6 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.11	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.12	Indenture dated as of November 15, 1996 among APS and The Bank of New York, as Trustee	4.5 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.13	First Supplemental Indenture	4.6 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.14	Second Supplemental Indenture	4.10 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.15	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.2 to the Company's 1988 Form 10-K Report	1-8962	3-31-89
4.16	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to the Company's 1987 Form 10-K Report	1-8962	3-30-88
4.17	Indenture dated as of January 15, 1998 among APS and and Chase Manhattan Bank, as Trustee	4.10 to APS' Registration The Statement Nos. 333-15379 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.18	First Supplemental Indenture dated as of January 15, 1998	4.3 to APS' Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.19	Second Supplemental Indenture dated as of February 15, 1999	4.3 to APS' Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99
4.20	Third Supplemental Indenture dated as of November 1, 1999	4.5 to APS' Registration Statement No. 333-58445 by means of November 2, 1999 Form 8-K Report	1-4473	11-5-99
4.21	Amended and Restated Rights Agreement, dated as of March 26, 1999, between Pinnacle West Capital Corporation and BankBoston, N.A., as Rights Agent, including (i) as Exhibit A thereto the form of Amended Certificate of Designation of Series A Participating Preferred Stock of Pinnacle West Capital Corporation, (ii) as Exhibit B thereto the form of Rights Certificate and (iii) as Exhibit C thereto the Summary of Right to Purchase Preferred Shares	4.1 to the Company's March 22, 1999 Form 8-K Report	1-8962	4-19-99

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.18[a]	Employment Agreement, effective as of February 5, 1990, between Richard Snell and the Company	10.1 to the Company's 1990 Form 10-K Report	2-96386	3-28-91
10.19	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS' September 1991 Form 10-Q Report	1-4473	11-14-91
10.20	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS' 1994 Form 10- K Report	1-4473	3-30-95
10.21	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.22	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.23	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS' 1996 Form 10-K Report	1-4473	3-28-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.24	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to the Company's 1991 Form 10-K Report	1-8962	3-26-92
10.25	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.26	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.27	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.1 to APS' June 1996 Form 10-Q Report	1-4473	8-9-96
10.28	Amendment No. 4 to 3-28-97 Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	APS 10.5 to APS' 1996 Form 10-K Report		1-4473
10.29	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.30	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91
10.31	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.32	Restated Transmission Agreement Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.33	Contract among PacifiCorp, APS and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.34	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.35	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high -level radioactive waste, ANPP	10.31 to the Company's Form S-14 Registration Statement	2-96386	3-13-85
10.36	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.37	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.38	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to the Company's Registration Statement on Form 8-B Report	1-8962	7-25-85

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.39	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.40	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.37 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85
10.41	Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site	5.05 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.42	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.38 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85
10.43	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS' Form S-7 Registration Statement	2-36505	3-23-70
10.44	Application and Grant of rights-of-way and easements, Navajo Plant	5(h) to APS' Form S-7 Registration Statement	2-36505	3-23-70
10.45	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to APS' Form S-7 Registration Statement	2-394442	3-16-71
10.46	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10. 1 to APS' 1988 Form 10-K	1-4473	3-8-89

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.47	Amendment No. 13, dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS' March 1991 Form 10-Q	1-4473	5-15-91
10.48[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86
10.49[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS' September 1986 Form 10-Q Report by means of Amendment No. on December 3, 1986 Form 8	1-4473	12-4-86
10.50[c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.51[c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.52	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS' November 18 1986 Form 8-K Report	1-4473	1-20-87
10.53	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
10.54	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.55[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS' June 1986 Form 10-Q Report	1-4473	8-13-86
10.56[a]	Second Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.57[a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS' September 1994 Form 10-Q	1-4473	11-10-94
10.58[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987 respectively	10.4 to APS' 1988 Form 10-K Report	1-4473	3-8-89

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.59	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.60[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS' September 1994 Form 10-Q Report	1-4473	11-10-94
10.61[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.62[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.63[a]	Arizona Public Service Company Supplemental Excess Benefit Retirement Plan as amended and restated on December 20, 1995	10.11 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.64[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, effective as of January 1, 1995	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.65[a]	Letter Agreement dated December 21, 1993, between APS and William L. Stewart	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-96
10.66[a]	Letter Agreement dated as of January 1, 1996 between APS and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.67[a]	Letter Agreement dated August 16, 1996 between APS and William L. Stewart	10.8 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.68[a]	Letter Agreement between APS and William L. Stewart	10.2 to APS' September 1997 Form 10-Q Report	1-4473	11-12-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.69[ad]	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.1 to June 1999 Form 10-Q Report	1-8962	8-16-99
10.70[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.71[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan, effective as of March 23, 1994	A to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.72[a]	Pinnacle West Capital Corporation Director Equity Participation Plan	B to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.73	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to APS' 1991 Form 10-K Report	1-4473	3-19-92
10.74	Agreement for the Sale and purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981, including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to APS' 1991 Form 10-K Report	1-4473	3-19-92
10.75[a]	First Amendment to Employment Agreement, effective March 31, 1995, between Richard Snell and the Company	10.2 to the Company's 1995 Form 10-K Report	1-8962	4-1-96
10.76[a]	Second Amendment to Employment Agreement, effective February 5, 1997, between Richard Snell and the Company	10.2 to the Company's 1996 Form 10-K Report	1-8962	3-31-97
10.77[a]	APS Director Equity Plan	10.1 to September 1997 Form 10-Q Report	1-4473	11-12-97

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.78	Territorial Agreement between the Company and Salt River Project	10.1 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.79	Power Coordination Agreement between the Company and Salt River Project	10.2 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.80	Memorandum of Agreement between the Company and Salt River Project	10.3 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.81	Addendum to Memorandum of Agreement between APS and Salt River Project dated as of May 19, 1998	10.2 to APS' May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS' 1992 Form 10 K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS' 1992 Form 10 K Report	1-4473	3-30-93
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS' Form S-3 Registration Statement	33-9480	10-24-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	28.14 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.15	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and ChemicalBank, as Indenture Trustee	10.2 to APS' November 18, 1986 Form 10-K Report	1-4473	1-20-87
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
99.17	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS' November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Arizona Corporation Commission Order dated December 6, 1991	28.1 to APS' 1991 Form 10-K Report	1-4473	3-19-92
99.23	Arizona Corporation Commission Order dated June 1, 1994	10.1 to APS' June 1994 form 10-Q Report	1-4473	8-12-94
99.24	Rate Reduction Agreement dated December 4, 1995 between APS and the ACC Staff	10.1 to APS' December 4, 1995 8-K Report	1-4473	12-14-95
99.25	ACC Order dated April 24, 1996	10.1 to APS' March 1996 Form 10-Q Report	1-4473	5-14-96
99.26	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to APS' 1996 Form 10-K Report	1-4473	3-28-97
99.27	Retail Electric Competition Rules	10.1 to APS' June 1998 Form 10-Q Report	1-4473	8-14-98
99.28	Arizona Corporation Commission Order, Decision No. 61973, dated October 6, 1999, approving APS' Settlement Agreement	10.1 to APS' September 1999 10-Q Report	1-4473	11-15-99
99.29	Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to APS' September 1999 10-Q Report	1-4473	11-15-99

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 1999, and the period ended March 29, 2000, the Company filed the following Report on Form 8-K:

Report dated September 29, 1999 regarding our plan to construct an electric generating plant of up to 2,120 megawatts near Palo Verde.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: March 29, 2000

/s/ WILLIAM J. POST
(William J. Post, President
and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	*Title*	*Date*
/s/WILLIAM J. POST (William J. Post, President and Chief Executive Officer)	Principal Executive Officer and Director	March 29, 2000
/s/MICHAEL V. PALMERI (Michael V Palmeri, Vice President, Finance)	Principal Financial Officer	March 29, 2000
/s/CHRIS N. FROGGATT (Chris N. Froggatt, Vice President and Controller)	Principal Accounting Officer	March 29, 2000
/s/RICHARD SNELL (Richard Snell, Chairman of the Board of Directors)	Director	March 29, 2000
/s/EDWARD N. BASHA, JR. (Edward N. Basha, Jr.)	Director	March 29, 2000
/s/MICHAEL L. GALLAGHER (Michael L. Gallagher)	Director	March 29, 2000
/s/PAMELA GRANT (Pamela Grant)	Director	March 29, 2000
/s/ROY A. HERBERGER, JR. (Roy A. Herberger, Jr.)	Director	March 29, 2000

/s/MARTHA O. HESSE (Martha O. Hesse)	Director	March 29, 2000
/s/WILLIAM S. JAMIESON, JR. (William S. Jamieson, Jr.)	Director	March 29, 2000
/s/HUMBERTO S. LOPEZ (Humberto S. Lopez)	Director	March 29, 2000

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1999

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number 1-4473

Arizona Public Service Company

(Exact name of registrant as specified in its charter)

ARIZONA (State or other jurisdiction of incorporation or organization)	86-0011170 (I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (Address of principal executive offices, including zip code)	(602) 250-1000 (Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) or 12(g) of the Act: None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in any amendment to this Form 10-K. [X]

As of March 29, 2000, there were issued and outstanding 71,264,947 shares of the registrant's common stock, $2.50 par value, all of which were held beneficially and of record by Pinnacle West Capital Corporation.

The registrant meets the conditions set forth in General Instruction I1(a) and (b) and is therefore filing this document with the reduced disclosure format.

TABLE OF CONTENTS

GLOSSARY

ACC — Arizona Corporation Commission

ACC Staff — Staff of the Arizona Corporation Commission

AFUDC — Allowance for Funds Used During Construction

ANPP — Arizona Nuclear Power Project, also known as Palo Verde

APS — Arizona Public Service Company

CC&N — Certificate of convenience and necessity

Cholla — Cholla Power Plant

Cholla 4 — Unit 4 of the Cholla Power Plant

Company — Arizona Public Service Company

CUC — Citizens Utilities Company

EPA — United States Environmental Protection Agency

FASB — Financial Accounting Standards Board

FERC — Federal Energy Regulatory Commission

Four Corners — Four Corners Power Plant

GAAP — Generally accepted accounting principles

ITC — Investment tax credit

kW — Kilowatt, one thousand watts

kWh — Kilowatt-hour, one thousand watts per hour

MW — Megawatt, one million watts

MWh — Megawatt hours, one million watts per hour

NGS — Navajo Generating Station

NRC — Nuclear Regulatory Commission

Palo Verde — Palo Verde Nuclear Generating Station

Pinnacle West — Pinnacle West Capital Corporation, an Arizona corporation, the Company's parent

SEC — Securities and Exchange Commission

Salt River Project — Salt River Project Agricultural Improvement and Power District

PART I

ITEM 1. BUSINESS

The Company

We were incorporated in 1920 under the laws of Arizona and are engaged principally in serving electricity in the State of Arizona. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000). Pinnacle West owns all of the outstanding shares of our common stock.

We are Arizona's largest electric utility, with 827,000 customers. We provide wholesale or retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area. During 1999, no single purchaser or user of energy accounted for more than 2% of total electric revenues. See Note 16 of Notes to Financial Statements for a discussion of business segments. At December 31, 1999, we employed 6,234 people, which includes employees assigned to joint projects where we are project manager.

This document contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; our ability to successfully compete outside our traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; and Year 2000 issues. See "Competition" in this Item for a discussion of some of these factors.

Competition

Retail

The ACC has regulatory authority over us in matters relating to retail electric rates, the issuance of securities, and the transaction of business with affiliated parties. See Note 3 of Notes to Financial Statements in Item 8 for a discussion of the electric industry restructuring in Arizona, including our 1999 Settlement Agreement, ACC rules for the introduction of retail electric competition, and Arizona legislative initiatives. See also "Financial Review - Competition and Industry Restructuring" in Item 7. In addition to the introduction of competition pursuant to the Settlement Agreement and the ACC rules, we are subject to varying degrees of competition in certain territories adjacent to or within areas that we serve that are also currently served by other utilities in our region (such as Tucson Electric Power Company, Southwest Gas Corporation, and Citizens Utility Company) as well as cooperatives, municipalities, electrical districts, and similar types of governmental organizations (principally Salt River Project)

We face competitive challenges from low-cost hydroelectric power and natural gas fuel, as well as the access of some utilities to preferential low-priced federal power and other subsidies. In addition, some customers, particularly industrial and large commercial, may own and operate facilities to generate their own electric energy requirements. Such facilities may be operated by the customers themselves or by other entities engaged for such purpose.

Wholesale

We compete with other utilities, power marketers, and independent power producers in the sale of electric capacity and energy in the wholesale market. We expect that competition to sell capacity will remain vigorous. Our rates for wholesale power sales and transmission services are subject to regulation by the FERC. During 1999, approximately 23% of our electric operating revenues resulted from such sales and charges.

The National Energy Policy Act of 1992 has promoted increased competition in the wholesale electric power markets. The Energy Act reformed provisions of the Public Utility Holding Company Act of 1935 (the "1935 Act") and the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, the Energy Act permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers and other third parties can sell at wholesale to customers wherever located. The Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

Effective July 9, 1996, a FERC decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with access to transmission facilities comparable to the transmission owners' access for wholesale transactions, establishes information requirements, and provides for recovery of certain wholesale stranded costs. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states, unless a state lacks authority to impose rates to recover such costs, in which case FERC will consider doing so. We have filed a revised open access tariff in accordance with this decision. We do not believe that this decision will have a material adverse impact on our results of operations or financial position.

Regulatory Assets

Our major regulatory assets are deferred income taxes and rate synchronization cost deferrals. As a result of our September 1999 Settlement Agreement, we have discontinued the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," for our generation operations. This means that regulatory assets, unless reestablished as recoverable through ongoing regulated cash flows, were eliminated and the generation assets were tested for impairment. We determined that the generation assets were not impaired. Prior to the Settlement Agreement, under a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. See Notes 1, 3, and 10 of Notes to Financial Statements in Item 8 for additional information.

Competitive Strategies

We are pursuing strategies to maintain and enhance our competitive position. These strategies include (i) cost management, with an emphasis on the reduction of variable costs (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; (ii) a focus on our core business through customer service, distribution system reliability, business segmentation, and the anticipation of market opportunities; (iii) an emphasis on good regulatory relationships; (iv) asset maximization (e.g., higher capacity factors and lower forced outage rates); (v) strengthening our capital structure and financial condition; (vi) leveraging core competencies into related areas, such as energy management products and services; and (vii) operating a trading floor and implementing a risk management program to provide for more stability of prices and the ability to retain or grow incremental margins through more competitive pricing and risk management. Underpinning our competitive strategies are the strong growth characteristics of our service territory. As competition in the electric utility industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a more competitive, restructured industry.

Generating Fuel and Purchased Power

1999 Energy Mix

Our sources of energy during 1999 were: coal – 29.9%; nuclear – 22.4%; purchased power – 43.2%; gas – 4.4%; and other – 0.1%.

Coal Supply

Leases NGS and Four Corners are located on the Navajo Reservation and held under easements granted by the federal government as well as leases from the Navajo Nation. See "Properties- Plant Sites Leased from the

Navajo Nation" in Item 2. Most of the coal for Cholla is supplied by a coal supplier who mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government, and private landholders. Remaining coal requirements are purchased on the spot market. All of the coal for Four Corners is purchased from a coal supplier with a long-term lease of coal reserves owned by the Navajo Nation. The coal for NGS comes from a supplier with a long-term lease with the Navajo Nation and the Hopi Tribe. See Note 12 of Notes to Financial Statements in Item 8 for information regarding our obligation for coal mine reclamation.

Contracts Cholla presently has sufficient coal under current contracts to ensure a reliable fuel supply through 2005. Portions of the fuel supply are bid on the spot market to take advantage of competitive pricing options. Following expiration of current contracts, there are numerous competitive fuel supply options available to ensure continuous plant operation. Cholla also has certain requirements for low sulfur coal and the current supplier is expected to continue to provide most of Cholla's low sulfur coal requirements through the current contract. There are sufficient reserves of low sulfur coal available from other suppliers to ensure the continued operation of Cholla for its useful life. The sulfur content of coal at Cholla for 1999 was 0.47%. Average prices paid for all coal supplied from reserves dedicated under existing contracts were slightly lower than, but comparable to, 1998. For the years remaining on the contracts after 2000, prices will be reduced.

Four Corners is a mine-mouth operation which is under contract for coal through 2004. There are options to extend the contract through the plant site lease expiration in 2017. The sulfur content of Four Corners coal for 1999 was 0.77%, and the units are equipped with scrubbers. The average price paid for all coal supplied under the existing contract was slightly lower than, but comparable to, 1998. The Four Corners lease waives, until July 2001, the requirement that we, as well as our fuel supplier, pay certain taxes to the Navajo Nation. In September 1997, a settlement agreement was finalized between the coal supplier, the Navajo Nation, and Four Corners participants, which settled certain issues in the lease regarding the obligation of the fuel supplier to pay taxes prior to the expiration of tax waivers in 2001. Pursuant to this agreement, the coal supplier currently pays a possessory interest tax to the Navajo Nation, which is contractually reimbursed by participants. The parties also agreed to investigate alternative contractual arrangements and business relationships before 2001 in an effort to permit the electricity generated at Four Corners to be priced competitively. We anticipate that additional taxes will be levied by the Navajo Nation upon the expiration of the tax waivers; however, we cannot currently predict the outcome of this matter or the amount of the additional taxes.

NGS is under contract with its coal supplier through 2011, with options to extend through the plant site lease. The sulfur content of coal at NGS for 1999 was 0.53%, and the units are equipped with scrubbers. Average price paid for coal supplied in 1999 under the existing contract was lower than, but comparable to, 1998. The NGS lease waives certain taxes through the lease expiration in 2019. The lease provides for the potential to renegotiate the coal royalty in 2007 and 2017, which may impact the fuel price.

Natural Gas Supply

We are a party to contracts with a number of natural gas suppliers that allow us to purchase natural gas in the method we determine to be most economic. Currently, we are purchasing the majority of our natural gas requirements from numerous companies under these contracts. Our natural gas supply is transported pursuant to a firm transportation service contract with El Paso Natural Gas Company. We continue to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

Nuclear Fuel Supply

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

- the mining and milling of uranium ore to produce uranium concentrates,
- the conversion of uranium concentrates to uranium hexafluoride,
- the enrichment of uranium hexafluoride,
- the fabrication of fuel assemblies,

- the utilization of fuel assemblies in reactors and
- the storage of spent fuel and the disposal thereof.

The Palo Verde participants have made contractual arrangements to obtain quantities of uranium concentrates anticipated to be sufficient to meet operational requirements through 2002. Existing contracts and options could be utilized to meet approximately 88% of requirements in 2003, 88% of requirements in 2004, 49% of requirements in 2005, and 16% of requirements in 2006 and beyond. Spot purchases on the uranium market will be made, as appropriate, in lieu of any uranium that might be obtained through contractual options.

The Palo Verde participants have contracted for uranium conversion services. Existing contracts and options could be utilized to meet approximately 70% of requirements in 2000, 75% of requirements in 2001 and 80% of requirements in 2002. The Palo Verde participants have an enrichment services contract and an enriched uranium product contract that furnish enrichment services required for the operation of the three Palo Verde units through 2003. In addition, existing contracts will provide fuel assembly fabrication services until at least 2015 for each Palo Verde unit.

Spent Nuclear Fuel and Waste Disposal. Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987, the United States Department of Energy ("DOE") is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The NRC, pursuant to the Waste Act, requires operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository. DOE has announced that such a repository now cannot be completed before 2010. In July 1996, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) ruled that the DOE has an obligation to start disposing of spent nuclear fuel no later than January 31, 1998. By way of letter dated December 17, 1996, DOE informed us and other contract holders that DOE anticipates that it would be unable to begin acceptance of spent nuclear fuel for disposal in a repository or interim storage facility by January 31, 1998. In November 1997, the D.C. Circuit issued a Writ of Mandamus precluding DOE from excusing its own delay on the grounds that DOE has not yet prepared a permanent repository or interim storage facility. On May 5, 1998, the D.C. Circuit issued a ruling refusing to order DOE to begin moving spent nuclear fuel. See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of interim spent fuel storage costs.

Several bills have been introduced in Congress contemplating the construction of a central interim storage facility; however, there is resistance to certain features of these bills both in Congress and the Administration.

Facility funding is a further complication. While all nuclear utilities pay into a so-called nuclear waste fund an amount calculated on the basis of the output of their respective plants, the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes). According to DOE spokespersons, the fund may now be at a level less than needed to achieve a 2010 operational date for a permanent repository. No funding will be available for a central interim facility until one is authorized by Congress.

We have storage capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002. Construction of a new facility for on-site dry storage of spent fuel is underway. Once this facility is completed and approvals are granted, we believe that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

A new low-level waste facility was built in 1995 on-site which could store an amount of waste equivalent to ten years of normal operation at Palo Verde. Although some low-level waste has been stored on-site, we are currently shipping low-level waste to off-site facilities. We currently believe 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.

We believe that scientific and financial aspects of the issues of spent fuel and low-level waste storage and disposal can be resolved satisfactorily. However, we also acknowledge that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which we are less able to predict.

Purchased Power Agreements

In addition to that available from its own generating capacity (see "Properties" in Item 2), we purchase electricity from other utilities under various arrangements. One of the most important of these is a long-term contract with Salt River Project. This contract may be canceled by Salt River Project on three years' notice and requires Salt River Project to make available, and us to pay for, certain amounts of electricity. The amount of electricity is based in large part on customer demand within certain areas now served by us pursuant to a related territorial agreement. The generating capacity available to us pursuant to the contract was 316 MW January through May 1999, and starting June 1999 changed to 302 MW. In 1999, we received approximately 1,056,200 MWh of energy under the contract and paid about $43.9 million for capacity availability and energy received. See Note 3 of Notes to Financial Statements for a discussion of amendments to this contract and other agreements with Salt River Project.

In September 1990, we entered into a thirty year agreement under which we and PacifiCorp engage in one-for-one seasonal capacity exchanges. We receive electricity from PacifiCorp during our summer peak season. We will have 480 MW of generating capacity available to us under the agreements until 2020. In 1999, we had 480 MW of generating capacity available from PacifiCorp and we received approximately 572,382 MWh of energy under the capacity exchange.

Construction Program

During the years 1997 through 1999, we incurred approximately $962 million in capital expenditures. Utility capital expenditures for the years 2000 through 2002 are expected to be primarily for expanding transmission and distribution capabilities to meet customer growth, upgrading existing facilities, and for environmental purposes. Capitalized expenditures, including expenditures for environmental control facilities, for the years 2000 through 2002 have been estimated as follows:

(Millions of Dollars)

By Year		By Major Facilities	
2000	$384	Production	$255
2001	342	Transmission and Distribution	691
2002	334	General	114
Total	$ 1,060	Total	$ 1,060

The amounts for 2000 through 2002 exclude capitalized interest costs and include capitalized property taxes and about $30-$35 million each year for nuclear fuel. We conduct a continuing review of our construction program.

Mortgage Replacement Fund Requirements

So long as any of our first mortgage bonds are outstanding, we are required for each calendar year to deposit with the trustee under our mortgage cash in a formularized amount related to net additions to our mortgaged utility plant. We may satisfy all or any part of this "replacement fund" requirement by utilizing redeemed or retired bonds, net property additions, or property retirements. For 1999, the replacement fund requirement amounted to approximately $143 million. Certain of the bonds we have issued under the mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash we deposit in the replacement fund. This is subject in many cases to a period of time after the original issuance of the bonds during which they may not be so redeemed.

Environmental Matters

EPA Environmental Regulation

Clean Air Act. We are subject to a number of requirements under the Clean Air Act. Pursuant to the Clean Air Act, the EPA adopted regulations that address visibility impairment in certain federally-protected areas which can be reasonably attributed to specific sources. In September 1991, the EPA issued a final rule that limited sulfur dioxide emissions at NGS. One NGS unit had to comply with this rule in 1997, one in 1998, and the last unit in 1999. Salt River Project is the NGS operating agent. Salt River Project estimates a capital cost of $430 million and annual operations and maintenance costs of approximately $14 million for all three units, for NGS to meet these requirements. We are required to fund 14% of these expenditures. About all of these capital costs have been incurred.

The Clean Air Act also addresses, among other things:

- "acid rain,"
- visibility in certain specified areas,
- hazardous air pollutants and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Clean Air Act establishes a system of sulfur dioxide emissions "allowances." Each existing utility unit is granted a certain number of "allowances." For Phase II plants, which include our plants, allowances will be required beginning in the year 2000 to operate the plants. Based on EPA allowance allocations, we will have sufficient allowances to permit continued operation of our plants at current levels without installing additional equipment.

The Clean Air Act also requires the EPA to set nitrogen oxides emissions limitations. These limitations require certain plants to install additional pollution control equipment. In December 1996, the EPA issued rules for nitrogen oxides emissions limitations that would have required us to install additional pollution control equipment at Four Corners by January 1, 2000. On February 14, 1997, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia. We alleged that the EPA improperly classified Four Corners Unit 4 in these rules, thereby subjecting Unit 4 to a more stringent emission limitation. Arizona Public Service Company v. United States Environmental Protection Agency, No. 97-1091. In February 1998, the Court vacated the Unit 4 emission limitation and remanded the issue to EPA for reconsideration. In December 1999, EPA's direct final rule, which classified Four Corners Unit 4 as we had proposed, became final. We do not currently expect this rule to have a material impact on our financial position or results of operations.

With respect to protection of visibility in certain specified areas, the Clean Air Act requires the EPA to conduct a study concerning visibility impairment in those areas and to identify sources contributing to such impairment. Interim findings of this study indicate that any beneficial effect on visibility as a result of the Amendments would be offset by expected population and industry growth. The Clean Air Act also requires EPA to establish a "Grand Canyon Visibility Transport Commission" to complete a study on visibility impairment in the "Golden Circle of National Parks" in the Colorado Plateau. NGS, Cholla, and Four Corners are located near the Golden Circle of National Parks. The Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA.

On April 22, 1999, the EPA announced final regional haze rules. These new regulations require states to submit, by 2008, implementation plans containing requirements to eliminate all man-made emissions causing visibility impairment in certain specified areas, including the Golden Circle of National Parks in the Colorado Plateau. The 2008 implementation plans must also include consideration and potential application of best available retrofit technology ("BART") for major stationary sources which came into operation between August

1962 and August 1977, such as the Navajo Generating Station, Cholla Power Plant and Four Corners Power Plant. The nine western states and tribes that participated in the Grand Canyon Visibility Transport Commission process will have the option to follow an alternate implementation plan and schedule for areas considered by the Commission. Under this option, those states and tribes would submit implementation plans by 2003, which would incorporate the emission reduction scheme adopted in the Commission's recommendations and application of BART by 2018, possibly using an emission trading program. Any states and tribes that implement this option will also have to submit revised implementation plans in 2008 to address visibility in certain specified areas that were not considered by the Commission. Because Arizona and the Navajo Nation have the discretion to choose between the national or Commission options and a variety of pollution controls to meet the requirements of the regional haze rules, the actual impact on us cannot be determined at this time.

Also, in July 1997, EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to the rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard. These standards were challenged and the court determined that EPA's promulgation of the standards violated the constitutional prohibition on delegation of legislative power. The court remanded the ozone standard, vacated the coarse particulate matter standard, and invited the parties to brief the court on vacating or remanding the fine particulate matter standard. We cannot currently predict EPA's response to this decision. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, we currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, we do not currently expect these rules to have a material adverse effect on our financial position or results of operations.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the Clean Air Act requires two studies. The results of the first study indicated an impact from mercury emissions from such units in certain unspecified areas. The EPA has not yet stated whether or not mercury emissions limitations will be imposed. Secondly, the EPA will complete a general study by December 2000 concerning the necessity of regulating hazardous air pollutant emissions from such units under the Clean Air Act. Because we cannot speculate as to the ultimate requirements by the EPA, we cannot currently estimate the capital expenditures, if any, which may be required as a result of these studies.

Certain aspects of the Clean Air Act may require us to make related expenditures, such as permit fees. We do not expect any of these to have a material impact on our financial position or results of operations.

Federal Implementation Plan. In September 1999, the EPA proposed a Federal Implementation Plan ("FIP") to set air quality standards at certain power plants, including the Navajo Generating Station and the Four Corners Power Plant. The comment period on this proposal ended in November 1999. The FIP is similar to current Arizona regulation of NGS and New Mexico regulation of Four Corners, with minor modifications. We do not currently expect FIP to have a material impact on our financial position or results of operations.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who generated, transported, or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often jointly and severally, liable for the cost of any necessary remediation of the substances. The EPA had previously advised us that the EPA considers us to be a PRP in the Indian Bend Wash Superfund Site, South Area. Our Ocotillo Power Plant is located in this area. We are in the process of conducting an investigation to determine the extent and scope of contamination at the plant site. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, we do not expect this matter to have a material impact on our financial position or results of operations.

Manufactured Gas Plant Sites. We are currently investigating properties which we now own or which were at one time owned by us or our corporate predecessors, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present
- such materials constitute an environmental or health risk and
- we have any responsibility for remedial action.

Where appropriate, we have begun remediation of certain of these sites. We do not expect these matters to have a material adverse effect on our financial position or results of operations.

Purported Navajo Environmental Regulation

Four Corners and NGS are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. We are the Four Corners operating agent. We own a 100% interest in Four Corners Units 1, 2, and 3, and a 15% interest in Four Corners Units 4 and 5. We own a 14% interest in NGS Units 1, 2, and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Acts"). Pursuant to the Acts, the Navajo Nation Environmental Protection Agency is authorized to promulgate regulations covering air quality, drinking water, and pesticide activities, including those that occur at Four Corners and NGS. By separate letters dated October 12 and October 13, 1995, the Four Corners participants and the NGS participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Acts apply to operations of Four Corners and NGS. On October 17, 1995, the Four Corners participants and the NGS participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that

- their respective leases and federal easements preclude the application of the Acts to the operations of Four Corners and NGS and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners and NGS.

On October 18, 1995, the Navajo Nation and the Four Corners and NGS participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. We cannot currently predict the outcome of this matter.

In February 1998, the EPA promulgated regulations specifying those provisions of the Clean Air Act for which it is appropriate to treat Indian tribes in the same manner as states. The EPA indicated that it believes that the Clean Air Act generally would supersede pre-existing binding agreements that may limit the scope of tribal authority over reservations. On April 10, 1998, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 98-1196. On February 19, 1999, the EPA promulgated regulations setting forth the EPA's approach to issuing Federal operating permits to covered stationary sources on Indian reservations. On April 15, 1999, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 99-1146.

Water Supply

Assured supplies of water are important for our generating plants. At the present time, we have adequate water to meet our needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions in recent years.

Both groundwater and surface water in areas important to our operations have been the subject of inquiries, claims, and legal proceedings which will require a number of years to resolve. We are one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from its allocation to offset the loss.

A summons served on us in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. Our rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde is potentially at issue in this action. As project manager of Palo Verde, we filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, we seek confirmation of such rights. Three of our less-utilized power plants are also located within the geographic area subject to the summons. Our claims dispute the court's jurisdiction over our groundwater rights with respect to these plants. Alternatively, we seek confirmation of such rights. The Arizona Supreme Court recently issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. We and other parties have petitioned the U.S. Supreme Court for review of this decision. Another issue important to the claims is pending on appeal to the Arizona Supreme Court. No trial date concerning our water rights claims has been set in this matter.

We have also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). Our groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. Our claims dispute the court's jurisdiction over our groundwater rights. Alternatively, we seek confirmation of such rights. The parties are in the process of settlement negotiations with respect to this matter. No trial date concerning our water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, we expect that the described litigation will not have a material adverse impact on our financial position, results of operations or liquidity.

ITEM 2. PROPERTIES

Accredited Capacity

Our present generating facilities have an accredited capacity as follows:

	Capacity(kW)
Coal:	
Units 1, 2, and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2, and 3 at Cholla Plant	615,000
14% owned Units 1, 2, and 3 at the Navajo Plant	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	435,000(1)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
	1,183,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Other	5,600
Total	3,986,900

(1) West Phoenix steam units (108,300 kW) are currently mothballed.

Reserve Margin

Our 1999 peak one-hour demand on our electric system was recorded on August 24, 1999 at 4,934,700 kW, compared to the 1998 peak of 5,027,000 kW recorded on July 16. Taking into account additional capacity then available to us under traditional long-term purchase power contracts as well as our own generating capacity, our capability of meeting system demand on August 24, 1999, amounted to 4,754,600 kW, for an installed reserve margin of (4.4%). The power actually available to us from our resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 1999 peak amounted to 3,587,100 kW, for a margin of (27.5%). Firm purchases, including short-term seasonal purchases, totaling 1,643,000 kW were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 9.1%.

Plant Sites Leased from Navajo Nation

Leases NGS and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. These are long term agreements with options to extend, and we do not believe that the risk with respect to enforcement of these easements and leases is material. The majority of coal contracted for use in these plants and certain associated transmission lines are also located on Indian reservations. See "Generating Fuel and Purchased Power — Coal Supply" in Item 1.

Tax and Royalty See "Generating Fuel and Purchased Power – Coal Supply" in Item 1 for a discussion of changes in the amount of royalty payments and expiration of tax waivers under the NGS and Four Corners leases.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 9 of Notes to Financial Statements in Item 8 for a discussion of three sale and leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize us, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

The NRC recently amended its rules on financial assurance requirements for the decommissioning of nuclear power plants. The amended rules became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. We currently rely on the external sinking fund mechanism to meet the NRC financial assurance requirements for our interests in Palo Verde Units 1, 2, and 3. The decommissioning costs of Palo Verde Units 1, 2, and 3 are currently included in ACC jurisdictional rates. ACC rules regarding the introduction of retail electric competition in Arizona (see Note 3 of Notes to Financial Statements) currently provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow us to maintain our external sinking fund mechanism. See Note 2 of Notes to Financial Statements in Item 8 for additional information about our nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters

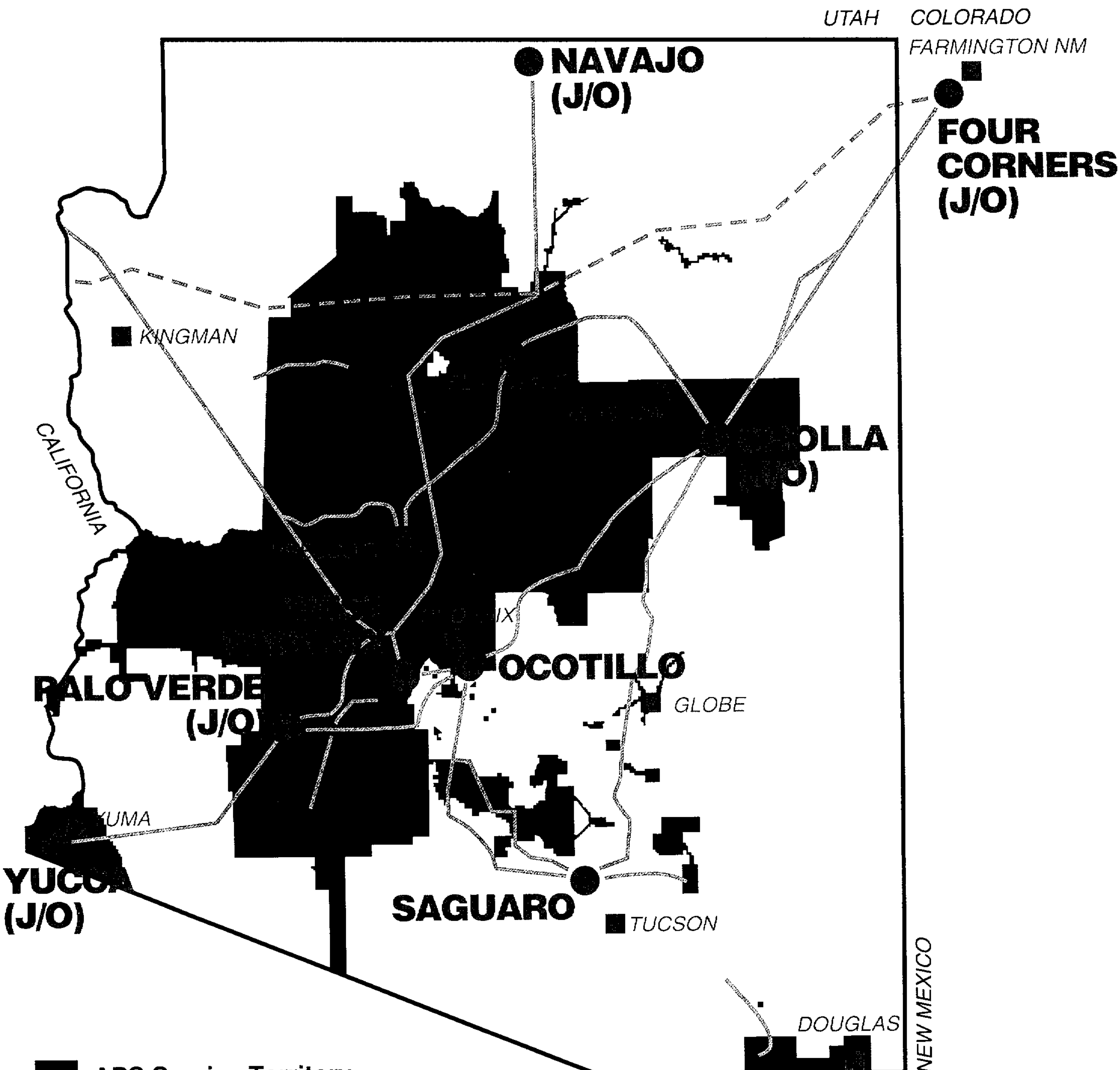
See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including us, for Palo Verde.

Other Information Regarding Our Properties

See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of our power plants.

See "Construction Program" in Item 1 and "Financial Review — Capital Needs and Resources" in Item 7 for a discussion of our construction plans.

See Notes 5, 8, and 9 of Notes to Financial Statements in Item 8 with respect to our property not held in fee or held subject to any major encumbrance.



- APS Service Territory
- Major APS Power Plants (J/O = Joint Ownership)
- Principal APS Transmission Lines
- Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

In June 1999, the Navajo Nation served Salt River Project with a lawsuit naming Salt River Project, several Peabody Coal Company entities ("Peabody"), Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo and Mohave Generating Stations. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS. We are a 14% owner of Navajo Generating Station, which Salt River Project operates. The suit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands" arising out of the [primary coal lease]. Salt River Project has advised us that it denies all charges and will vigorously defend itself. Because the litigation is in preliminary stages, we cannot currently predict the outcome of this matter.

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See "Regulatory Matters" in Note 3 of Notes to Financial Statements in Item 8 for a discussion of competition and the rules regarding the introduction of retail electric competition in Arizona and related litigation. In December 1999, we filed a lawsuit to protect our legal rights regarding the rules, and in the complaint we asked the Court for (i) a judgment vacating the retail electric competition rules, (ii) a declaratory judgment that the rules are unlawful because, among other things, they were entered into without proper legal authorization, and (iii) a permanent injunction barring the ACC from enforcing or implementing the rules and from promulgating any other regulations without lawful authority. Arizona Public Service Company v. Arizona Corporation Commission, CV 99-21907. On August 28, 1998, we filed two lawsuits to protect our legal rights under the stranded cost order and in its complaints the Company asked the Court to vacate and set aside the order. Arizona Public Service Company v. Arizona Corporation Commission, CV 98-15728. Arizona Public Service Company v. Arizona Corporation Commission, 1-CA-CC-98-0008.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED SECURITY HOLDER MATTERS

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

The chart below sets forth the dividends declared on the Company's common stock for each of the four quarters for 1999 and 1998.

Common Stock Dividends
(Thousands of Dollars)

Quarter	1999	1998
1st Quarter	$42,500	$42,500
2nd Quarter	42,500	42,500
3rd Quarter	42,500	42,500
4th Quarter	42,500	42,500

After payment or setting aside for payment of cumulative dividends and mandatory sinking fund requirements, where applicable, on all outstanding issues of preferred stock, the holders of common stock are entitled to dividends when and as declared out of funds legally available therefor. See Note 5 of Notes to Financial Statements in Item 8 for restrictions on retained earnings available for the payment of common stock dividends.

ITEM 6. SELECTED FINANCIAL DATA

	1999	1998	1997	1996	1995
			(Thousands of Dollars)		
Electric Operating Revenues	$2,292,798	$2,006,398	$1,878,553	$1,718,272	$1,614,952
Fuel Expenses	795,494	545,297	443,571	329,489	275,487
Operating Expenses	1,108,380	1,090,290	1,063,157	1,023,575	957,711
Operating Income	388,924	370,811	371,825	365,208	381,754
Other Income	20,990	20,448	21,586	35,217	25,548
Interest Deductions — Net	141,592	136,012	141,918	156,954	167,732
Income Before Extraordinary Charge	268,322	255,247	251,493	243,471	239,570
Extraordinary Charge – Net of Tax	139,885	--	--	--	--
Net Income	128,437	255,247	251,493	243,471	239,570
Preferred Dividends	1,016	9,703	12,803	17,092	19,134
Earnings for Common Stock	$ 127,421	$ 245,544	$ 238,690	$ 226,379	$ 220,436
Total Assets	$6,117,624	$6,393,299	$6,331,142	$6,423,222	$6,418,262
Capital Structure:					
Common Stock Equity	$1,983,174	$1,975,755	$1,849,324	$1,729,390	$1,621,555
Non-Redeemable Preferred Stock	--	85,840	142,051	165,673	193,561
Redeemable Preferred Stock	--	9,401	29,110	53,000	75,000
Long-Term Debt Less Current Maturities	1,997,400	1,876,540	1,953,162	2,029,482	2,132,021
Total Capitalization	3,980,574	3,947,536	3,973,647	3,977,545	4,022,137
Commercial Paper	38,300	178,830	130,750	16,900	177,800
Current Maturities of Long-Term Debt	114,711	164,378	104,068	153,780	3,512
Total	$4,133,585	$4,290,744	$4,208,465	$4,148,225	$4,203,449

See "Financial Review" in Item 7 for a discussion of certain information in the foregoing table.

ITEM 7. FINANCIAL REVIEW

In this section, we explain our results of operations, general financial condition, and outlook, including:

- the changes in our earnings from 1998 to 1999 and from 1997 to 1998
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results and outlook
- our capital needs and resources and
- our management of market risks.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Financial Statements that begin on page 30. These Notes add further details to the discussion.

Results of Operations

1999 Compared with 1998. Our 1999 earnings decreased $118 million from 1998 earnings primarily because of the effects of a $140 million after-tax extraordinary charge for a regulatory disallowance related to our comprehensive Settlement Agreement that was approved by the Arizona Corporation Commission (ACC) in September 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the regulatory disallowance and the Settlement Agreement. Earnings excluding the extraordinary charge increased $21 million – a 9% increase - over 1998 earnings primarily because of increases in the number of customers and in the average amount of electricity used by customers and lower financing costs. These positive impacts more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See Note 3 for additional information about the price reductions.

In 1999, electric operating revenues increased $286 million primarily because of:

- increased power marketing and trading revenues ($219 million)
- increases in the number of customers and the average amount of electricity used by customers ($81 million) and
- miscellaneous factors ($8 million).

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

The increase in power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power 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 $18 million primarily because of $19 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were more than offset by lower employee benefit costs and movement of certain marketing functions to APS Energy Services in early 1999.

1998 Compared with 1997. Our 1998 earnings increased $7 million – a 3% increase - over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, the prior year's benefits of the two fuel-related settlements recorded in 1997, and retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the average amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

The increase in power marketing revenues resulted from higher prices and increased activity in western U.S. bulk power markets. The revenue increases were accompanied by an increase in purchased power expenses. These activities contributed positively to earnings in both periods; the contribution in 1998 was higher than in 1997.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $13 million primarily because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because we had more plant in service.

Financing costs decreased by $9 million primarily because of lower amounts of outstanding debt and preferred stock.

Regulatory Agreements. Regulatory agreements approved by the ACC affect the results of our operations. The following discussion focuses on three agreements approved by the ACC: the 1999 Settlement Agreement to implement retail electric competition; a 1996 agreement that accelerated the amortization of our regulatory assets; and a 1994 settlement that included accelerated amortization of our deferred investment tax credits (ITCs).

As part of the 1999 Settlement Agreement, we reduced our rates for standard offer service for customers with loads less than 3 megawatts 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 related to the 1996 regulatory agreement (see below). For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

Also, under the Settlement Agreement a regulatory disallowance removed $234 million before income 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. Before the ACC approved the 1999 Settlement Agreement, we were recovering substantially all of our regulatory assets through accelerated amortization over an eight-year period that would end June 30, 2004 under the 1996 agreement. For more details, see Note 1.

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

(Millions of Dollars)

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

Also, as part of the 1996 regulatory agreement, we reduced our 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). We also agreed to share future cost savings with our customers during the term of the 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, which was included in the July 1, 1999 1.5% price reduction under the 1999 Settlement Agreement.

Capital Needs and Resources

Our capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. We pay for our capital requirements with cash from our operations and, to the extent necessary, external financing.

As part of the 1996 regulatory agreement, we received annual cash infusions from Pinnacle West of $50 million from 1996 through 1999. During the period from 1997 through 1999, we paid for all of our capital expenditures with cash from our operations. We expect to do so in 2000 through 2002 as well.

Our capital expenditures in 1999 were $332 million. Our projected capital expenditures for the next three years are: $384 million in 2000; $342 million in 2001; and $334 million in 2002. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

During 1999, we redeemed about $323 million of long-term debt and $96 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. We no longer have any outstanding preferred stock. Our long-term debt redemption requirements and payment obligations on a capitalized lease for the next three years are approximately: $115 million in 2000; $253 million in 2001; and $125 million in 2002. In addition, we made optional redemptions of about $89 million of long-term debt in January 2000. Based on market conditions and optional call provisions, we may make optional redemptions of long-term debt from time to time.

As of December 31, 1999, we had credit commitments from various banks totaling about $350 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1999, we had about $38 million of commercial paper and $50 million of long-term bank borrowings outstanding.

In February 1999, we issued $125 million of unsecured long-term debt and in November 1999, we issued $250 million of unsecured long-term debt.

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

Competition and Industry Restructuring

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. See "Results of Operations – Regulatory Agreements" and Note 3 for additional information about our Settlement Agreement with the ACC related to the implementation of retail electric competition, the ACC rules that provide a framework for the introduction of retail electric competition in Arizona, and other competitive developments, including an agreement with Salt River Project.

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 a discussion of legislative developments.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. 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.

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 its financial statements. As a result of our Settlement Agreement (see Note 3), we discontinued the application of SFAS No. 71 for our generation operations. This meant that the generation assets were tested for impairment and the portion of the regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. We determined that the generation assets were not impaired. A regulatory disallowance ($140 million after income taxes) was reported as an extraordinary charge on the income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the Settlement Agreement.

Year 2000 Readiness Disclosure

Some companies expected to face problems on January 1, 2000 in the case that computer systems and equipment would not properly recognize calendar dates. During 1997, we had initiated a comprehensive company-wide Year 2000 program to review and resolve all Year 2000 issues in mission critical systems in a timely manner to ensure the reliability of electric service to our customers. We have spent about $5 million to be Year 2000 ready. To date, we have not experienced any material Year 2000 related problems, and we do not anticipate any in the future.

Accounting Matters

We describe a new standard on accounting for derivatives in Note 2. The new standard on derivatives is effective for us in 2001. We are currently evaluating what impact it will have on our financial statements. 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.

Risk Management

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, 1999 and December 31, 1998. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 1999 and December 31, 1998.

Expected Maturity/Principal Repayment
December 31, 1999
(Thousands of Dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2000	5.33%	$ 38,300	--	$ --	5.79%	$ 114,711
2001	--	--	6.85%	250,000	7.48%	2,488
2002	--	--	--	--	8.13%	125,000
2003	--	--	5.50%	50,000	--	--
2004	--	--	--	--	6.17%	205,000
Years thereafter	--	--	3.15%	476,860	7.87%	895,148
Total		$ 38,300		$ 776,860		$1,342,347
Fair value		$ 38,300		$ 776,860		$1,312,423

Expected Maturity/Principal Repayment
December 31, 1998
(Thousands of Dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
1999	5.88%	$ 178,830	--	$ --	7.24%	$ 164,378
2000	--	--	--	--	5.79%	114,711
2001	--	--	--	--	7.48%	2,488
2002	--	--	--	--	8.13%	125,000
2003	--	--	5.94%	125,000	-	--
Years thereafter	--	--	3.39%	456,860	7.75%	1,058,963
Total		$ 178,830		$ 581,860		$1,465,540
Fair value		$ 178,830		$ 581,860		$1,525,900

Commodity Price Risk. We are exposed to the impact of market fluctuations in the price and distribution costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage our 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 these derivative transactions for trading and to hedge certain natural gas in storage as well as purchases and sales of electricity, fuels, and emissions allowances/credits.

As of December 31, 1999, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would decrease the fair market value of these contracts by approximately $6 million. This analysis does not include the favorable impact this same hypothetical price move would have on the underlying position being hedged with the commodity derivative portfolio.

We are exposed to credit losses in the event of non-performance or non-payment by counterparties. We use a credit management process to assess and monitor our financial exposure to counterparties. We do not expect counterparty defaults to materially impact our financial condition, results of operations, or net cash flow.

Forward-Looking Statements

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; our ability to successfully compete outside our traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; and Year 2000 issues.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

See "Financial Review" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

See Note 14 of Notes to Financial Statements for the selected quarterly financial data required to be presented in this Item.

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. Such information was prepared in accordance with generally accepted accounting principles 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 accounting controls. A limiting factor in all systems of internal accounting 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 accounting 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.

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
Chief Executive Officer

Chris N. Froggatt
Vice President and Controller
Pinnacle West Capital Corporation

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying balance sheets of Arizona Public Service Company as of December 31, 1999 and 1998 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1999 and 1998 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Phoenix, Arizona
February 18, 2000

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME

	Year Ended December 31, 1999	1998	1997
	(Thousands of Dollars)		
Electric Operating Revenues	$2,292,798	$ 2,006,398	$ 1,878,553
Fuel Expenses:			
Fuel for electric generation	243,849	231,967	201,341
Purchased power	551,645	313,330	242,230
Total	795,494	545,297	443,571
Operating Revenues Less Fuel Expenses	1,497,304	1,461,101	1,434,982
Other Operating Expenses:			
Operations and maintenance excluding fuel expenses	437,729	419,433	406,025
Depreciation and amortization (Note 1)	382,057	376,574	365,671
Income taxes (Note 10)	192,015	192,207	184,737
Other taxes	96,579	102,076	106,724
Total	1,108,380	1,090,290	1,063,157
Operating Income	388,924	370,811	371,825
Other Income (Deductions):			
Income taxes (Note 10)	32,527	32,751	31,413
Other — net	(11,537)	(12,303)	(9,827)
Total	20,990	20,448	21,586
Income Before Interest Deductions	409,914	391,259	393,411
Interest Deductions:			
Interest on long-term debt	132,676	137,214	140,931
Interest on short-term borrowings	8,272	7,481	9,404
Debt discount, premium and expense	7,323	7,580	7,791
Capitalized interest	(6,679)	(16,263)	(16,208)
Total	141,592	136,012	141,918
Income Before Extraordinary Charge	268,322	255,247	251,493
Extraordinary Charge – net of income taxes of $94,115 (Note 1)	139,885	--	--
Net Income	128,437	255,247	251,493
Preferred Stock Dividend Requirements	1,016	9,703	12,803
Earnings for Common Stock	$ 127,421	$ 245,544	$ 238,690

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
ASSETS

	December 31, 1999	December 31, 1998
	(Thousands of Dollars)	
Utility Plant (Notes 5, 8 and 9):		
Electric plant in service and held for future use	$ 7,545,575	$ 7,265,604
Less accumulated depreciation and amortization	3,026,041	2,814,762
Total	4,519,534	4,450,842
Construction work in progress	184,764	228,643
Nuclear fuel, net of amortization of $66,357 and $68,569	49,114	51,078
Utility Plant — net	4,753,412	4,730,563
Investments and Other Assets (Note 13)	208,457	183,549
Current Assets:		
Cash and cash equivalents	7,477	5,558
Accounts receivable:		
Service customers	201,704	205,999
Other	35,684	23,213
Allowance for doubtful accounts	(1,538)	(1,725)
Accrued utility revenues	72,919	67,740
Materials and supplies (at average cost)	69,977	69,074
Fossil fuel (at average cost)	21,869	13,978
Deferred income taxes (Note 10)	8,163	3,999
Other	30,885	26,695
Total Current Assets	447,140	414,531
Deferred Debits:		
Regulatory assets (Note 1)	613,729	980,084
Unamortized debt issue costs	15,172	14,916
Other	79,714	69,656
Total Deferred Debits	708,615	1,064,656
Total	$ 6,117,624	$ 6,393,299

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
LIABILITIES

	December 31,	
	1999	1998
	(Thousands of Dollars)	
Capitalization (Notes 4 and 5):		
Common stock	$ 178,162	$ 178,162
Additional paid - in capital	1,246,804	1,195,625
Retained earnings	558,208	601,968
Common stock equity	1,983,174	1,975,755
Non-redeemable preferred stock	--	85,840
Redeemable preferred stock	--	9,401
Long-term debt less current maturities	1,997,400	1,876,540
Total Capitalization	3,980,574	3,947,536
Current Liabilities:		
Commercial paper (Note 6)	38,300	178,830
Current maturities of long-term debt (Note 5)	114,711	164,378
Accounts payable	170,662	145,139
Accrued taxes	62,858	59,827
Accrued interest	32,299	31,218
Customer deposits	24,682	26,815
Other	26,248	16,755
Total Current Liabilities	469,760	622,962
Deferred Credits and Other:		
Deferred income taxes (Note 10)	1,178,085	1,312,007
Deferred investment tax credit (Note 10)	4,839	32,465
Unamortized gain — sale of utility plant (Note 9)	73,212	77,787
Customer advances for construction	38,150	31,451
Other	373,004	369,091
Total Deferred Credits and Other	1,667,290	1,822,801
Commitments and Contingencies (Note 12)		
Total	$ 6,117,624	$ 6,393,299

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999	1998	1997
	(Thousands of Dollars)		
Cash Flows from Operations:			
Net income	$128,437	$ 255,247	$ 251,493
Items not requiring cash:			
Depreciation and amortization	382,057	376,574	365,671
Nuclear fuel amortization	31,371	32,856	32,702
Deferred income taxes — net	(29,654)	(26,374)	(55,278)
Deferred investment tax credit — net	(27,626)	(27,628)	(27,630)
Extraordinary Charge — net of income taxes	139,885	--	--
Changes in certain current assets and liabilities:			
Accounts receivable — net	(8,363)	(56,490)	(11,069)
Accrued utility revenues	(5,179)	(9,181)	(3,089)
Materials, supplies and fossil fuel	(8,794)	(2,797)	7,793
Other current assets	(4,190)	(2,166)	(1,762)
Accounts payable	22,992	33,731	(56,710)
Accrued taxes	3,031	(26,059)	(441)
Accrued interest	1,081	(442)	(7,455)
Other current liabilities	7,833	(4,654)	(3,997)
Other — net	(4,922)	(29,641)	46,625
Net cash provided	627,959	512,976	536,853
Cash Flows from Investing:			
Capital expenditures	(322,547)	(319,142)	(307,876)
Capitalized interest	(6,679)	(16,263)	(16,208)
Other	(8,173)	(8,593)	(15,982)
Net cash used	(337,399)	(343,998)	(340,066)
Cash Flows from Financing:			
Long-term debt	392,952	126,245	109,906
Short-term borrowings — net	(140,530)	48,080	113,850
Common equity infusion from parent	50,000	50,000	50,000
Dividends paid on common stock	(170,000)	(170,000)	(170,000)
Dividends paid on preferred stock	(1,393)	(10,279)	(13,307)
Repayment of preferred stock	(96,499)	(75,517)	(47,201)
Repayment and reacquisition of long-term debt	(323,171)	(144,501)	(240,004)
Net cash used	(288,641)	(175,972)	(196,756)
Net increase (decrease) in cash and cash equivalents	1,919	(6,994)	31
Cash and cash equivalents at beginning of year	5,558	12,552	12,521
Cash and cash equivalents at end of year	$ 7,477	$ 5,558	$ 12,552
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest (excluding capitalized interest)	$132,995	$128,627	$ 141,991
Income taxes	$189,002	$235,475	$ 236,676

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1999	1998	1997
	(Thousands of Dollars)		
Retained earnings at beginning of year	$ 601,968	$ 528,798	$ 460,106
Add: Net income	128,437	255,247	251,493
Total	730,405	784,045	711,599
Deduct:			
Dividends:			
Common stock (Notes 4 and 5)	170,000	170,000	170,000
Preferred stock (at required rates) (Note 4)	1,016	9,703	12,801
Other	1,181	2,374	--
Total deductions	172,197	182,077	182,801
Retained earnings at end of year	$ 558,208	$ 601,968	$ 528,798

See Notes to Financial Statements.

APS
NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Operations. We are Arizona's largest electric utility, with approximately 827,000 customers. We provide retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area. We also generate, sell and deliver electricity and energy-related products and services to wholesale and retail customers in the western United States.

Accounting Records. Our accounting records are maintained in accordance with generally accepted accounting principles (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. We are regulated by the ACC and the Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the rate-making policies of these commissions. For our regulated operations, 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 its financial statements.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (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.

In September 1999, our Settlement Agreement was approved by the ACC (see Note 3 for a discussion of the agreement). We have discontinued the application of SFAS No. 71 for our generation operations. This means that the generation assets were tested for impairment and the portion of regulatory assets that were deemed to be unrecoverable through ongoing regulated cash flows was eliminated. We determined that the generation assets were not impaired. 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. Prior to the 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 this Settlement Agreement are now being amortized as follows:

(Millions of Dollars)

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

The majority of our regulatory assets relate to deferred income taxes (see Note 10) 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:

(Thousands of Dollars)

	December 31, 1999	December 31, 1998
Electric plant in service and held for future use	$ 3,770,234	$ 3,680,482
Accumulated depreciation and amortization	(1,817,589)	(1,681,099)
Construction work in progress	67,306	107,324
Nuclear fuel, net of amortization	49,114	51,078

Common Stock All of the outstanding shares of our common stock are owned by Pinnacle West (see Note 4).

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.

Utility Plant and Depreciation Utility plant is the term we use to describe the business property and equipment that supports electric service. 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 1997 through 1999 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1999 was 3.34%. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Capitalized Interest Capitalized interest represents the cost of debt funds used to finance construction of utility plant. 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 6.65% for 1999, 6.88% for 1998, and 7.25% for 1997.

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 We charge 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. We divide the cost of the fuel by the estimated number of thermal units that we expect to produce with that fuel. We then multiply that rate by the number of thermal units that we produce within the current period. This calculation determines the current period nuclear fuel expense.

We also charge 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 us $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.

Reacquired Debt Costs For debt related to the regulated portion of our business, we amortize gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, we are 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.

Cash and Cash Equivalents For purposes of reporting cash flows, we define cash equivalents as highly liquid investments that will mature in three months or less.

Reclassifications We reclassified certain prior year amounts for comparison purposes with the 1999 presentation.

2. Accounting Matters

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2001. 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. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

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 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

Settlement Agreement. On May 14, 1999, we 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 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the Settlement Agreement. One of the parties questioned the authority of the ACC to approve the Settlement Agreement and both parties challenged several specific provisions of the Settlement Agreement.

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

- We will reduce rates for standard offer service for customers with loads less than 3 megawatts 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) includes the July 1, 1999 retail price decrease of approximately $11 million annually ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. For customers having loads 3 megawatts or greater, standard offer rates will be reduced in annual increments that total 5% through 2002.

- Unbundled rates being charged by us for competitive direct access service (for example, distribution services) became effective upon approval of the Settlement Agreement, retroactive to July 1, 1999, and also will be 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 the Company 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 our cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.

- We 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 our "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.

- Our distribution system opened for retail access effective September 24, 1999. Customers will be 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), with an additional 140 megawatts being made available to eligible non-residential customers. Unless subject to judicial or regulatory restraint, we will open our distribution system to retail access for all customers on January 1, 2001.

- Prior to the Settlement Agreement, we were recovering substantially all of our regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the Settlement Agreement states that we have demonstrated that our allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value. We will not be allowed to recover $183 million net present value of the above amounts. The Settlement Agreement provides that we 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 will be credited/debited against the costs subject to recovery under the adjustment clause described above.

- We will form a separate corporate affiliate or affiliates and transfer to that affiliate(s) our 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. We will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of our costs to accomplish the required transfer of generation assets to an affiliate.

- When the Settlement Agreement approved by the ACC is no longer subject to judicial review, we will move to dismiss all of our litigation pending against the ACC as of the date we entered into the Settlement Agreement. To protect our rights, we have 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 Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," 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 (Rules). If any of the Rules conflict with the Settlement Agreement, the terms of the Settlement Agreement govern. On December 8, 1999, we filed a lawsuit to protect our legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery and the adoption or amendment of the Rules, but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions. On January 14, 2000, a special action was filed requesting the Arizona Supreme Court to enjoin implementation of the Rules and decide whether the ACC can allow the competitive marketplace, rather than the ACC, to set just and reasonable rates under the Arizona Constitution. The issue of competitively set rates has been decided by lower Arizona courts in favor of the ACC in four separate lawsuits, two of which relate to telecommunications companies. The Supreme Court denied to hear the case as a special action on March 17, 2000. The lower court litigation will continue.

The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including us.

- The Rules require each affected utility, including us, to make available at least 20% of its 1995 system retail peak demand for competitive generation supply beginning when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever is earlier, and 100% beginning January 1, 2001. Under the Settlement Agreement, the Company will provide retail access to customers representing the minimum 20% required by the ACC and an additional 140 megawatts of non-residential load in 1999, and to all customers as of January 1, 2001, or such other dates as approved by the ACC.

- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date, which for the Company's customers was the approval of the Settlement Agreement. Customers may also aggregate smaller loads to meet this one megawatt requirement.

- When effective, residential customers will be phased in at 1.25% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.

- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) 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 Settlement Agreement, the Company received a waiver to allow transfer of its competitive generation assets and services to affiliates no later than December 31, 2002.

1996 Regulatory Agreement. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and us. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases of approximately $49 million ($29 million after income taxes), or 3.4%, effective July 1, 1996; approximately $18 million ($11 million after income taxes), or 1.2%, effective July 1, 1997; approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998; and approximately $11 million ($7 million after income taxes), or 0.7%, effective as of July 1, 1999. The July 1, 1999 rate decrease was included in the first rate reduction under the Settlement Agreement discussed above. The regulatory agreement also required Pinnacle West to infuse $200 million of common equity into us 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 megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999-2000 legislative session on certain competitive issues.

General

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

Federal

The Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. We do not expect these rules to have a material impact on our financial statements.

Several electric utility industry restructuring bills have been introduced during the 106th Congress. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2000 and beyond. These bills, other bills that 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.

Agreement with Salt River Project

On April 25, 1998, we entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The ACC approved the Agreement on February 18, 1999. The Agreement contains the following major components:

- Both parties amended the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.
- Both parties amended the Power Coordination Agreement to lower the price that we pay Salt River Project for purchased power. During 1999, the price we paid Salt River Project for purchased power was reduced by approximately $3 million (pretax) and we estimate the decrease to be approximately $16 million (pretax) in 2000 and annual lesser amounts through 2006.
- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal levels.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) became effective upon the introduction of competition. See "Settlement Agreement" and "ACC Rules" above.

4. Common and Preferred Stocks

On March 1, 1999, we redeemed all of our preferred stock. Common and preferred stock balances at December 31, 1999 and 1998 are shown below:

	Authorized	Number of Shares Outstanding 1999	Number of Shares Outstanding 1998	Par Value Per Share	Par Value Outstanding 1999 (Thousands of Dollars)	Par Value Outstanding 1998 (Thousands of Dollars)
Common Stock	100,000,00	71,264,947	71,264,947	$2.50	$178,162	$178,162
Preferred Stock:						
Non-Redeemable:						
$1.10	160,000	--	139,030	$25.00	$ --	$ 3,476
$2.50	105,000	--	86,440	50.00	--	4,322
$2.36	120,000	--	32,520	50.00	--	1,626
$4.35	150,000	--	62,986	100.00	--	6,299
Serial preferred...............	1,000,000					
$2.40 Series A		--	200,587	50.00	--	10,029
$2.625 Series C...........		--	214,895	50.00	--	10,745
$2.275 Series D		--	90,691	50.00	--	4,534
$3.25 Series E...........			304,475	50.00	--	15,224
Serial preferred..............	4,000,000					
Adjustable rate — Series Q..................		--	295,851	100.00	--	29,585
Total........................		--	1,427,475		$ --	$ 85,840
Redeemable:						
Serial preferred:						
$10.00 Series U		--	94,011	$100.00	$ --	$ 9,401

Redeemable preferred stock transactions during each of the three years in the period ended December 31, 1999 are as follows:

Description	Number of Shares Outstanding 1999	Number of Shares Outstanding 1998	Number of Shares Outstanding 1997	Par Value Outstanding (Thousands of Dollars) 1999	Par Value Outstanding (Thousands of Dollars) 1998	Par Value Outstanding (Thousands of Dollars) 1997
Balance, January 1	94,011	291,098	530,000	$ 9,401	$29,110	$53,000
Retirements:						
$10.00 Series U..................	(94,011)	(197,087)	(118,902)	(9,401)	(19,709)	(11,890)
$7.875 Series V..................	--	--	(120,000)	--	--	(12,000)
Balance, December 31..............	--	94,011	291,098	$ --	$ 9,401	$29,110

5. Long-Term Debt

The following table presents the components of long-term debt outstanding at December 31, 1999 and December 31, 1998:

	Maturity Dates (a)	Interest Rates	December 31 1999	1998
			(Thousands of Dollars)	
First mortgage bonds	1999	7.625%	$ --	$100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	80,000	85,000
	2020	10.25%	100,550	100,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	70,650	91,900
	2024	8.75%	121,668	121,668
	2025	8%	47,075	88,300
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(5,860)	(6,482)
Pollution control bonds	2024-2034	Adjustable rate (b)	476,860	456,860
Funds held in trust account for certain pollution control bonds			(1,236)	--
Collateralized loan	1999-2000	5.375% - 6.125%	10,000	20,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2004	5.875%	125,000	--
Floating rate notes	2001	Adjustable rate (c)	250,000	
Senior notes(d)	1999	6.72%	--	50,000
Senior notes(d)	2006	6.75%	83,695	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate (e)	50,000	125,000
Capitalized lease obligation	1999-2001	7.48% (f)	7,199	11,612
Total long-term debt			2,112,111	2,040,918
Less current maturities			114,711	164,378
Total long-term debt less current maturities			$1,997,400	$1,876,540

(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, 1999 was 3.15% and for December 31, 1998 was 3.39%. 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, 1999 was 6.8525%.*

(d) *We currently have 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. Our payments of principal, premium, and/or interest on the senior notes satisfy our 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 we repay all of our 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, 1999 was 5.50% and for December 31, 1998 was 5.94%. Changes in short-term interest rates would affect the costs associated with this debt.*

(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 (see Note 9).*

Principal payments due on total long-term debt and sinking fund requirements over the next five years are approximately:

- $115 million in 2000
- $253 million in 2001
- $125 million in 2002
- $50 million in 2003 and
- $205 million in 2004.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1999.

6. Lines of Credit

We had committed lines of credit with various banks of $350 million at December 31, 1999 and $400 million at December 31, 1998, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1999 and 1998 for these lines of credit ranged from 0.07% to 0.125% per annum. We had long-term bank borrowings of $50 million outstanding at December 31, 1999 and $125 million outstanding at December 31, 1998.

Our commercial paper borrowings outstanding were $38 million at December 31, 1999 and $179 million at December 31, 1998. The weighted average interest rate on commercial paper borrowings was 5.33% for the year ended December 31, 1999 and 5.88% for December 31, 1998. By Arizona statute, our short-term borrowings cannot exceed 7% of our total capitalization unless approved by the ACC.

7. 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, 1999 and 1998 due to their short maturities. We hold investments in debt and equity securities for purposes other than trading. The December 31, 1999 and 1998 fair values of such investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amounts.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.10 billion on December 31, 1999, with an estimated fair value of $2.08 billion. On December 31, 1998, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.03 billion, with an estimated fair value of $2.11 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

8. Jointly-Owned Facilities

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities at December 31, 1999. Our share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(Thousands of Dollars)		
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,829,633	$ 751,567	$7,220
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	572,574	240,696	17,145
Four Corners Steam Generating Station Units 4 and 5	15.0%	139,209	71,333	364
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	230,536	94,332	4,555
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	68,643	38,068	1,679
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,133	21,446	7
Navajo Southern System	31.4%(b)	27,364	17,550	42
Palo Verde-Yuma 500KV System	23.9%(b)	11,728	4,388	36
Four Corners Switchyards	27.5%(b)	3,071	1,855	--
Phoenix-Mead System	17.1%(b)	36,434	1,768	--

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

(b) *Weighted average of interests.*

9. Leases

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. We account 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 $46 million in 2000 and approximately $49 million per year in 2001-2015.

In accordance with the 1999 Settlement Agreement, we are continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004. The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 1999 was $43 million. Lease expense was approximately $42 million in each of the years 1997 through 1999.

We have a capital lease on a combined cycle plant, which we sold and leased back. The lease requires semiannual payments of $3 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54 million; accumulated amortization at December 31, 1999 was $51 million.

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

Miscellaneous lease expense was approximately $7 million in 1999, $10 million in 1998 and $8 million in 1997.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

Year	(Dollars in Millions)
2000	$ 13
2001	14
2002	14
2003	14
2004	14
Thereafter	82
Total future commitments	$ 151

10. Income Taxes

We are included in Pinnacle West's consolidated tax return. However, when Pinnacle West allocates income taxes to us, it does so based on our taxable income or loss alone. Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our investment tax credits (ITCs) over a five-year period (1995-1999).

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.

We have recorded a regulatory asset related to income taxes on our 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. We amortize this amount as the differences reverse. In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the regulatory asset for income taxes over an eight-year period that will end on June 30, 2004. We have included this accelerated amortization in depreciation and amortization expense on the Statements of Income.

The components of income tax expense for income before the extraordinary charge are as follows:

	Year Ended December 31,		
	1999	1998	1997
	(Thousands of Dollars)		
Current:			
Federal	$ 175,227	$170,806	$187,701
State	41,541	42,652	48,531
Total current	216,768	213,458	236,232
Deferred	(29,654)	(26,374)	(55,278)
Investment tax credit amortization	(27,626)	(27,628)	(27,630)
Total expense	$ 159,488	$159,456	$153,324

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

	Year Ended December 31,		
	1999	1998	1997
	(Thousands of Dollars)		
Federal income tax expense at 35% statutory rate	$ 149,710	$145,146	$141,686
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	14,575	17,848	14,694
Investment tax credit amortization	(27,626)	(27,628)	(27,630)
State income tax — net of federal income tax benefit	24,135	23,024	23,160
Other	(1,306)	1,066	1,414
Income tax expense	$ 159,488	$ 159,456	$ 153,324

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

	December 31,	
	1999	1998
	(Thousands of Dollars)	
Deferred tax assets:		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 29,446	$ 31,285
Other	139,518	159,432
Total deferred tax assets	168,964	190,717
Deferred tax liabilities:		
Plant related	1,104,769	1,117,253
Regulatory assets	234,117	381,472
Total deferred tax liabilities	1,338,886	1,498,725
Deferred income taxes — net	$1,169,922	$1,308,008

11. Retirement Plans and Other Benefits

Pension Plan. Through 1999, we sponsored a defined benefit pension plan for our employees. As of January 1, 2000, this plan is now sponsored by Pinnacle West. 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 this plan 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, 1999 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- $4 million in 1999
- $10 million in 1998 and
- $9 million in 1997.

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

	1999	1998	1997
		(Thousands of Dollars)	
Service cost — benefits earned during the period	$24,266	$24,126	$19,881
Interest cost on projected benefit obligation	52,208	50,863	47,824
Expected return on plan assets	(67,528)	(53,883)	(47,422)
Amortization of:			
Transition asset	(3,216)	(3,216)	(3,216)
Prior service cost	2,063	2,063	2,063
Net periodic pension cost	$ 7,793	$19,953	$19,130

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

	1999	1998
	(Thousands of Dollars)	
Funded status — Pension plan assets more than (less than) projected benefit obligation	$ 37,784	$ (38,957)
Unrecognized net transition asset	(19,943)	(23,159)
Unrecognized prior service cost	20,499	22,562
Unrecognized net actuarial gains	(99,602)	(38,916)
Net pension liability recognized in the balance sheets	$ (61,262)	$ (78,470)

The following table sets forth the defined benefit pension plan's change in projected benefit obligation for the plan years 1999 and 1998:

	1999	1998
	(Thousands of Dollars)	
Projected pension benefit obligation at beginning of year	$721,229	$699,600
Service cost	24,266	24,126
Interest cost	52,208	50,863
Benefit payments	(29,444)	(29,384)
Actuarial gains	(35,348)	(23,976)
Projected pension benefit obligation at end of year	$732,911	$721,229

The following table sets forth the defined benefit pension plan's change in the fair value of plan assets for the plan years 1999 and 1998:

	1999	1998
	(Thousands of Dollars)	
Fair value of pension plan assets at beginning of year	$ 682,272	$ 612,392
Actual return on plan assets	92,867	85,764
Employer contributions	25,000	13,500
Benefit payments	(29,444)	(29,384)
Fair value of pension plan assets at end of year	$ 770,695	$ 682,272

	1999	1998
We made the assumptions below to calculate the pension liability:		
Discount rate	7.75%	7.00%
Rate of increase in compensation levels	4.25%	3.50%
Expected long-term rate of return on assets	10.00%	10.00%

Employee Savings Plan Benefits. Through 1999, we sponsored a defined contribution savings plan for nearly all of our employees. As of January 1, 2000, this plan is now sponsored by Pinnacle West and covers nearly all of our employees. 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 each of the last three years (1997-1999).

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:

- $6 million for 1999
- $9 million for 1998 and
- $9 million for 1997.

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

	1999	1998	1997
		(Thousands of Dollars)	
Service cost — benefits earned during the period	$ 8,676	$ 7,676	$ 6,865
Interest cost on accumulated benefit obligation	17,188	15,610	14,315
Expected return on plan assets	(18,454)	(12,001)	(8,706)
Amortization of:			
Transition obligation	7,652	7,652	7,652
Net actuarial gains	(5,095)	(2,927)	(2,647)
Net periodic postretirement benefit cost	$ 9,967	$16,010	$17,479

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

	1999	1998
	(Thousands of Dollars)	
Funded status — postretirement plan assets more than (less than) accumulated benefit obligation	$ 27,930	$ (21,912)
Unrecognized net obligation at transition	99,482	107,134
Unrecognized net actuarial gains	(127,338)	(86,131)
Net postretirement amount recognized in the balance sheets	$ 74	$ (909)

The following table sets forth the postretirement benefit plan's change in accumulated benefit obligation for the plan years 1999 and 1998:

	1999	1998
	(Thousands of Dollars)	
Accumulated postretirement benefit obligation at beginning of year	$235,322	$197,581
Service cost	8,675	7,676
Interest cost	17,188	15,610
Benefit payments	(8,761)	(10,347)
Actuarial (gains) losses	(22,816)	24,802
Accumulated postretirement benefit obligation at end of year	$229,608	$235,322

The following table sets forth the postretirement benefit plan's change in the fair value of plan assets for the plan years 1999 and 1998:

	1999	1998
	(Thousands of Dollars)	
Fair value of postretirement plan assets at beginning of year	$213,410	$151,146
Actual return on plan assets	42,975	47,284
Employer contributions	9,914	25,327
Benefit payments	(8,761)	(10,347)
Fair value of postretirement plan assets at end of year	$257,538	$213,410

We made the assumptions below to calculate the postretirement liability:		
Discount rate	7.75%	7.00%
Expected long-term rate of return on assets-after tax	8.77%	8.73%
Initial health care cost trend rate – under age 65	7.00%	7.50%
Initial health care cost trend rate – age 65 and over	6.00%	6.50%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would increase by approximately $5 million and the accumulated benefit obligation as of December 31, 1999 would increase by approximately $37 million.

Assuming a 1% decrease in the health care cost trend rate, the 1999 cost of postretirement benefits other than pensions would decrease by approximately $4 million and the accumulated benefit obligations as of December 31, 1999 would decrease by approximately $29 million.

12. Commitments and Contingencies

Litigation. We are a 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.

Palo Verde Nuclear Generating Station. Under the Nuclear Waste Policy Act, 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 DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including us. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision.

We have capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002, and believe we 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. We currently estimate that we will incur $113 million (in 1999 dollars) over the life of Palo Verde for our share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 1999, we had recorded a liability and regulatory asset of $37 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date. We currently believe that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

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, we 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 29.1% 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. We have 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. We are a party to various fuel and purchased power contracts with terms expiring from 2000 through 2020 that include required purchase provisions. We estimate our 2000 contract requirements to be about $177 million. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit us to decrease our required purchases under certain circumstances.

We must reimburse certain coal providers for amounts incurred for coal mine reclamation. We estimate our 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 $57 million at December 31, 1999 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 approved by the ACC, we are 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, 1999 was about $41 million.

Construction Program. Total capital expenditures in 2000 are estimated at $384 million.

13. Nuclear Decommissioning Costs

We recorded $11 million for decommissioning expense in each of the years 1999, 1998, and 1997. We estimate it will cost about $1.8 billion ($472 million in 1999 dollars) to decommission our 29.1% share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. We charge decommissioning costs to expense over each unit's operating license term and include them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

Our 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 for us. We are required to update the study every three years.

To fund the costs we expect to incur to decommission the plant, we established external trusts in accordance with Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" in our Balance Sheets at their market value of $176 million at December 31, 1999 and $146 million at

December 31, 1998. We invest the trust funds primarily in fixed-income securities and domestic stock and classify 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)

Quarterly financial information for 1999 and 1998 is as follows:

Quarter Ended	Electric Operating Revenues	Operating Income (a)	Net Income/ (Loss) (b)	Earnings/ (Loss) for Common Stock
		(Thousands of Dollars)		
1999				
March 31	$413,983	$66,956	$33,795	$32,779
June 30	511,434	98,503	69,542	69,542
September 30	867,504	150,914	(10,377)	(10,377)
December 31	499,877	72,551	35,477	35,477
1998				
March 31	$380,423	$ 63,541	$ 31,935	$ 29,057
June 30	441,715	81,299	52,184	49,749
September 30	740,734	155,079	133,193	130,846
December 31	443,526	70,892	37,935	35,892

(a) *Our utility business is 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) *The quarter ended September 30, 1999 includes an extraordinary charge of $139,885, net of income taxes of $94,115.*

15. Stock-Based Compensation

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

The most recent 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. The plan also provides for the granting of any combination of restricted stock, stock appreciation rights or dividend equivalents. The awards outstanding under the incentive plans at December 31, 1999 approximate 1,441,124 non-qualified stock options, 159,837 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. This statement encourages, but does not require, that a company record compensation expense based on the 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 would have been reduced to the following pro forma amounts:

	1999	1998	1997
	(Thousands of Dollars)		
Net income			
As reported	$128,437	$255,247	$251,493
Pro forma (fair value method)	$127,658	$254,640	$251,142

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation.

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:

	1999	1998	1997
Risk-free interest rate	5.68%	4.54%	5.66%
Dividend yield	3.33%	3.03%	4.50%
Volatility	20.50%	18.80%	15.63%
Expected life (months)	60	60	60

16. Business Segments

Historically, we reported our operations as a single, integrated business segment due to our regulated operating environment. The ACC authorized a combined rate for supplying and delivering electricity to customers which was cost-based and was designed to recover the Company's operating expenses and investment in electric utility assets and to provide a return on the investment.

As a result of the 1999 Settlement Agreement, our generation operations are now deregulated for accounting purposes. For the purposes of complying with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" (SFAS No. 131), we are required to disclose information about our business segments separately. Accordingly, we have separately identified expenses between the two segments and allocated revenues and other expenses using a study that identifies the portion of our base rates related to generation and delivery. We then used that information to develop the financial information of the business segments for each of the three years ended December 31, 1999 (or as of December 31, 1999 and 1998, with respect to assets).

Beginning in 1999, we have two principal business segments (determined by products, services and regulatory environment) which consist of the generation of electricity (generation business segment) and the transmission and distribution of electricity (delivery business segment). Intercompany eliminations primarily relate to intercompany sales of electricity. Financial data for business segments is provided as follows:

APS
NOTES TO FINANCIAL STATEMENTS

(Thousands of Dollars)	Business Segments Generation	Delivery	Eliminations	Total
Year Ended December 31, 1999				
Operating Revenues	$ 853,755	$ 2,292,798	$ (853,755)	$ 2,292,798
Operating Expenses	522,925	1,672,169	(853,755)	1,341,339
Operating Margin	330,830	620,629	--	951,459
Depreciation and Amortization	121,683	260,374	--	382,057
Interest and Preferred Stock Dividend Requirements	40,753	101,855	--	142,608
Pre-Tax Margin	168,394	258,400	--	426,794
Income Taxes	47,976	111,512	--	159,488
Extraordinary Charge-Net of Income Tax of $94,115	--	139,885	--	139,885
Earnings for Common Stock	$ 120,418	$ 7,003	$ --	$ 127,421
Total Assets	$ 2,321,778	$ 3,795,846	$ --	$ 6,117,624
Capital Expenditures	$ 90,285	$ 241,469	$ --	$ 331,754
Year Ended December 31, 1998				
Operating Revenues	$ 858,340	$ 2,006,398	$ (858,340)	$ 2,006,398
Operating Expenses	522,696	1,414,753	(858,340)	1,079,109
Operating Margin	335,644	591,645	--	927,289
Depreciation and Amortization	135,406	241,168	--	376,574
Interest and Preferred Stock Dividend Requirements	37,045	108,670	--	145,715
Pre-Tax Margin	163,193	241,807	--	405,000
Income Taxes	49,969	109,487	--	159,456
Earnings for Common Stock	$ 113,224	$ 132,320	$ --	$ 245,544
Total Assets	$ 2,399,560	$ 3,993,740	$ --	$ 6,393,300
Capital Expenditures	$ 85,767	$ 241,638	$ --	$ 327,405
Year Ended December 31, 1997				
Operating Revenues	$ 803,647	$ 1,878,553	$ (803,647)	$ 1,878,553
Operating Expenses	471,992	1,297,802	(803,647)	966,147
Operating Margin	331,655	580,751	--	912,406
Depreciation and Amortization	131,684	233,987	--	365,671
Interest and Preferred Stock Dividend Requirements	50,311	104,410	--	154,721
Pre-Tax Margin	149,660	242,354	--	392,014
Income Taxes	44,898	108,426	--	153,324
Earnings for Common Stock	$ 104,762	$ 133,928	$ --	$ 238,690
Capital Expenditures	$ 84,960	$ 217,047	$ --	$ 302,007

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements

See the Index to Financial Statements in Part II, Item 8.

Exhibits Filed

Exhibit No.		*Description*
12.1	—	Computation of Ratio of Earnings to Fixed Charges
23.1	—	Consent of Deloitte & Touche LLP
27.1	—	Financial Data Schedule

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.1	Bylaws, amended as of February 20, 1996	3.1 to 1995 Form 10-K Report	1-4473	3-29-96
3.2	Resolution of Board of Directors temporarily suspending Bylaws in part	3.2 to 1994 Form 10-K Report	1-4473	3-30-95
3.3	Articles of Incorporation, restated as of May 25, 1988	4.2 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report	1-4473	9-29-93
4.1	Mortgage and Deed of Trust Relating to the Company's First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to August 1, 1993 Form 8-K Report	1-4473	9-27-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.5	Fifty-second Supplemental Indenture	4.1 to September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94
4.7	Fifty-fourth Supplemental Indenture	4.1 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.8	Fifty-fifth Supplemental Indenture	4.8 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to 1993 Form 10-K Report	1-4473	3-30-94
4.10	Indenture dated as of January 1, 1995 among the Company and The Bank of New York, as Trustee	4.6 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.11	First Supplemental Indenture dated as of January 1, 1995	4.4 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.12	Indenture dated as of November 15, 1996 among the Company and The Bank of New York, as Trustee	4.5 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96

Exhibit No.	***Description***	***Originally Filed as Exhibit:***	***File No.***[b]	***Date Effective***
4.13	First Supplemental Indenture	4.6 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.14	Second Supplemental Indenture dated as of April 1, 1997	4.10 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.15	Indenture dated as of January 15, 1998 among the Company and The Chase Manhattan Bank, as Trustee	4.10 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.16	First Supplemental Indenture dated as of January 15, 1998	4.3 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.17	Second Supplemental Indenture dated as of February 15, 1999	4.3 to Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99
4.18	Third Supplemental Indenture dated as of November 1, 1999	4.5 to Registration Statement No. 333-58445 by means of November 2, 1999 Form 8-K Report	1-4473	11-5-99

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.1	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between the Company and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to September 1991 Form 10-Q	1-4473	11-14-91
10.2	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of December 1, 1994	10.1 to 1994 Form 10-K Report	1-4473	3-30-95
10.3	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to 1996 Form 10-K Report	1-4473	3-28-97
10.4	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of December 1, 1994	10.2 to 1994 Form 10-K Report	1-4473	3-30-95
10.5	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to 1996 Form 10-K Report	1-4473	3-28-97
10.6	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among the Company, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West 1991 Form 10-K Report	1-8962	3-26-92

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.7	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to 1992 Form 10-K Report	1-4473	3-30-93
10.8	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of November 1, 1994	10.3 to 1994 Form 10-K Report	1-4473	3-30-95
10.9	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.1 to June 1996 Form 10-Q Report	1-4473	8-9-96
10.10	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.5 to 1996 Form 10-K Report	1-4473	3-28-97
10.11	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to June 1991 Form 10-Q Report	1-4473	8-8-91
10.12	Long-Term Power Transactions Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 8, 1991	10.2 to June 1991 Form 10-Q Report	1-4473	8-8-91
10.13	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement	2-96386	3-13-85
10.14	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transactions Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and the Company	10.3 to 1995 Form 10-K Report	1-4473	3-29-96

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.15	Restated Transmission Agreement between PacifiCorp and the Company dated April 5, 1995	10.4 to 1995 Form 10-K Report	1-4473	3-29-96
10.16	Contract among PacifiCorp, the Company and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to 1995 Form 10-K Report	1-4473	3-29-96
10.17	Reciprocal Transmission Service Agreement between the Company and PacifiCorp dated as of March 2, 1994	10.6 to 1995 Form 10-K Report	1-4473	3-29-96
10.18	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to Form S-7 Registration Statement	2-59644	9-1-77
10.19	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to Form S-7 Registration Statement	2-59644	9-1-77
10.20	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease, Four Corners, dated April 25, 1985	10.36 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.21	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to Form S-7 Registration Statement	2-59644	9-1-77
10.22	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.37 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.23	Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site	5.05 to Form S-7 Registration Statement	2-59644	9-1-77
10.24	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.38 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.25	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to Form S-7 Registration Statement	2-36505	3-23-70
10.26	Application and Grant of rights-of-way and easements, Navajo Plant	5(h) to Form S-7 Registration Statement	2-36505	3-23-70
10.27	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to Form S-7 Registration Statement	2-39442	3-16-71
10.28	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10.1 to 1988 Form 10-K Report	1-4473	3-8-89

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.29	Amendment No. 13 dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to March 1991 Form 10-Q Report	1-4473	5-15-91
10.30[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	4.3 to Form S-3 Registration Statement	33-9480	10-24-86
10.31[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.5 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
10.32[c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to 1988 Form 10-K Report	1-4473	3-8-89

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.33[c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.3 to 1992 Form 10-K Report	1-4473	3-30-93
10.34	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.1 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
10.35	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
10.36	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.4 to 1992 Form 10-K Report	1-4473	3-30-93
10.37[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to June 1986 Form 10-Q Report	1-4473	8-13-86
10.38[a]	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2 to 1993 Form 10-K Report	1-4473	3-30-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.39[a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan effective as of May 1, 1993	10.1 to September 1994 Form 10-Q	1-4473	11-10-94
10.40[a]	Fourth Amendment dated December 28, 1999 to the Arizona Public Service Company Directors Deferred Compensation Plan	10.8 to Pinnacle West's 1999 Form 10-K	1-8962	3-30-00
10.41[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to 1988 Form 10-K Report	1-4473	3-8-89
10.42[a]	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to 1993 Form 10-K Report	1-4473	3-30-94
10.43[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to September 1994 Form 10-Q Report	1-4473	11-10-94
10.44[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to 1997 Form 10-K Report	1-4473	3-28-97
10.45[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to 1995 Form 10-K Report	1-4473	3-29-96

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.46[a]	First Amendment effective as of January 1, 1998, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.6 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.47[a]	Second Amendment effective as of January 1, 2000, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.48[a]	Arizona Public Service Company Supplemental Excess Benefit Retirement Plan as amended and restated on December 20, 1995	10.11 to 1995 Form 10-K Report	1-4473	3-29-96
10.49[a]	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 7, 1999	10.13 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.50[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan effective as of January 1, 1995	10.7 to 1994 Form 10-K Report	1-4473	3-30-95
10.51[a]	Arizona Public Service Company Director Equity Plan	10.1 to September 1997 Form 10-K Report	1-4473	11-12-97
10.52[a]	Letter Agreement dated December 21, 1993, between the Company and William L. Stewart	10.6 to 1994 Form 10-K Report	1-4473	3-30-95

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.53[a]	Letter Agreement dated August 16, 1996 between the Company and William L. Stewart	10.8 to 1996 Form 10-K Report	1-4473	3-28-97
10.54[a]	Letter Agreement between the Company and William L. Stewart	10.2 to September 1997 Form 10-Q Report	1-4473	11-12-97
10.55[a]	Letter Agreement dated December 13, 1999 between the Company and William L. Stewart	10.9 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.56[a]	Letter Agreement dated as of January 1, 1996 between the Company and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to 1995 Form 10-K Report	1-4473	3-29-96
10.57[a]	Letter Agreement dated October 3, 1997 between the Company and James M. Levine	10.17 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.58[a]	Employment Agreement, effective as of February 5, 1990, between Richard Snell and Pinnacle West	10.1 to Pinnacle West's 1990 Form 10-K	1-8962	3-28-91
10.59[a]	First Amendment to Employment Agreement, effective March 31, 1995, between Richard Snell and Pinnacle West	10.2 to Pinnacle West's 1995 Form 10-K Report	1-8962	4-1-96
10.60[a]	Second Amendment to Employment Agreement, effective February 5, 1997, between Richard Snell and Pinnacle West	10.2 to Pinnacle West's 1996 Form 10-K Report	1-8962	3-31-97
10.61[ad]	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.1 to Pinnacle West's June 1999 Form 10-Q Report	1-8962	8-16-99
10.62[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.63[a]	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.11 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.64[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan effective as of March 23, 1994	A to the Proxy Statement for the Plan Report Pinnacle West 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.65[a]	First Amendment dated December 7, 1999, to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan	10.12 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.66	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.67	First Amendment dated December 7, 1999, to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.68[a]	2000 Management Variable Incentive Plan (APS)	10.4 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.69[a]	2000 Senior Management Variable Incentive Plan (APS)	10.5 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.70[a]	2000 Officer Variable Incentive Plan (APS)	10.6 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.71	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to 1991 Form 10-K Report	1-4473	3-19-92
10.72	Agreement for the Sale and Purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981, including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to 1991 Form 10-K Report	1-4473	3-19-92
10.73	Territorial Agreement between the Company and Salt River Project	10.1 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.74	Power Coordination Agreement between the Company and Salt River Project	10.2 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.75	Memorandum of Agreement between the Company and Salt River Project	10.3 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.76	Addendum to Memorandum of Agreement between the Company and Salt River Project dated as of May 19, 1998	10.2 to May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.2 to 1992 Form 10-K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.3 to 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.1 to September 1992 Form 10-Q Report	1-4473	11-9-92
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1,1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	10.8 to September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.4 to 1992 Form 10-K Report	1-4473	3-30-93
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to Form S-3 Registration Statement	33-9480	10-24-86
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.4 to 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to Form S-3 Registration Statement	33-9480	10-24-86
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, the Company, and the Owner Participant named therein	28.2 to September 1992 Form 10-Q Report	1-4473	11-9-92
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, the Company, and the Owner Participant named therein	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Owner Participant named therein	28.5 to 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.15	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
99.17	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to November 18, 1986 Form 8-K Report	1-4473	1-20-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to 1992 Form 10-K Report	1-4473	3-30-93
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by the Company	28.3 to 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Arizona Corporation Commission Order dated December 6, 1991	28.1 to 1991 Form 10-K Report	1-4473	3-19-92
99.23	Arizona Corporation Commission Order dated June 1, 1994	10.1 to June Form 10-Q Report	1-4473	8-12-94
99.24	Rate Reduction Agreement dated December 4, 1995 between the Company and the ACC Staff	10.1 to December 4, 1995 Form 8-K Report	1-4473	12-14-95
99.25	Arizona Corporation Commission Order dated April 24, 1996	10.1 to March 1996 Form 10-Q Report	1-4473	5-14-96
99.26	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to 1996 Form 10-K Report	1-4473	3-28-97
99.27	Retail Electric Competition Rules	10.1 to June 1998 Form 10-Q Report	1-4473	8-14-98

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.28	Arizona Corporation Commission Order, Decision No. 61973, dated October 6, 1999, approving our Settlement Agreement	10.1 to September 1999 10-Q Report	1-4473	11-15-99
99.29	Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to September 1999 10-Q Report	1-4473	11-15-99

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional officers and key employees of the Company. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 1999 and the period ended March 29, 2000, the Company filed the following Reports on Form 8-K:

Report dated November 2, 1999 comprised of Exhibits to our Registration Statement (Registration No. 333-58445) relating to our offering of $250 million of Notes.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: March 29, 2000

/s/ WILLIAM J. POST
(William J. Post, Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	*Title*	*Date*
/s/ WILLIAM J. POST (William J. Post, Chief Executive Officer)	Principal Executive Officer, Principal Accounting Officer and Director	March 29, 2000
/s/ MICHAEL V. PALMERI (Michael V. Palmeri, Vice President, Finance)	Principal Financial Officer	March 29, 2000
/s/ JACK E. DAVIS (Jack E. Davis)	President and Director	March 29, 2000
/s/ MICHAEL L. GALLAGHER (Michael L. Gallagher)	Director	March 29, 2000
/s/ MARTHA O. HESSE (Martha O. Hesse)	Director	March 29, 2000
/s/ MARIANNE M. JENNINGS (Marianne M. Jennings)	Director	March 29, 2000
/s/ ROBERT E. KEEVER (Robert E. Keever)	Director	March 29, 2000
/s/ ROBERT G. MATLOCK (Robert G. Matlock)	Director	March 29, 2000
/s/ KATHRYN L. MUNRO (Kathryn L. Munro)	Director	March 29, 2000

/s/ BRUCE J. NORDSTROM (Bruce J. Nordstrom)	Director	March 29, 2000
/s/ DONALD M. RILEY (Donald M. Riley)	Director	March 29, 2000
/s/ QUENTIN P. SMITH, JR. (Quentin P. Smith, Jr.)	Director	March 29, 2000
/s/ RICHARD SNELL (Richard Snell)	Director	March 29, 2000
/s/ WILLIAM L. STEWART (William L. Stewart)	President and Director	March 29, 2000
/s/ DIANNE C. WALKER (Dianne C. Walker)	Director	March 29, 2000
/s/ BEN F. WILLIAMS, JR. (Ben F. Williams, Jr.)	Director	March 29, 2000