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161-01984-WFC/JRP
June 1, 1989

Dockets Nos. STN 50-528/529/530

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Mail Station P1-137
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Dear Sir:

Subject: Palo Verde Nuclear Generating Station
PVNGS Units 1, 2, and 3
License Guarantee of Payment of Deferred Premium
File: 89-003-240

Pursuant to the requirements in 10 CFR 140.21, as defined in subpart (e) of this section, Arizona Public Service Company, for itself and on behalf of the participants in Palo Verde Nuclear Generating Station, herewith submit projected 1989 cash flow statements.

Should you have any questions, please feel free to call.

Very truly yours,

WFConway

W. F. Conway
Executive Vice President

WFC/JRP/jle

Attachments

cc: D. B. Karner
G. W. Knighton
T. L. Chan
M. J. Davis
J. B. Martin
T. J. Polich

A004
1/1

SALT RIVER PROJECT

INTERNAL CASH FLOW PROJECTION
FOR
PALO VERDE NUCLEAR GENERATING STATION
FOR FISCAL YEARS ENDED APRIL 30, 1988 AND 1989
($000)

	1988 ACTUAL	1989 PROJECTED
Net Income after taxes	16,261	35,284
Less dividends paid:		
Preferred dividend requirements		
Dividends on common stock		
Retained Earnings	16,261	35,284
Adjustments:		
Depreciation and amortization	151,318	150,652
Deferred Income Taxes and Investment Tax Credits		
Allowance for Funds Used During Construction	(42,428)	(14,947)
Total Adjustments	108,890	135,705
Internal Cash Flow	125,151	170,989
Average Quarterly Cash Flow	31,288	42,747
Percentage Ownership in all nuclear units		
Unit 1	17.49%	17.49%
Unit 2	17.49%	17.49%
Unit 3	17.49%	17.49%

SOUTHERN CALIFORNIA EDISON COMPANY

1989 Internal Cash Flow Projection
(Dollars in Thousands)

	1988 Actual	1989 Projected
Net Income After Taxes	$731,000	*
Dividends Paid	578,000	*
Retained Earnings	$153,000	*
Adjustments:		
Depreciation & Amortization	644,000	682,000
Deferred Taxes	109,000	119,000
Allowance for Funds Used During Construction	(30,000)	(15,000)
Total Adjustments	$723,000	$786,000
Internal Cash Flow	$876,000	*
Average Quarterly Cash Flow	$219,000	*

Percentage Ownership in All Nuclear Units:	
San Onofre Nuclear Generating Station Unit 1	
Southern California Edison Company	80.00%
San Diego Gas & Electric Company	20.00%
San Onofre Nuclear Generating Station Units 2 & 3	
Southern California Edison Company	75.05%
San Diego Gas & Electric Company	20.00%
City of Anaheim	3.16%
City of Riverside	1.79%
Palo Verde Nuclear Generating Station Units 1 & 2	15.80%
Maximum Total Contingent Liability:	
San Onofre Nuclear Generating Station Unit 1	$10,000
San Onofre Nuclear Generating Station Unit 2	10,000
San Onofre Nuclear Generating Station Unit 3	10,000
Palo Verde Nuclear Generating Station Unit 1	1,580
Palo Verde Nuclear Generating Station Unit 2	1,580
Palo Verde Nuclear Generating Station Unit 3	1,580
	$34,740

* Company policy prohibits disclosure of financial data which will enable unauthorized persons to forecast earnings or dividends, unless assured confidentiality. The Net Estimated Cash Flow for 1989 is expected to be comparable to the Actual Cash Flow for 1988.

Nucins_PV LM-m23

ARIZONA PUBLIC SERVICE COMPANY

1989 Net Cash Flow Projection for Palo Verde Nuclear Generating Station (000's)

Participant: Arizona Public Service Company

		1988 Actual	1989 Projected
1.	Net income after taxes	$271,211	$273,654
	Less:		
2.	Dividends Paid on Preferred Stock	33,003	32,126
3.	Dividends Paid on Common Stock	210,944	210,944
4.	Retained Earnings	27,264	30,584
	Adjustments:		
5.	Depreciation and Amortization (1)	245,499	248,179
6.	Deferred income taxes (2)	114,295	107,427
7.	ITC net deferred	(9,107)	(7,488)
8.	Allowance for funds used during construction (equity and borrowed)	(21,918)	(18,829)
9.	Gross cost deferrals	(146,911)	(152,012)
10.	Other (3)	(1,687)	(1,692)
11.	Total Adjustments	180,171	175,585
12.	Internal cash flow (line 4 + line 11)	207,435	206,169
13.	Average quarterly cash flow (line 12/4)	51,859	51,542

Percentage ownership in all nuclear units:

Unit 1 - 29.1%
Unit 2 - 29.1% (4)
Unit 3 - 29.1%

Maximum total contingent liability for PVNGS=
$30,000,000 ($10,000,000 per unit)

(1) Includes nuclear fuel amortization.
(2) Excludes deferred income taxes on deferred fuel adjustment revenues.
(3) Includes amortization of tax benefits sold in 1981.
(4) Includes portion of Palo Verde Unit 2 leased.

1989 PROFORMA CASH FLOW STATEMENT
FOR PUBLIC SERVICE COMPANY OF NEW MEXICO
(Excluding Non-utility Subsidiaries)

	1988 Actual	1989 Projected
Net Income After Taxes	(66,778)	85,148
Less Dividends Paid	89,204	26,245
Retained Earnings	(155,982)	58,903
Adjustments:		
Depreciation and Amortization	66,920	70,816
Deferred Income Taxes and Investment Tax Credits	(15,135)	19,075
Allowance for Funds Used During Construction	(4,659)	(3,511)
Other, Non-cash	159,040	423
TOTAL ADJUSTMENTS	206,166	86,803
INTERNAL CASH FLOW	50,184	145,706
Average Quarterly Cash Flow	12,546	36,427

Percentage Entitlement in All Nuclear Units:

Palo Verde Unit 1--10.2%
Palo Verde Unit 2--10.2%
Palo Verde Unit 3--10.2%

By: BDLackey
Billy D. Lackey
Vice President and Corporate Controller

1989 Internal Cash Flow Projection of
Los Angeles Department of Water and Power
for Palo Verde Nuclear Power Station

(Thousands of Dollars)

	1987-88 Actual Total	1988-89 Protection Total
Net Income	$175,561	$207,800
Less Transfer to City	(70,182)	(78,500)
Retained Earnings	105,379	129,300
Adjustments		
Depreciation and Amortization	124,004	134,900
Allowance for funds used during construction	(5,674)	(8,700)
Total Adjustments	118,330	126,200
Internal Cash Flow	$223,709	$255,500
Average Quarterly Cash Flow	$ 55,927	$ 63,875

Percentage Ownership in all operating nuclear units	Palo Verde	5.7%
Maximum Total Contingent Liability		$ 1,710,000

1988-89 INTERNAL CASH FLOW PROJECTION
EL PASO ELECTRIC COMPANY
(THOUSANDS OF DOLLARS)

	1988	1989
Net Income After Taxes	$ 24,369	$ 30,606
Less Dividends Paid	65,557	25,116
Increase in Retained Earnings	(41,188)	5,490
Adjustments:		
Depreciation and Amortization	34,254	42,947
Deferred Income Taxes and ITC	14,036	(3,924)
AFUDC	(21,478)	(29,165)
Total Adjustments	26,812	9,858
Internal Cash Flow	$ (14,376)	$ 15,348
Average Quarterly Cash Flow	$ (3,594)	$ 3,837

Percentage Ownership in	Unit 1	15.8%
Palo Verde Nuclear Generating System	Unit 2	15.8%
	Unit 3	15.8%

Maximum Total Contingent Liability $ 0

SCPPA

Southern California Public Power Authority

1987-88 Annual Report

50-528
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-NOTICE-

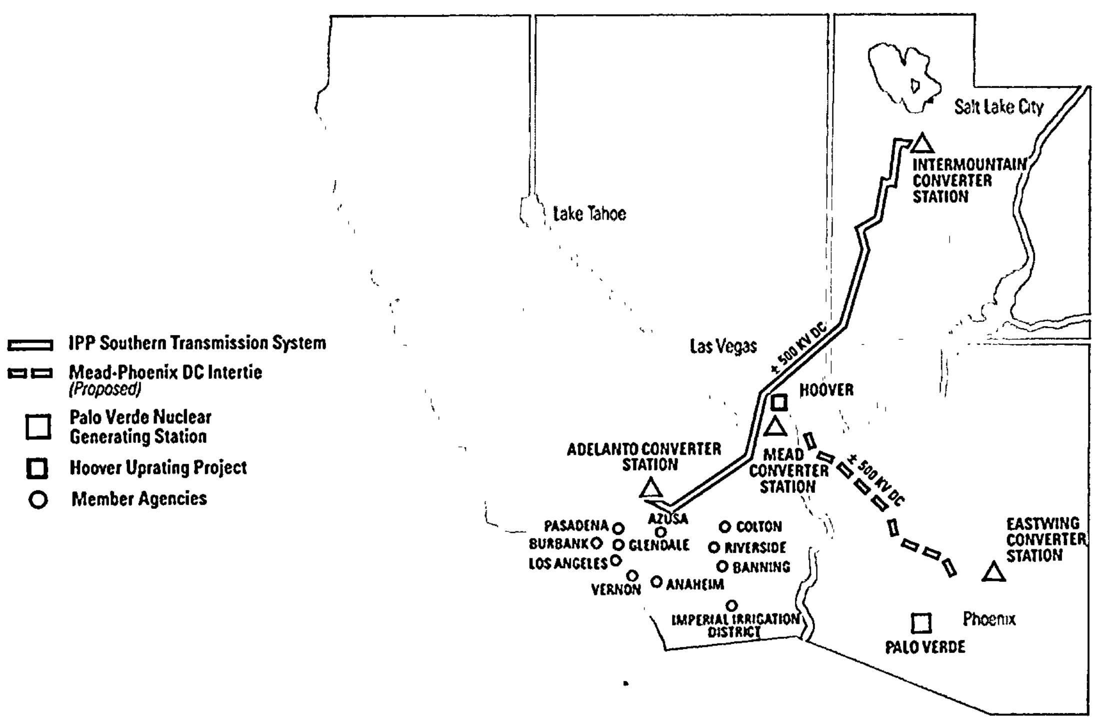
More than 1.7 million customers benefit from the power supplied by the Authority.

In 1980 the newly formed Southern California Public Power Authority was charged with the mission of financing projects which would generate or transmit electrical energy for its member agencies. The Authority represents all of the public power agencies in Southern California, a customer base in excess of 1.7 million.

These customers cover a wide range of growing communities from rural areas to industrial districts to residential centers. The Authority is comprised of the Imperial Irrigation District and the municipalities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon.

Through the Authority's efforts, the member agencies and their customers have benefited from a supply of reliable and economical energy. The combined membership recorded non-coincidental peak requirements of 6,721 megawatts.

SCPPA's high level of acceptance in the financial community has enabled it to secure the financing required to carry out its mission. Since first going to the market in 1982, the Authority has issued approximately $4 billion in bonds and notes, including refunding issues.



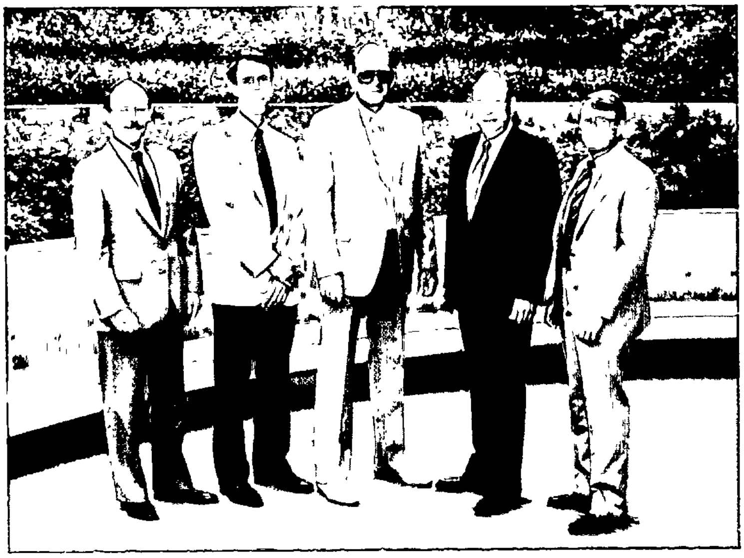
President
Gale A. Drews
Electrical Utility Director
City of Colton

Vice President
W. E. Cameron
Director of Public Service
City of Glendale

Secretary
Eldon A. Cotton
Assistant Chief Engineer-Power
Los Angeles Department of
Water and Power—
City of Los Angeles

Assistant Secretary
Horace W. Rupp, Jr.
Manager of Power Contracts
Los Angeles Department of
Water and Power—
City of Los Angeles

Executive Director
Arthur T. Devine
Former Assistant City Attorney
City of Los Angeles
Former Electrical Engineer
Los Angeles Department of
Water and Power—
City of Los Angeles



Management left to right: Eldon A. Cotton, Horace W. Rupp, Gale A. Drews, W. E. Cameron, Arthur T. Devine

Kenneth S. Noller
Assistant Power Manager
Coachella Power Division
Imperial Irrigation District
Imperial, California

Joseph F. Hsu
Director of Utilities
Azusa, California

Ronald V. Stassi
General Manager
Burbank Public
Service Department
Burbank, California

Gordon W. Hoyt
General Manager
Anaheim Public
Utilities Department
Anaheim, California

W.E. Cameron
Director of Public
Service
Glendale Public
Service Department
Glendale, California

Timothy Dempsey
Public Utilities Director
Banning, California

David C. Plumb
General Manager
Pasadena Water and
Power Department
Pasadena, California

Gale A. Drews
Electrical Utility Director
Colton, California

Eldon A. Cotton
Assistant General Manager — Power
Los Angeles Department of
Water and Power-
City of Los Angeles
Los Angeles, California

Bruce V. Malkenhorst
Executive Director of
Light & Power
Vernon, California

Bill D. Carnahan
Public Utility Director
Riverside Public
Utilities Department
Riverside, California

With its creation in 1980, the Southern California Public Power Authority took on the challenge of helping to provide the energy needs of its member agencies. The Authority has met that challenge through the financing of various projects designed to efficiently provide power. Importantly, SCPPA remains one of the most effective joint financing action agencies in the nation and continues to carry a financial rating of AA.

Earlier this year Unit 3 of the Palo Verde Nuclear Generating Station came on-line. Ten Authority members are receiving electrical energy through their entitlement in this nuclear facility. Units 1 and 2 have been on-line since 1986.

Six member agencies participated in the SCPPA funding of the Hoover Uprating Project. Designed to increase the output rating of Hoover Power Plant generators, this project is scheduled for completion in 1992.

Studies continue on the feasibility of the Mead-Phoenix DC Intertie project. Funding for the study was arranged through loans secured by the Authority.

I am pleased that this past year has seen the Authority efficiently serve its members. The responsibility for our continued success is due mainly to the professionalism of the staff, Board of Directors, and others. I would like to thank everyone for their hard work, for that is truly the strength of this organization.

Gale A. Drews

Gale A. Drews
President

Anaheim

Founded in 1857 by a group of German winegrowers, Anaheim has grown over the years to become the largest city in Orange County. Located just 25 miles south of Los Angeles, this community ranks as one of the fastest growing population centers in the United States.

Anaheim is known the world over as the home of Mickey Mouse. Disneyland and other popular tourist attractions bring millions of visitors to Anaheim each year. An attendant industry that includes hundreds of hotels, motels, restaurants, and the 680,000 gross-square-foot Anaheim Convention center forms an important part of the Anaheim economy.

Anaheim is also home to the California Angels of the American Baseball League and the Los Angeles Rams of the National Football League.The strong presence of high-tech defense business rounds out the economic base of the city.

Power needs are supplied by an ownership interest in San Onofre Nuclear Generating Station Units 2 and 3, the Intermountain Generating Station and entitlement in the Hoover Power Plant, in addition to firm power and economy energy purchased from utilities throughout the western United States. In fiscal 1988, power purchases and generation of 2,846,000 megawatt-hours were required to meet the needs of Anaheim's 96,700 customers.

Azusa

The history of Azusa stretches back to the days of the Shoshone Indians, who settled a small village at the mouth of the San Gabriel Canyon. Over the years a succession of Spanish and then English explorers and settlers came to the region. The city, located 20 miles east of Los Angeles, was incorporated in 1898. The 11 square miles that make up modern-day Azusa support a population of 35,000.

The city had been almost exclusively dependent on wholesale power from Southern California Edison Company (Edison) until receiving its Palo Verde Nuclear Generating Station and Hoover Power Plant entitlements. Last year, the utility had a peak demand of 47 megawatts and sold approximately 185,000 megawatt-hours.

Banning

In the 1850's a small town grew up around the stagecoach station on the San Gorgonio Ranch. The stage line was owned by Gen. Phineas T. Banning, and the town was named after him. Even when the stagecoach was replaced by the railroad in 1876, the name Banning stuck. In fact, the town is still known as "Stagecoach Town USA."

Banning was incorporated in 1913, and its 17 square miles hold a population of 14,000. Located about 85 miles east of Los Angeles, Banning enjoys a scenic setting with the San Gorgonio Mountains to the north and the San Jacinto Mountains to the south.

With its entitlements from Palo Verde Nuclear Generating Station and Hoover Power Plant, Banning has been able to offset some of its purchased power. Previously, the city had relied exclusively on power purchased wholesale from its only supplier, Edison.

The city had a peak demand of 18.5 megawatts last year and sold approximately 79,000 megawatt-hours.

Burbank

As headquarters for Burbank Studios, Walt Disney Productions, National Broadcasting Company, and Warner Bros., Burbank holds an important position in the entertainment industry. Burbank is also prominent in aviation as home to Lockheed Aircraft. Burbank industries employ more than 70,000 people.

The city is nestled in the eastern San Fernando Valley along the base of the Verdugo Mountains. When it was incorporated in 1887, Burbank had a population of only 400. Today more than 85,000 people reside here.

Burbank supplies electricity to its customers through a combination of oil- and gas-fired generating facilities in the Los Angeles Basin, entitlements from Hoover Power Plant, Palo Verde Nuclear Generating Station, the Intermountain Generating Station, and purchases from the Bonneville Power Administration and other utilities in the Pacific Northwest and the Southwest.

During the past year the city had a peak demand of 244 megawatts while generating and purchasing 1,001,000 megawatt-hours of energy.

Colton

Colton's roots date back to 1875 when one square mile of land was deeded to the Southern Pacific Railroad. In return, the railroad agreed to make Colton its headquarters for the area. The town quickly became known as "Hub City" since it was on the main line of three major railroads. The era of the automobile only added to Colton's "Hub City" distinction; it is

now the meeting point for three major interstate highways.

Located 55 miles east of Los Angeles in San Bernardino County, Colton covers an area of 16 square miles and is home to 33,000 residents.

Last year the city had a peak power requirement of 40 megawatts and total energy requirements of 165,000 megawatt-hours. Colton purchases the majority of its capacity from Edison. Energy comes from its entitlement in the Palo Verde Nuclear Generating Station, Hoover Power Plant, Western States Power Pool, Edison and other non-firm energy contracts.

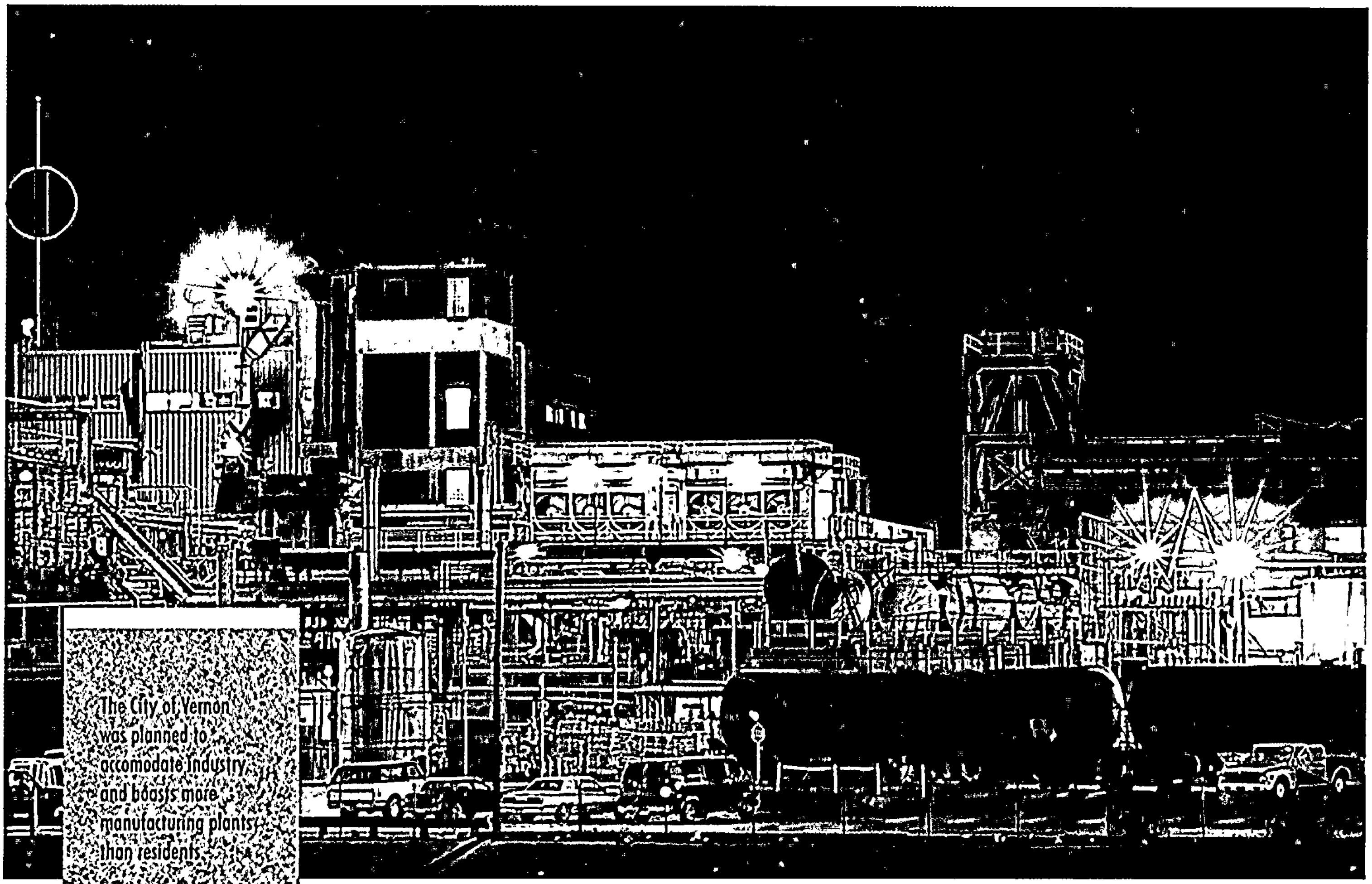
Glendale

Located just north of Los Angeles at the foot of the Verdugo Mountains, Glendale has a population of 162,000. The history of the city dates back to 1798 when Corporal Jose Maria Verdugo obtained title to the Rancho San Rafael from the King of Spain. As the area was settled, the large rancho was divided up. In 1884, a 150-acre parcel of the rancho became the original townsite and was named Glendale.

By 1906 the city had grown tenfold in size and was incorporated. Glendale continued to grow and the city now occupies 30 square miles. While its boundaries have changed dramatically through the years, Glendale remains true to its heritage and is still known today as the "Jewel of the Verdugos."

Glendale supplies its 75,000 customers with a total of approximately 910,000 megawatt-hours of energy either purchased or generated. The peak demand was 244 megawatts during the past year.

The city receives entitlements



The City of Vernon was planned to accomodate industry and boasts more manufacturing plants than residents.

from the Intermountain Generating Station and the Palo Verde Nuclear Generating Station. Glendale also receives power from oil- and gas-fired generation in the Los Angeles Basin, hydroelectrical generation from Hoover Power Plant, and purchases from the Bonneville Power Administration and other utilities.

Los Angeles

With a population of 3.4 million, Los Angeles is the largest Authority member. From a humble pueblo settled back in 1781, Los Angeles has grown to become a major international city covering more than 465 square miles.

The Los Angeles Department of Water and Power, the largest municipal utility in the United States, provides water and energy needs to this vast metropolis. During the fiscal year, the city had a peak demand of 4,922 megawatts while a total of 21 million megawatt-hours were produced.

Los Angeles receives power from hydroelectric generating stations, coal, oil- and gas-fired facilities, and a nuclear generating station, in addition to purchased power from Pacific Northwest and Southwest utilities. Last year the Department's system had a net dependable system capability of 7,280 megawatts.

Through its association with the Authority, Los Angeles has been able to add two new sources to its system: the Intermountain Generating Station in Utah and the Palo Verde Nuclear Generating Station in Arizona. An entitlement through the Authority provides for approximately 145 megawatts from the Palo Verde Nuclear Generating Station.

Pasadena

Pasadena is scenically located at the foot of the rugged San Gabriel mountains northeast of Los Angeles. Founded in 1875 and incorporated one year later, Pasadena has grown to be a major economic, cultural, residential, and recreational center in Southern California.

The city is home to some prestigious institutions such as the Norton Simon Museum, the Jet Propulsion Laboratory, and the California Institute of Technology.

Pasadena is perhaps best known for the Annual Tournament of Roses parade, held every New Year's Day since 1890. The granddaddy of college football games, the Rose Bowl, is also held New Year's Day in the city's venerable football stadium, the Rose Bowl.

Pasadena supplies electricity through a combination of oil- and gas-fired generation in the Los Angeles Basin, hydroelectric generation from Hoover Power Plant, and purchases from the Bonneville Power Administration, as well as receiving an entitlement from the Intermountain Generating Station and Palo Verde Nuclear Generating Station.

During the year Pasadena's peak power requirement was 232 megawatts and the city generated and purchased approximately 1 million megawatt-hours. Pasadena has 50,000 electric customers and a population of 130,000.

Riverside

The City of Riverside, located about 45 miles east of Los Angeles, was incorporated in 1883. Lands owned by an irrigation company were annexed to ensure an adequate water supply. A small hydroelectric plant was opened in 1886 on a canal, giving rise to what is the oldest municipal utility in California.

Riverside is now a 77 square-mile municipality with more than 195,000 residents. Riverside serves more than 81,700 customers, including the University of California, Riverside. These customers are served through 13 substations and more than 1,700 circuit miles of subtransmission and distribution lines. This past year the city had a peak demand of 317 megawatts and total energy sales of 1.27 million megawatt-hours.

Riverside purchases power from Edison at wholesale rates, has ownership in Units 2 and 3 of the San Onofre Nuclear Generating Station, and receives more from an entitlement in the Palo Verde Nuclear Generating Station, Hoover Power Plant, and the Intermountain Generating Station. In addition, Riverside purchases firm and non-firm energy from a large number of western utilities.

Vernon

From its inception Vernon was planned to be an industrial center. Incorporated in 1905 and located just four miles South of Los Angeles, the city was designed to provide a well-organized, hospitable home for all types of industry. Here, more than 525 manufacturing plants and another 400 establishments engage in the wholesale-retail trade.

The residential population of Vernon is only a few hundred, but during the day the working

population numbers in excess of 55,000. The city is served by four railroads and boasts 114 miles of rail lines within its five-square-mile city area. Virtually every industry or business is on a direct transcontinental rail line. In addition, 77 trucking lines operate terminals in the city.

During the year, Vernon had a total energy requirement of 1.12 million megawatt-hours and a peak demand of 190 megawatts. The Vernon Electrical System, established in 1931, receives most of its energy from Edison. The remainder comes from its entitlements in the Palo Verde Nuclear Generating Station, Hoover Power Plant, and a city operated diesel generating plant.

Imperial Irrigation District

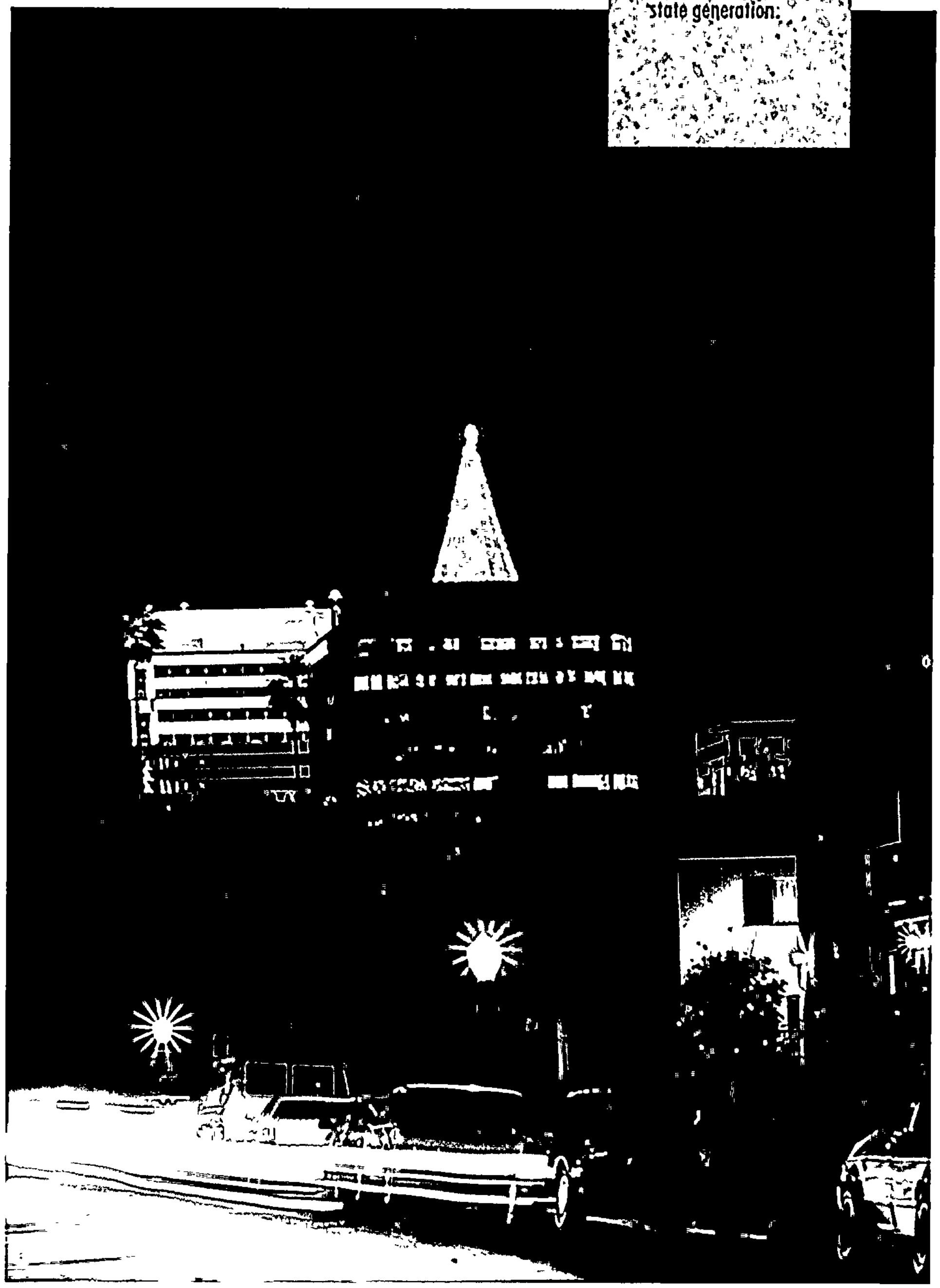
In 1911 the Imperial Irrigation District (IID) was formed to deliver water from distribution canals to 500,000 acres of farmland in Imperial County. When hydroelectric plants were built along the waterways, IID entered the power business.

By 1943 it had become the sole distributor of electric energy in Imperial County and part of the Coachella Valley of Riverside County. Today, IID serves over 66,000 customers in one of the most productive agricultural areas in the nation.

In addition to its hydroelectric plants, IID generates power from oil-fired units, gas turbines, and diesel generators. It receives power from the Palo Verde Nuclear Generating Station, and purchases power from other utilities in the Southwest.

In the past year, IID had a peak demand of 455 megawatts and produced and purchased 1,561,000 megawatt-hours.

Glendale and its growing commercial area are dependent on power from local plants and out-of-state generation.



Palo Verde Nuclear Generating Station

Early in 1988, Unit 3 of the Palo Verde Nuclear Generating Station (Palo Verde) went on-line. With Units 1 and 2 on-line since 1986, this station, which is located about 50 miles west of Phoenix, Arizona, now has a capacity of approximately 3810 megawatts.

A net annual output of more than 22 million megawatt-hours is projected from Palo Verde by the early 1990s. The Authority has a 5.91 percent interest in the generating station and receives up to 216 megawatts (based on the licensed reactor thermal power level per unit of 1221 MW).

Palo Verde is managed by Arizona Public Service Company, with the switchyard portion operated by the Salt River Project. The Authority will use a certain portion of the project transmission system.

Total financing for the project amounted to $1.16 billion. Taking advantage of lower interest rates, the Authority issued approximately $1 billion in refunding bonds in 1985, 1986 and early 1987 in five issues. As a result, participating members will experience a gross debt savings of $269 million over the life of the project.

Ten member agencies have contracted with the Authority for entitlement in Palo Verde. They will use the stations output to meet new growth needs to replace more expensive purchased power, and to displace oil- and gas-fired generation.

Southern Transmission System

The ± 500 kilovolt Southern Transmission System (STS) is a direct current transmission line that carries power across 488 miles of mountains and deserts from the Intermountain Generating Station (IGS) in Utah to six Authority members. The IGS consists of two coal-fueled generating units capable of producing 1600 MW in total. An adjacent converter station takes the alternating current produced by the IGS and changes it into direct current. After transmission over the STS, the direct current is changed back to alternating at the Adelanto Converter Station in Southern California and then delivered to the member participants. The STS has an official capacity of 1920 MW.

A total of 36 utilities in Utah, California, and Nevada are receiving power from the IGS. While the generating station is owned by the Intermountain Power Agency (IPA), a political subdivision of the State of Utah, Los Angeles has been appointed project manager and operating agent.

The Authority has completed three refunding sales totaling approximately $1 billion. This program has produced a gross debt service savings of approximately $725 million over the life of the project.

Power transmitted over the system will be used by Authority members to meet load growth, displace Los Angeles based oil- and gas-fueled generation and, for some, to reduce purchases from Edison.

Palo Verde Project Participation

Participants	Project Entitlement	Generating Capability (Megawatts)
Los Angeles	67.0%	145.04
Imperial Irrigation District	6.5%	14.07
Riverside	5.4%	11.69
Vernon	4.9%	10.61
Burbank	4.4%	9.53
Glendale	4.4%	9.53
Pasadena	4.4%	9.53
Azusa	1.0%	2.16
Banning	1.0%	2.16
Colton	1.0%	2.16
Total	100.0%	216.48

Southern Transmission System Participation

Participants	Project Entitlement
Los Angeles	59.5%
Anaheim	17.6%
Riverside	10.2%
Burbank	4.5%
Glendale	2.3%
Pasadena	5.9%
Total	100.0%

Los Angeles continues to experience growth as electrical demand increases each year.

Hoover Uprating Project

In 1986 the U.S. Bureau of Reclamation took over operation of the 50-year old Hoover Power Plant. The Bureau is in the process of uprating Hoover's 17 original generators to increase the capacity of the plant from 1,450 megawatts to 1,903 megawatts.

The increase is made possible by installing modern stator windings and turbine impellers, and upgrading various auxiliary equipment. Other increases in plant efficiency can be realized through the replacement of existing transformer banks. Additional plant improvements include consolidation of control rooms and modernization to provide for automatic and remote control. The project is scheduled for completion in 1992.

Six Authority members have contracted to help finance the uprating, and the Authority has issued approximately $34.5 million in bonds to finance their share. Participating members have begun receiving energy and capacity entitlements as the units are uprated and returned to service. Additional amounts will be received as new groups of generators are uprated with a full entitlement of 94 megawatts expected in 1992.

Mead-Phoenix DC Intertie Project

The Authority and other Southwest utilities continue to study the feasibility of constructing, owning, and operating a ± 500 kilovolt, direct-current transmission line. The intertie between Phoenix, Arizona and Boulder City, Nevada would have an initial capacity of 1,600 megawatts which could later be expanded to 2,200 megawatts.

When completed in the mid-1990s, the project would transmit Palo Verde generation entitlements for the Authority participants and facilitate economy energy/capacity transaction with other utilities in the Southwest: Other participants in the study are Salt River Project, M-S-R, and the Western Area Power Administration.

If the project is undertaken, it would provide 1500 megawatts for Authority participants, increasing to 2,062 megawatts if the 2,200-megawatt expansion is carried out.

Hoover Uprating Participation

Participants	Project Entitlement
Anaheim	42.6%
Riverside	31.9%
Azusa	4.2%
Banning	2.1%
Colton	3.2%
Burbank	16.0%
Total	100.0%

Report of Independent Accountants
September 2, 1988

To the Board of Directors of
Southern California Public
Power Authority

In our opinion, the accompanying combined balance sheet and the related combined statements of operations and of cash flows present fairly the financial position of the Southern California Public Power Authority (Authority) at June 30, 1988 and 1987, and the results of its operations and its cash flows for the years then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying separate balance sheets and the related separate statements of cash flows of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project and Mead-Phoenix Project, and the separate statements of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project present fairly the financial position of each of the Projects at June 30, 1988, and their cash flows and the results of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project for the year, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceding year. Our examination of these statements was made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

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

Price Waterhouse

Los Angeles, California

Southern California Public Power Authority
Combined Balance Sheet
(In Thousands)

	June 30, 1988					
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Total*	*June 30, 1987 Total*
Assets						
Utility plant						
Production	$ 600,458				$ 600,458	$ 368,755
Transmission	5,988	$ 656,773			662,761	636,546
General	81	18,724			18,805	18,126
	606,527	675,497			1,282,024	1,023,427
Less—Accumulated depreciation	34,224	38,064			72,288	34,072
	572,303	637,433			1,209,736	989,355
Construction work in progress	2,028	912		$12,600	15,540	236,512
Nuclear fuel, at amortized cost	31,330				31,330	36,415
Net utility plant	605,661	638,345		12,600	1,256,606	1,262,282
Special funds						
Investments	221,918	150,768	$26,970	1,843	401,499	412,547
Advance to Intermountain Power Agency		20,161			20,161	20,981
Advances for capacity and energy, net			6,009		6,009	3,064
Interest receivable	2,204	855	264		3,323	5,223
Cash			684	14	698	546
	224,122	171,784	33,927	1,857	431,690	442,361
Accounts receivable	836				836	5,587
Materials and supplies	6,528				6,528	
Costs recoverable from future billings to participants	42,967	71,776	(95)		114,648	8[illegible]
Deferred costs						
Unamortized debt expenses, less accumulated amortization of $36,164 and $28,178 in 1988 and 1987	210,841	161,546	1,159	54	373,600	386,802
Other deferred costs	1,309				1,309	1,542
	212,150	161,546	1,159	54	374,909	388,344
	$1,092,264	$1,043,451	$34,991	$14,511	$2,185,217	$2,182,884
Liabilities						
Long-term debt	$1,028,965	$ 998,578	$34,294	$ 100	$2,061,937	$2,087,332
Current liabilities						
Long-term debt due within one year	13,095	2,260		14,048	29,403	
Accrued interest	37,573	38,611	689	351	77,224	77,180
Accounts payable and accrued expenses	12,631	4,002	8	12	16,653	18,372
	63,299	44,873	697	14,411	123,280	95,552
Commitments and contingencies						
	$1,092,264	$1,043,451	$34,991	$14,511	$2,185,217	$2,182,884

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

Southern California Public Power Authority
Combined Statement of Operations

(In Thousands)

	Year ended June 30, 1988				
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Total*	*Year ended June 30, 1987 Total*
Operating revenues					
Sales of electric energy	$ 85,828		$2,530	$ 88,358	$ 52,015
Sales of transmission services		$ 82,332		82,332	40,617
Total operating revenues	85,828	82,332	2,530	170,690	92,632
Operating expenses					
Nuclear fuel	9,042			9,042	7,259
Other operation	13,313	8,750	1,131	23,194	17,264
Maintenance	6,388	3,159		9,547	6,274
Depreciation	18,241	19,975		38,216	30,732
Expense charged to projects during construction	(520)			(520)	(370)
Total operating expenses	46,464	31,884	1,131	79,479	61,159
Debt expenses					
Interest on debt, net	72,961	63,983	1,304	138,248	148,941
Allowance for borrowed funds used during construction	(16,699)			(16,699)	(40,498)
Net debt expense	56,262	63,983	1,304	121,549	108,443
Total expenses	102,726	95,867	2,435	201,028	169,602
Costs recoverable from future billings to participants	$ (16,898)	$ (13,535)	$ 95	$ (30,338)	$ (76,970)

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

Southern California Public Power Authority
Combined Statement of Cash Flows

(In Thousands)

	Year ended June 30, 1988					
	Palo Verde Project	*Southern Transmission System Project*	*Hoover Uprating Project*	*Mead-Phoenix Project*	*Total*	*Year en[illegible] June 30, 1987 Total*
Cash flows from operating activities:						
Sales of electric energy	$ 85,828		$ 2,530		$ 88,358	$ 52,015
Sales of transmission services		$ 82,332			82,332	40,617
Expenses of operations	(102,726)	(95,867)	(2,435)		(201,028)	(169,602)
Adjustments to arrive at net cash provided by (used for) operating activities:						
Depreciation and amortization	27,283	19,975			47,258	37,187
Other, net	10,388	6,752			17,140	17,775
Changes in current assets and liabilities:						
Interest receivable	(451)	2,113	238		1,900	(677)
Accounts receivable	2,023	2,662	66		4,751	(155)
Materials and supplies	(6,528)				(6,528)	
Other assets	232	68	54		354	23,206
Accrued interest	119				119	(14,947)
Accounts payable and accrued expenses	(1,639)	774	(816)		(1,681)	1,544
Net cash provided by (used for) operating activities	14,529	18,809	(363)		32,975	(13,037)
Cash flows from investing activities:						
Payments for construction of facility	(15,378)	(25,307)			(40,685)	(72,590)
Advances for capacity and energy, net			(2,945)		(2,945)	
Payments for feasibility study				$(1,061)	(1,061)	(771)
Purchases of investments	(1,082,161)	(1,821,388)	(149,058)	(4,479)	(3,057,086)	(2,14[illegible]
Proceeds from sale of investments	1,082,472	1,827,066	153,050	5,546	3,068,134	2,23[illegible]
Refund from (advance to) Intermountain Power Agency		820			820	(20,981)
Net cash provided by (used for) investing activities	(15,067)	(18,809)	1,047	6	(32,823)	(9,103)
Cash flows from financing activities:						
Proceeds from sale of refunding bonds						679,434
Proceeds from sale of revenue bonds						34,293
Payment for bond issue costs						(107,549)
Payment for defeasance of revenue bonds						(508,703)
Payment of bond anticipation notes						(75,000)
Net cash provided by financing activities						22,475
Net increase (decrease) in cash	(538)		684	6	152	335
Cash at beginning of year	538			8	546	211
Cash at end of year	$ —	$ —	$ 684	$ 14	$ 698	$ 546
Cash paid during the year for interest (net of amount capitalized)	$ 58,328	$ 77,221	$ 2,757	$ —	$ 138,306	$ 121,113

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

Notes to Financial Statements

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

The members have the following participation percentages in the Authority's interest in the four projects:

Participant	Palo Verde	Southern Transmission System	Hoover Uprating	Mead-Phoenix
City of Los Angeles	67.0%	59.5%		61.2%
City of Anaheim		17.6	42.6%	15.0
City of Riverside	5.4	10.2	31.9	6.0
Imperial Irrigation District	6.5			
City of Vernon	4.9			3.0
City of Azusa	1.0		4.2	.6
City of Banning	1.0		2.1	.6
City of Colton	1.0		3.2	.6
City of Burbank	4.4	4.5	16.0	5.0
City of Glendale	4.4	2.3		5.0
City of Pasadena	4.4	5.9		3.0
	100.0%	100.0%	100.0%	100.0%

Palo Verde Project—The Authority, pursuant to an assignment agreement dated as of August 14, 1981 with the Salt River Project Agricultural Improvement and Power District, purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). As of July 1, 1981, ten participants had entered into power sales contracts with the Authority to purchase the Authority's share of PVNGS capacity and energy. Units 1, 2 and 3 of the Palo Verde Project began commercial operation in January and September 1986, and January 1988, respectively.

Southern Transmission System Project—The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has agreed to make payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), a transmission line which will provide for the transmission of energy from the Intermountain Power Project (IPP) in Utah to Southern California. The Authority entered into an agreement also dated as of May 1, 1983 with six of its participants pursuant in which each member assigned its entitlement to capacity of STS to the Authority in return for the Authority's agreement to make payments-in-aid of construction to IPA. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles, a member of the Authority, has served as project manager and operating agent of IPP.

Hoover Uprating Project—The Authority and six participants entered into an agreement dated as of March 1, 1986, pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation (USBR) on behalf of such participants. Construction is scheduled for completion by September 1992. The Authority will have an 18.68% interest in the contingent capacity of the Hoover Uprating Project. Several "uprated" generators of the Hoover Uprating Project have commenced commercial operations since June 1987.

Mead-Phoenix Project—The Authority has also studied the feasibility of constructing the proposed Mead-Phoenix DC Intertie Project (Mead-Phoenix Project), a transmission line from Arizona to Nevada. The Authority's present interest in the Mead-Phoenix Project is 93.75%. The feasibility study is substantially complete and present plans call for the Authority to decide whether to continue with the project in fiscal year 1989.

NOTE B—Summary of significant accounting policies:
The Authority maintains its records substantially in accordance with accounting principles and methods prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by such commissions.

Utility plant—All expenditures, including general administrative and other overhead expenses, payments-in-aid of construction, interest net of related investment income, deferred cost amortization and the fair value of test power generated and delivered to the participants are capitalized as utility plant construction work in progress until a facility begins commercial operation.

The Authority's share of costs associated with PVNGS is included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service life of thirty-five years. Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the Authority is charged one mill per kilowatt-hour on its share of electricity produced by PVNGS. The Authority records this charge as a current year expense.

The costs associated with STS are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years.

Advances for capacity and energy—Advance payments to USBR for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by USBR billings to participants for energy and capacity.

Nuclear decommissioning — Decommissioning of PVNGS is projected to start sometime after 2027. The Authority is providing for its share of the estimated future decommissioning costs over the life of the nuclear power plant through annual charges to expense.

A Nuclear Decommissioning Fund was established in 1986. The deposits to the fund plus the interest earnings on the fund balances are expected to be sufficient to pay the Authority's share of the decommissioning costs.

Deferred costs — Deferred costs are shown net of accumulated amortization. Unamortized debt issue costs, including the cost of refunding, are amortized over the terms of the respective issues. Other deferred costs are amortized generally over five years.

Investments — Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities, These investments are stated at amortized cost. As discussed in Note C, all of the investments are restricted as to their use.

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

Debt expenses — Debt expenses include interest on debt, the amortization of bond premiums and discounts, debt issue and refunding costs. Income from investments is recorded as a reduction of debt expense.

Statement of Cash Flows — During the year ended June 30, 1988, the Authority adopted Statement of Accounting Standards No. 95, "Statement of Cash Flows." Accordingly, fiscal year 1987 items have been restated to conform with the fiscal year 1988 presentation.

NOTE C—Special funds:

The Bond Indentures for three of the four projects require the following special funds to be established to account for the Authority's receipts and disbursements. The moneys and investments held in these funds are restricted in use to the purposes stipulated in the bond indentures. A summary of these funds follows:

Fund	Held by	Purpose
Construction	Trustee	To disburse funds for the acquisition and construction of the Project
Debt Service	Trustee	To pay interest and principal related to the Revenue Bonds
Revenue	Trustee	To initially receive all revenues and disburse them to other funds
Operating	Trustee	To pay operating expenses
Reserve and Contingency	Trustee	To pay capital improvements and make up deficiencies in other funds and, in the case of the Palo Verde Project, accumulate funds for decommissioning
General Reserve	Trustee	To make up any deficiencies in other funds
Advance Payments	Trustee	To disburse funds for the cost of acquisition of capacity

Special funds, in thousands, were as follows:

	June 30,			
	1988		1987	
Project	Carrying Value	Market	Carrying Value	Market
Palo Verde	$224,122	$231,950	$224,520	$235,136
STS	171,784	171,139	180,395	192,319
Hoover Uprating	33,927	33,609	34,528	34,217
Mead-Phoenix	1,857	1,860	2,918	2,918
	$431,690	$438,558	$442,361	$464,590

Palo Verde Project — The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Construction Fund—		
Initial Facilities Account	$ 48,666	$ 38,454
Debt Service Fund—		
Debt Service Account	63,780	67,711
Debt Service Reserve Account	90,050	90,235
Bond Anticipation Note Fund	30	30
Revenue Fund	735	1
Operating Fund	11,155	15,739
Reserve and Contingency Fund	9,706	8,169
General Reserve Fund		4,181
Total Special Funds	$224,122	$224,520

Southern Transmission System Project — The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Construction Fund—		
Initial Facilities Account	$ 10,310	$ 18,638
Debt Service Fund—		
Debt Service Account	41,086	38,623
Debt Service Reserve Account	89,079	91,192
Revenue Fund	1	1
Operating Fund	7,239	6,249
General Reserve Fund	3,908	4,711
Total Special Funds	$151,623	$159,414

During fiscal year 1987 the Authority advanced to IPA $20,981,000 for their proportionate share of certain operating and capital requirements associated with STS. During fiscal year 1988 the advance was reduced to $20,161,000.

Hoover Uprating Project — The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Advance Payments Fund	$ 23,244	$ 27,277
Operating Working Capital Fund	340	
Debt Service Fund		
Debt Service Account	714	932
Debt Service Reserve Account	3,620	3,255
Total Special Funds	$ 27,918	$ 31,464

At June 30, 1988 the Authority had advances to USBR amounting to $6,009,000.

Mead-Phoenix Project—At June 30, 1988 and 1987, the balance in the Development Fund was $1,857,000 and $2,918,000 of which substantially all were invested in securities of the United States Government.

NOTE D—Long-term debt:

Palo Verde Project—To finance the purchase and construction of the Authority's share of the Palo Verde Project, the Authority issued Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of July 1, 1981 (Bond Indenture), as amended and supplemented. Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Palo Verde Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject to the provisions of the Palo Verde Project Bond Indenture providing for the application thereof.

All outstanding Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal year 1998 for the 1982 Series A Bonds, 1999 for the 1982 Series B Bonds and the 1983 Series A Bonds, 2001 for the 1984 Series A Bonds and the 1985 Series A Bonds, 2005 for the 1985 Series B Bonds and 2003 for the 1986 Series A Bonds, the 1986 Series B Bonds and the 1987 Series A Bonds. Scheduled principal maturities for the Palo Verde Project during the five fiscal years following June 30, 1988 are $13,095,000 in 1989, $13,870,000 in 1990, $14,745,000 in 1991, $15,790,000 in 1992 and $16,955,000 in 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 7.2% and 8.4%, respectively.

Southern Transmission System Project—To finance payments-in-aid of construction to IPA for construction of STS the Authority issued Transmission Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of May 1, 1983 (Bond Indenture), as amended and supplemented. Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to STS (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture; subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Transmission Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal year 2000 for the 1984 Series A Bonds, 2001 for the 1984 Series B Bonds and the 1985 Series A Bonds, 2003 for the 1986 Series A Bonds and 2002 for the 1986 Series B Bonds. Scheduled principal maturities for STS during the five fiscal years following June 30, 1988 are $2,260,000 in 1989, $3,785,000 in 1990, $7,945,000 in 1991, $8,485,000 in 1992 and $9,115,000 in 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 7.7%.

Hoover Uprating Project—To finance advance payments to USBR for application to the costs of the Hoover Uprating Project, the Authority issued Hydroelectric Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of March 1, 1986 (Bond Indenture). Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) the proceeds from the sale of the bonds, (2) all revenues from sales of energy to participants (see Note E), (3) interest or other receipts derived from any moneys or securities held pursuant to the Bond Indenture and (4) all funds established by the Indenture of Trust (except for the Interim Advance Payments Account in the Advance Payment Fund); subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Hydroelectric Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires manadatory sinking fund instalments to be made beginning in fiscal year 2002 for the 1986 Series A Bonds. No principal maturities of bonds outstanding at June 30, 1988 are scheduled for fiscal years 1989 through 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 8.0% and 8.1%, respectively.

The Authority estimates that the total financing requirements for its interest in the Hoover Uprating Project will approximate $34 million, of which substantially all will be expended for payments for capacity and associated firm energy and the acquisition of entitlements to capacity.

Mead-Phoenix Project—At June 30, 1988, the Authority had borrowed $14,148,000 to finance the feasibility study and development costs of the Mead-Phoenix Project. This loan bears interest at approximately 67% of the prime rate; however, the interest rate cannot exceed 12%. The average interest rate on this loan was 5.9% and 5.2% during fiscal years 1988 and 1987, respectively.

The proceeds of the loan were deposited in a Development Fund for which the lender is the trustee and can only be used for payment of Mead-Phoenix Project development costs, costs of issuance of the loan, including general and administrative expenses of the Authority related to the Mead-Phoenix Project, and loan principal and interest.

The feasibility study is substantially complete and present plans call for the Authority to decide whether to continue with the project in fiscal year 1989.

On April 6, 1988, the Authority adopted a note retirement plan. The plan involves voluntary payments by each participant of its proportionate share of the liability with respect to the loan. The Authority intends to repay all but $100,000 during fiscal year 1989.

Refunding bonds—During fiscal year 1987, the proceeds from the sale of $707,275,000 of Power Project Refunding Bonds were used to advance refund $630,120,000 of previously issued bonds. In connection therewith, the net proceeds of the refunding bonds have been invested in securities of the United States Government, the principal and interest from which will be sufficient to fund the remaining principal, interest and call premium payments on the refunded bonds until the stated first call dates of the respective issues. Accordingly, all amounts related to the refunded bonds have been removed from the balance sheets and the cost of refunding the debt is included in unamortized debt expenses. At June 30, 1988 the aggregate amount of debt considered to be extinguished was $1,875,050,000.

NOTE E—Power sales and transmission service contracts:
The Authority has sold its entitlement to the output of the Palo Verde Project pursuant to power sales contracts with ten participants (see Note A). Under the terms of the contracts, the participants are entitled to power output from the Palo Verde Nuclear Generating Station and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Power Project Revenue Bonds and other debt, whether or not the Palo Verde Project or any part thereof has been completed, is operating or operable, or its output is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2030 and, as long as any Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

The Authority has entered into transmission service contracts with six participants of STS (See Note A). Under the terms of the contracts, the participants are entitled to transmission service utilizing STS and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Transmission Project Revenue Bonds and other debt, whether or not STS or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2027 and, as long as any Transmission Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In March 1986, the Authority entered into power sales contracts with six participants of the Hoover Uprating Project (see Note A). Under the terms of the contracts, the participants are entitled to capacity and associated firm energy of the Hoover Uprating Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service whether or not the Hoover Uprating Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2018 and as long as the Hydroelectric Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

NOTE F—Costs recoverable from future billings to participants:
Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. Those expenses, according to generally accepted accounting principles, which are not included as "costs" are deferred to such periods as they are intended to be recovered through billings.

NOTE G—Commitments and contingencies:
As a participant in the PVNGS, the Authority could be subject to assessment of retroactive insurance premium adjustments in the event of a nuclear incident at the PVNGS or at any other licensed reactor in the United States.

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

Index to Supplemental Financial Information

Southern California Public Power Authority
Combined Schedule of Long-Term Debt
June 30, 1988
Thousands)

	Series	Date of Sale	Effective Interest Rate	Maturity on July 1	Total
Palo Verde Project Revenue and Refunding Bonds	1982A	8/13/82	10.9%	1988 to 2017	$ 26,325
	1982B	11/12/82	7.7%	1988 to 2017	44,445
	1983A	4/ 8/83	8.8%	1988 to 2017	36,015
	1984A	7/18/84	10.3%	1990 to 2004	24,090
	1985A	5/22/85	8.7%	1988 to 2014	12,515
	1985B	7/ 2/85	9.1%	1988 to 2017	101,815
	1986A	3/13/86	8.2%	1988 to 2015	157,645
	1986B	12/16/86	7.2%	1988 to 2017	354.630
	1987A	2/11/87	6.9%	1988 to 2017	352,645
					1,110,125
Southern Transmission System Project Revenue and Refunding Bonds	1984A	2/ 9/84	9.3%	1990 to 2004	65,945
	1984B	10/17/84	10.2%	1990 to 2000	18,770
	1985A	8/15/85	8.9%	1989 to 2021	121,620
	1986A	3/18/86	8.0%	1988 to 2021	371,720
	1986B	4/29/86	7.5%	1988 to 2023	480,010
					1,058,065
Hoover Uprating Project Revenue Bonds	1986A	8/13/86	8.1%	1993 to 2017	34,435
Mead-Phoenix Bank Loan					14,148
Total Principal Amount					2,216,773
Less: Unamortized Bond Discount—					
Palo Verde Project Revenue and Refunding Bonds					68,065
Southern Transmission System Project Revenue and Refunding Bonds					57,227
Hoover Uprating Project Revenue Bonds					141
Total Unamortized Bond Discount					125,433
Total Long-Term Debt Less Unamortized Bond Discount					$2,091,340

Bonds which have been refunded are excluded from this schedule.

Southern California Public Power Authority
Palo Verde Project
Supplemental Balance Sheet

(In Thousands)

	June 30, 1988	June 30, 1987
Assets		
Utility plant		
Production	$ 600,458	$ 368,755
Transmission	5,988	3,512
General	81	58
	606,527	372,325
Less — Accumulated depreciation	34,224	15,983
	572,303	356,342
Construction work in progress	2,028	224,809
Nuclear fuel, at amortized cost	31,330	36,415
Net utility plant	605,661	617,566
Special funds		
Investments	221,918	222,229
Interest receivable	2,204	1,753
Cash		538
	224,122	224,520
Accounts receivable	836	2,859
Materials and supplies	6,528	
Costs recoverable from future billings to participants	42,967	26,069
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $18,643 and $13,698 in 1988 and 1987	210,841	218,503
Other deferred costs	1,309	1,[illegible]
	212,150	220,[illegible]
	$1,092,264	$1,091,059
Liabilities		
Long-term debt	$1,028,965	$1,039,335
Current liabilities		
Long-term debt due within one year	13,095	
Accrued interest	37,573	37,454
Accounts payable and accrued expenses	12,631	14,270
	63,299	51,724
Commitments and contingencies		
	$1,092,264	$1,091,059

Southern California Public Power Authority
Palo Verde Project
Supplemental Statement of Operations
(In Thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Operating revenue		
Sales of electric energy	$ 85,828	$ 51,949
Operating expenses		
Nuclear fuel	9,042	7,259
Other operation	13,313	10,162
Maintenance	6,388	3,192
Depreciation	18,241	12,643
Expense charged to projects during construction	(520)	(370)
Total operating expenses	46,464	32,886
Debt expenses		
Interest on debt, net	72,961	78,290
Allowance for borrowed funds used during construction	(16,699)	(40,498)
Net debt expense	56,262	37,792
Total expenses	102,726	70,678
Costs recoverable from future billings to participants	$ (16,898)	$ (18,729)

Southern California Public Power Authority
Palo Verde Project
Supplemental Statement of Cash Flows
(In Thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Cash flows from operating activities:		
Sales of electric energy	$ 85,828	$ 51,949
Expenses of operations	(102,726)	(70,678)
Adjustments to arrive at net cash provided by (used for) operating activities:		
Depreciation and amortization	27,283	19,098
Other, net	10,388	9,723
Changes in current assets and liabilities:		
Interest receivable	(451)	515
Accounts receivable	2,023	2,560
Materials and supplies	(6,528)	
Other assets	232	
Accrued interest	119	(4,529)
Accounts payable and accrued expenses	(1,639)	5,055
Net cash provided by operating activities	14,529	13,693
Cash flows from investing activities:		
Payments for construction of facility	(15,378)	(55,131)
Purchases of investments	(1,082,161)	(1,124,179)
Proceeds from sale of investments	1,082,472	1,176,515
Net cash used for investing activities	(15,067)	(2,795)
Cash flows from financing activities:		
Proceeds from sale of refunding bonds		679,434
Payment for bond issue costs		(106,289)
Payment for defeasance of revenue bonds		(508,703)
Payment of bond anticipation notes		(75,000)
Net cash used for financing activities		(10,558)
Net increase (decrease) in cash	(538)	340
Cash and beginning of year	538	198
Cash at end of year	$ —	$ 538
Cash paid during the year for interest (net of amount capitalized)	$ 58,328	$ 43,819

Southern California Public Power Authority
Palo Verde Project
Supplemental Schedule of Receipts and Disbursements in Funds Required by the Bond Indenture
Year Ended June 30, 1988

(In Thousands)

	Construction Fund Initial Facilities Account	*Debt Service Fund*	*Bond Anticipation Note Fund*	*Revenue Fund*	*Operating Fund*	*Reserve & Contingency Fund*	*General Reserve Fund*	*Total*
Balance at June 30, 1987	$ 38,234	$157,906	$ 29		$15,575	$8,478	$ 4,178	$224,400
Additions								
Investment earnings	2,335	14,896	1	$ 82	1,323	1,040	6	19,683
Sales	1,896			85,716				87,612
Other income	58				59			117
Transfer of interest payment		102,906						102,906
Transfer of investments	8,458				(2,563)	(1,724)	(4,171)	
Transfer of investment earnings	5,597	(14,630)	(1)	11,112	(1,308)	(764)	(6)	
Transfer of sales receipts		71,680		(99,488)	19,038	3,880	4,890	
Miscellaneous transfers	1,453	(66)		2,996	250	264	(4,897)	
Total	19,797	174,786	—	418	16,799	2,696	(4,178)	210,318
Deductions								
Construction expenditures	5,489					845		6,334
Operating expenditures					18,046			18,046
Fuel costs	2,920				591			3,511
Interest		178,052						178,052
Property tax	1,332				2,665			3,997
Financing costs	141							141
Interest on investment purchases	14	22			15	18		69
Premium on investment purchases	368	244				628		1[illegible]
Total	10,264	178,318			21,317	1,491		211,3[illegible]
Balance at June 30, 1988	$ 47,767	$154,374	$ 29	$ 418	$11,057	$9,683	$ —	$223,328

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,204 and $1,753 at June 30, 1988 and 1987, nor do they include total amortized net investment premiums of $1,724 and $1,632 at June 30, 1988 and 1987.

Southern California Public Power Authority
Southern Transmission System Project
Supplemental Balance Sheet
(In thousands)

	June 30, 1988	June 30, 1987
Assets		
Utility plant		
Transmission	$ 656,773	$ 633,034
General	18,724	18,068
	675,497	651,102
Less—Accumulated depreciation	38,064	18,089
	637,433	633,013
Construction work in progress	912	
Net utility plant	638,345	633,013
Special funds		
Investments	150,768	156,446
Advance to Intermountain Power Agency	20,161	20,981
Interest receivable	855	2,968
	171,784	180,395
Accounts receivable		2,662
Costs recoverable from future billings to participants	71,776	58,241
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $16,910 and $13,999 in 1988 and 1987	161,546	167,084
	$1,043,451	$1,041,395
Liabilities		
Long-term debt	$ 998,578	$ 999,556
Current liabilities		
Long-term debt due within one year	2,260	
Accrued interest	38,611	38,611
Accounts payable and accrued expenses	4,002	3,228
	44,873	41,839
Commitments and contingencies		
	$1,043,451	$1,041,395

Southern California Public Power Authority
Southern Transmission System Project
Supplemental Statement of Operations
(In Thousands)

	Year ended June 30, 1988	1987
Operating revenue		
Sales of transmission services	$ 82,332	$ 40,617
Operating expenses		
Other operation	8,750	7,036
Maintenance	3,159	3,082
Depreciation	19,975	18,089
Total operating expenses	31,884	28,207
Debt expenses		
Interest on debt, net	63,983	70,651
Total expenses	95,867	98,858
Costs recoverable from future billings to participants	$(13,535)	$(58,241)

Southern California Public Power Authority
Southern Transmission System Project
Supplemental Statement of Cash Flows
(In Thousands)

	Year ended June 30, 1988	1987
Cash flows from operating activities:		
Sales of transmission services	$ 82,332	$ 40,617
Expenses of operations	(95,867)	(98,858)
Adjustments to arrive at net cash provided by (used for) operating activities:		
Depreciation and amortization	19,975	18,[illegible]
Other, net	6,752	8,052
Changes in current assets and liabilities:		
Interest receivable	2,113	(690)
Accounts receivable	2,662	(2,649)
Other assets	68	23,157
Accrued interest		(11,107)
Accounts payable and accrued expenses	774	(4,335)
Net cash provided by (used for) operating activities	18,809	(27,724)
Cash flows from investing activities:		
Payments for construction of facility	(25,307)	(14,395)
Purchases of investments	(1,821,388)	(933,018)
Proceeds from sale of investments	1,827,066	996,118
Refund from (advance to) Intermountain Power Agency	820	(20,981)
Net cash provided by (used for) investing activities	(18,809)	27,724
Net increase (decrease) in cash		
Cash at beginning of year		
Cash at end of year	$ —	$ —
Cash paid during the year for interest	$ 77,221	$ 77,294

Southern California Public Power Authority
Southern Transmission System Project
Supplemental Schedule of Receipts and Disbursements in Funds Required by the Bond Indenture
Year Ended June 30, 1988

(In Thousands)

	Construction Fund Initial Facilities Account	*Debt Service Fund*	*Revenue Fund*	*Operating Fund*	*General Reserve Fund*	*Total*
Balance at June 30, 1987	$18,480	$126,864		$6,237	$ 4,584	$156,165
Additions						
Investment earnings	987	20,407	$ 143	479	416	22,432
Sales			82,255			82,255
Transfer of interest payment		85,841				85,841
Transfer of investments	11,295				(11,295)	
Transfer of investment earnings		(6,392)	2,505	(479)	4,367	1
Transfer of funds	3,307	(6,416)	(2,647)		5,762	6
Transfer of sales receipts		72,408	(82,256)	9,848		
Miscellaneous receipts	2,948					2,948
Total	18,537	165,848	—	9,848	(750)	193,483
Deductions						
Payments-in-aid of construction and administrative costs	26,921					26,921
Operating expenditures				8,855		8,855
Interest		163,061				163,061
Interest on investment purchases		505				505
Premium on investment purchases		14				14
Total	26,921	163,580		8,855		199,356
Balance at June 30, 1988	$10,096	$129,132	$ —	$7,230	$ 3,834	$150,292

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $855 and $2,968 at June 30, 1988 and 1987, nor do they include total amortized net investment discounts of $477 and $281 at June 30, 1988 and 1987.

Southern California Public Power Authority
Hoover Uprating Project
Supplemental Balance Sheet
(In Thousands)

	June 30, 1988	June 30, 1987
Assets		
Special funds		
Investments	$26,970	$30,962
Interest receivable	264	502
Cash	684	
	27,918	31,464
Accounts receivable		66
Advances for capacity and energy, net	6,009	3,064
Cost recoverable from future billings to participants	(95)	
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $102 and $49 in 1988 and 1987	1,159	1,212
	$34,991	$35,806
Liabilities		
Long-term debt	$34,294	$34,293
Current liabilities		
Accrued interest	689	689
Accounts payable and accrued expenses	8	824
	697	1,513
Commitments and contingencies		
	$34,991	$35,806

Southern California Public Power Authority
Hoover Uprating Project
Supplemental Statement of Operations
(In Thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Operating revenues		
Sales of electric energy	$ 2,530	$ 66
Operating expenses		
Capacity charges	235	13
Energy charges	652	53
Other operation	244	
Total operating expenses	1,131	66
Debt expenses		
Interest on debt, net	1,304	
Total expenses	2,435	66
Cost recoverable from future billings to participants	$ 95	$ —

Southern California Public Power Authority
Hoover Uprating Project
Supplemental Statement of Cash Flows
(In thousands)

	Year ended June 30, 1988	1987
Cash flows from operating activities:		
Sales of electric energy	$ 2,530	$ 66
Expenses of operations	(2,435)	(66)
Adjustments to arrive at net cash provided by (used for) operating activities:		
Changes in current assets and liabilities:		
Interest receivable	238	(502)
Accounts receivable	66	(66)
Accrued interest		689
Other assets	54	49
Accounts payable and accrued expenses	(816)	824
Net cash provided by (used for) operating activities	(363)	994
Cash flows from investing activities:		
Payments for construction of facility	(2,945)	(3,064)
Purchases of investments	(149,058)	(85,662)
Proceeds from sale of investments	153,050	54,699
Net cash provided by (used for) investing activities	1,047	(34,027)
Cash flows from financing activities:		
Proceeds from sale of revenue bonds		34,293
Payment for bond issue costs		(1,260)
Net cash provided by financing activities		33,033
Net increase in cash	684	
Cash at beginning of year		
Cash at end of year	$ 684	$ —
Cash paid during the year for interest	$ 2,757	$ —

Southern California Public Power Authority
Hoover Uprating Project
Supplemental Schedule of Receipts and Disbursements in Funds Required by the Bond Indenture
For the Year Ended June 30, 1988

(In Thousands)

	Advance Payments Fund	*Interim Advance Payments Fund*	*Revenue Fund*	*Operating Fund*	*Operating Working Capital Fund*	*Debt Service Account*	*Debt Service Reserve Account*	*Total*
Balance at June 30, 1987	$25,242	$2,243				$ 941	$3,253	$31,679
Additions								
Investment earnings	2,185	373	$ 3		$ 17	72	296	2,946
Sales			2,596					2,596
Transfer of investments	(3,915)	3,915						
Transfer of investment earnings	738	(410)	(3)		(17)	(26)	(282)	
Transfer of sales receipts			(2,596)	$66		2,530		
Miscellaneous transfers	(3,136)	2,424			340		372	
Total	(4,128)	6,302	—	66	340	2,576	386	5,542
Deductions								
Advances for capacity and energy		4,448						4,448
Payments for capacity and energy charges				66				66
Administrative expenditures	921							921
Interest						2,757		2,757
Interest on investment purchases							14	14
Premium on investment purchases	439	16				46	1	502
Total	1,360	4,464		66		2,803	15	8,708
Balance at June 30, 1988	$19,754	$4,081	$ —	$—	$ 340	$ 714	$3,624	$28,513

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balan the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $264 and $466 at June 30, 1988 and 1987, they include total amortized net investment premiums of $858 and $676 at June 30, 1988 and 1987.

Southern California Public Power Authority
Mead-Phoenix Project
Supplemental Balance Sheet
(In Thousands)

	June 30, 1988	June 30, 1987
Assets		
Utility plant		
Construction work in progress	$12,600	$11,703
Special funds		
Investments	1,843	2,910
Cash	14	8
	1,857	2,918
Deferred charges		
Unamortized debt expenses, less accumulated amortization of $509 and $432 in 1988 and 1987	54	3
	$14,511	$14,624
Liabilities		
Long-term debt	$ 100	$14,148
Current liabilities		
Long-term debt due within one year	14,048	
Accrued interest	351	426
Accounts payable and accrued expenses	12	50
	14,411	476
Commitments and contingencies		
	$14,511	$14,624

Southern California Public Power Authority
Mead-Phoenix Project
Supplemental Statement of Cash Flows
(In Thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Cash flows from operating activities:	$ —	$ —
Cash flows from investing activities:		
Payments for feasibility study	(1,061)	(771)
Purchases of investments	(4,479)	(6,299)
Proceeds from sale of investments	5,546	7,065
Net cash provided by (used for) investing activities	6	(5)
Cash flows from financing activities:	—	—
Net increase (decrease) in cash	6	(5)
Cash at beginning of year	8	13
Cash at end of year	$ 14	$ 8

SCPPA

Southern
California
Public Power
Authority
633 E. Broadway
Room 300
Glendale,
California 91205

NEW ISSUE

$295,005,000

Southern California Public Power Authority

(a public entity organized under the laws of the State of California)

Power Project Revenue Bonds, 1989 Refunding Series A

(Palo Verde Project)

Dated: January 15, 1989 Due: July 1, as shown below

(Zero Coupon Bonds are dated as of delivery date)

Semiannual interest on the 1989 Bonds (payable each January 1 and July 1, commencing July 1, 1989) is payable by check or draft mailed to the registered owner. Principal of the 1989 Bonds is payable at the principal corporate trust offices of First Interstate Bank of California, Los Angeles, California, Trustee. The 1989 Bonds will be issued as fully registered bonds in the denomination of $5,000 or any integral multiple thereof.

The 1989 Bonds are subject to redemption prior to maturity as set forth herein.

In the opinion of Bond Counsel, under existing law, interest on the 1989 Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the tax covenant described herein, interest on the 1989 Bonds is excluded from gross income for Federal income tax purposes and is not a specific preference item for purposes of the Federal alternative minimum tax. See, however, "Federal and State Income Taxes" herein for a description of certain other taxes on corporations.

The 1989 Bonds are being issued to provide moneys to advance refund certain of the Authority's outstanding Power Project Revenue Bonds, all of which were issued to finance costs of acquisition and construction of the Authority's interest and rights in the Palo Verde Nuclear Generating Station located near Phoenix, Arizona and certain associated facilities, and to finance costs of issuance related thereto.

The principal of, premium, if any, and interest on the 1989 Bonds are payable solely from and secured solely by a pledge and assignment of Revenues and certain other moneys as described herein. Such Revenues include all payments attributable to the Project to be made to the Authority by the Project Participants pursuant to the Power Sales Contracts. Such payments, together with other available Revenues, are to equal the Authority's costs relating to the Project. Each Project Participant has agreed to make its share of such payments solely from its electric system revenues. The payment obligations of the Project Participants under the Power Sales Contracts are not contingent upon the operation of the Project or the performance or nonperformance by any party under any agreement for any cause whatever.

The 1989 Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 1989 Bonds. The Authority has no taxing power.

AMOUNTS, MATURITIES, INTEREST RATES AND PRICES OR YIELDS

$72,680,000 Serial Bonds

Amount	Maturity	Interest Rate	Price
$ 500,000	1989	5.80%	100%
510,000	1990	6	100
535,000	1991	6.10	100
575,000	1992	6.20	100
605,000	1993	6.30	100
645,000	1994	6.40	100
3,930,000	1995	6.40	100 *

Amount	Maturity	Interest Rate	Price or Yield
$ 6,120,000	1996	6½ %	100%*
14,375,000	1997	6.60	100 *
13,360,000	1998	6.70	100 *
11,695,000	1999	6.80	100 *
9,580,000	2001	7	100 *
10,250,000	2003	7¼	7.20

$23,125,000 7% Term Bonds Due July 1, 2007 — Price 97.472%*

$42,040,000 7% Term Bonds Due July 1, 2010 — Price 97.000%*

$24,040,000 5% Term Bonds Due July 1, 2015 — Price 74.000%*

(Accrued interest to be added)

$133,120,000 Zero Coupon Bonds

Principal Amount	Initial Amount	Maturity	Yield	Price (per $100)
$14,010,000	$6,404,111	2000	7 %	$45.711*
10,245,000	4,054,766	2002	7.05	39.578*
6,695,000	2,272,819	2004	7.15	33.948*
20,360,000	4,136,541	2011	7¼	20.317*
$28,890,000	$5,466,277	2012	7¼ %	$18.921*
28,890,000	5,090,418	2013	7¼	17.620*
24,030,000	3,943,083	2014	7¼	16.409*

* Payment of the principal of and interest on the Insured Bonds when due will be insured by a municipal bond insurance policy to be issued by AMBAC Indemnity Corporation simultaneously with the delivery of the Insured Bonds.

The 1989 Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel, and certain other conditions. Certain legal matters will be passed upon for the Underwriters by their counsel, O'Melveny & Myers. It is expected that the 1989 Bonds in definitive form will be available for delivery in New York, New York on or about February 15, 1989.

Smith Barney, Harris Upham & Co.
Incorporated

The First Boston Corporation

Merrill Lynch Capital Markets

Shearson Lehman Hutton Inc.

Dean Witter Capital Markets

Grigsby, Brandford & Co., Inc.

February 2, 1989

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

BOARD OF DIRECTORS

W. E. Cameron (Glendale)
Bill D. Carnahan (Riverside)
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MANAGEMENT

Gale A. Drews — President
W. E. Cameron — Vice President
Eldon A. Cotton — Secretary
Arthur T. Devine — Executive Director, Treasurer/Auditor
Horace W. Rupp, Jr. — Assistant Secretary

PROJECT PARTICIPANTS

Department of Water and Power of The City of Los Angeles
Imperial Irrigation District
City of Riverside
City of Vernon
City of Burbank
City of Glendale
City of Pasadena
City of Azusa
City of Banning
City of Colton

TRUSTEE, REGISTRAR AND PAYING AGENT

First Interstate Bank of California
Los Angeles, California

CONSULTING ENGINEER

R. W. Beck and Associates
Seattle, Washington

BOND COUNSEL

Mudge Rose Guthrie Alexander & Ferdon
Los Angeles, California

SPECIAL COUNSEL

Rourke & Woodruff, a Professional Corporation
Orange, California

FINANCIAL ADVISOR

O'Brien Partners Inc.
New York, New York

No dealer, broker, salesman or other person has been authorized by Southern California Public Power Authority or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Authority or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 1989 Bonds by any person in any jurisdiction in which it is unlawful for such persons to make such offer, solicitation or sale.

The information set forth herein has been furnished by the Authority and the Project Participants, and includes information obtained from other sources which are believed to be reliable, but no representation as to the accuracy or completeness of such information is made by the Underwriters. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Project Participant since the date hereof.

IN CONNECTION WITH THE OFFERING OF THE 1989 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

TABLE OF CONTENTS

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Official Statement

relating to

$295,005,000

Southern California Public Power Authority

Power Project Revenue Bonds, 1989 Refunding Series A

INTRODUCTION

This Official Statement (which includes the cover page, the table of contents and the Appendices attached hereto) is furnished by Southern California Public Power Authority (the "Authority"), a joint powers agency and a public entity organized under the laws of the State of California, to provide information concerning the Project described herein, and the $295,005,000 aggregate principal amount of Power Project Revenue Bonds, 1989 Refunding Series A (the "1989 Bonds") to be issued by the Authority.

The 1989 Bonds are being issued pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), and the Authority's Indenture of Trust (the "Original Indenture"), dated as of July 1, 1981, by and between the Authority and First Interstate Bank of California, as trustee (the "Trustee"), as amended and supplemented by the First Supplemental Indenture of Trust, dated as of August 1, 1982, by and between the Authority and the Trustee, and as supplemented by the Tenth Supplemental Indenture of Trust, dated as of January 1, 1989, by and between the Authority and the Trustee. The Original Indenture and indentures supplemental thereto and amendatory thereof, including the First Supplemental Indenture of Trust and the Tenth Supplemental Indenture of Trust, are herein collectively referred to as the "Bond Indenture", The 1989 Bonds and other bonds heretofore or hereafter issued by the Authority pursuant to the Act and the Bond Indenture, to the extent Outstanding (as defined in the Bond Indenture) are herein referred to as the "Bonds".

The Authority currently has Outstanding $1,097,030,000 aggregate principal amount of Bonds, including the Bonds being refunded by the 1989 Bonds (together, the "Prior Series Bonds"), issued to finance costs of acquisition and construction of the Authority Interest (hereinafter defined). Upon issuance of the 1989 Bonds, $1,204,400,000 aggregate principal amount of Bonds will be Outstanding.

The 1989 Bonds are being issued by the Authority to provide moneys to advance refund certain of the Prior Series Bonds all of which were issued to finance costs of acquisition and construction of the Authority Interest and to pay costs of issuance related thereto. See "The Authority's Refunding Plan".

The Authority

The Authority, the membership of which is comprised of ten cities and one irrigation district of the State of California, was formed pursuant to the Act, and the Joint Powers Agreement, dated as of November 1, 1980 (said Joint Powers Agreement as amended to the date hereof being hereinafter referred to as the "Joint Powers Agreement"). See "Southern California Public Power Authority — Formation and Membership". Certain duties and responsibilities of the Authority arising in connection with the Project are performed by the Department of Water and Power of The City of Los Angeles (the "Agent" or "Department") pursuant to the Agency Agreement, dated as of July 1, 1981 (the "Agency Agreement"). See "Southern California Public Power Authority — Organization and Management".

The Project and the ANPP Transmission System

The Prior Series Bonds were issued by the Authority for the purpose of financing the purchase from Salt River Project Agricultural Improvement and Power District ("Salt River Project"), pursuant to the Salt River Project-Authority Palo Verde Nuclear Generating Station Assignment Agreement, dated as of August 14, 1981, as amended (the "Assignment Agreement"), and financing costs of acquisition, construction and placing into operation, of (a)(i) a 5.91% undivided ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3 ("PVNGS"), certain associated facilities and contractual rights relating thereto, and (ii) a 5.56% undivided ownership interest in the ANPP High Voltage Switchyard and contractual rights relating thereto; and (b) a 6.55% share of the right to use the Arizona Nuclear Power Project Valley Transmission System. PVNGS, including certain associated facilities and contractual rights and the ANPP High Voltage Switchyard and associated contractual rights are collectively referred to herein as the "Project". Additionally, the Arizona Nuclear Power Project Valley Transmission System is referred to herein as the "ANPP Transmission System". The Authority's ownership interest in and rights to use the Project and the ANPP Transmission System are collectively referred to herein as the "Authority Interest". The transfer of the Authority Interest from Salt River Project to the Authority took place on September 10, 1982 at a cost to the Authority of $265,005,281. The Project and the ANPP Transmission System are presently owned as tenants in common by Salt River Project, Arizona Public Service Company ("APS"), Public Service Company of New Mexico ("PNM") and El Paso Electric Company ("El Paso") pursuant to the Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, as amended (the "Participation Agreement"). The Authority, Southern California Edison Company ("Edison") and the Department are also owners as tenants in common of the Project pursuant to the Participation Agreement, but they have no ownership interest in the ANPP Transmission System. In connection with financing of the Project, APS, PNM and El Paso have transferred portions of their ownership interests in PVNGS and related facilities in various sale and leaseback transactions. See "Availability of Operating Funds and Available Information Concerning Other Owners of Palo Verde Nuclear Generating Station". Pursuant to the Participation Agreement, APS has constructed and operates and maintains the Project on its behalf and on behalf of the other owners, with the exception of the switchyard portions of the Project which were constructed and are being managed by Salt River Project.

Construction of the Project began on June 10, 1976. The construction of large electric generating facilities such as the Project includes two basic phases. The first phase, identified and reported by APS as "construction," includes erection of the various buildings and installation of equipment and systems. The second phase, identified and reported by APS as "startup," includes certain operational activities such as cleaning systems, starting and testing equipment and systems and measuring performance. The start-up phase is completed upon the loading of nuclear fuel into the reactor pressure vessel. Following fuel loading, the operation of each unit is tested, in a power ascension program, at various power levels up to 100 percent power. The power ascension program is completed upon declaration that the unit has achieved firm power operation at full power.

Units 1, 2 and 3 were declared to have achieved firm power operation on January 27, 1986, September 18, 1986 and January 19, 1988, respectively.

Based on among other things, cost estimates provided by APS, and considering that the Project and ANPP Transmission System are fully operational and certain assumptions provided by the Department, as the Authority's agent, the estimated construction costs of the Authority Interest is $465,170,000. The Authority has completed financing of the estimated costs of acquisition and construction of the Authority Interest.

Power Sales and Transmission

The Authority has sold the entire capability of the Authority Interest in the Project pursuant to power sales contracts (the "Power Sales Contracts") with nine California municipalities and a California irrigation district (collectively, the "Project Participants"), each of which is a member of

the Authority and is represented on the Authority's Board of Directors. For selected information with respect to the Project Participants, see "The Project Participants" and Appendix B hereto.

The existing power supplies for the Project Participants consist of owned generation and purchases from other utilities. Although the Authority Interest provides a source of firm capacity and energy to assist in meeting load growth, it is more important to the Project Participants as a source of energy which can be produced from fuel sources other than oil and natural gas.

Under the Power Sales Contracts, the Project Participants are entitled to Project generation capabilities based on their respective Project Entitlement Shares, and the Project Participants are obligated to make payments therefor on a "take or pay" basis, that is, whether or not the Authority Interest or any part thereof is operating or is operable (or has been completed), or its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The payment obligations under the Power Sales Contracts constitute operating expenses of the respective Project Participants, payable solely from their electric system revenues. See "Security and Sources of Payment for the Bonds — Power Sales Contracts" and "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C hereto.

Pursuant to the Transmission Agreement, dated as of August 14, 1981, as amended, between the Authority and Salt River Project (the "Transmission Agreement"), the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which will be utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of the Imperial Irrigation District (the "District"). The output of the Authority Interest, with the exception of the District's Project Entitlement, is received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project makes available to the Authority an equivalent amount of power and energy at a combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation (the "Project Interconnection Point"). The Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station. The District has acquired an ownership interest in the Palo Verde to Imperial Valley portion of the APS/San Diego Gas & Electric Company 525 kV Interconnection Project (the "Southwest Powerlink") as a permanent means of transmitting its Project Entitlement. This project was completed in June 1984. The District completed the new 230 kV interconnection between the Southwest Powerlink and the District system in December 1984.

Cost and Entitlement Shares

The following table sets forth the Cost and Entitlement Shares of each of the Project Participants with respect to the Authority Interest.

Project Participants	Cost Share and Entitlement Share
Department of Water and Power of The City of Los Angeles	67.0%
Imperial Irrigation District	6.5
City of Riverside	5.4
City of Vernon	4.9
City of Burbank	4.4
City of Glendale	4.4
City of Pasadena	4.4
City of Azusa	1.0
City of Banning	1.0
City of Colton	1.0
Total	100.0%

In preparing this Official Statement, the Authority has relied upon (i) the studies, considerations, assumptions and opinions of R.W. Beck and Associates (the "Consulting Engineer") set forth in its report attached hereto as Appendix A (the "Consulting Engineer's Report"), (ii) a letter of the Department, a copy of which is attached hereto as Appendix F, (iii) certain information relating to the Project provided to the Authority by Salt River Project, APS and the Agent, and (iv) certain information relating to the Project Participants furnished to the Authority by the respective Project Participants. This Official Statement also includes summaries of the terms of the Bonds, the Bond Indenture and certain contracts and other arrangements for the supply of power and energy. The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, report or instrument. Capitalized terms not defined herein shall have the meanings as set forth in the respective documents.

THE AUTHORITY'S REFUNDING PLAN

The 1989 Bonds are being issued for the purpose of advance refunding the $187,635,000 aggregate principal amount of the Bonds identified in the chart below (the "Refunded Bonds"). See also "Estimated Sources and Uses of Funds".

Refunded Bonds

Power Project Revenue Bonds	Maturity Date July 1	Principal Amount	Redemption Date July 1
1982 Series A	1995	$ 3,245,000	1992
1982 Series A	1996	3,625,000	1992
1982 Series A	1997	4,040,000	1992
1982 Series B	1996	1,920,000	1992
1982 Series B	1997	2,115,000	1992
1982 Series B	1998	2,320,000	1992
1983 Series A	1998	2,550,000	1993
1983 Series A	2003	16,680,000	1993
1984 Series A	1997	2,510,000	1994
1984 Series A	1998	2,780,000	1994
1984 Series A	1999	3,070,000	1994
1984 Series A	2000	3,415,000	1994
1985 Series A	2000	1,510,000	1995
1985 Series B	2001	1,015,000	1995
1985 Series B	2002	1,100,000	1995
1985 Series B	2003	1,200,000	1995
1985 Series B	2004	1,310,000	1995
1985 Series B	2015	55,500,000	2000
1986 Series A	2015	77,730,000	1996

Pursuant to the terms of the Bond Indenture, the advance refunding of the Refunded Bonds will be effected by depositing a portion of the proceeds of the 1989 Bonds and transferring certain other available moneys to the 1989 Refunding Series A Bonds Escrow Fund created and established pursuant to the Bond Indenture (the "Escrow Fund"). Such proceeds and moneys will be used to purchase certain non-callable State and Local Government Series direct obligations of the United States of America issued by the Bureau of Public Debt and certain other direct obligations of the United States of America purchased on the open market (collectively, the "Government Obligations"). The Government Obligations will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their respective terms, sufficient moneys

will be available to pay the Redemption Price of the Refunded Bonds on their respective redemption dates set forth above and interest to become due on or prior to the respective dates of redemption of the Refunded Bonds. The Escrow Fund shall be held by the Trustee in irrevocable trust and used solely for the payment of the Redemption Price of and interest on the Refunded Bonds, subject only to the payment to the Authority in accordance with the Bond Indenture of any cash not required for such purpose.

The refunding of the Refunded Bonds will discharge the pledge and assignment of any Revenues and other moneys and securities securing the Refunded Bonds under the Bond Indenture, except for the rights of the holders of the Refunded Bonds to payments from the Escrow Fund.

The mathematical accuracy of certain computations relating to the adequacy of the Government Obligations and the interest thereon to pay the Redemption Price and interest due on the Refunded Bonds on and prior to the redemption dates thereof will be verified at the time of delivery of the 1989 Bonds by Ernst & Whinney, independent certified public accountants. See "Verification of Mathematical Computations".

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds (excluding accrued interest) to accomplish the refunding of the Refunded Bonds is shown below:

Sources:	
Principal Amount of 1989 Bonds	$295,005,000
Original Issue Discount	(109,804,000)
Underwriters' Discount	(2,125,800)
Subtotal	$183,075,200
Transfer from Debt Service Account	981,700
Transfer from Debt Service Reserve Account	200
Total Sources	$184,057,100
Uses:	
Deposit to Escrow Fund	$181,808,400
Costs of Issuance*	2,248,700
Total Uses	$184,057,100

* Includes AMBAC Indemnity insurance premium.

DESCRIPTION OF THE 1989 BONDS

General

The 1989 Bonds are to be issued in the aggregate principal amount of $295,005,000, will be dated January 15, 1989 (except for the 1989 Bonds bearing a 0% interest rate, which will be dated their date of initial delivery), will bear interest at the rates per annum set forth on the cover page of this Official Statement and will mature on July 1 in the years and in the principal amounts set forth on the cover page of this Official Statement. Interest on the 1989 Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 1989.

The 1989 Bonds will be issued as fully registered bonds in the denomination of $5,000 or any integral multiple thereof.

The principal of and premium, if any, on the 1989 Bonds are payable at the principal corporate trust office of First Interstate Bank of California, Los Angeles, California, Trustee and Paying Agent. Semiannual interest on the 1989 Bonds will be payable by check or draft mailed to the registered owner thereof as of the applicable record date at such owner's address as shown on the registration

books of the Authority kept for that purpose at the corporate trust office of the Trustee, acting as Bond Registrar. The record date for the 1989 Bonds is the close of business on the 15th day of the calendar month immediately preceding the interest payment date.

The 1989 Bonds will rank on a parity with all other Bonds to be Outstanding immediately after the advance refunding of the Refunded Bonds. See "The Authority's Refunding Plan" and Appendix D hereto.

Optional Redemption

The 1989 Bonds maturing on July 1, 2001 and July 1, 2003 are subject to redemption prior to maturity at the option of the Authority on and after July 1, 1999, in whole or in part at any time, at the following redemption prices, plus accrued interest to the date of redemption:

Period During Which Redeemed (both dates inclusive)	Redemption Prices
July 1, 1999 to June 30, 2000	102%
July 1, 2000 to June 30, 2001	101
July 1, 2001 and thereafter	100

The 1989 Bonds maturing on July 1, 2007, July 1, 2010 and July 1, 2015 shall also be subject to redemption prior to maturity at the option of the Authority as a whole or in part, at any time on or after July 1, 1999, at par plus accrued interest to the redemption date.

The 1989 Bonds maturing on July 1 in each of the years 2000, 2002, 2004, 2011, 2012, 2013, and 2014 shall not be subject to redemption prior to maturity.

If less than all of the 1989 Bonds are to be so redeemed, the Authority may select the maturity or maturities to be redeemed. If less than all of the 1989 Bonds of any maturity are to be redeemed, the particular 1989 Bonds or portion of 1989 Bonds of such maturity to be redeemed shall be selected at random by the Trustee in such manner as the Trustee in its discretion may deem fair and appropriate. The portion of any registered 1989 Bond of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or an integral multiple thereof, and in selecting portions of such Bonds for redemption the Trustee will treat each such Bond as representing that number of Bonds of $5,000 denomination which is obtained by dividing the principal amount of such Bond by $5,000.

Mandatory Redemption

The 1989 Bonds maturing on July 1, 2007 and July 1, 2010 will be subject to mandatory redemption prior to maturity at a redemption price of 100% of the principal amount thereof plus interest accrued to the redemption date on July 1, 2005 and July 1, 2008, respectively, and on each July 1 thereafter to maturity, in the following principal amounts in the years specified:

1989 Bonds Maturing July 1, 2007

Year	Principal Amount
2005	$ 5,265,000
2006	5,635,000
2007 (final maturity)	12,225,000

1989 Bonds Maturing July 1, 2010

Year	Principal Amount
2008	$13,075,000
2009	13,990,000
2010 (final maturity)	14,975,000

Giving effect to the mandatory redemption schedule set forth above, the average lives of the 1989 Bonds maturing on July 1, 2007 and July 1, 2010 would be approximately 17 years and 9 months and 20 years and 6 months, respectively, calculated from the date of such 1989 Bonds.

Notice of Redemption

The Bond Indenture requires the Trustee to give notice of any redemption of the 1989 Bonds by publication and, in the case of registered 1989 Bonds, by mail. Failure to mail notice, or any defect in such mailed notice, however, will not affect the validity of the proceedings for redemption of any 1989 Bond. See "Summary of Certain Provisions of the Bond Indenture — Notice of Redemption" in Appendix C hereto.

Interchangeability

The 1989 Bonds may be exchanged and transferred as provided in the Bond Indenture. See "Summary of Certain Provisions of the Bond Indenture — Interchangeability" in Appendix C hereto.

AMBAC Insurance

AMBAC Indemnity Corporation ("AMBAC Indemnity"), has made a commitment to issue a municipal bond insurance policy (the "Municipal Bond Insurance Policy") relating to the 1989 Bonds maturing on July 1 in each of the years 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2004, 2007, 2010, 2011, 2012, 2013, 2014 and 2015 (the "Insured Bonds"), effective as of the date of issuance of the 1989 Bonds. A form of the Municipal Bond Insurance Policy is attached hereto as Appendix G. The information relating to AMBAC Indemnity contained below has been furnished by AMBAC Indemnity. No representation is made herein as to the accuracy or adequacy of such information or as to the absence of material adverse changes in such information subsequent to the date hereof.

Under the terms of the Municipal Bond Insurance Policy, AMBAC Indemnity will pay to the United States Trust Company of New York, in New York, New York or any successor thereto (the "Insurance Trustee") that portion of the principal of and interest on the Bonds which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer (as such terms are defined in the Municipal Bond Insurance Policy). AMBAC Indemnity will make such payments to the Insurance Trustee on the later of the date on which such principal and interest becomes Due for Payment or the fifth (5th) business day next following the date on which AMBAC Indemnity shall have received notice of Nonpayment from the Trustee. The insurance will extend for the term of the Bonds and, once issued, cannot be cancelled by AMBAC Indemnity.

The Municipal Bond Insurance Policy will insure payment only on stated maturity dates and sinking fund installment dates, in the case of principal, and on stated dates for payment, in the case of interest. It will not insure payment on acceleration, as a result of a call for redemption (other than sinking fund redemption) or as a result of any other advancement of maturity, nor will it insure the payment of any redemption, prepayment or acceleration premium or any risk other than Nonpayment. In the event of any acceleration of the principal of the Bonds, the payments insured will be made at such times and in such amounts as would have been made had there not been an acceleration.

The Municipal Bond Insurance Policy will not insure against nonpayment of principal or interest caused by the insolvency or negligence of any Trustee or Paying Agent, if any, or the Insurance Trustee. If the Bonds become subject to mandatory redemption and insufficient funds are available for redemption of all outstanding Bonds, AMBAC Indemnity will remain obligated to pay principal of and interest on outstanding Bonds on the originally scheduled interest and principal payment dates including mandatory sinking fund redemption dates. In the event the Trustee has notice that any payment of principal of or interest on a Bond which has become Due for Payment and which is made to a Bondholder by or on behalf of the Issuer has been deemed a preferential transfer and theretofore recovered from its registered owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such registered owner will be

entitled to payment from AMBAC Indemnity to the extent of such recovery if sufficient funds are not otherwise available.

If it becomes necessary to call upon the Municipal Bond Insurance Policy, payment of principal requires surrender of Bonds to the Insurance Trustee together with an appropriate instrument of assignment so as to permit ownership of such Bonds to be registered in the name of AMBAC Indemnity. Payment of interest pursuant to the Municipal Bond Insurance Policy requires proof of Bondholder entitlement to interest payments and an appropriate assignment of the Bondholder's right to payment to AMBAC Indemnity.

Upon payment of the insurance benefits, AMBAC Indemnity will become the owner of the surrendered Insured Bonds and will be fully subrogated to the surrendering Bondholders' rights to payment.

AMBAC Indemnity has obtained a ruling from the Internal Revenue Service to the effect that the insuring of an obligation by AMBAC Indemnity will not affect the treatment for federal income tax purposes of interest on such obligation and that insurance proceeds representing maturing interest paid by AMBAC Indemnity under policy provisions substantially identical to those contained in the municipal bond insurance policy shall be treated for federal income tax purposes in the same manner as if such payments were made by the issuer of the bonds.

AMBAC Indemnity Corporation is a Wisconsin-domiciled stock insurance company, regulated by the Insurance Department of the State of Wisconsin, and licensed to do business in various states, with admitted assets (unaudited) of approximately $1,065,000,000 and statutory capital (unaudited) of approximately $670,000,000 as of September 30, 1988. Statutory capital consists of AMBAC Indemnity's statutory contingency reserve and policyholders' surplus. AMBAC Indemnity is a wholly-owned subsidiary of AMBAC Inc., a financial holding company which is owned by Citibank, N.A., the employees of AMBAC Indemnity, Xerox Financial Services, Inc. and Stephens Inc. Neither AMBAC Inc. nor its shareholders are obligated to pay the debts of or claims against AMBAC Indemnity. Standard & Poor's Corporation and Moody's Investors Service, Inc. have assigned their ratings of "AAA" and "Aaa", respectively, to the claims paying ability of AMBAC Indemnity. Copies of AMBAC Indemnity's financial statements prepared in accordance with statutory accounting standards are available from AMBAC Indemnity. The address of AMBAC Indemnity's administrative offices and its telephone number are One State Street Plaza, 17th Floor, New York, New York, 10004 and (212) 668-0340.

AMBAC Indemnity has entered into quota share reinsurance agreements under which a percentage of the insurance underwritten pursuant to certain municipal bond insurance programs of AMBAC Indemnity has been and will be assumed by such reinsurers.

SECURITY AND SOURCES OF PAYMENT FOR THE BONDS

Pledge Effected by the Bond Indenture

The Bond Indenture provides that the Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (i) the proceeds of the sale of Bonds, (ii) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to the ownership and operation of the Authority Interest, the proceeds of any insurance covering business interruption loss relating to the Authority Interest and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and required to be paid into the Revenue Fund ("Revenues"), and (iii) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject only to the provisions of the Bond Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Bond Indenture (including application of the moneys on deposit in the Escrow Fund).

The Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the Bonds. The Bonds shall never constitute debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution or statutes of the State of California, and shall not constitute nor give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power.

See "Summary of Certain Provisions of the Bond Indenture" in Appendix C hereto for further discussion of certain of the terms and provisions of the Bond Indenture.

Power Sales Contracts

Each Power Sales Contract between the Authority and a Project Participant constitutes an obligation of the parties until the terms of all of the Power Sales Contracts expire on October 31, 2030 or such later date as all Bonds and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made. As long as any Bonds issued under the Bond Indenture are Outstanding or until provision has been made for the payment of any Bonds Outstanding in accordance with the Bond Indenture, the Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of, or extend the time for, the payments which are pledged as security for the Bonds or which will impair or adversely affect the rights of the holders of the Bonds.

The payment obligations under the Power Sales Contracts constitute operating expenses of the respective Project Participants, payable solely from their electric system revenues.

Each Project Participant has covenanted in its Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves, are adequate to enable it to pay the Authority all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

Payments are to be made by the Project Participants on a "take or pay" basis, that is, whether or not the Authority Interest or any part thereof, is operating or operable (or has been completed), or its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

A failure of a Project Participant to make payments when due under its Power Sales Contract may result in larger payments being made by the other Project Participants in subsequent periods for the purpose of enabling the Authority to pay operating expenses, debt service and other costs of the Authority Interest and to maintain required reserves therefor. To the extent the amount to be paid by the nonpaying Project Participant is not offset by revenues from sales of power derived by the Authority in respect of such non-paying Project Participant's Project Entitlement Share, such non-payment may result in deficits in funds under the Bond Indenture. In such event, the Authority would be required to amend, in accordance with the Power Sales Contracts and the Bond Indenture, the Annual Budget to provide increases in subsequent billings to all Project Participants, including the non-paying Project Participant, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Project Participant's Project Entitlement Share to the other Project Participants. Amounts thereafter collected from such non-paying Project Participant shall be credited against the next billing of such other Project Participants as shall be appropriate. In the event, however, of a termination of the Project and a resultant default by the Authority under the Bond Indenture, each Project Participant would, under its Power Sales Contract, be severally obligated to pay only its respective Project Entitlement Share of the debt service on the Bonds (including fees and expenses of the Trustee and Paying Agents) and other fixed costs.

The Power Sales Contracts provide that the obligations of the Project Participants under the respective Power Sales Contracts are several and not joint. During each Power Supply Year, each Project Participant is obligated to pay its share of Monthly Power Costs, which consist of all of the Authority's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Authority Interest, to the extent not paid from the proceeds of Bonds or from Notes or other evidences of indebtedness issued in anticipation of the issuance of Bonds. Such Monthly Power Costs, which consist of a minimum cost component and a variable cost component, are to be billed monthly.

The minimum cost component will be billed each month for the then current month based on the estimates contained in the Annual Budget prepared by the Authority prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each month, the minimum cost component includes:

(1) The amounts which the Bond Indenture requires the Authority to pay or deposit during such month into funds or accounts for: debt service on the Bonds or reserve requirements for the Bonds; and the payment of interest on Notes or other evidences of indebtedness issued in anticipation of the issuance of Bonds; and

(2) One-twelfth of: the amount which the Authority is required under the Bond Indenture to pay or deposit during the then current Power Supply Year into any other fund or account established by the Bond Indenture, including any amount needed to eliminate a deficiency in any such other fund whether or not resulting from a default in payments by any Project Participant of amounts due under any Power Sales Contract; the costs of producing and delivering capacity and energy from the Authority Interest during the then current Power Supply Year, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of fuel for the Authority Interest; and the amount necessary during the then current Power Supply Year to pay or provide reserves for all taxes which the Authority is required to pay with respect to the Authority Interest.

The variable cost component will be billed each month for the immediately preceding month. The variable cost component of Monthly Power Costs consists of: (i) all costs of fuel not included in the minimum cost component and (ii) the Authority's cost of transmission under the Transmission Agreement.

The Bond Indenture requires the Authority, quarterly, to review its estimates set forth in the then current Annual Budget and in the event such estimates do not substantially correspond with actual Revenues, Authority Operating Expenses or other requirements, to adopt an amended Annual Budget for the remainder of the Power Supply Year. The Authority is also required to adopt such an amended Annual Budget if there are at any time during the year extraordinary receipts or payments of unusual costs.

The amount of Monthly Power Costs to be paid by each Project Participant for any month shall be the sum of (i) its Project Entitlement Share times the minimum cost component for such month and (ii) the percentage of the energy delivered from the Authority Interest to it during such month times the variable cost component.

Within 120 days after the end of each Power Supply Year, the Authority will submit to each Project Participant a statement of the actual amounts payable under the Power Sales Contracts for such year and any adjustments to such amounts for any prior year, based on the annual audit required by the Power Sales Contracts. If for any Power Supply Year the actual amounts payable under the Power Sales Contract exceed the amount which the Project Participants have been billed, the Project Participants shall promptly pay the amount of such excess to the Authority; if such amounts are less than the amounts billed, the Authority will credit the excess against the Project Participants' next monthly payment.

In the event of a default or inability to perform by a Project Participant under its Power Sales Contract, the Authority shall proceed to enforce the Project Participant's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity. The Power Sales

Contracts also provide that if a payment due under the Power Sales Contract remains unpaid when due, the Authority shall, upon 120 days' written notice to the Project Participant, discontinue the delivery of capacity and energy to, and the use of the Authority Interest facilities by, such Project Participant while the default continues. Except as a result of a transfer of the defaulting Project Participant's rights to delivery of capacity and energy and the use of the Authority Interest facilities, the discontinuance of delivery of capacity and energy to and the use of the Authority Interest facilities by a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Power Sales Contract. See "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C hereto for a discussion of certain additional provisions of the Power Sales Contracts.

Authority Rate Covenant

Pursuant to the Bond Indenture, the Authority has covenanted to at all times establish and collect rates and charges with respect to the Authority Interest to provide Revenues at least sufficient, together with other available funds, for the payment each Fiscal Year of the sum of: (i) Authority Operating Expenses, (ii) Aggregate Debt Service, (iii) all other required deposits to any funds under the Bond Indenture and (iv) all other charges or liens payable out of Revenues.

Budgeting

The Power Sales Contracts require the Authority to adopt an Annual Budget not less than 30 days prior to the beginning of each Power Supply Year. Each such Annual Budget will set forth a detailed estimate of the Monthly Power Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Power Supply Year. See "Security and Sources of Payment for the Bonds — Power Sales Contracts". The Bond Indenture requires the Authority, following the end of each quarter of each Power Supply Year, to review its estimates set forth in the Annual Budget for such Power Supply Year and in the event such estimates do not substantially correspond with actual Revenues, Authority Operating Expenses or other requirements, adopt an amended Annual Budget. The Authority shall also adopt an amended Annual Budget, in accordance with the Power Sales Contracts, if there are at any time during the year extraordinary receipts or payment of unusual costs. The Authority may also at any time, in accordance with the provisions of the Power Sales Contracts, adopt an amended Annual Budget for the remainder of the then current Power Supply Year.

Flow of Funds

The Bond Indenture establishes the following funds and accounts (each of which is held by the Trustee): Construction Fund, Revenue Fund, Operating Fund, Debt Service Fund (including the Debt Service Account and Debt Service Reserve Account), Reserve and Contingency Fund (including the Renewal and Replacement Account, Decommissioning Account and Reserve Account), General Reserve Fund, 1985 Refunding Series A Bonds Escrow Fund, 1985 Refunding Series B Bonds Escrow Fund, 1986 Refunding Series A Bonds Escrow Fund, 1986 Refunding Series B Bonds Escrow Fund, 1987 Refunding Series A Bonds Escrow Fund and the Escrow Fund.

Pursuant to the Bond Indenture, all Revenues received are to be deposited promptly in the Revenue Fund. Amounts in the Revenue Fund are to be paid monthly to the following funds in the following order of priority:

(1) To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as reserves, equals the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month.

(2) To the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such accounts (excluding, in the case of the Debt Service Account, the amount set aside therein from the proceeds of Bonds or otherwise for payment of interest on Bonds in excess of the amount to be applied to pay interest accrued and unpaid and to accrue on Bonds to the last day of the then current calendar month) equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement, respec-

tively, as of the end of the then current month. The Trustee will apply amounts in the Debt Service Account to the payment of principal of, redemption premium, if any, and interest on the Bonds.

(3) To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund in excess of the amount thereof shall equal all interest accrued and unpaid and to accrue on outstanding Bond Anticipation Notes to the end of the then current calendar month. The Trustee will apply amounts in the Bond Anticipation Note Fund to the payment of interest on Bond Anticipation Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Bond Anticipation Notes.

(4) To the Reserve and Contingency Fund, for credit to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account, the respective amounts provided for such purposes for the then current month in the current Annual Budget.

(5) To the General Reserve Fund, the balance if any, in the Revenue Fund.

For a more detailed discussion of the application of moneys deposited in the various funds and accounts, see "Summary of Certain Provisions of the Bond Indenture — Application of Revenues" in Appendix C hereto.

Debt Service Reserve Account

Moneys already on deposit in the Debt Service Reserve Account will be sufficient to satisfy the Debt Service Reserve Requirement at the time of issuance of the 1989 Bonds. For the definition of Debt Service Reserve Requirement, see "Summary of Certain Provisions of the Bond Indenture — Debt Service Reserve Requirement and Certain Other Definitions Pertaining to the Issuance of Bonds" in Appendix C hereto. Should the amount on deposit in the Debt Service Reserve Account fall below the Debt Service Reserve Requirement, such deficit is to be cured by application of funds from amounts in the General Reserve Fund, the Reserve Account in the Reserve and Contingency Fund, the Renewal and Replacement Account in the Reserve and Contingency Fund, and the Bond Anticipation Note Fund, and from the first available Revenues (after payments to the Operating Fund and Debt Service Account required by the Bond Indenture), in that order.

Additional and Refunding Bonds

The Authority may issue additional Bonds for the purpose of financing the costs of acquisition and construction of the Authority Interest on the terms and conditions specified in the Bond Indenture. Any additional Bonds, including the Lender Bonds (as defined in the Bond Indenture), will rank equally as to security and payment with the Outstanding Bonds and the 1989 Bonds except that certain Lender Bonds will not have any interest in, lien on or pledge of moneys on deposit in the Debt Service Reserve Account. The Bond Indenture also provides for the issuance of refunding Bonds to refund Outstanding Bonds, in certain circumstances. The Project Participants have authorized the issuance of refunding Bonds by the Authority at such times as the Board of Directors determines. See "Summary of Certain Provisions of the Bond Indenture — Certain Requirements of and Conditions to Issuance of Bonds", "Summary of Certain Provisions of the Bond Indenture — Additional Bonds" and "Summary of Certain Provisions of the Bond Indenture — Refunding Bonds" in Appendix C hereto.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation and Membership

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement, for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement has a term expiring in 2030.

Organization and Management

The Authority is governed by a Board of Directors which consists of one representative for each of the members. The current representatives are listed on the inside cover of this Official Statement. The management of the Authority is under the direction of its Executive Director, Arthur T. Devine, who serves at the pleasure of the Board of Directors. Prior to his appointment as Executive Director, Mr. Devine served the Department for over 25 years as an electrical engineer and, more recently, as an Assistant City Attorney.

The other officers of the Authority also serve at the pleasure of the Board of Directors. The President of the Authority is Gale A. Drews, who has been the Electrical Utility Director for the City of Colton since 1978. W. E. Cameron, the Vice President of the Authority, has been the Director of Public Services for the City of Glendale since 1984. Eldon A. Cotton, the Secretary of the Authority, has been employed by the Department since 1965 and has served as the Assistant General Manager — Power of the Department since November 28, 1988. Horace W. Rupp, Jr., the Assistant Secretary of the Authority, has been employed by the Department as an engineer since 1968. Mr. Rupp has held the title of Manager of Power Contracts since 1985.

With respect to any matter involving the Authority Interest to be decided by the Board of Directors, each Director is entitled to cast votes weighted according to the size of the entitlement to the Authority Interest of the Project Participant represented by such Director in addition to the vote each Director is entitled to cast as a member of the Authority. See "Introduction — Cost and Entitlement Shares". All such matters involving the Authority Interest must be decided by at least 80% of the votes cast, and no such vote may be taken unless there shall be present at the meeting Directors entitled to cast more than 50% of the votes relative to such matter.

The Authority has entered into the Agency Agreement pursuant to which the Department, as agent, represents, and undertakes certain activities on behalf of, the Authority in connection with the Authority's acquisition, construction, operation and maintenance of the Authority Interest. The Agency Agreement gives the Agent the responsibility of (a) undertaking those activities necessary (i) to secure regulatory approvals to allow the Authority to acquire the Authority Interest, (ii) to determine the cost of acquisition, construction, operation and maintenance of the Authority Interest, (iii) to formulate arrangements for the transmission of Authority Interest output to the Project Participants, (iv) to formulate the financing program and develop financing documents and (v) to construct, operate and maintain the Authority Interest, and (b) representing the Authority with respect to matters arising under or in connection with the Project Agreements or the construction, operation and maintenance of the Authority Interest.

Further information concerning the Authority may be obtained from the Executive Director, Southern California Public Power Authority, 613 East Broadway, Glendale, California 91205.

Other Activities of the Authority

Southern Transmission System. The Authority has entered in agreements providing for (i) the making of payments-in-aid of construction by the Authority to Intermountain Power Agency with respect to a ± 500 kV DC bi-pole transmission line from the coal-fired, steam-electric generation station and switchyard located near Lynndyl, in Millard County, Utah, to Adelanto, California, 488 miles in length, together with an AC/DC converter station at each end and related microwave communication system facilities (the "Southern Transmission System"), (ii) the acquisition of the entitlements to the capability of such System previously held by the Department and the California cities of Anaheim, Riverside, Burbank, Glendale and Pasadena (the "Southern Transmission System Participants") and (iii) the sale by the Authority of transmission service on the Southern Transmission System to the Southern Transmission System Participants. The Authority has issued and has outstanding $1,147,130,000 principal amount of its bonds, including refunding bonds, to finance the making of payments-in-aid of construction with respect to the Southern Transmission System. Such bonds are payable from payments to be made by the Southern Transmission System Participants under transmis-

sion service contracts (on the basis of transmission service shares). According to the Consulting Engineer, the permanent financing necessary to provide for all such payments-in-aid of construction and the acquisition of such entitlements totals $1,147,130,000. For a discussion of the Intermountain Power Project of which the Southern Transmission System is a part, see "The Project Participants — Other Projects of the Project Participants".

Mead-Phoenix DC Intertie Project. In 1982, the Authority executed agreements pursuant to which the Authority, Salt River Project, M-S-R Public Power Agency, and the Western Area Power Administration ("Western") are studying the feasibility of constructing, owning and operating the Mead-Phoenix DC Intertie Project. The Mead-Phoenix DC Intertie Project is a proposed 240 mile ± 500 kV DC transmission line (with AC/DC converter stations at each end) to be constructed between Mead Substation near Boulder City, Nevada and the Phoenix, Arizona area. The Authority has issued notes in the aggregate principal amount of approximately $14.1 million, of which all but $100,000 has been prepaid, to finance the costs of such study. The remaining $100,000 note matures on December 1, 1991 and is payable from the proceeds of long-term bonds to be issued by the Authority for the Mead-Phoenix DC Intertie Project or from payments by the participants, under project development agreements, on the basis of project entitlement shares. It is currently planned that the transmission line would have a capacity of 2,200 MW and that the converter stations would be built with an initial capacity of 1,600 MW. The initial converter station capacity could be upgraded to the transmision line capacity should this become desirable. If the Mead-Phoenix DC Intertie Project is undertaken, the Authority would finance its interest from the proceeds of long-term bonds secured by payments to be made by the participants on a "take or pay" basis under transmission service contracts. The Authority's present interest is 93.75%. It is estimated that this facility, if built, would be in service in the mid-1990's. For a further discussion of the Mead-Phoenix DC Intertie Project, see the caption "The Department of Water and Power of The City of Los Angeles — The Power System — Transmission and Distribution" in Appendix B hereto.

Mead-Adelanto Transmission Project. In connection with the Mead-Phoenix DC Intertie Project, certain members of the Authority, Salt River Project, M-S-R Public Power Agency, and Western are studying the feasibility and projected costs of the construction and operation of a new ± 500-kV DC transmission line from the Mead Substation near Boulder City, Nevada to the vicinity of Adelanto, California, a distance of approximately 215 miles. The proposed participants anticipate that, if constructed, the transmission line could be put into service within the same time frame as the Mead-Phoenix DC Intertie Project. It has not been determined what, if any, role the Authority will have in the financing or construction of this transmission line project; however, the participants, by resolution, notified the Authority that if the transmission line is constructed, certain participants, if not all, will request the Authority to finance on their behalf.

Hoover Power Plant. In 1985, in accordance with the Hoover Power Plant Act of 1984, Western allocated 127 MW of capacity and approximately 143,000 megawatt-hours ("MWh") of associated energy from the Hoover uprating program to the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon. The cities entered into contracts with the United States Bureau of Reclamation (the "Bureau") and Western which provide for advancement of funds by the cities to the Bureau and the purchase of power from the Hoover uprating program, respectively. In 1986, Anaheim, Riverside, Burbank, Azusa, Colton and Banning (the "Hoover Participants") assigned to the Authority their entitlement to the Hoover uprating program capacity and associated energy in return for the Authority's agreement to advance funds to the Bureau for the Hoover uprating program. The Authority has issued $34,435,000 of its Hydroelectric Power Project Revenue Bonds, the proceeds of which are projected to be sufficient for this purpose. The Authority's proportionate share of the total capacity of the Hoover uprating program is expected to be approximately 94 MW and associated energy. The Hoover Participants and the Authority executed power sales contracts, under which the Hoover Participants will be entitled to their shares of the Authority's proportionate share of Hoover capacity and associated energy as they become available (the "Hoover Entitlements") and agreed to make monthly payments on a "take or pay" basis. Western has been making the Hoover Entitlements

available at the Mead Substation. The cities have each completed the necessary transmission service arrangements from the Mead Substation to the respective cities' electric systems.

Utah-Nevada Transmission Project. Members of the Authority, together with several electric utilities providing service in Utah and Nevada, are considering constructing, owning and operating an electric transmission project to include facilities to be located in Utah and Nevada. This project, if undertaken and built, would be in operation in the mid-1990's. It is anticipated that, to the extent its members participate in and the Authority undertakes this project, the Authority will own and finance a portion of the project on behalf of its participating members, who would purchase transmission service or capability of the project from the Authority.

THE PROJECT AND THE ANPP TRANSMISSION SYSTEM

General Description

PVNGS consists of three nominal 1,270 MW nuclear generating units, each of which has commenced commercial operation. In May 1986, APS reported to the NRC an adjustment to the design electrical rating of each Unit from 1,270 MW net to 1,221 MW net maximum dependable capacity to reflect the licensed reactor thermal power level. For purposes of its analysis, the Consulting Engineer based the Authority interest output on an assumed production capacity of 1,221 MW net from each of the three units. Based on this assumption, the Project presently has a net generating capacity of approximately 3,663 MW. Additionally, it is projected that by 1992 each unit will have achieved a mature plant factor and the Project will have an annual energy output of approximately 22,500,000 MWh. It is projected that the Authority Interest will be capable of delivering approximately 207.4 MW of capacity on average, annually at the various points of delivery, after adjustment for transmission losses. The Project is located on a site of approximately 4,000 acres about 50 miles west of downtown Phoenix, Arizona. The three units are essentially identical in design and share certain common facilities, including a water reclamation plant, make-up water storage reservoir, two on-site wells, domestic water system, demineralized water system, sanitary waste treatment facility, evaporation ponds, laundry and decontamination facility, administration building, guardhouse, security facilities, service warehouse building, switchyard and miscellaneous buildings. Each unit is designed and licensed for a forty year operating life.

The nuclear steam supply system for each unit of the Project, supplied by Combustion Engineering, Inc., is a closed-cycle pressurized water reactor system licensed at 3,817 megawatts of thermal capacity with two reactor coolant loops containing two reactor coolant pumps in each loop. The turbine generators are tandem compound units supplied by the General Electric Company. The main condensers were supplied by the Westinghouse Electric Company and are cooled by circulating water through mechanical draft cooling towers. Make-up water for the dissipated circulating water is obtained primarily from the 91st Avenue Sewage Treatment Plant operated by the City of Phoenix. This processed effluent is piped to the on-site water reclamation plant where it undergoes additional treatment and is then stored in the on-site reservoir as make-up water. Blow-down from the circulating water system, demineralized water wastes, domestic water wastes, nonradioactive demineralizer regenerants and miscellaneous nonradioactive wastes are directed to the on-site evaporation ponds where they are completely evaporated. Thus, no off-site liquid discharges are required.

At design steam flow and condenser back pressure, the output from the main turbine-generators is 1,304 MW. The main transformers will step up the output voltage of each generator to 525 kV for interconnection into the ANPP Transmission System.

APS is the Project Manager and also operates the three Project units and the Westwing 525 kV Switchyard. The switchyard portions of the Project were constructed and are being managed by Salt River Project.

Pursuant to the Participation Agreement and the Assignment Agreement, the utilities listed in the following table currently have the indicated interests in the Project. See "Availability of Construction Funds and Available Information Concerning Other Owners of Palo Verde Nuclear Generating Station".

	Current Interests
Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Department of Water and Power of The City of Los Angeles	5.70
Total	100.00%

In connection with financing of the Project, APS, PNM and El Paso have recently entered into several sale and leaseback transactions involving certain portions of their respective ownership interests in the Project.

Units 1, 2 and 3 were declared to have achieved firm power operation on January 27, 1986, September 18, 1986 and January 19, 1988, respectively.

The ANPP High Voltage Switchyard consists of a breaker-and-a-half scheme which comprises the termination facilities for the transmission lines, generator step-up transformers and auxiliaries, including, but not limited to, the high voltage busses, structures, power circuit breakers, disconnect switches, control building, switchyard auxiliary, protection systems and fencing.

The ANPP Transmission System consists of the facilities listed below, along with associated rights-of-way:

Palo Verde — Westwing 525 kV Transmission Lines Nos. 1 and 2
Palo Verde — Kyrene 525 kV Transmission Line
Westwing 525 kV Switchyard expansion
Kyrene 230 kV Switchyard expansion
Second Kyrene 230 kV Switchyard
Kyrene 525/230 kV Switchyard
Microwave Communication System

Construction of the major components of the ANPP Transmission System is complete and the system is operational.

Additional information concerning the Project and the ANPP Transmission System is set forth in the Consulting Engineer's Report.

Estimated Construction Costs

The most recent estimate of the construction costs for the Project by APS is dated November 15, 1988. APS has also estimated the cash flow requirements for nuclear fuel associated with the Project. Expected payments for the construction costs for the ANPP Transmission System have been completed. The following table shows the total estimated costs for the Project and the ANPP Transmission System and the total estimated cost for the Authority Interest, including an additional Authority contingency to allow for uncertainties in addition to those provided for by APS.

Estimated Construction Costs

($000)

	Total Project and ANPP Transmission System	Authority Interest
Plant, Preoperations and Startup Costs(1)	$5,949,499	$ 351,615
Sewage Effluent Prepayment and Startup Power Costs(2)	77,771	4,594
Transmission Facilities Rights and Ownership Interest(3)	115,949	7,369
Other(4)	98,251	5,807
Direct Construction Costs	$6,241,470	$ 369,385
Project and Transmission Facilities Rights and Ownership Interest Purchase Costs(5)		52,784
Nuclear Fuel(2)		27,457
Ad Valorem Taxes(2)		9,659
Additional Capital Items and Authority's Contingency(6)		5,885
Total Construction Costs		$ 465,170

(1) Estimated by APS. Includes land, structures, nuclear steam supply system, turbine generator, other improvements and nuclear information communications costs.

(2) Based on actual Authority expenditures subsequent to purchase of the Authority Interest on September 10, 1982.

(3) Based on actual Authority expenditures subsequent to purchase of the Authority interest on September 10, 1982. Includes ANPP High Voltage Switchyard, Kyrene and Westwing switchyards, associated transmission lines and rights-of-way, microwave facilities and capitalized operation and maintenance expenses during the construction period.

(4) Includes expenditures prior to purchase of the Authority Interest under the Assignment Agreement for the following: startup power costs, ad valorem taxes, Green Mountain Uranium Venture, research and development and Salt River Project direct costs. Also reflects an adjustment for differences between APS's estimate of cash flow requirements dated November 15, 1988 and actual cash flow requirements as well as the Authority's portion of the costs incurred for a prudency audit.

(5) Based on actual closing costs in connection with purchase of the Authority Interest. With the exception of an additional ownership interest in the ANPP High Voltage Switchyard, includes Salt River Project AFUDC, carrying costs from Project inception to September 10, 1982 and an administrative charge. Includes such applicable costs from Project inception to May 2, 1983 for the additional ownership interest in the ANPP High Voltage Switchyard.

(6) Provided by the Authority to allow for payment of certain additional capital costs which may be included in the APS Final Completion Report and payment of certain claims against the Project in the event either claimant is successful.

Authority Interest Financing

Based on the APS Project construction cost estimate, the Salt River Project estimate of ANPP Transmission System construction costs, consultation with the Authority's Financial Advisor and considering the Project is fully operational, the borrowing required for the completion of the Authority's Interest has been completed, other than any additional refundings which the Authority might authorize.

Authority Interest Financing
($000)

	Total Requirement
Total Construction Costs	$ 465,170
Debt Service Reserve(1)	88,246
Interest During Construction(2)	367,713
Working Capital, Reserve and Contingency Fund and Authority Expenses(3)	14,700
Financing Costs(4)	302,764
Gross Requirements	$1,238,593
Investment Income(5)	(146,032)
Defeasance of Prior Series Bonds	(1,184,466)
Net Deposits to Escrow Funds(6)	1,309,400
Total Financing(7)	$1,217,495
Bonds Retired to Date	(13,095)
Total Bonds Outstanding	$1,204,400

(1) Maximum annual debt service deposited in the Debt Service Reserve Account in the Debt Service Fund for the Prior Series Bonds as adjusted by the 1989 Bonds.

(2) Based on the actual interest capitalized.

(3) Working Capital requirements are based on providing 90 days of estimated annual costs, excluding debt service. Reserve and Contingency Fund requirements are based on 1.5% of the net utility plant component of the Authority Interest in the Project and are deposited in the Reserve Account in the Reserve and Contingency Fund. Authority expenses are projected by the Authority.

(4) Includes actual underwriters' discount and original issue discount of approximately $285,206,724 and other costs of issuance estimated at approximately $17,557,468.

(5) The investment of undisbursed proceeds of the Prior Series Bonds in the Initial Facilities Account of the Construction Fund through December 31, 1990 has been included at an interest rate of 7.0%.

(6) For refunding bonds, deposit required into the refunding series bonds' escrow funds, net of any funds released from the Debt Service Account and Debt Service Reserve Account in the Debt Service Fund pursuant to the applicable Supplemental Indenture of Trust.

(7) Changes in interest or reinvestment rate assumptions may result in changes to the Total Financing.

Authority Interest Annual Costs of Power

The following table shows the projected annual costs of power from the Authority Interest at the high voltage bus of the ANPP High Voltage Switchyard for fiscal years 1989 through 1993.

The projections set forth in the Consulting Engineer's Report are based on preliminary discussions with APS and are subject to adjustment by APS. For purposes of this analysis, the plant factor for each unit is assumed by the Consulting Engineer to vary from an initial level of approximately 60% for the first cycle of commercial operation of Unit 3 to approximately 65% for the second cycle and to approximately 70% for the third cycle and thereafter.

Projected Annual Cost of Power from the Authority Interest(1) ($000)

	Fiscal Year Ending June 30				
	1989(12)	1990	1991	1992	1993
Interest and Amortization:					
Prior Series Bonds(2)(3)	$ 82,146	$ 75,368	$ 75,372	$ 75,369	$ 75,367
1989 Bonds(2)	4,467	10,995	10,989	10,997	10,991
Operation and Maintenance(4)	12,927	14,550	16,840	17,152	18,118
Administrative and General(5)	3,697	2,120	2,300	2,370	2,483
Insurance(6)	1,156	1,203	1,271	1,307	1,346
Nuclear Fuel(7)	9,538	10,721	9,315	10,290	10,934
Renewals and Replacements(4)	2,331	2,850	2,839	2,379	2,323
Taxes(8)	4,198	4,408	4,408	4,408	4,408
Subtotal Project	$120,460	$122,215	$123,335	$124,271	$125,970
Less: Interest Earnings(9)	12,643	9,010	9,028	9,050	8,941
Total Project	$107,817	$113,206	$114,306	$115,221	$117,029
Total Project Unit Cost (Mills/kWh)	86.76	82.36	93.75	84.99	82.41
Total ANPP Transmission System Rights	$ 1,382	$ 1,385	$ 1,397	$ 1,410	$ 1,417
Total ANPP Transmission System Rights Unit Cost (Mills/kWh)	1.11	1.01	1.15	1.04	1.00
TOTAL COST OF POWER TO AUTHORITY(10)	$109,199	$114,591	$115,703	$116,631	$118,446
Energy Delivered (000 MWh)(11)	1,243	1,374	1,219	1,356	1,420
TOTAL AVERAGE UNIT COST (Mills/kWh)	87.88	83.37	94.89	86.03	83.41

(1) Based on cost estimate which includes Authority financing contingency as previously discussed and shown in the tables entitled "Estimated Construction Costs" and "Authority Interest Financing."

(2) Principal payments began July 1, 1988. Interest is accrued during the six months prior to each semi-annual payment on July 1 and January 1. Principal is accrued during the twelve months prior to each annual payment on July 1.

(3) Reflects interest and amortization of the Prior Series Bonds, net of the interest and amortization on the Refunded Bonds.

(4) Based on estimates provided by APS.

(5) Based on estimates provided by APS. Also includes projected Authority expenses.

(6) Based on estimates provided by APS. Includes nuclear insurance.

(7) Based on APS's estimate of nuclear fuel costs. The Authority is obligated to provide its ownership interest share of the funds required for decommissioning of the Project. An additional sinking fund allowance, which was based, on APS's estimate for decommissioning each unit, has been added by the Consulting Engineer to the annual nuclear fuel cost. The NRC has issued its final rule entitled "General Requirements for Decommissioning Nuclear Facilities" which became effective July 27, 1988. This rule amended NRC regulations to set forth technical and financial criteria for decommissioning licensed nuclear facilities, including Palo Verde. The proposed amendments address decommissioning planning needs, timing, funding methods, and environmental review requirements. The Authority believes that its provision for funding its ownership interest share of the funds required for decommissioning of the Project meets the intent of the NRC's final rule. A ruling on the Authority's specific method of providing such funding has not been made. Should such method not be approved, changes to the Projected Annual Cost of Power may result.

(8) Based on the Authority ad valorem taxes at rates estimated by APS and Salt River Project.

(9) Based on transferring all of the investment income to the Revenue Fund from the Debt Service and Debt Service Reserve Accounts in the Debt Service Fund, the Reserve Account in the Reserve and Contingency Fund and the Operating Fund.

(10) Sum of Total Project and Total ANPP Transmission System Rights costs.

(11) At the high voltage bus of the ANPP High Voltage Switchyard. Computed as the Authority's share of estimated total generation at the Project site.

(12) Based on the Authority's budget. Interest and amortization has been adjusted to reflect the issuance of the 1989 Bonds.

Project Participants' Costs for Power

Each Project Participant will incur additional costs to deliver its power to its electric system, pursuant to the transmission and other arrangements discussed in the Consulting Engineer's Report. The estimates of the Consulting Engineer of costs of the Project Participants for power from the Authority Interest assume, among other things, that the cities of Riverside, Azusa, Banning and Colton will enter into transmission service agreements, and into supplemental agreements to their respective existing Integrated Operations Agreements, with Edison. Such agreements have been entered into by each of the above-named cities and Edison.

Transmission Arrangements

Pursuant to the Transmission Agreement, the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which is being utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of the District. The Authority has purchased from Salt River Project an undivided ownership interest in the entire ANPP High Voltage Switchyard. The output of the Authority Interest, with the exception of the District's Project Entitlement, will be received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project is making available to the Authority an equivalent amount of power and energy at a combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation. Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station.

The Department is transmitting its Project Entitlement from the Project Interconnection Point utilizing its own transmission system.

Pursuant to the terms and conditions of the Palo Verde Nuclear Generating Station Transmission Service Agreements between the Department and the other Project Participants, with the exception of the District (the "Transmission Service Agreements"), the Department is providing transmission service for each such Project Participant's Project Entitlement between the Project Interconnection Point and the Project Participant's Points of Interconnection.

The District has acquired an ownership interest in the Southwest Powerlink as a permanent means of transmitting its Project Entitlement. This project was completed in June 1984. The District completed the new 230 kV interconnection between the Southwest Powerlink and the District system in December 1984.

The proposed Mead-Phoenix DC Intertie Project, although not required for transmission of the Authority Interest, would allow the Authority members to operate more efficiently. In the event that the Mead-Phoenix DC Intertie is constructed, pursuant to the Transmission Agreement, Salt River Project will transmit, as necessary, the Authority Interest power and energy, with the exception of the District's Project Entitlement, to the Authority at the Project Interconnection Point. The effects of these proposed facilities have not been included in the Consulting Engineer's analysis.

Permits, Licenses and Approvals

Units 1, 2 and 3 have each received a 40-year Full-Power Operating License from the NRC. APS has stated that all necessary permits, licenses and approvals have been secured.

Operating Experience

The first refueling of Unit 1 was completed in March 1988. As the result of the occurrence of initial operating problems normally expected in a large, new generating facility, the performance of Unit 1 was approximately 51% as compared to the 60% capacity factor assumed by the Consulting Engineer in

previous analyses for the first fuel cycle of commercial operation. For the first nine months of the second fuel cycle, Unit 1 has achieved a 71.3% capacity factor.

The first refueling of Unit 2 was completed in June 1988. This unit performed well during its first fuel cycle. Specifically, it achieved approximately a 66% capacity factor as compared with the 60% capacity factor assumed by the Consulting Engineer in previous analyses for the first fuel cycle of commercial operation. For the first five months of the second fuel cycle, Unit 2 has achieved a 94.2% capacity factor.

Unit 3 has been operating on a commercial basis for approximately twelve months. For this portion of the first fuel cycle, Unit 3 has achieved approximately a 91.7% capacity factor.

The Department, as the Authority's agent, has indicated APS has either solved or is developing solutions to the operational anomalies encountered by APS in Units 1, 2 and 3 during the first fuel cycles.

Operation and Maintenance

The Consulting Engineer has reviewed the APS organizational structure which establishes the responsibilities and relationships for operation and maintenance of the Project. Included in the review were certain procedures and methodologies for operation and maintenance, as well as the results of certain NRC assessments of APS' performance in these functional areas.

The NRC, as part of its responsibilities, monitors and evaluates all nuclear plant licensees with respect to operational performance. As part of this industry monitoring function, the NRC has authority to take regulatory action ranging from increased monitoring of selected aspects of a nuclear facility to precluding operations.

The NRC released its most recent Systematic Assessment of Licensee Performance ("SALP") Report for the Project on December 23, 1988. This SALP Report reflected the results of the NRC's periodic evaluation of the performance of the Project for the period November 1, 1987 through October 31, 1988. Although the SALP Report indicates that the overall performance of licensed activities at the Project is satisfactory and directed toward safe facility operation, such performance was considered to have declined when compared to the previous SALP assessment period. Based in part on "enforcement items" which are listed in the SALP Report, the NRC indicated that additional management attention must be given to specified functional areas. The NRC has proposed and APS has paid civil penalties of $350,000 for "enforcement items" identified at the Project during the last year in the functional areas of operations and radiation protection. APS has indicated that it recognizes that it must improve its operational performance at the Project. It has developed plans for such improvement which the NRC has indicated it considers to be positive. APS has indicated that it has initiated such improvements.

Operating Statistics

Operating results of Units 1, 2 and 3 are shown in the following table. Although these units have not been operating long enough for their operating statistics to be meaningful compared to industry averages for similar size units, such statistics do provide an indication of how the units have performed when compared to similar units with more operating experience. While Unit 3 has experienced an above-average level of performance, Unit 3 is in its first year of commercial operation and has not experienced any maintenance outages or refueling. Based on historical experience of comparable generating units, it is not expected that Unit 3 will continue to achieve, over the long-term, the

substantially above-average level of performance that has been demonstrated during its first fuel cycle of operation to date.

Operating Statistics(1)

	Unit 1	Unit 2	Unit 3	Industry Averages(2)
Net Energy Generated (MWh)	17,071,401	16,784,125	9,103,692	—
Plant Factor(3)	60.0%	60.5%	91.7%	57.09%
Operating Availability(4)	59.7%	73.6%	94.9%	64.23%
Equivalent Availability(5)	56.1%	68.7%	91.3%	60.50%

(1) Operating statistics for Units 1, 2 and 3 reflect operation through December 31, 1988, which for Units 1 and 2 includes completion of the first refueling outage.

(2) Information is for 23 pressurized water reactor units larger than 1000MW as obtained from the Generating Availability Data Systems Report published by the North American Electric Reliability Council for the period 1982-1986.

(3) The Plant Factor is the ratio of the net energy generated to the net capability of that unit times the hours in the period and reflects the unit availability, as well as the actual need for power produced by the unit. Net energy generated is for the periods of firm power operation for each unit. For this application, Plant Factor is essentially equivalent to capacity factor.

(4) The Operating Availability is the ratio of hours in the period that the unit is capable of operating at some level to the number of hours in the period.

(5) The Equivalent Availability Factor provides an adjustment of the Operating Availability by incorporating the effect of deratings (losses in MW capability) and is essentially "equivalent to" the percentage of a period during which a unit was available for maximum net capability operation.

THE PROJECT PARTICIPANTS

General

The Project Participants, each of which has executed a Power Sales Contract with the Authority, are the Department, the District, the City of Riverside, the City of Vernon, the City of Burbank, the City of Glendale, the City of Pasadena, the City of Azusa, the City of Banning and the City of Colton. Although a member of the Authority, the City of Anaheim is not a Project Participant. Each of the Project Participants owns and operates an electric system for the distribution of electric energy to its retail customers. This section briefly describes the Project Participants. For additional information about the Project Participants and their respective electric systems, see "The Project Participants" in the Consulting Engineer's Report and Appendix B hereto.

Historical Operations

The following tables summarize certain historical operating statistics of the Department and the other Project Participants' electric systems, respectively. See "The Project Participants" in the Consulting Engineer's Report and Appendix B hereto for more detailed information.

Historical Number of Customers, Load Requirements and Operating Revenues for the Department

Fiscal Year Ending June 30	Average Number of Customers	% Increase (*)	Energy Requirements (MWh)	% Increase (*)	Peak Demand (MW)	% Increase (*)	Operating Revenues ($000)	% Increase (*)	Operating Revenues per kWh (Mills)	% Increase (*)
1984	1,243,092	—	21,848,064	—	4,444	—	1,177,469	—	53.89	—
1985	1,251,206	0.65	22,529,539	3.12	4,882	9.86	1,287,967	9.38	57.17	6.09
1986	1,261,972	0.86	22,262,629	−1.18	4,713	−3.46	1,358,134	5.45	61.01	6.72
1987	1,275,920	1.11	22,792,990	2.38	4,744	0.66	1,403,441	3.34	61.57	0.92
1988	1,304,603	2.25	23,701,912	3.99	4,922	3.75	1,570,028	11.87	66.24	7.58
Compound Annual Growth Rate 1984-1988		1.21%		2.06%		2.59%		7.46%		5.29%

* Over previous year.

Historical Number of Customers, Load Requirements and Operating Revenues for All Project Participants Excluding the Department

Fiscal Year Ending June 30	Average Number of Customers (2)	% Increase (3)	Energy Requirements (MWh) (4)	% Increase (3)	Peak Demand (MW) (5)	% Increase (3)	Operating Revenues ($000)	% Increase (3)	Operating Revenues per kWh (Mills)	% Increase (3)
1984	324,031	—	6,767,039	—	1,587	—	430,663	—	63.64	—
1985	327,988	1.22	7,108,863	5.05	1,730	9.01	484,294	12.45	68.13	7.06
1986	337,513	2.90	7,204,329	1.34	1,717	−0.75	481,007	−0.68	66.72	−2.07
1987	348,565	3.27	7,425,104	3.06	1,697	−1.16	494,627	2.83	67.68	1.44
1988(1)	360,308	3.37	7,862,326	5.89	1,762	3.83	546,477	10.48	69.51	2.69
Compound Annual Growth Rate 1984-1988		2.69%		3.82%		2.65%		6.13%		2.23%

(1) Preliminary, unaudited data.

(2) District data have been adjusted, on an average annual basis, from calendar year to fiscal year.

(3) Over previous year.

(4) Excludes Bonneville Power Administration ("BPA") exchange obligation.

(5) Non-Coincidental.

The Department

The Department, the largest municipal utility in the United States, is a separate proprietary agency of The City of Los Angeles, controlling its own funds and with full responsibility for meeting the water and electric requirements of The City of Los Angeles. It provides water and electricity services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.4 million.

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners. The Board of Water and Power Commissioners fixes the Department's electric rates, subject to the approval of the City Council, by ordinance. The Department's rates are not regulated by any California state agency and are not subject to approval by any Federal agency, but the Department is subject to certain ratemaking provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The Department's maximum net hourly peak demand, 4,991 MW, occurred in September 1988. The power supply of the Department consists primarily of its own generating resources, part of which are located within the Los Angeles Basin, and its 491 MW entitlement from the Hoover Power Plant. As of December 31, 1988, the Department had a net dependable system capability of over 7,200 MW, which is owned or operated generation. Steam electric generating capability was equal to 73% of the system's total net capability and owned or operated hydroelectric generating capacity accounted for 20% of such capability. Purchases are made on a day to day or week to week basis that will alter these percentages. The Department estimates that its capital expenditures for power generating and distribution facilities for the five-year period which began July 1, 1988 will total approximately $1.7 billion.

Imperial Irrigation District

The District is a publicly-owned water and power utility located in southern California. The gross area served by the District is approximately 6,400 square miles in Imperial County and the Coachella Valley of Riverside County. The power supply of the District consists of hydroelectric units on the All-American Canal and oil- and gas-fired generating facilities, as well as purchases of capacity and energy from other sources. In the twelve months ended December 31, 1988, the District experienced a peak demand of approximately 455.0 MW, generated 781,371 MWh and purchased 1,127,202 MWh.

Administration of the District is under the direction of a five-member Board of Directors. Electric rates are set by the Board of Directors after a series of public hearings and presentations to the city councils of the cities located within the District's service area. The District's electric rates are not subject to regulation by any California state agency and are not subject to approval by any Federal agency, but the District is subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

Cities of Riverside, Vernon, Azusa, Banning and Colton

The cities of Riverside, Vernon, Azusa, Banning and Colton each are municipal corporations existing under the laws of the State of California, each owning and operating electric public utilities for their respective citizens, providing electric service to virtually all of the electric customers within the respective city limits, which together encompass a total of approximately 128 square miles. The principal facilities of the cities' electric systems are sub-transmission and distribution lines aggregating approximately 1,619 circuit miles of transmission lines, and for the City of Riverside, 740 circuit miles of street lighting distribution lines, as of June 30, 1988.

Electric rates for the City of Riverside are established by the Riverside Board of Public Utilities, subject to approval of the Riverside City Council. Electric rates for the other cities are established by the respective city councils. None of these electric rates are subject to regulation by any California

state agency. The cities of Riverside and Vernon (because of the magnitude of their energy sales) are subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

The five cities operate their respective electric systems and obtain their bulk power supply in accordance with provisions of their respective Integrated Operations Agreements, as amended ("IOA"), which each city has executed with Edison. Each IOA provides, among other things, that the requirements of each city's electric system will be met by generating resources in which each such city has a contractual ownership interest and, to the extent required, by wholesale purchases from Edison.

The City of Riverside has a 1.79% ownership interest, approximately 38.49 MW, in the San Onofre Nuclear Generating Station, Units 2 and 3 ("San Onofre"). San Onofre Unit 2 commenced commercial operation in October 1983 and Unit 3 commenced commercial operation in April 1984.

At this time the cities of Riverside, Vernon, Azusa, Banning and Colton receive power and energy from their respective Project Entitlements in Unit 1, Unit 2 and Unit 3, Hoover Entitlements and short term firm purchases and purchase interruptible energy from other utilities and governmental agencies when it is available at an economically attractive price and transmission is available. The City of Riverside also has a 7.617% generation entitlement share in IPP (121.87 MW). The City of Riverside has entered into a power sales agreement with Deseret Generation Transmission Co-operative ("Deseret") pursuant to which the City of Riverside has agreed to purchase 46.69 MW, plus losses which are to be determined between IPP and the Mona 345-kV bus, of firm capacity and associated energy. Riverside's contract also provides Deseret with first rights to supply the City of Riverside with certain economy and replacement energy. The capacity and energy from Deseret is currently available although it has not been integrated with Edison and is not subject to provisions of the IOA. The City of Vernon receives power and energy from its diesel units and a recently installed gas turbine. All remaining power and energy requirements for each of the five cities are purchased from Edison at wholesale rates.

The City of Banning has issued $2,570,000 of Certificates of Participation to fund a hydroelectric generating project which is anticipated to generate approximately 829 kW and 5,280 MWh annually. Additionally, the City of Vernon has issued $125,000,000 of Electric System Revenue Bonds to fund such City's Bear Butte hydroelectric, pumped storage project which is anticipated by the City to generate approximately 120 MW of peaking capacity and 205,500 MWh and 161,100 MWh annually during high and low water years, respectively. The City further anticipates utilizing approximately 42 MW to meet a portion of its electric load with the balance of the project power sold to one or more publicly owned utilities. The project is presently in the design and engineering phase and is anticipated by the City to be in commercial operation during 1997. Due to the preliminary nature of design, licensing and contract status, the Consulting Engineer has not included the power and energy from this project in its analysis.

Cities of Burbank, Glendale and Pasadena

The cities of Burbank, Glendale and Pasadena are each municipal corporations existing under the laws of the State of California, owning and operating electric public utilities providing electric service to virtually all of the electric customers within their respective city limits.

Electric rates for each city are fixed by its City Council and are not subject to regulation by any California state agency. Each city is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978.

Burbank, Glendale and Pasadena supply electricity to their respective electric systems through a combination of oil- and gas-fired generating facilities located in the Los Angeles Basin, 34 MW of hydroelectric generation at the Hoover Power Plant and purchases from the Bonneville Power Administration and other utilities in the Northwest and Southwest. The City of Pasadena also purchases electric energy from the Azusa Hydroelectric Plant. In the twelve months ended June 30, 1988, the three cities generated an aggregate of 861,770 MWh of energy and purchased an aggregate of 2,224,939 MWh.

Other Projects of the Project Participants

Intermountain Power Project. In 1977, several Utah municipalities organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah. The purpose of IPA is to provide for the financing, constructing and operating of the Intermountain Power Project ("IPP").

In 1980, the Department and the cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (the "California IPP Purchasers") each entered into a power sales contract with IPA which obligates each such Purchaser to purchase, on a "take or pay" basis, a percentage share of IPP capacity and energy. The Department and the cities of Burbank, Glendale and Pasadena also entered into an Excess Power Sales Agreement, also on a "take or pay" basis, with the Utah municipal and cooperative IPP purchasers, pursuant to which IPP generation entitlement projected to be surplus to such Utah purchasers' needs will be made available to the Department and the cities of Burbank, Glendale and Pasadena.

In early 1983, each IPP Purchaser entered into amendments to its power sales contract and the Excess Power Sales Agreement. All California IPP Purchasers except Glendale also entered into Lay-off Power Purchase Contracts (the "Lay-off Contracts") with IPA and Utah Power & Light Company ("UP&L") through which UP&L assigned portions of its entitlement to IPP capacity and energy to such Purchasers. UP&L has recently merged with and is a division of PacifiCorp.

The IPP generation entitlement of each of the California IPP Purchasers resulting from the power sales contracts, as amended, and the Lay-off Contracts is shown in the following table:

	Percentage Share	Generating Capability (kW)
Los Angeles Department of Water and Power	44.617%	713,872
City of Anaheim	13.225	211,600
City of Riverside	7.617	121,872
City of Pasadena	4.409	70,544
City of Burbank	3.371	53,936
City of Glendale	1.704	27,264
Total	74.943%	1,199,088

The California IPP Purchasers will receive, pursuant to the power sales contracts, as amended, and the Lay-off Contracts, approximately 1,169 MW of capacity and, assuming both IPP generating units operate at a 70% plant factor, 7,170,458 MWh of energy annually, after losses, at the Adelanto point of delivery. The amounts of generating capability that will be available pursuant to the Excess Power Sales Agreement, as amended, will vary in accordance with the provisions of that Agreement. Presently, and through March 24, 1999, according to the most recent forecasts furnished pursuant to terms of the Excess Power Sales Agreement, as amended, the quantities of capacity and energy that will be available at the Adelanto point of delivery are approximately 328 MW and, assuming a 70% plant factor, approximately 2,011,296 MWh annually.

IPP consists of the following: (a) a two unit, 1,600 MW net coal-fired, steam-electric generation station located near Lynndyl, Utah; (b) the Southern Transmission System; and (c) two 50-mile 345 kV AC transmission lines from the generation station to a switchyard near Mona, Utah and a 230 kV AC transmission line from the generation station to a switchyard near Ely, Nevada.

A portion of the funds required for IPP construction is being provided by IPA with the remainder being provided by the Authority as payments-in-aid of construction with respect to the Southern Transmission System. IPA has outstanding approximately $6,954,682,000 par amount of bonds, including $1,634,995,000 of special obligation bonds and special obligation Refunding bonds which together with the payments-in-aid of construction with respect to the Southern Transmission System provided by the Authority have allowed IPA to construct and place IPP in service. The amount of IPA's outstanding debt is expected to be reduced on July 1, 1995 by $1,532,110,000 when the special obligation bonds and special obligation refunding bonds are expected to be used to effect the

redemption of certain of IPA's outstanding bonds and will thereby reduce IPA's overall debt service. IPA will continue to review the options that are available to it to reduce its annual debt service and may undertake additional refundings. For a discussion of the Southern Transmission System, including the total financing requirements for the Authority's payments-in-aid of construction, see the caption "Future Power Supply Resources — Southern Transmission System" in the Consulting Engineer's Report.

The first IPP generating unit was declared available for commercial operation in June 1986, the second unit in May 1987.

Despite the occurrence of operating problems normally expected in a new generating facility and certain abnormal conditions, IPP has to date operated with a high degree of availability. The Department and the Intermountain Power Service Corporation have either solved or are working on solutions to the problems encountered.

All permits, licenses and approvals required to be obtained for IPP to date have been obtained.

The Authority has been informed that litigation seeking to apply southern California air quality requirements to the IPP generation station has been threatened by a company whose efforts to construct a 35 MW power plant in southern California have been adversely impacted by the more stringent southern California air quality requirements. The Authority has been advised by the Department that all air quality permits necessary to operate the IPP generation station have been obtained.

The Department has executed agreements to provide transmission service from the Adelanto Converter Station as necessary to enable the other five California IPP Purchasers to accept delivery of their shares of IPP generation.

Southern Transmission System. Certain of the Project Participants have entitlements in the Southern Transmission System totalling approximately 82.4%. See "Southern California Public Power Authority — Other Activities of the Authority" for a discussion of this project.

White Pine Power Project. Certain of the Project Participants, apart from the Authority and together with other public and private utilities in California and Nevada, have conducted studies to establish the feasibility of and proceed with the licensing activities necessary for constructing a coal-fired generating station near Ely, Nevada. This generating station would have a capability of approximately 1,500 MW. It is contemplated that White Pine County would own all, or a major portion of, and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the project. The Project Participants' combined entitlement percentage share for feasibility studies is approximately 47.36%. The participants in the White Pine Power Project entered into power supply development agreements with White Pine County in the fall of 1980 for the purpose of conducting a study to determine the feasibility of constructing and operating the project. White Pine County has issued notes in the principal amount of $19,929,000 for such purposes, all but $500,000 principal amount of which has been prepaid. The remaining $500,000 note matures December 31, 1992 and is payable from the proceeds of long-term bonds to be issued by the County or from payments by the participants under such agreements on the basis of entitlement shares. The projected commercial operation date for the two 750 MW generating units, if built, is in the mid-1990's. For a further discussion of the White Pine Power Project, see the caption "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions — White Pine Power Project" in Appendix B hereto.

Mead-Phoenix DC Intertie Project. Certain of the Project Participants have entitlements in the Authority's interest in the Mead-Phoenix DC Intertie Project totalling approximately 93.75%. See "Southern California Public Power Authority — Other Activities of the Authority" for a discussion of this proposed project.

Devers-Palo Verde #2 Transmission Line. The Department, the District, M-S-R Public Power Agency, and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton along with Edison, as project manager, have undertaken studies to explore the feasibility of constructing a 500 kV AC transmission line. This proposed Devers-Palo Verde #2 transmission line, if built, will

parallel the existing Devers-Palo Verde #1 transmission line from the Project to Edison's Devers Substation, which is located west of Desert Hot Springs, California. The Project Participants' participation rights in the proposed Devers-Palo Verde #2 transmission line total 36.8%. Edison has scheduled this project for completion in 1993. On December 8, 1988, the California Public Utilities Commission ("CPUC") granted Edison a Certificate of Public Convenience and Necessity for this project. In its decision, the CPUC reserves the right to reevaluate its approval if the proposed Edison — San Diego Gas & Electric Company ("SDG&E") merger (CPUC Application 8-12-035; FERC Docket No. EC 89-5-000) is consummated or is still pending as of January 1, 1990. The decision notes that there may be no economic benefit from the line for Edison ratepayers if the merger is completed. Pursuant to an agreement with Edison, the Department has the right to construct this transmission line if Edison fails to commence construction before July 1, 1989. It is not clear what effect, if any, the above-described developments will have on the construction of this transmission line or the participation of the above mentioned utilities.

California-Oregon Transmission Project. The cities of Riverside, Vernon, Azusa, Banning and Colton executed a Memorandum of Understanding, dated as of December 19, 1984, which authorizes these cities, along with other utilities and governmental agencies located in California, to study the construction of the California-Oregon Transmission Project. Such Project relates to possible alternative methods of developing additional 500 kV AC transmission facilities between California and the Pacific Northwest. The participants have executed a project development agreement pursuant to which they will study the feasibility of constructing and operating the California-Oregon Transmission Project. It has not been determined what role, if any, the Authority will have in this transmission line project.

Sylmar Expansion Project. The Department and the cities of Burbank, Glendale and Pasadena are participants in the Sylmar Expansion Project ("SEP") which is an 1,100 MW expansion of the terminal capacity at the existing AC/DC converter station which is located at Sylmar, California. This Project will increase the capacity of the Pacific Northwest-Southwest DC Intertie ("Intertie") from 2,000 MW to 3,100 MW. The Department is the project manager for the southern terminal of the Intertie and is responsible for the construction of the SEP. The Bonneville Power Administration is the project manager for the northern terminal and is responsible for a similar expansion at the northern converter station of the Intertie in Oregon. The Department projects that the cost of the SEP will be $171,000,000 and that the SEP will be completed in February 1989. Each participant is providing its own funding for its share of the SEP.

For a discussion of other projects under consideration by the Department, see "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions" in Appendix B hereto.

AVAILABILITY OF OPERATING FUNDS AND AVAILABLE INFORMATION CONCERNING OTHER OWNERS OF PALO VERDE NUCLEAR GENERATING STATION

Continued operation of the Project is dependent upon, among other things, the owners making timely payment of their respective payment obligations under the Participation Agreement. The capability of the owners to provide such payment is dependent upon their continued ability to generate the necessary funds from internal or external sources.

Information concerning other owners of the Project is available from a number of sources.

APS, Edison, El Paso Electric Company and Public Service Company of New Mexico, respectively, are subject to the informational requirements of the Securities Exchange Act of 1934 and in accordance therewith file reports and other information with the SEC, which can be inspected and copied at the offices of the Commission at Room 1024, 450 Fifth Street, N.W., Washington, D.C.; Room 1204, Everett McKinley Dirksen Building, 219 South Dearborn Street, Chicago, Illinois; Room 1102, Jacob K. Javits, Federal Building, 26 Federal Plaza, New York, New York; and Suite 500 East, 5757 Wilshire Boulevard, Los Angeles, California. Copies of such material can also be obtained at prescribed rates from the Public Reference Section of the SEC at its principal office at 450 Fifth Street, N.W.,

Washington, D.C. 20549. Certain securities of APS and Edison, respectively, are listed on the New York and Pacific Stock Exchanges. Reports, proxy material and other information concerning APS and Edison can be inspected at the respective offices of these exchanges located on the 7th Floor, 20 Broad Street, New York, New York, and at 115 Sansome Street, San Francisco, California. Information regarding Edison, which is also listed on the American Exchange, may also be obtained at the offices of the American Exchange at 86 Trinity Place, New York, New York. Information regarding Public Service Company of New Mexico, which is listed on the New York Stock Exchange, may be obtained at said Exchange's offices listed above.

Copies of the most recent official statement and annual report of the Department may be obtained from B C Monk, Department of Water and Power, 333 South Beaudry, 18th Floor, Los Angeles, California 90012.

Copies of the most recent official statement and annual report of Salt River Project may be obtained from Mark B. Bonsall, Corporate Treasurer, Box 52025, Phoenix, Arizona 85072-2025.

CONSIDERATIONS, ASSUMPTIONS AND OPINIONS OF THE CONSULTING ENGINEER

Principal Considerations and Assumptions

The estimates and projections contained herein are based, in part, on the following information which was provided by the identified sources. While the Consulting Engineer believes these sources to be reliable and has no reason to believe such information is unreasonable, the Consulting Engineer has not independently verified such information.

1. Projections of the Department's power and energy requirements, resources and power supply costs, excluding costs of its Project Entitlement and IPP generation entitlements, were provided by the Department.
2. Projections of power and energy requirements for the cities of Riverside, Burbank, Glendale, Pasadena, Vernon, Azusa, Banning and Colton and the District were provided by those Project Participants.
3. Excluding their Project Entitlements, IPP generation entitlements and the Hoover uprating project, projections of resources for the cities of Burbank, Glendale and Pasadena were provided by those Project Participants.
4. Projections of capital expenditures and operation and maintenance expenses for the Department, and the cities of Riverside, Burbank, Glendale and Pasadena were provided by those Project Participants.
5. The District and the City of Vernon provided projections of their capital expenditures.
6. The financial advisor has provided the Consulting Engineer with assumed investment rates of 8.0% through fiscal year 1992 and 7.85% for fiscal year 1993 for the proceeds of Prior Series Bonds and the 1989 Bonds deposited in the Debt Service Reserve Account in the Debt Service Fund and the Reserve and Contingency Fund, and 7.0% for such proceeds deposited in all other funds.

The Consulting Engineer's Report projected wholesale power and energy rates for Edison. Oil and gas prices have a direct impact on Edison rates. The oil price level used in the analyses of future Edison rates is based on an average cost of $18.54 per barrel in 1988 increasing at 4.2% per year through 1993 and at 5.7% per year after 1990. The natural gas price level is based on an average cost of $3.04 per million BTU in 1988 increasing at 4.2% per year through 1990 and at 5.7% per year after 1990. Additionally, the Consulting Engineer cannot presently determine to what extent Edison will be allowed to include CWIP in its wholesale electric rates. Edison has not included CWIP in its most recent rate settlement with the cities of Riverside, Vernon, Azusa, Banning and Colton. The Consulting Engineer's projections of Edison's wholesale electric rates do not include an allowance for CWIP in its

rate base. The Consulting Engineer has not analyzed what impact, if any, the proposed merger, if approved, of SDG&E with Edison will have on Edison's operations or its wholesale electric rates.

Additionally, in the preparation of its report and the numbered opinions that follow, the Consulting Engineer has made certain assumptions with respect to conditions which may occur in the future. While the Consulting Engineer believes these assumptions are reasonable for the purpose of its report, they are dependent upon future events, and actual conditions may differ from those assumed. In making such assumptions, the Consulting Engineer has used and relied upon certain information provided to the Consulting Engineer by the Department, acting as the Authority's agent, the Project Participants, Edison and others. While the Consulting Engineer believes the sources to be reliable, the Consulting Engineer has not independently verified the information. To the extent that actual future conditions differ from those assumed in the Consulting Engineer's Report or from the information provided to the Consulting Engineer by others, the actual results will vary from those projected. The principal assumptions made by the Consulting Engineer and the principal information related to such assumptions provided to the Consulting Engineer by others include the following:

1. Based on actual expenditures through November 30, 1988, APS's estimate of direct construction costs of the Project, and the Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project provided by the Department, as the Authority's Agent, the cost of acquisition of the Authority Interest will be $465,170,000.
2. Operating costs of the Project were projected by APS with the exception of taxes.
3. Based on APS's projection, as adjusted by the Consulting Engineer, Unit 3 will have a plant factor of approximately 60% during the first cycle of operation and each unit will have a plant factor of approximately 65% during the second cycle of operation and 70% thereafter.
4. By such time as the on-site fuel storage facilities reach capacity, a national program for spent fuel disposal will have been implemented.
5. Existing environmental laws and regulations will not be modified to adversely affect the construction cost or scheduled completion date of the Project or the Project operation.
6. If additional permits, licenses and approvals are necessary to continue operating the Project, they will be received on a timely basis.
7. The variable cost of power from the project will, in the future, maintain its same position relative to the variable costs of power from alternative resources which are now available to the Project Participants.
8. The cities of Riverside, Vernon, Azusa, Banning and Colton have integrated their respective Project Entitlements as a City Capacity Resource under their respective Integrated Operations Agreements with Edison.
9. Power and energy requirements of the cities of Vernon, Azusa, Banning and Colton, beyond that provided by their respective Project Entitlements and their respective Hoover uprating project entitlements, including Western energy credits, their respective short-term firm power purchases under contract or agreement and the City of Vernon's diesel generators and the City of Banning's hydroelectric generating project, will be purchased from Edison in accordance with the terms of their respective Integrated Operations Agreements.
10. Power and energy requirements of the City of Riverside, beyond those provided by its Project Entitlement, San Onofre Nuclear Generating Station Units 2 and 3, IPP, Deseret and its Hoover uprating project entitlement, including Western Energy credits, and short-term firm power purchases under contract or agreement will be purchased from Edison in accordance with the terms of its Integrated Operations Agreement.
11. With the exception of the Department and the cities of Burbank, Glendale and Pasadena, the Project Participants' participation in other potential resources or economy purchases which are not under contract but which may become available to such Project Participants during

the projected period have not been included in the projected power costs or the Consulting Engineer's projected resources of the Project Participants.

12. Based on information provided by the Project Participants, the District, Glendale, Azusa and Colton will finance the projected costs of normal capital replacements and improvements, if any, to their electric systems from current revenues.

13. Transmission for each Project Participant's Project Entitlement will be provided in accordance with the agreements as discussed in the Consulting Engineer's Report.

14. Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, recent rate filings, and Edison's electric system resource plans and load forecasts. Further, in projecting Edison rates, the Consulting Engineer has supplemented recent Edison filings with the following assumptions: (1) FERC will allow Edison a 13.00% rate of return on common equity in 1988 through 1990 and 13.5% in 1991 and thereafter; (2) the basic rate of inflation will be approximately 4.2% per year; (3) annual escalation for coal will be 5.7% per year; (4) operating expenses will escalate at 4.2% per year; and (5) the costs of construction will generally escalate at 5.2% per year. The resulting wholesale energy charges paid by the cities of Azusa, Banning, Colton, Riverside, and Vernon to Edison would increase at approximately 3.7%, per year for fiscal years 1988-1993.

15. The 1988 average revenue per unit of energy sales, based on 1988 revenues from the sales of electricity and total energy sales, as provided by all Project Participants with the exception of the Department, will continue at the same level for the projected energy sales over the period of fiscal years ending June 30, 1989 through 1993.

16. The existing ratemaking authority of the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District to establish rates for the purpose of providing necessary revenues for their respective electric utility systems will not be adversely modified.

17. The capital expenditures and operation and maintenance expenses for the cities of Azusa, Banning and Colton will follow historical trends.

18. The operation and maintenance expenses for the District and the City of Vernon will follow historical trends.

Opinions

Based upon the Consulting Engineer's studies and analyses, the considerations and assumptions set forth above and the information supplied by the Project Participants, the Department, acting as the Authority's Agent, and Edison with respect to the Authority's acquisition, construction and placing into operation of the Authority Interest, the Consulting Engineer is of the opinion that:

1. Financing by the Authority to provide funds to allow completion of the Authority Interest has been completed.

2. The projected cost of power from the Authority Interest is reasonable when compared with the cost of power expected from other long-term power supply resources which may be available to the Project Participants in the same time frame as the Project.

3. The Project Participants will continue to schedule the maximum amount of the production available from their respective Project Entitlements.

4. The projected revenue requirements from the sale of electricity for the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District during fiscal years ending June 30, 1989 through 1993 can reasonably be met.

LETTER OF THE DEPARTMENT

As stated in the letter of the Department attached hereto as Appendix F, based upon, among other things, the Department's studies and analyses which have included projections with respect to, among other things, the estimated cost of power from the Authority Interest as contained in the Consulting Engineer's Report, the estimated cost and availability of oil and natural gas, future load growth in The City of Los Angeles, and the estimated future electric system revenue requirements, as estimated by the Department, the Department is of the opinion that:

1. The Department's share of the output from the Authority Interest will, over time, be economically beneficial to the Department in displacing base load oil- and natural gas-fired generation in the Los Angeles basin;

2. The projected cost of power to the Department from the Authority Interest makes such power economically attractive in the long term to the Department when compared with the projected price levels of oil and natural gas and with the projected cost of power from other alternative resources which may be available to the Department; and

3. For the period through June 30, 1993, the Department's electric system revenues will be sufficient to enable it to pay the Authority all amounts payable under the Department's Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, the Department's power system revenues.

CERTAIN FACTORS AFFECTING THE UTILITY INDUSTRY AND TAKE OR PAY POWER SUPPLY AGREEMENTS

The electric utility industry has experienced and is experiencing various problems, including the effect of inflation on the cost of construction and operation of utility facilities, the fluctuating costs and uncertain availability of fuel, particularly fossil fuels, compliance with new legislation, the uncertain availability and increased cost of capital, cancellation of projects and related contractual litigation, and environmental regulations, licensing procedures, litigation and other factors which may delay the construction and increase the cost of new facilities, the cost of power or limit use of, or necessitate costly modifications to, existing facilities.

Federal energy legislation enacted in 1978 authorizes the President to allocate coal supplies in the event of an energy supply interruption or fuel supply shortage, authorizes the Federal Energy Regulatory Commission to order mandatory interconnection and wheeling and to review automatic rate adjustment clauses and directs state regulatory authorities and nonregulated utilities to consider certain standards for rate design and other utility procedures. The Authority is unable to determine the effect such legislation may have on its operations and those of the Project Participants.

In June 1983, the Supreme Court of the State of Washington held invalid the "take or pay" participation agreements between the Washington Public Power Supply System (the "Supply System"), a joint action power agency, and certain State of Washington public entities relating to two terminated nuclear generating projects of the Supply System. The Court held that those public entities lacked statutory authority under Washington law to enter into such participation agreements. Following the Court's decisions, the Superior Court of King County, Washington held unenforceable the "take or pay" participation agreements entered into between the Supply System and the 88 participants in the two terminated nuclear generating projects. The Superior Court's decision was affirmed by the Supreme Court of the State of Washington. A petition seeking review of that decision was denied by the United States Supreme Court. In March 1984, the Supreme Court of the State of Oregon unanimously reversed a lower court decision and upheld the authority of Oregon public entities to enter into the "take or pay" participation agreements. Additionally, the Supreme Court of the State of Idaho in September 1983 held that the "take or pay" participation agreements entered into between the five Idaho cities and the Supply System are void because the Idaho cities failed to comply

with a constitutional provision requiring voter approval before incurring indebtedness or liability exceeding a certain amount.

Notwithstanding the foregoing litigation and decisions, the Authority believes that the Power Sales Contracts are valid, binding and enforceable obligations of the Project Participants. Mudge Rose Guthrie Alexander & Ferdon, Bond Counsel, are of the opinion that none of these decisions affect the validity of the Power Sales Contracts. See the proposed form of the opinion of Bond Counsel attached hereto as Appendix E.

LITIGATION

At the time of delivery of the 1989 Bonds, an appropriate officer of the Authority will certify that, except for the action and threatened proceedings described below under "Thurston Litigation", there is no litigation or other proceeding pending or, to the knowledge of the Authority, threatened in any court, agency or other administrative body (either state or Federal) restraining or enjoining the issuance, sale or delivery of the 1989 Bonds or the collection of Revenues, or in any way questioning or affecting (i) the proceedings under which the 1989 Bonds are to be issued, (ii) the validity of any provision of the 1989 Bonds or the Bond Indenture, (iii) the pledge by the Authority under the Bond Indenture, (iv) the validity or enforceability of the Power Sales Contracts, (v) the legal existence of the Authority or the title to office of the present officials of the Authority, or (vi) the authority of the Authority to own and operate the Authority Interest.

Thurston Litigation

On July 27, 1982, three individual plaintiffs filed an action entitled *Thurston et al. v. Southern California Public Power Authority et al.* in the Superior Court for the County of Los Angeles against the Authority, the Department and other unnamed defendants, seeking, among other relief, a temporary restraining order, a preliminary injunction and a permanent injunction to, among other things, prevent the Authority from selling or issuing revenue bonds to finance the Authority Interest and to prevent the expenditure of public moneys by the defendants with respect to the Authority Interest. The plaintiffs allege, among other things, that (i) the undertaking by the Department of its obligations under, and the performance by the Department of, its Power Sales Contract violates certain provisions of the Constitution and statutes of the State of California and the Los Angeles City Charter, (ii) the terms of the revenue bonds proposed to be issued by the Authority would violate, and the authorization of such issuance by the Project Participants without a vote of the electorate violates, certain provisions of the statutes of the State of California, and (iii) the proposed transactions and certain acts of the defendants in connection therewith are unsound or unlawful business practices, an unsound business venture, or are otherwise illegal. On July 27, 1982, the plaintiffs' motion for a temporary restraining order was denied.

A hearing on plaintiffs' motion for a preliminary injunction in the action was held on August 10, 1982; plaintiffs' motion was denied at that hearing. On August 16, 1982, the plaintiffs appealed to the California Court of Appeal for the Second Appellate District from the denial of their motion for a preliminary injunction. The plaintiffs also filed with that court a petition for writ of supersedeas to stay enforcement of the order denying the preliminary injunction and to enjoin the Authority from issuing indebtedness, and from delivering any proceeds of indebtedness pursuant to the assignment agreement. On August 20, 1982, the Court of Appeal denied plaintiffs' petition. On July 12, 1984, the Court of Appeal entered its decision affirming the decision of the trial court and rejecting all issues raised by the plaintiffs.

The plaintiffs did not seek appellate review by the California Supreme Court of the July 12, 1984 Court of Appeal decision. The action has now been returned to the Superior Court, as the trial court, and is awaiting further action, if any, by the plaintiffs. The Authority and its Legal Counsel, Rourke & Woodruff, and the Department and the Los Angeles City Attorney have reviewed the complaint and the other court documents filed in the action (including those relating to the Court of Appeal proceedings) and have researched the legal issues raised by the plaintiffs therein. Based upon such review and research, the Authority and its Legal Counsel are of the opinion that insofar as the action

relates to the Authority, and the Department and the Los Angeles City Attorney are of the opinion that insofar as the action relates to the Department, the issues raised by the plaintiffs are without merit and the defendants have sound legal defenses to the causes of action contained in the complaint.

Project-Related Litigation

In January 1982, the Salt River Pima-Maricopa Indian Community filed an action entitled *Salt River Pima-Maricopa Indian Community v. United States et al.* against the United States, the Secretary of the Interior, Salt River Project, Salt River Valley Water Users Association, a number of water conservation and irrigation districts, the City of Phoenix, and other cities in the Greater Phoenix Metropolitan area, and the participants in the Project.

The action was originally brought only against the United States and the Secretary of the Interior in the United States District Court for the District of Columbia. The United States moved for transfer of the action to the United States District Court for Arizona and the motion was granted. Upon transfer, the Indian Community filed an amended complaint adding the additional parties, including the Authority and the Department.

The gist of the Complaint is that the Indian Community is entitled to certain water rights in and to the waters of the Salt River, including underground waters, under the Winters doctrine, contracts, court decisions and other federal law, and that the United States is not requiring Salt River Project to make water available to the Indian Community in accordance with those rights. Among the claims is the claim that Salt River Project delivers water to certain cities, including the City of Phoenix; that these cities pump water from the ground water basin; that the waters delivered to and pumped by the cities are subject to the claims made by the Indian Community; that the City of Phoenix and the other cities have agreed to sell effluent from the sewage treatment plant of the City to the Project for cooling purposes, and such effluent is subject to the claims of the Indian Community, and therefore the contract for sale of a portion of the effluent to the Project is invalid. The participants in the Project joined with other defendants in a motion to dismiss. The District Court's judgment, as amended on June 13, 1983, dismissed the entire action as to the Authority, the Department and APS, among others, but not as to Salt River Project. The District Court held that the plaintiff had no standing to challenge the Salt River Project — APS effluent contract. On June 13, 1983, the plaintiff appealed from the District Court's judgment. On September 4, 1984, the United States Court of Appeals for the Ninth Circuit reversed the District Court's judgment. The Ninth Circuit held that the plaintiffs had standing to challenge the effluent contract and remanded the case to the District Court. The Authority and other participants in the Project filed a petition for a writ of certiorari seeking review of the Ninth Circuit's decision by the United States Supreme Court. This petition was denied. On February 25, 1985, the District Court stayed discovery on the claim challenging the effluent contract, pending resolution of the claims against the Secretary of the Interior and Salt River Project relating to the administration of the reclamation project. Since that date, a proposed settlement between the Indian Community and Salt River Project has been announced which would lead to the dismissal of this litigation without any adverse effect on the primary effluent contract. The proposed settlement was contingent, however, upon the passage of federal legislation and the appropriation of federal monies. On October 31, 1988, the President signed federal legislation conforming to the requirements of the proposed settlement. However, Congress has not yet appropriated the federal money necessary to effectuate the settlement. Furthermore, the Arizona State Legislature will have to appropriate approximately $3 million before the settlement will become final.

On November 3, 1982, a lawsuit entitled *A Tumbling T Ranches, et al. v. City of Phoenix, et al.* was filed in the Arizona Superior Court by certain Arizona farm operators against, among others, the Department, the City of Phoenix and the Project participants, including the Authority. The lawsuit seeks, among other relief, declarations that the plaintiffs have previously established rights to some of the sewage effluent water contracted for by the Project participants for use at the Project and that the sale of that effluent by the City of Phoenix and other cities violates Arizona statutory and common law, and a permanent injunction enjoining the sale and delivery of the sewage effluent to the Project. The

Project participants, including the Authority, have answered the complaint denying the substantive allegations thereof and discovery has commenced.

On January 23, 1983, APS and Salt River Project, as contracting parties to the effluent contract, and others filed a declaratory relief action in the Arizona Superior Court against the plaintiffs in the *A Tumbling T Ranches* action and the plaintiffs in the federal action entitled *Long, et al. v. Salt River Project, et al.* (described below). This state suit, which is entitled *Arizona Public Service Co., et al. v. Long, et al.*, seeks a declaration that, under Arizona law, effluent is neither surface water nor groundwater, but rather is the property of, and can be disposed of, by the entity that produces it. This state action has been consolidated with the *A Tumbling T Ranches* action (hereinafter, "consolidated state cases").

On October 2, 1985, the Judge in the consolidated state cases ruled on cross-motions for summary judgment, denying the motions filed by the plaintiffs in the *A Tumbling T Ranches* action and the defendants in *Arizona Public Service Co., et al. v. Long, et al.* and granting APS', Salt River Project's and others' motions for summary judgment to the extent said motions were consistent with his declaration that "[t]he effluent which is the subject of the sales contracts between the Cities and the utilities in this case is not subject to regulation under the surface water or ground water laws of the State of Arizona." The plaintiffs in the *A Tumbling T Ranches* action filed a motion for new trial which was denied on February 4, 1986. The defendants in *Arizona Public Service Co., et al. v. Long, et al.* filed a Notice of Appeal on January 14, 1986. The Authority and the other participants in the Project except for Salt River Project filed a notice of cross-appeal in order to preserve an issue in the event of a remand. On December 17, 1986, the appeals were ordered transferred from the Arizona Court of Appeals to the Arizona Supreme Court. Oral argument before the Arizona Supreme Court was heard in February 1987. As a result of recusal by three members of the Arizona Supreme Court panel because of possible conflicts of interest, the matter was reargued before a new panel of the Arizona Supreme Court in February 1988.

A federal lawsuit was filed on December 12, 1983 in the United States District Court for the District of Arizona entitled *Long, et al. v. Salt River Project, et al.*, by an owner of land within the Salt River Project district and others, naming the Authority, the Department, Salt River Project and others as defendants. The lawsuit challenges on several grounds the validity of the primary contract for the sale of effluent for cooling purposes at the Project. The federal action also asserted on behalf of an alleged class a claim against the Project participants, including the Authority, for $50,000,000 based upon alleged inverse condemnation of water rights. On November 22, 1985, the District Court entered judgment dismissing the federal action. On December 19, 1985 the plaintiffs in the federal action filed a notice of appeal, and in June 1987 the Ninth Circuit of the United States Court of Appeals affirmed the dismissal of the action. The plaintiffs did not seek further review of that ruling and the time to do so has expired.

On November 22, 1985, certain cities who are parties to the effluent contract (the "Cities") filed a declaratory relief action entitled *City of Phoenix et al. v. John F. Long* in the Arizona Superior Court against the Long plaintiffs in the above-described federal action seeking a judgment that the primary effluent contract is valid. The defendants filed a Special Action counterclaim against the Cities. The court subsequently added APS and Salt River Project to the counterclaim as real parties in interest. The counterclaim sought a judgment declaring, among other things, that in approving the effluent contract the Cities exceeded their legal authority and that the Cities should be directed to cease performance under the effluent contract. APS and Salt River Project denied the allegations of the counterclaim and asserted as affirmative defenses that the defendants lacked standing to assert the counterclaim and that the counterclaim was barred by the statute of limitations and by laches. The defendants sought leave to file an amended answer and counterclaims and to join additional parties, including the Authority. By Order dated May 29, 1986, the court permitted the defendants to file their amended answer and counterclaims only to the extent that counterclaims 1 through 4 restated the substance of the original counterclaims concerning the legal authority of the Cities to approve the effluent contract. The defendants were denied leave to file their remaining proposed counterclaims

and to add the parties named therein. By Order dated June 2, 1986, the court ruled on cross-motions for summary judgment, denying the defendants' motion and granting judgment in favor of the Cities, APS and Salt River Project. The court rejected each of the defendants' challenges to the effluent contract and declared that it "is a valid and enforceable contract." The defendants filed a Notice of Appeal on August 27, 1986, and APS filed a Notice of Cross-Appeal on September 15, 1986, concerning the issue of whether the defendants' claims are barred by laches, estoppel, the statute of limitations and lack of standing. On February 11, 1988 the Arizona Court of Appeals affirmed the ruling in favor of Salt River Project and APS and reversed a lower court ruling which had denied APS its costs. On March 14, 1988 the Longs petitioned the Arizona Supreme Court for review. APS filed an opposition to the petition. Subsequently, three members of the Supreme Court recused themselves from this matter because of possible conflicts of interest. Accordingly, the Supreme Court appointed three members of the Court of Appeals to participate in the decision on whether to review the petition, and in any decision of the matter should review be granted. On September 26, 1988, the Arizona Supreme Court denied the Longs' petition for review. The Longs did not seek review of this decision by the United States Supreme Court, and the time to do so has expired.

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 entitled *In Re the General Adjudication of All Right to Use Water in the Gila River System and Source,* pending in the Maricopa County Superior Court. The Project is located within the geographic area subject to the summons, and the rights of the Project participants, including the Authority, to the use of groundwater and effluent at the Project is potentially at issue in this action. APS, as project manager for the Project, filed claims challenging the jurisdiction of the court over the Project participants' groundwater rights and their contractual rights to effluent relating to the Project, and alternatively, seeking confirmation of such rights. No trial date has been set in the proceeding.

A number of the participants in the Project brought suit in the United States District Court for the District of Arizona seeking significant monetary damages for breach of contract by Combustion Engineering Incorporated because of the failure of a backup water supply system, which needed to be redesigned, resulting in the delay of completion of the Project. Combustion Engineering Inc. has cross-complained for significant monetary damages. The case has not yet been set for trial. (*Arizona Public Service Company, et al v. Combustion Engineering Inc.*)

FEDERAL AND STATE INCOME TAXES

The Internal Revenue Code of 1986, as amended ("the Code"), establishes certain requirements which must be met subsequent to the issuance and delivery of the 1989 Bonds for interest thereon to be and remain excluded from gross income for Federal income tax purposes. Noncompliance with such requirements could cause the interest on the 1989 Bonds to be included in gross income for Federal income tax purposes retroactive to the date of issue of the 1989 Bonds. These requirements include, but are not limited to, provisions which prescribe yield and other limits within which the proceeds of the 1989 Bonds are to be invested and require, under certain circumstances, that certain investment earnings on the foregoing be rebated on a periodic basis to the Treasury Department of the United States of America. The Authority has covenanted in the Tenth Supplemental Indenture of Trust to comply with each applicable requirement of the Code necessary to maintain the exclusion of the interest on the 1989 Bonds from gross income for Federal income tax purposes.

In the opinion of Mudge Rose Guthrie Alexander & Ferdon, Bond Counsel, under existing law, interest on the 1989 Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the aforementioned covenant, interest on the 1989 Bonds is excluded from gross income for Federal income tax purposes. Bond Counsel is also of the opinion that the 1989 Bonds are not "specified private activity bonds" within the meaning of Section 57(a)(5) of the Code and, therefore, interest on the 1989 Bonds will not be treated as a preference item for purposes of computing the alternative minimum tax imposed by Section 55 of the Code.

However, interest on the 1989 Bonds owned by corporations will be taken into account: (1) in determining the alternative minimum tax imposed by Section 55 of the Code on one-half (75 percent after 1989) of the excess of adjusted net book income (adjusted current earnings after 1989) over alternative minimum taxable income (determined without regard to this adjustment and the alternative tax net operating loss deduction); (2) in calculating the environmental tax equal to 0.12 percent of a corporation's modified alternative minimum taxable income in excess of a certain amount (generally $2 million) imposed by Section 59A of the Code; and (3) in determining the foreign branch profits tax imposed on the effectively connected earnings and profits (with adjustments) of United States branches of foreign corporations by Section 884 of the Code.

Bond Counsel is further of the opinion that the difference between the principal amount of the 1989 Bonds maturing on July 1 in each of the years 2000, 2002, 2004, 2007, 2010, 2011, 2012, 2013, 2014 and 2015 (the "Discount 1989 Bonds") and the initial offering price to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters or wholesalers) at which price a substantial amount of such Discount 1989 Bonds of the same maturity was sold constitutes original issue discount which is excluded from gross income for Federal income tax purposes to the same extent as interest on the 1989 Bonds. Further, such original issue discount accrues actuarially on a constant interest rate basis over the term of each Discount 1989 Bond and the basis of each Discount 1989 Bond acquired at such initial offering price by an initial purchaser thereof will be increased by the amount of such accrued original issue discount.

Bond Counsel has not undertaken to advise in the future whether any events after the date of issuance of the 1989 Bonds may affect the tax status of interest on the 1989 Bonds.

Although Bond Counsel has rendered an opinion that interest on the 1989 Bonds is excluded from gross income for Federal income tax purposes, a Bondholder's Federal tax liability may otherwise be affected by the ownership or disposition of the 1989 Bonds. The nature and extent of those other tax consequences will depend upon the Bondholder's other items of income or deduction. Bond Counsel has expressed no opinion regarding any such other tax consequences.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 1989 Bonds from the Authority at an aggregate Underwriters' discount of $2,125,783.16 and to make a bona fide public offering of the 1989 Bonds at not in excess of public offering prices, plus accrued interest, agreed to by the Underwriters and the Authority. The Underwriters will be obligated to purchase all such 1989 Bonds if any such 1989 Bonds are purchased.

The 1989 Bonds may be offered and sold to certain dealers (including Underwriters and other dealers depositing such Bonds into investment trusts) at prices lower than such public offering prices, and such public offering prices may be changed, from time to time, by the Underwriters.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 1989 Bonds are subject to the approval of Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel. The form of opinion Bond Counsel proposes to render with respect to the 1989 Bonds is attached as Appendix E hereto. Copies of such opinion will be provided to the original purchasers without charge. Certain legal matters with respect to the Authority will be passed upon by its special counsel, Rourke & Woodruff, a Professional Corporation, Orange, California. Certain legal matters will be passed upon for the Underwriters by O'Melveny & Myers, Counsel to the Underwriters.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

Upon delivery of the 1989 Bonds, Ernst & Whinney, independent certified public accountants, will deliver a report stating that the firm has reviewed (a) the mathematical accuracy of certain computations relating to the adequacy of the Government Obligations and the interest thereon to pay the Redemption Price of and interest on the Refunded Bonds on and prior to the redemption dates thereof, and (b) the computations of actuarial yield of the 1989 Bonds and Government Obligations which support Bond Counsel's conclusion that interest on the 1989 Bonds is excluded from Federal gross income.

MISCELLANEOUS

During the initial offering period for the 1989 Bonds, copies of the Authority's audited financial statements for the year ended June 30, 1988 may be obtained upon written request from the Executive Director of the Authority, 613 East Broadway, Glendale, California 91205, and copies of the forms of the Power Sales Contracts, the Bond Indenture, the Participation Agreement, the Agency Agreement, and the Transmission Agreement may be obtained upon written request from Smith Barney, Harris Upham & Co. Incorporated, 1345 Avenue of Americas, 50th floor, New York, New York 10105, Attention: Municipal Finance Department.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By: /s/ GALE A. DREWS
President

R.W. BECK
AND ASSOCIATES

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Board of Directors
SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY
613 East Broadway
Glendale, California 91205

February 2, 1989

Gentlemen:

Consulting Engineer's Report
Southern California Public Power Authority
Palo Verde Project

INTRODUCTION

Presented herewith is a summary of our analyses and studies with respect to the proposal by the Southern California Public Power Authority (the "Authority") to issue $295,005,000 of its Power Project Revenue Bonds, 1989 Refunding Series A (the "1989 Bonds"), to provide for advance refunding of outstanding Power Project Revenue Bonds of the Authority in the aggregate amount of $187,635,000 (the "Refunded Bonds") and to meet financing cost requirements. The Refunded Bonds were issued to finance (a) (i) a portion of the costs of acquisition, construction and placing into operation of the Authority's 5.91% ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3, including certain associated facilities and contractual rights, and (ii) the Authority's 5.56% ownership interest in the ANPP High Voltage Switchyard and contractual rights; and (b) the Authority's 6.55% share of the rights to use the Arizona Nuclear Power Project Valley Transmission System. The Palo Verde Nuclear Generating Station, Units 1, 2 and 3, including certain associated facilities and contractual rights and the ANPP High Voltage Switchyard and contractual rights are collectively referred to herein as the "Project." Additionally, the Arizona Nuclear Power Project Valley Transmission System is referred to herein as the "ANPP Transmission System." The Authority's ownership interests in and rights to the Project and the ANPP Transmission System are referred to herein as the "Authority Interest."

Upon issuance of the 1989 Bonds, the Authority will have outstanding a total of $1,204,400,000 of its Power Project Revenue Bonds. Such Bonds include Power Project Revenue Bonds, 1982 Series A and B, 1983 Series A, 1984 Series A, 1985 Refunding Series A and B, 1986 Refunding Series A and B and 1987 Refunding Series A (the "Prior Series Bonds"). Financing of the estimated construction costs of the Authority Interest contemplated by the Authority's present financing program was completed by the Prior Series Bonds. (See "Authority Interest Financing".)

Austin, TX ■ Boston, MA ■ Columbus, NE ■ Denver, CO ■ Indianapolis, IN ■ Minneapolis, MN
Nashville, TN ■ Orlando, FL ■ Phoenix, AZ ■ Sacramento, CA ■ Seattle, WA

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

The Authority is organized pursuant to the provisions relating to the joint exercise of powers found in the Government Code of California, as amended, and the Joint Powers Agreement, dated as of November 1, 1980, as amended. Its membership consists of 10 cities and one irrigation district which supply electric energy in southern California. The Authority is governed by its Board of Directors which consists of a representative of each of its members. The management of the Authority is under the direction of the Executive Director, who serves at the pleasure of the Board of Directors.

THE PROJECT AND ANPP TRANSMISSION SYSTEM

The Project

The Palo Verde Nuclear Generating Station consists of three nominal 1,270 MW nuclear generating units, each of which has commenced commercial operation. Arizona Public Service Company ("APS") has reported to the Nuclear Regulatory Commission (the "NRC") an adjustment to the design electrical rating of each of the units from 1,270 MW net to 1,221 MW net maximum dependable capacity to reflect the licensed reactor thermal power level. For purposes of this analysis, we have based the Authority Interest output on an assumed production capacity of 1,221 MW net from each of the three units. Based on this assumption, the Project presently has a net generating capacity of approximately 3,663 MW. Additionally, it is projected that by 1992 each unit will have achieved a mature plant factor and the Project will have an annual energy output of approximately 22,500,000 megawatt-hours ("MWh"). It is projected that the Authority Interest will be capable of delivering approximately 207.4 MW of capacity and, on average, 1,271,777 MWh of energy annually at the various points of delivery, after adjustment for transmission losses. The Project is located on a site of approximately 4,000 acres about 50 miles west of downtown Phoenix, Arizona. The three units are essentially identical in design and share certain common facilities, including a water reclamation plant, make-up water storage reservoir, two on-site wells, domestic water system, demineralized water system, sanitary waste treatment facility, evaporation ponds, laundry and decontamination facility, administration building, guardhouse, security facilities, service warehouse building, switchyard and miscellaneous buildings. Each unit is designed and licensed for a forty year operating life.

The nuclear steam supply system for each unit of the Project, supplied by Combustion Engineering, Inc., is a closed-cycle pressurized water reactor system licensed at 3,817 megawatts of thermal capacity, with two reactor coolant loops, containing two reactor coolant pumps in each loop. The turbine generators are tandem compound units supplied by the General Electric Company. The main condensers were supplied by the Westinghouse Electric Company and are cooled by circulating water through mechanical draft cooling towers. Make-up water for the dissipated circulating water is obtained primarily from the 91st Avenue Sewage Treatment Plant operated by the City of Phoenix. This processed effluent is piped to the on-site water reclamation plant where it undergoes additional treatment and is then stored in the on-site reservoir as make-up water. Blow-down from the circulating water system, demineralized water wastes, domestic water wastes, nonradioactive demineralizer regenerants and miscellaneous nonradioactive wastes are directed to the on-site evaporation ponds where they are completely evaporated. Thus, no off-site liquid discharges are required.

At design steam flow and condenser back pressure, the output from the main turbine-generators is 1,304 MW. The main transformers will step up the output voltage of each generator to 525 kV for interconnection into the ANPP Transmission System.

ANPP High Voltage Switchyard and ANPP Transmission System

The ANPP High Voltage Switchyard consists of a breaker-and-a-half scheme which comprises the termination facilities for the transmission lines, generator step-up transformers and auxiliaries, including, but not limited to, the high voltage busses, structures, power circuit breakers, disconnect switches, control building, switchyard auxiliary, protection systems and fencing.

The ANPP Transmission System consists of the facilities listed below, along with associated rights-of-way:

Palo Verde — Westwing 525 kV Transmission Lines Nos. 1 and 2
Palo Verde — Kyrene 525 kV Transmission Line
Westwing 525 kV Switchyard expansion
Kyrene 230 kV Switchyard expansion
Second Kyrene 230 kV Switchyard
Kyrene 525/230 kV Switchyard
Microwave Communication System

Construction of the major components of the ANPP Transmission System is complete and the system is operational.

Project Interests

Pursuant to the Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, as amended (the "Participation Agreement"), and the Salt River-Authority Palo Verde Nuclear Generating Station Assignment Agreement, dated as of August 14, 1981, as amended (the "Assignment Agreement"), the utilities listed in the table below are participants in the Project in the following percentages.

	Current Interests
Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Department of Water and Power of The City of Los Angeles	5.70
Total	100.00%

In connection with financing of the Project, APS, Public Service Company of New Mexico ("PNM") and El Paso Electric Company ("EPE"), have entered into sale and leaseback transactions involving certain portions of their respective ownership interests in the Project.

The Authority has sold the entire capability of the Authority Interest pursuant to power sales contracts (the "Power Sales Contracts") with nine California municipalities and a California irrigation district (the "Project Participants"). The following is a list of the Project Participants, their percentage shares of the Authority Interest (the "Project Entitlement") and the estimated maximum Project generating capability available to each at the high voltage bus of the ANPP High Voltage Switchyard:

	Project Entitlement	Generating Capability* (MW)
Department of Water and Power of The City of Los Angeles	67.0%	145.04
Imperial Irrigation District	6.5	14.07
City of Riverside	5.4	11.69
City of Vernon	4.9	10.61
City of Burbank	4.4	9.53
City of Glendale	4.4	9.53
City of Pasadena	4.4	9.53
City of Azusa	1.0	2.16
City of Banning	1.0	2.16
City of Colton	1.0	2.16
Total	100.0%	216.48

* Based on the assumed per unit production capacity level of 1,221 MW net.

Under the Power Sales Contracts, the Project Participants are entitled to the generating capability of the Authority Interest based on their respective Project Entitlements, and the Project Participants are obligated to make payments therefor on a "take or pay" basis. For a further discussion by the Authority of the Power Sales Contracts, see the Official Statement to which this report is attached (the "Official Statement") and "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C thereto.

PROJECT OPERATION

Operating Arrangements

APS is the Project Manager and also operates the three Project units and the Westwing 525 kV Switchyard. The ANPP Transmission System, with the exception of the Westwing 525 kV Switchyard, is managed and operated by the Salt River Project Agricultural Improvement and Power District ("Salt River Project").

Operating Experience

The first refueling of Unit 1 was completed in March 1988. As the result of the occurrence of initial operating problems normally expected in a large, new generating facility, the performance of Unit 1 was approximately 51% as compared to the 60% capacity factor assumed by us in previous analyses for the first fuel cycle of commercial operation. For the first nine (9) months of the second fuel cycle, Unit 1 has achieved a 71.3% capacity factor.

The first refueling of Unit 2 was completed in June 1988. This unit performed well during its first fuel cycle. Specifically, it achieved approximately a 66% capacity factor, as compared with the 60% capacity factor assumed by us in previous analyses for the first fuel cycle of commercial operation. For the first five (5) months of the second fuel cycle, Unit 2 has achieved a 94.2% capacity factor.

Unit 3 has been operating on a commercial basis for approximately twelve months. For this portion of the first fuel cycle Unit 3 has achieved approximately a 91.7% capacity factor.

The Department of Water and Power of The City of Los Angeles (the "Department"), as the Authority's agent, has indicated APS has either solved or is developing solutions to the operational anomalies encountered by APS in Units 1, 2 and 3 during the first fuel cycles.

Operation and Maintenance

We have reviewed the APS organizational structure which establishes the responsibilities and relationships for operation and maintenance of the Project. Included in our review were certain procedures and methodologies for operation and maintenance, as well as the results of certain NRC assessments of APS' performance in these functional areas.

The NRC, as part of its responsibilities, monitors and evaluates all nuclear plant licensees with respect to operational performance. As part of this industry monitoring function, the NRC has authority to take regulatory action ranging from increased monitoring of selected aspects of a nuclear facility to precluding operations.

The NRC released its most recent Systematic Assessment of Licensee Performance ("SALP") Report for the Project on December 23, 1988. This SALP Report reflected the results of the NRC's periodic evaluation of the performance of the Project for the period November 1, 1987 through October 31, 1988. Although the SALP Report indicates that the overall performance of licensed activities at the Project is satisfactory and directed toward safe facility operation, such performance was considered to have declined when compared to the previous SALP assessment period. Based in part on "enforcement items" which are listed in the SALP Report, the NRC indicated that additional management attention must be given to specified functional areas. The NRC has proposed and APS has paid civil penalties of $350,000 for "enforcement items" identified at the Project during the last year in the functional areas of operations and radiation protection. APS has indicated that it recognizes that it must improve its operational performance at the Project. It has developed plans for such improvement which the NRC has indicated it considers to be positive. APS has indicated that it has initiated such improvements.

Operating Statistics

Operating results of Units 1, 2 and 3 are shown in the following table. Although these units have not been operating long enough for their operating statistics to be meaningful compared to industry averages for similar size units, such statistics do provide an indication of how the units have performed when compared to similar units with more operating experience. While Unit 3 has experienced an above-average level of performance, Unit 3 is in its first year of commercial operation and has not experienced any maintenance outages or refueling. Based on historical experience of comparable generating units, it is not expected that Unit 3 will continue to achieve, over the long-term, the substantially above-average level of performance that has been demonstrated during its first fuel cycle of operation to date.

Operating Statistics(1)

	Unit 1	Unit 2	Unit 3	Industry Averages(2)
Net Energy Generated (MWh)	17,071,401	16,784,125	9,103,692	—
Plant Factor(3)	60.0%	60.5%	91.7%	57.09%
Operating Availability(4)	59.7%	73.6%	94.9%	64.23%
Equivalent Availability(5)	56.1%	68.7%	91.3%	60.50%

(1) Operating statistics for Units 1, 2 and 3 reflect operation through December 31, 1988, which for Units 1 and 2 include completion of the first refueling outage.

(2) Information is for 23 pressurized water reactor units larger than 1000MW as obtained from the Generating Availability Data Systems Report published by the North American Electric Reliability Council for the period 1982-1986.

(3) The Plant Factor is the ratio of the net energy generated to the net capability of that unit times the hours in the period and reflects the unit availability, as well as the actual need for power produced by the unit. Net energy generated is for the periods of firm power operation for each unit. For this application, Plant Factor is essentially equivalent to capacity factor.

(Footnotes continued on following page)

(4) The Operating Availability is the ratio of hours in the period that the unit is capable of operating at some level to the number of hours in the period.

(5) The Equivalent Availability Factor provides an adjustment of the Operating Availability by incorporating the effect of deratings (losses in MW capability) and is essentially "equivalent to" the percentage of a period during which a unit was available for maximum net capability operation.

Permits, Licenses and Approvals

Units 1, 2 and 3 have each received a 40-year Full-Power Operating License from the NRC. APS has stated that all necessary permits, licenses and approvals have been secured.

On or about November 28, 1986, Plains Electric Generation and Transmission Cooperative, Inc. ("Plains") filed a request with the NRC for an antitrust hearing and for the imposition of conditions on the operating license for Unit 3. This petition was dismissed with prejudice by Plains as a result of a settlement agreement between Plains and EPE. No antitrust hearing was held. The jurisdiction of the NRC to conduct antitrust hearings with respect to the Project expired with the issuance of the Operating License for Unit 3.

Nuclear Fuel

The nuclear fuel cycle consists of four basic activities necessary for the manufacture of fuel assemblies. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium into fuel assemblies. After the fuel has been used in the reactor, it is removed for reprocessing or disposal.

The following tabulation shows the approximate percentages of the required amounts of materials and services APS presently has under contract, including options, for the Project:

	Uranium	Conversion	Enrichment	Fabrication
1989	100%	50%*	100%	100%
1990-2000	100%	*	100%	100%

* APS is in the process of negotiating for additional conversion services and expects to contract for such required services well in advance of its needs.

APS expects to contract for the required conversion services beyond 2000 well in advance of its needs. APS has been notified that, as of September 18, 1985, the U.S. District Court of Colorado ruled that the form of the utilities services enrichment contract used by the United States Department of Energy ("DOE") in its negotiations with utilities, including APS, is null and void. APS has a utilities services enrichment contract which is subject to this ruling. This contract obligates DOE to furnish the enrichment services required for operation of the Project over a term which expires in November 2014. The district court also held that DOE must restrict the enrichment of foreign uranium when failure to do so would jeopardize the viability of the domestic uranium industry. DOE appealed the decision and announced that it will continue to honor the contracts through the appeal process. On July 20, 1987, the United States Court of Appeals for the Tenth Circuit affirmed the district court's decision regarding the enrichment of foreign uranium, but remanded the case to the district court for a determination of whether the plaintiffs have standing to challenge the form of the utility services enrichment contract. Due to the unresolved standing issue, no decision was made as to the validity of the form of the utility services enrichment contract. The decision of the court of appeals regarding the enrichment of foreign uranium was appealed by DOE to the United States Supreme Court. On June 15, 1988, the Supreme Court reversed the decision of the court of appeals, holding that if restrictions upon the enrichment of foreign uranium would not render the domestic uranium industry viable, then DOE was not required to impose any such restrictions. The case was remanded for trial of issues respecting the determination of the viability of the domestic uranium industry. To the best of our information, the matter is still pending before the district court. Regardless of the outcome of the case, APS does not anticipate any difficulty in procuring enrichment services for the Project even if this ruling is upheld.

At the present time, no operating facilities for the reprocessing of spent fuel are available. On October 8, 1981, the President of the United States released a policy statement lifting the ban previously placed on the commercial reprocessing of spent nuclear fuel. The policy statement has not had any significant impact on the matters which it addressed and its future effects cannot be predicted at this time. On-site spent fuel storage capacity for the Project is estimated by APS to be sufficient to accommodate storage of all spent fuel into the 1990's and, by adding special materials to the spent fuel pool storage racks, is estimated by APS to be sufficient to accommodate storage of all spent fuel, including maintaining full core discharge capability, during approximately 20 years of normal operation. This spent fuel storage capability could allow operation until 2005, 2006 and 2007 for Units 1, 2 and 3, respectively. On January 7, 1983, the President of the United States signed the Nuclear Waste Policy Act of 1982. This Act establishes a national program for spent fuel disposal which is to be further defined and implemented over the next several years. DOE is responsible for the national program for spent fuel disposal and is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. Pursuant to this Act, the NRC also requires operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. APS, on its own behalf and on behalf of the other participants in the Project, has executed a spent fuel disposal contract with DOE. This Act also obligates DOE to develop the facilities necessary for the disposal of all spent nuclear fuel generated and to be generated by domestic power reactors and to have the first such facility in operation by 1998, under prescribed conditions. In December 1987, Congress passed the National Waste Policy Amendments Act of 1987 which substantially changed the previous Act by selecting a site in Nevada for initial characterization and authorizing a Monitored Retrievable Storage Facility. We are unable to predict the impact this legislation will have on the national program for spent fuel disposal, the extent to which the program will be implemented, and the extent to which either reprocessing or off-site storage services may be required or available.

Waste Management

Enabling legislation to establish a low-level radioactive waste compact was enacted by California, Arizona and South Dakota in the Spring of 1988. The compact was submitted to Congress and was adopted in October 1988. Pursuant to the terms of the compact, the California Department of Health Services has selected a site, has completed the requisite environmental studies which call for certain mitigating measures to be taken and has contracted for development and operation of the disposal facility. The projected operational date of the disposal facility is late 1991.

During the last ten years, substantial federal, state and local legislation regarding management of various types of non-radioactive, yet hazardous waste has been enacted. Federal laws as set forth in acts such as the Resource Conservation and Recovery Act and the Comprehensive Environmental Response Compensation and Liability Act, as amended by the Superfund Amendments and Reauthorization Act, impose strict liability regardless of time or location on generators, transporters, storers and disposers of hazardous waste for cleanup costs or damages resulting from releases or contamination. Many normal activities in connection with the generation and transmission of electricity generate both non-hazardous and hazardous non-radioactive wastes. APS and SRP report they have established hazardous waste management plans for the Project facilities each organization operates and maintains. Each organization has also established certain procedures for the disposal of hazardous, non-radioactive wastes generated by Project facilities for which each is responsible at duly regulated hazardous waste repositories. APS and SRP have indicated that each respective waste management program is in compliance with all federal, state and local statutes and guidelines. We have not independently reviewed either waste management program.

AUTHORITY INTEREST FINANCING

Estimated Construction Costs

The most recent estimate of the construction costs for the Project by APS is dated November 15, 1988. APS has also estimated the cash flow requirements for nuclear fuel associated with the Project. Expected payments for the construction costs for the ANPP Transmission System have been completed. The following table shows the total estimated costs for the Project and the ANPP Transmission System and the total estimated cost for the Authority Interest, including an additional Authority contingency to allow for uncertainties in addition to those provided for by APS.

Estimated Construction Costs

($000)

	Total Project and ANPP Transmission System	Authority Interest
Plant, Preoperations and Startup Costs(1)	$5,949,499	$ 351,615
Sewage Effluent Prepayment and Startup Power Costs(2)	77,771	4,594
Transmission Facilities Rights and Ownership Interest(3)	115,949	7,369
Other(4)	98,251	5,807
Direct Construction Costs	$6,241,470	$ 369,385
Project and Transmission Facilities Rights and Ownership Interest Purchase Costs(5)		52,784
Nuclear Fuel(2)		27,457
Ad Valorem Taxes(2)		9,659
Additional Capital Items and Authority's Contingency(6)		5,885
Total Construction Costs		$ 465,170

(1) Estimated by APS. Includes land, structures, nuclear steam supply system, turbine generator, other improvements and nuclear information communications costs.

(2) Based on actual Authority expenditures subsequent to purchase of the Authority Interest on September 10, 1982.

(3) Based on actual Authority expenditures subsequent to purchase of the Authority Interest on September 10, 1982. Includes ANPP High Voltage Switchyard, Kyrene and Westwing switchyards, associated transmission lines and rights-of-way, microwave facilities and capitalized operation and maintenance expenses during the construction period.

(4) Includes expenditures prior to purchase of the Authority Interest under the Assignment Agreement for the following: startup power costs, ad valorem taxes, Green Mountain Uranium Venture, research and development and Salt River Project direct costs. Also reflects an adjustment for differences between APS's estimate of cash flow requirements dated November 15, 1988 and actual cash flow requirements as well as costs incurred for a prudency audit.

(5) Based on actual closing costs in connection with purchase of the Authority Interest. With the exception of an additional ownership interest in the ANPP High Voltage Switchyard, includes Salt River Project AFUDC, carrying costs from Project inception to September 10, 1982 and an administrative charge. Includes such applicable costs from Project inception to May 2, 1983 for the additional ownership interest in the ANPP High Voltage Switchyard.

(6) Provided by the Authority to allow for payment of certain additional capital costs which may be included in the APS Final Completion Report and payment of certain claims against the Project in the event that either claimant is successful.

Authority Interest Financing

Based on the APS Project construction cost estimate, the Salt River Project estimate of ANPP Transmission System construction costs, consultation with the Authority's Financial Advisor, and considering that the Project is fully operational, the borrowing required for the completion of the Authority Interest has been completed, other than any additional refundings which the Authority might authorize. After the issuance of the 1989 Bonds, exclusive of any potential additional refinancing, the Authority's outstanding bond obligation will amount to $1,204,400,000, as shown below.

Authority Interest Financing
($000)

	Total Requirement
Total Construction Costs	$ 465,170
Debt Service Reserve(1)	88,246
Interest During Construction(2)	367,713
Working Capital, Reserve and Contingency Fund and Authority Expenses(3)	14,700
Financing Costs(4)	302,764
Gross Requirements	$1,238,593
Investment Income(5)	(146,032)
Defeasance of Prior Series Bonds	(1,184,466)
Net Deposits to Escrow Funds(6)	1,309,400
Total Financing(7)	$1,217,495
Bonds Retired to Date	(13,095)
Total Bonds Outstanding	$1,204,400

(1) Maximum annual debt service deposited in the Debt Service Reserve Account in the Debt Service Fund for the Prior Series Bonds, as adjusted by the 1989 Bonds.

(2) Based on the actual interest capitalized.

(3) Working Capital requirements are based on providing 90 days of projected annual costs, excluding debt service. Reserve and Contingency Fund requirements are based on 1.5% of the net utility plant component of the Authority Interest in the Project and are deposited in the Reserve Account in the Reserve and Contingency Fund. Authority expenses are projected by the Authority.

(4) Includes actual underwriters' discount and original issue discount of approximately $285,206,724 and other costs of issuance estimated at approximately $17,557,468.

(5) The investment of undisbursed proceeds of the Prior Series Bonds in the Initial Facilities Account of the Construction Fund through December 31, 1990 has been included at an interest rate of 7.0%.

(6) For refunding bonds, deposit required into the refunding series bonds' escrow fund, net of any funds released from the Debt Service Account and Debt Service Reserve Account in the Debt Service Fund pursuant to the applicable Supplemental Indenture of Trust.

(7) Changes in interest or reinvestment rate assumptions may result in changes to the Total Financing.

Authority Interest Annual Costs of Power

The following table shows the projected annual costs of power from the Authority Interest at the high voltage bus of the ANPP High Voltage Switchyard for fiscal years 1989 through 1993. The projections set forth herein are based on preliminary discussions with APS and are subject to adjustment by APS. For purposes of this analysis, the plant factor for each unit is assumed by us to vary from an initial level of approximately 60% for the first cycle of commercial operation of Unit 3 to approximately 65% for the second cycle and to approximately 70% for the third cycle and thereafter.

Projected Annual Cost of Power from the Authority Interest(1) ($000)

	Fiscal Year Ending June 30				
	1989(12)	1990	1991	1992	1993
Interest and Amortization:					
Prior Series Bonds(2)(3)	$ 82,146	$ 75,368	$ 75,372	$ 75,369	$ 75,367
1989 Bonds(2)	4,467	10,995	10,989	10,997	10,991
Operation and Maintenance(4)	12,927	14,550	16,840	17,152	18,118
Administrative and General(5)	3,697	2,120	2,300	2,370	2,483
Insurance(6)	1,156	1,203	1,271	1,307	1,346
Nuclear Fuel(7)	9,538	10,721	9,315	10,290	10,934
Renewals and Replacements(4)	2,331	2,850	2,839	2,379	2,323
Taxes(8)	4,198	4,408	4,408	4,408	4,408
Subtotal Project	$120,460	$122,215	$123,335	$124,271	$125,970
Less; Interest Earnings(9)	12,643	9,010	9,028	9,050	8,941
Total Project	$107,817	$113,206	$114,306	$115,221	$117,029
Total Project Unit Cost (Mills/kWh)	86.76	82.36	93.75	84.99	82.41
Total ANPP Transmission System Rights	$ 1,382	$ 1,385	$ 1,397	$ 1,410	$ 1,417
Total ANPP Transmission System Rights Unit Cost (Mills/kWh)	1.11	1.01	1.15	1.04	1.00
TOTAL COST OF POWER TO AUTHORITY(10)	$109,199	$114,591	$115,703	$116,631	$118,446
Energy Delivered (000MWh)(11)	1,243	1,374	1,219	1,356	1,420
TOTAL AVERAGE UNIT COST (Mills/kWh)	87.88	83.37	94.89	86.03	83.41

(1) Based on cost estimate which includes Authority financing contingency as previously discussed and shown in the tables entitled "Estimated Construction Costs" and "Authority Interest Financing."

(2) Principal payments begin July 1, 1988. Interest is accrued during the six months prior to each semi-annual payment on July 1 and January 1. Principal is accrued during the twelve months prior to each annual payment on July 1.

(3) Reflects interest and amortization of the Prior Series Bonds, net of the interest and amortization on the Refunded Bonds as defined in the Official Statement.

(4) Based on estimates provided by APS.

(5) Based on estimates provided by APS. Also includes projected Authority expenses.

(6) Based on estimates provided by APS. Includes nuclear insurance.

(7) Based on APS's estimate of nuclear fuel costs. The Authority is obligated to provide its ownership interest share of the funds required for decommissioning of the Project. An additional sinking fund allowance, which was based on APS's estimate for decommissioning each unit, has been added by us to the annual nuclear fuel cost. The NRC has issued its final rule entitled "General Requirements for Decommissioning Nuclear Facilities" which became effective July 27, 1988. This rule amended NRC regulations to set forth technical and financial criteria for decommissioning licensed nuclear facilities, including Palo Verde. The proposed amendments address decommissioning planning needs, timing, funding methods, and environmental review requirements. The Authority believes that its provision for funding its ownership interest share of the funds required for decommissioning of the Project meets the intent of the NRC's final rule. A ruling on the Authority's specific method of providing such funding has not been made. Should such method not be approved, changes to the Projected Annual Cost of Power may result.

(8) Based on the Authority ad valorem taxes at rates estimated by APS and Salt River Project.

(9) Based on transferring all of the investment income to the Revenue Fund from the Debt Service and Debt Service Reserve Accounts in the Debt Service Fund, the Reserve Account in the Reserve and Contingency Fund and the Operating Fund.

(10) Sum of Total Project and Total ANPP Transmission System Rights costs.

(11) At the high voltage bus of the ANPP High Voltage Switchyard. Computed as the Authority's share of estimated total generation at the Project site.

(12) Based on the Authority's budget. Interest and amortization has been adjusted to reflect the issuance of the 1989 Bonds.

Transmission of the Authority Interest

Pursuant to the Transmission Agreement, dated as of August 14, 1981, as amended, between the Authority and Salt River Project (the "Transmission Agreement"), the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which is being utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of Imperial Irrigation District (the "District"). The Authority has purchased from Salt River Project an undivided ownership interest in the entire ANPP High Voltage Switchyard. The output of the Authority Interest, with the exception of the District's Project Entitlement, is being received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project is making available to the Authority an equivalent amount of power and energy at a combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation (the "Project Interconnection Point"). The Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station.

The Department is transmitting its Project Entitlement from the Project Interconnection Point utilizing its own transmission system.

Pursuant to the terms and conditions of the Palo Verde Nuclear Generating Station Transmission Service Agreements between the Department and the other Project Participants, with the exception of the District (the "Transmission Service Agreements"), the Department is providing transmission service for each such Project Participant's Project Entitlement between the Project Interconnection Point and the Project Participant's Points of Interconnection. These Transmission Service Agreements extend for an indefinite period, subject to termination by the Department on ten years prior notice upon a finding by the Department that surplus capacity for such transmission will not be available. The Point of Interconnection for the cities of Burbank, Glendale and Pasadena is the point where the Department's Victorville-McCullough transmission line connects to the 525 kV bus at the McCullough Switching Station ("Point of Interconnection A"). The Point of Interconnection for the cities of Riverside, Vernon, Azusa, Banning and Colton is either the point where the Department's McCullough-Eldorado transmission line connects to the 525 kV bus at the Eldorado Substation ("Point of Interconnection B") or the midpoint of the Victorville-Lugo transmission line where the Department's and Southern California Edison Company's ("Edison") electric systems interconnect ("Point of Interconnection C"). For purposes of this analysis, we have assumed that the cities of Riverside, Vernon, Azusa, Banning and Colton each continue to designate Point of Interconnection C as the point of delivery.

Pursuant to the terms and conditions of the McCullough-Victorville Line 2 Transmission Agreement between the Department and the cities of Burbank, Glendale and Pasadena (the "McCullough-Victorville Line 2 Transmission Agreement"), the Victorville to Receiving Station E — Transmission Service Agreements between the Department and the cities of Burbank and Glendale and the Victorville to Sylmar Switching Station Transmission Service Agreement between the Department and the City of Pasadena, the Department is providing transmission service to the points of interconnection with the cities' electric systems for the cities of Burbank and Glendale, or to an interconnection point with Edison's electric system for the City of Pasadena. Pursuant to the 230 kV Interconnection and Transmission Agreement between the City of Pasadena and Edison, as amended, Edison is providing transmission service from the Sylmar Switching Station to the City of Pasadena's electric system through 2010.

The cities of Riverside, Vernon, Azusa, Banning and Colton have each signed an Integrated Operations Agreement and a Supplemental Agreement for the integration of their separate Project Entitlements of the Authority Interest (the "Supplemental Agreements") with Edison which provide, among other things, that Edison will continue to supply the cities' power and energy requirements, over and above the capability of the cities' Project Entitlements and any other city-owned resource and will credit the cities on their monthly billing statements for the power and energy generated by

such resources that are integrated with Edison's resources. The Supplemental Agreements provide that these cities' Project Entitlements are included as an integrated resource pursuant to each City's respective Integrated Operations Agreement.

The cities of Riverside, Vernon, Azusa, Banning and Colton have signed Transmission Service Agreements with Edison. Pursuant to these Transmission Service Agreements, Edison is providing transmission service for these cities from Point of Interconnection C to the respective cities' electric systems.

The District has acquired an ownership interest in the Palo Verde to Imperial Valley portion of the APS/San Diego Gas & Electric Company ("SDG&E") 525 kV Interconnection Project (the "Southwest Powerlink"). The District is transmitting its Project Entitlement from the high voltage bus of the ANPP High Voltage Switchyard to the District system at the Imperial Valley Substation over its ownership entitlement in the Southwest Powerlink.

The Authority, Salt River Project, M-S-R Public Power Agency and the Western Area Power Administration ("Western") are studying the feasibility of constructing, owning and operating new electrical transmission facilities connecting the Phoenix, Arizona area with southern Nevada and southern California. For a discussion of this topic, see the paragraph entitled "Mead-Phoenix DC Intertie Project" under the caption "Future Power Supply Resources — Mead-Phoenix DC Intertie Project." These proposed facilities are not required for transmission of the Authority Interest, but would allow Authority members to operate more efficiently. In the event that the Mead-Phoenix DC Intertie is constructed, pursuant to the Transmission Agreement, Salt River Project will transmit, as necessary, the Authority Interest power and energy, with the exception of the District's Project Entitlement, to the Authority at the Project Interconnection Point. The effects of these proposed facilities have not been included in our analysis.

The Department, the District and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton along with Edison, as project manager, have undertaken studies to explore the feasibility of constructing a 500 kV AC transmission line. This proposed Devers-Palo Verde #2 transmission line, if built, will parallel the existing Devers-Palo Verde #1 transmission line from the Project to Edison's Devers Substation, which is located west of Desert Hot Springs, California. The Project Participants' participation rights in the proposed Devers-Palo Verde #2 transmission line total 36.8%. Edison has scheduled this project for completion in 1993. On December 8, 1988, the California Public Utilities Commission ("CPUC") granted Edison a Certificate of Public Convenience and Necessity for this project. In its decision, the CPUC reserves the right to reevaluate its approval if the proposed Edison — SDG&E merger (CPUC Application 8-12-035; FERC Docket No. EC 89-5-000) is consummated or is still pending as of January 1, 1990. The decision notes that there may be no economic benefit from the line for Edison ratepayers if the merger is completed. Pursuant to an agreement with Edison, the Department has the right to construct this transmission line if Edison fails to commence construction before July 1, 1989. It is not clear what effect, if any, the above-described developments will have on the construction of this transmission line or the participation of the above-mentioned utilities.

POWER SUPPLY PLANNING

The Authority and the Project Participants have ongoing programs to investigate other power supply resources and transmission capability. In addition to the Authority Interest and other resources mentioned in the following paragraphs, certain of the Project Participants are interested in varying degrees in certain hydroelectric and geothermal projects in California and other generating facilities which may be available to them.

Intermountain Power Project

In 1977, several Utah municipalities organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah. The purpose of IPA is to provide for the financing, constructing and operating of the Intermountain Power Project ("IPP").

In 1980, the Department and the cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (the "California IPP Purchasers") each entered into a power sales contract with IPA which obligates each such Purchaser to purchase, on a "take or pay" basis, a percentage share of IPP capacity and energy. The Department and the cities of Burbank, Glendale and Pasadena also entered into an Excess Power Sales Agreement, also on a "take or pay" basis, with the Utah municipal and cooperative IPP purchasers, pursuant to which IPP generation entitlement projected to be surplus to such Utah purchasers' needs will be made available to the Department and the cities of Burbank, Glendale and Pasadena.

In early 1983, each IPP Purchaser entered into amendments to its power sales contract and the Excess Power Sales Agreement. All California IPP Purchasers except Glendale also entered into Lay-off Power Purchase Contracts (the "Lay-off Contracts") with IPA and Utah Power & Light Company ("UP&L"), which has recently merged with, and is a division of, PacifiCorp, through which UP&L assigned portions of its entitlement to IPP capacity and energy to such Purchasers.

The IPP generation entitlement of each of the California IPP Purchasers resulting from the power sales contracts, as amended, and the Layoff Contracts is shown in the following table:

	Percentage Share	Generating Capability (kW)
Los Angeles Department of Water and Power	44.617%	713,872
City of Anaheim	13.225	211,600
City of Riverside	7.617	121,872
City of Pasadena	4.409	70,544
City of Burbank	3.371	53,936
City of Glendale	1.704	27,264
Total	74.943%	1,199,088

The California IPP Purchasers will receive, pursuant to the power sales contracts, as amended, and the Lay-off Contracts, approximately 1,169 MW of capacity and, assuming both IPP generating units operate at a 70% plant factor, 7,170,458 MWh of energy annually, after losses, at the Adelanto point of delivery. The amounts of generating capability that will be available pursuant to the Excess Power Sales Agreement, as amended, will vary in accordance with the provisions of that Agreement. Presently, and through March 24, 1999, according to the most recent forecasts furnished pursuant to the terms of the Excess Power Sales Agreement, as amended, the quantities of capacity and energy that will be available at the Adelanto point of delivery are approximately 328 MW and, assuming a 70% plant factor, approximately 2,011,296 MWh annually.

IPP consists of the following: (a) a two unit, 1,600 MW net coal-fired, steam-electric generation station located near Lynndyl, Utah; (b) a ±500 kV DC transmission line ("HVDC transmission line") from the generation station to Adelanto, California with an AC/DC converter station at each end (the "Southern Transmission System"); and (c) two 345 kV AC transmission lines from the generation station to a switchyard near Mona, Utah and a 230 kV AC transmission line from the generation station to a switchyard near Ely, Nevada.

A portion of the funds required for IPP construction is being provided by IPA with the remainder being provided by the Authority as payments-in-aid of construction with respect to the Southern Transmission System. IPA has outstanding approximately $6,954,682,000 par amount of bonds, including $1,634,995,000 of special obligation bonds and special obligation refunding bonds which together with the payments-in-aid of construction with respect to the Southern Transmission System provided

by the Authority have allowed IPA to construct and place IPP in service. The amount of IPA's outstanding debt is expected to be reduced on July 1, 1995 by $1,532,110,000 when the special obligation bonds and special obligation refunding bonds are expected to be used to effect the redemption of certain of IPA's outstanding bonds and will thereby reduce IPA's annual debt service. IPA will continue to review the options that are available to it to reduce its annual debt service and may undertake additional refundings. For a discussion of the Southern Transmission System, including the total financing requirements for the Authority's payments-in-aid of construction, see the caption "Future Power Supply Resources — Southern Transmission System".

The first IPP generating unit was declared available for commercial operation in June 1986, the second unit in May 1987.

Despite the occurrence of operating problems normally expected in a new generating facility and certain abnormal conditions, IPP has to date operated with a high degree of availability. The Department and the Intermountain Power Service Corporation have either solved or are working on solutions to the problems encountered.

Southern Transmission System

The Southern Transmission System consists of the AC/DC Intermountain Converter Station adjacent to the IPP AC switchyard, the HVDC transmission line, 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California, and the AC/DC Adelanto Converter Station at that point where it connects to the Department's transmission system. The HVDC transmission line is designed to have the capability of transmitting capacity in excess of the capacity of IPP anticipated to be delivered to the California IPP Purchasers. The AC/DC converter stations have a rating of 1,920 MW. These facilities are in service.

IPA and the Authority have entered into the Southern Transmission System Agreement, dated as of May 1, 1983. The Southern Transmission System Agreement provides for, among other things, the financing and making payments-in-aid of construction by the Authority with respect to the Southern Transmission System. Pursuant to the Southern Transmission System Agreement, the Authority will make such payments to IPA, and IPA will apply these payments to pay costs of the Southern Transmission System. The Authority has issued and has outstanding $1,147,130,000 principal amount of its bonds, including refunding bonds, to finance the making of payments-in-aid of construction with respect to the Southern Transmission System. The Authority anticipates that, other than any additional refundings it might authorize, the borrowing required for the Southern Transmission System has been completed.

Hoover Power Plant

In 1985, in accordance with the Hoover Power Plant Act of 1984, Western allocated 127 MW of capacity and approximately 143,000 megawatt-hours ("MWh") of associated energy from the Hoover uprating program to the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon. The cities entered into contracts with the United States Bureau of Reclamation (the "Bureau") and Western which provide for advancement of funds by the cities to the Bureau and the purchase of power from the Hoover uprating program, respectively. In 1986, Anaheim, Riverside, Burbank, Azusa, Colton and Banning (the "Hoover Participants") assigned to the Authority their entitlement to the Hoover uprating program capacity and associated energy in return for the Authority's agreement to advance funds to the Bureau for the Hoover uprating program. The Authority has issued $34,435,000 of its Hydroelectric Power Project Revenue Bonds, the proceeds of which are projected to be sufficient for this purpose. The Authority's proportionate share of the total capacity of the Hoover uprating project is expected to be approximately 94 MW (Contingent Capacity), and associated firm energy. The Hoover Participants and the Authority have executed power sales contracts, under which the Hoover Participants are entitled to their shares of the Authority's proportionate share of Hoover capacity and associated energy as they become available (the "Hoover Entitlements") and have agreed to make monthly payments on a "take or pay" basis.

Western began making the Hoover Entitlements available at the Mead Substation on June 1, 1987. The Hoover Participants each have obtained the necessary transmission service from the Mead Substation to their respective electric systems.

Western has initiated the procedure to adjust the rates for Hoover. A final determination of the level of such rate adjustment and the effective date have yet to be made. To the extent that Hoover rates are increased, they will be offset by repayment to the participants of construction costs contributions. For the purposes of this report, we have not included any such rate increase in our analysis.

White Pine Power Project

Certain of the Project Participants, apart from the Authority and together with other public and private utilities in California and Nevada, have conducted studies to establish the feasibility of and proceed with the licensing activities necessary for constructing a coal-fired generating station near Ely, Nevada. This generating station would have a capability of approximately 1,500 MW. It is contemplated that White Pine County would own all, or a major portion of, and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the project. The Project Participants' combined entitlement percentage share for feasibility studies is approximately 47.36%. The participants in the White Pine Power Project entered into power supply development agreements with White Pine County in the fall of 1980 for the purpose of conducting a study to determine the feasibility of constructing and operating the project. White Pine County has issued notes in the principal amount of $19,929,000 for such purposes, all but $500,000 principal amount of which have been prepaid. The remaining $500,000 note matures December 31, 1992 and is payable from the proceeds of long-term bonds to be issued by the County or from payments by the participants under such agreements on the basis of entitlement shares. The projected commercial operation date for the two 750 MW generating units, if built, is in the mid 1990's. For a further discussion by the Department of the White Pine Power Project, see "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions — White Pine Power Project" in Appendix B to the Official Statement.

Mead-Phoenix DC Intertie Project

The Authority has executed agreements pursuant to which the Authority, Salt River Project, M-S-R Public Power Agency, and Western are studying the feasibility of constructing, owning and operating the Mead-Phoenix DC Intertie Project. The Mead-Phoenix DC Intertie Project is a proposed ±500 kV DC transmission line, with AC/DC converter stations at each end, to be constructed between Mead Substation near Boulder City, Nevada and the Phoenix, Arizona area. The Authority has issued notes in the aggregate principal amount of approximately $14.1 million, of which approximately $14 million has been prepaid, to finance the costs of such study. The remaining $100,000 note matures on December 1, 1991 and is payable from the proceeds of long-term bonds to be issued by the Authority for the Mead-Phoenix DC Intertie Project or from payments by the participants under project development agreements, on the basis of project entitlement shares. It is currently planned that the transmission line would have a capacity of 2,200 MW and that the converter stations would be built with an initial capacity of 1,600 MW. The initial converter station capacity could be upgraded to the transmission line capacity should this become desirable. If the Mead-Phoenix DC Intertie Project is undertaken, the Authority would finance its 93.75% interest from the proceeds of long-term bonds secured by payments to be made by the participants under transmission service contracts. The Project Participants' entitlement shares of this interest total approximately 53.1%. It is projected that this facility, if built, would be in service in the mid 1990's. For a further discussion by the Authority of the Mead-Phoenix DC Intertie Project, see "Southern California Public Power Authority — Other Activities of the Authority" in the Official Statement.

Mead-Adelanto Transmission Project

In connection with the Mead-Phoenix DC Intertie Project, certain members of the Authority, Salt River Project, M-S-R Public Power Agency, and Western are studying the feasibility and estimated costs of the construction and operation of a new ± 500 kV DC transmission line from the Mead Substation near Boulder City, Nevada to the vicinity of Adelanto, California, a distance of approximately 215 miles. The proposed participants anticipate that, if constructed, the transmission line could be put into service within the same time frame as the Mead-Phoenix DC Intertie Project. It has not been determined what, if any, role the Authority will have in the financing or construction of this transmission line project; however, the participants notified the Authority by resolution that if this project is constructed, certain participants, if not all, will request the Authority to finance on their behalf.

California-Oregon Transmission Project

The cities of Riverside, Vernon, Azusa, Banning and Colton executed a Memorandum of Understanding, dated as of December 19, 1984, which authorizes these cities, along with other utilities and governmental agencies located in California, to study the construction of the California-Oregon Transmission Project. Such Project relates to possible alternative methods of developing additional 500 kV AC transmission facilities between California and the Pacific Northwest. The participants have executed a project development agreement pursuant to which they will study the feasibility of constructing and operating the California-Oregon Transmission Project. It has not been determined what role, if any, the Authority will have in this transmission line project.

The Sylmar Expansion Project

The Department and the cities of Burbank, Glendale and Pasadena are participants in the Sylmar Expansion Project ("SEP") which is an 1,100 MW expansion of the terminal capacity at the existing AC/DC converter station which is located at Sylmar, California. This project will increase the capacity of the Pacific Northwest-Southwest DC Intertie ("Intertie") from 2,000 MW to 3,100 MW. The Department is the project manager for the southern terminal of the Intertie and is responsible for the construction of the SEP. The Bonneville Power Administration ("BPA") is the project manager for the northern terminal and is responsible for a similar expansion at the northern converter station of the Intertie in Oregon. The Department projects that the cost of the SEP will be $171,000,000 and that the SEP will be completed in February 1989. Each participant is providing its own funding for its share of the SEP.

Utah-Nevada Transmission Project

Members of the Authority, together with several electric utilities providing service in Utah and Nevada, are considering constructing, owning and operating an electric transmission project to include facilities to be located in Utah and Nevada. This project, if undertaken and built, would be in operation in the mid-1990's. It is anticipated that, to the extent its members participate in, and the Authority undertakes, this project, the Authority will own and finance a portion of the project on behalf of its participating members, who would purchase transmission service or capability of the project from the Authority.

Certain Matters Relating to Power Supply Planning

Edison has filed applications with the Federal Energy Regulatory Commission (Docket No. EC 89-5-000) and the California Public Utilities Commission (Application No. 88-12-035) seeking approval of a proposed merger with SDG&E in accordance with a November 30, 1988, Agreement and Plan of Reorganization among SCE Corp., Edison and SDG&E (the "Merger Agreement"). The merger is to be effective upon the closing of certain transactions described in the Merger Agreement and regulatory approval. Members of the Authority have intervened or may intervene in these proceedings. We have not analyzed what impact, if any, the proposed merger will have on Edison's operations or its wholesale electric rates.

THE PROJECT PARTICIPANTS

Historical Operations of Project Participants

During the fiscal year period 1984 through 1988, average number of customers, peak demand, energy requirements and operating revenues have increased for all Project Participants, with the exception of the City of Vernon. For a discussion of historical and projected peak demand and energy requirements, see "Power Requirements". The following tables summarize this historical data for the Project Participants.

Historical Number of Customers, Load Requirements and Operating Revenues for the Department

Fiscal Year Ending June 30	Average Number of Customers	% Increase *	Energy Requirements (MWh)	% Increase *	Peak Demand (MW)	% Increase *	Operating Revenues ($000)	% Increase *	Operating Revenues per kWh (Mills)	% Increase *
1984	1,243,092	—	21,848,064	—	4,444	—	1,177,469	—	53.89	—
1985	1,251,206	0.65	22,529,539	3.12	4,882	9.86	1,287,967	9.38	57.17	6.09
1986	1,261,972	0.86	22,262,629	-1.18	4,713	-3.46	1,358,134	5.45	61.01	6.72
1987	1,275,920	1.11	22,792,990	2.38	4,744	0.66	1,403,441	3.34	61.57	0.92
1988	1,304,603	2.25	23,701,912	3.99	4,922	3.75	1,570,028	11.87	66.24	7.58
Compound Annual Growth Rate 1984-1988		1.21%		2.06%		2.59%		7.46%		5.29%

* Over previous year.

Historical Number of Customers, Load Requirements and Operating Revenues for All Project Participants Excluding the Department

Fiscal Year Ending June 30	Average Number of Customers (2)	% Increase (3)	Energy Requirements (MWh) (4)	% Increase (3)	Peak Demand (MW) (5)	% Increase (3)	Operating Revenues ($000)	% Increase (3)	Operating Revenues per kWh (Mills)	% Increase (3)
1984	324,031	—	6,767,039	—	1,587	—	430,663	—	63.64	—
1985	327,988	1.22	7,108,863	5.05	1,730	9.01	484,294	12.45	68.13	7.06
1986	337,513	2.90	7,204,329	1.34	1,717	-0.75	481,007	-0.68	66.72	-2.07
1987	348,565	3.27	7,425,104	3.06	1,697	-1.16	494,627	2.83	67.68	1.44
1988(1)	360,308	3.37	7,862,326	5.89	1,762	3.83	546,477	10.48	69.51	2.69
Compound Annual Growth Rate 1984-1988		2.69%		3.82%		2.65%		6.13%		2.23%

(1) Preliminary, unaudited data.

(2) District data have been adjusted, on an average annual basis, from calendar year to fiscal year.

(3) Over previous year.

(4) Excludes BPA exchange obligation.

(5) Non-Coincidental.

Power Requirements

As a group and individually, the Project Participants' peak load forecasts and energy requirements for the period 1989 through 1993 show a lower rate of growth than that experienced during the 1984 to 1988 period, with the exception of the City of Riverside's projection of peak load growth. Abnormally high temperatures in September 1984 resulted in record peak demand for most of the Project Participants. The load forecasts, as developed by these Project Participants, were prepared considering, among other things, a stable economy, price elasticity, normal temperatures and ongoing conservation efforts. Each such Project Participant anticipates growth in loads over the next twenty years.

A summary of the fiscal year historical and projected future peak power and energy requirements, as provided by the Project Participants are shown on the following table.

PROJECT PARTICIPANTS' POWER REQUIREMENTS

Peak Requirements (MW) (1)

	Historical					Projected				
	Fiscal Year Ending June 30									
	1984	1985	1986	1987	1988(2)	1989	1990	1991	1992	1993
The Department	4,444	4,882	4,713	4,744	4,922	4,991	5,074	5,157	5,259	5,368
The District	376	404	413	420	436	455	457	471	485	499
City of Riverside	293	332	323	292	317	367	378	390	401	413
City of Vernon	191	192	193	194	190	190	190	190	190	190
City of Burbank	217	234	228	232	245	250	256	261	266	272
City of Glendale	208	232	232	225	228	237	242	247	253	258
City of Pasadena	214	238	231	232	240	247	254	260	266	273
City of Azusa	40	45	43	44	47	48	50	51	52	54
City of Banning	18	18	19	19	19	19	19	19	19	19
City of Colton	30	35	35	39	40	41	44	47	50	54
Total	6,031	6,612	6,430	6,441	6,684	6,845	6,964	7,093	7,241	7,400

(1) Non-coincidental.
(2) Preliminary data.

Total Energy Requirements (000 MWh)

	Historical					Projected				
	Fiscal Year Ending June 30									
	1984	1985	1986	1987	1988(1)	1989	1990	1991	1992	1993
The Department	21,848	22,530	22,263	22,793	23,702	23,845	23,966	24,040	24,367	24,632
The District	1,474	1,556	1,570	1,649	1,811	1,935	1,993	2,052	2,114	2,177
City of Riverside	1,134	1,205	1,208	1,258	1,345	1,386	1,428	1,470	1,513	1,556
City of Vernon	1,061	1,107	1,151	1,152	1,157	1,157	1,157	1,157	1,157	1,157
City of Burbank(2)	931	973	982	1,009	1,056	1,050	1,070	1,092	1,114	1,136
City of Glendale(2)	862	892	895	914	961	939	965	987	1,011	1,035
City of Pasadena(2)	936	993	1,007	1,021	1,070	1,094	1,113	1,141	1,168	1,196
City of Azusa	164	170	178	186	196	197	205	209	213	220
City of Banning	69	74	71	74	79	82	83	84	86	87
City of Colton	136	139	143	163	187	168	176	185	193	203
Total	28,615	29,639	29,468	30,219	31,564	31,853	32,156	32,417	32,936	33,399

(1) Preliminary data.
(2) Excludes BPA peaking exchange obligation.

Utilization of Project Entitlement

The Project is being operated by APS as a base load resource and all of the Project Participants are utilizing, and expect to continue to utilize, their respective Project Entitlements as a base load resource. Based on the Project Participants' load requirements and the variable cost of power from the Authority Interest, as compared to other alternatives available to meet the Project Participants' load requirements, the Authority Interest has been utilized by the Project Participants as a base load resource since commercial operation of each of the three units. It is anticipated that the variable cost of power from the Authority Interest will, in the future, maintain its same relative position to the

variable cost of power from alternative resources which are now available to the Project Participants and that the Project Participants will continue to schedule the maximum amount of production available from their respective Project Entitlements.

The existing power supplies for the Project Participants consist of owned generation and firm and non-firm purchases from other utilities. Although the Authority Interest provides a source of firm capacity and energy to assist in meeting load growth, it is more important to the Project Participants as a source of energy which can be produced from fuel sources other than oil and natural gas.

The Department desires to substantially reduce its dependence on oil and gas. The Department's long-term projections indicate that oil and natural gas prices will return to an increasing trend. Based on the Department's current price of approximately $18.64 per barrel of oil and the current efficiency of the Department's plants, which produce about 575 kWh per barrel of oil, the present unit fuel oil cost is approximately 32.4 mills per kWh.

The Department's Project Entitlement and other currently planned resources will assist in reducing its dependence on oil- and gas-fired generation by at least 50% from the 1974 through 1978 levels. Similarly, their respective Project Entitlements will allow the cities of Burbank, Glendale and Pasadena to reduce their dependence upon oil and gas for generation. Based on the projected price levels of oil and natural gas, it is economically attractive, in the long term, for these Project Participants to replace the energy from those sources with energy from the Authority Interest.

The present power supply configuration for each of the cities of Riverside, Vernon, Azusa, Banning and Colton consists of their respective Project Entitlements in Units 1, 2 and 3, their respective Hoover Entitlements, short-term firm purchases and purchases of interruptible energy from other public and private utilities and governmental agencies when it is available at an economically attractive price. In addition to these sources of supply, the City of Riverside receives power and energy from an ownership interest in the San Onofre Nuclear Generating Station, Units 2 and 3 ("San Onofre"), a project entitlement in IPP Units 1 and 2 and an intermediate power purchase from Deseret Generation & Transmission Co-operative (Deseret"). The City of Vernon also utilizes its diesel generators and a gas turbine to meet a portion of its total power and energy requirements. All remaining power and energy requirements for the five cities are purchased from Edison at wholesale rates. Edison is substantially dependent upon gas and oil as fuels for its generating resources. Based on these projected wholesale power and energy rates for Edison, we believe that it will be economically attractive, over the long term, for these Project Participants to replace wholesale purchases of energy from Edison with energy from the Authority Interest.

In calendar year 1988, the District produced or purchased approximately 27% of its energy requirements from oil- and gas-fired generation and produced or purchased approximately 24% from hydroelectric sources. The remaining energy requirements are obtained from the Authority, purchases from the system resources of EPE and from purchases of economy energy. It is estimated that the District's Project Entitlement, together with the District owned resources and other purchases, will allow the District to meet its projected electric power and energy requirements through fiscal year 1995.

The Department of Water and Power of The City of Los Angeles

The Department, the largest municipal utility in the United States, is a separate proprietary agency of The City of Los Angeles, controlling its own funds and with full responsibility for meeting the water and electric requirements of The City of Los Angeles. It provides water and electricity services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.4 million.

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners. The Board of Water and Power Commissioners fixes the Department's electric rates, subject to the approval of the City Council, by ordinance. The Department's rates are not

regulated by any California state agency and are not subject to approval by any Federal agency, but the Department is subject to certain ratemaking provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The Department's maximum net hourly peak demand, 4,991 MW, occurred in September 1988. The power supply of the Department consists primarily of its own generating resources, part of which are located within the Los Angeles Basin, and its 491 MW entitlement from the Hoover Power Plant. As of December 31, 1988 the Department had a net dependable system capability of over 7,200 MW, which is owned or operated generation. Steam electric generating capability was equal to 73% of the system's total net capability, and owned or operated hydroelectric generating capacity account for 20% of such capability. Purchases are made on a day to day or week to week basis that will alter these percentages. The Department estimates that its capital expenditures for power generating and distribution facilities for the five-year period which began July 1, 1988 will total approximately $1.7 billion.

The Department had an ownership interest in the Coronado coal-fired project in the amount of 210 MW. This ownership interest was exchanged for a 5.7% ownership interest in the Project on January 29, 1986. The Department has entered into contracts to purchase 44.617% of IPP capacity and energy. The Department has contracted to purchase 59.534% of the transmission capacity of the Southern Transmission System. The Department has a 39.117% feasibility study participation percentage in the White Pine Power Project. The Department has a 40% ownership interest in the SEP.

The following table summarizes the Department's fiscal year historical peak loads and resources and its projection of future peak loads and resources through 1993:

The Department
Peak Loads and Resources (MW)

	Historical					Projected				
	Fiscal Year Ending June 30									
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Loads	4,444	4,882	4,713	4,744	4,922	4,991	5,074	5,157	5,259	5,368
Resources(1):										
Basin Thermal (Oil & Gas)	3,178	3,252	3,252	3,252	3,113	3,113	3,202	3,202	3,202	3,140
Hydroelectric(2)	1,924	1,933	1,948	1,948	1,938	1,938	1,938	1,938	1,938	1,938
Joint Facilities(3)	1,076	1,076	1,508	1,437	1,861	1,861	1,861	1,861	1,861	1,861
Project Entitlement(4)	0	0	48	96	145	145	145	145	145	145
Additional Project Interest(4)(5)	0	0	70	141	209	209	209	209	209	209
Other(6)	598	0	589	170	0	0	0	74	74	74
Total	6,776	6,261	7,415	7,044	7,266	7,266	7,355	7,429	7,429	7,367
Balance Available for Reserves	2,332	1,379	2,702	2,300	2,344	2,275	2,281	2,272	2,170	1,999

(1) In the years for which historical loads and resources are presented, some of the Department's resources were not available at the time of system peak. These figures do not include losses.

(2) Actual water conditions for historical years 1984 through 1988. Assumes average water conditions for the years 1989 through 1993. Includes the Department's Hoover Entitlement for 1988 through 1993.

(Footnotes continued on following page)

(3) Includes ownership shares of Mohave, Navajo and Coronado coal-fired plants through 1985. The Department's ownership interest in Coronado was exchanged for an equivalent ownership interest in the Project on January 29, 1986. Also includes purchased power from the Intermountain Power Project.

(4) Project capacity shown is based on the assumed per unit production capacity level of 1221 MW net at the date of commercial operation, which may not coincide with the Department's peak load and capability used for planning purposes.

(5) Department's separate 5.7% ownership interest in the Project.

(6) Includes purchase of peaking capacity from the Pacific Northwest through 1984, co-generation, geothermal, generic and, until April 1984, 73 MW purchased from Tucson Electric Power Company.

The following table summarizes the projected cost of power to the Department of its Project Entitlement at the Project Interconnection Point, which also is the point of interconnection with the Department's electric system.

Projected Annual Cost to the Department of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Project Entitlement Costs(1)	$73,228	$76,841	$77,587	$78,210	$79,426
Transmission Cost to the Project Interconnection Point(2)	319	329	340	350	359
Total Estimated Annual Costs	$73,547	$77,170	$77,927	$78,560	$79,785
Energy Delivered (000 MWh)(3)	797.1	881.7	782.1	869.6	910.9
Unit Cost (Mills/kWh)	92.3	87.5	99.6	90.3	87.6
Capacity Delivered (MW)(3)	138.9	138.9	138.9	138.9	138.9

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) To the Department's distribution network after losses. Loss rates provided by the Department.

The following table summarizes the projected system power costs to the Department. This projection is based on the costs of the Department's Project Entitlement, as projected herein, together with projections of the costs of power, as provided by the Department, from the other power supply resources scheduled to be used to meet the Department's loads.

Projected Power Supply Costs to the Department

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Power Costs:					
Fuel(1)	$ 934,700	$ 936,600	$ 994,700	$1,073,400	$1,153,800
Project Entitlement	73,547	77,170	77,927	78,560	79,785
Intermountain Power Project(2)	310,988	336,611	348,706	360,741	366,893
Other Purchased Power(3)	337,460	404,326	407,785	383,293	416,608
Total Annual Power Supply Costs	$1,656,695	$1,754,707	$1,829,118	$1,895,994	2,017,086
Total Energy Requirements (000 MWh)	23,845	23,966	24,040	24,367	24,632
Unit Power Supply Costs (Mills/kWh)	69.5	73.2	76.1	77.8	81.9

(1) Includes the Department's estimated annual cost for operation and maintenance, taxes and depreciation, and is based on the Department's projection of fuel prices and energy production.

(2) Includes Southern Transmission Project costs.

(Footnotes continued on following page.)

(3) Includes the Department's projected annual costs of power supply from purchases of power and energy from other resources. A portion of these purchases is currently under contract, while the remaining balance is assumed by the Department to be available in sufficient quantities and at rates which would economically displace the Department's basin thermal generation. Also includes IPP purchases pursuant to the Excess Power Sales Agreement which reflect the current load forecasts of the IPP Utah Municipal and Cooperative Purchasers.

Imperial Irrigation District

The District is a publicly-owned water and power utility located in southern California. The gross area served by the District is approximately 6,400 square miles in Imperial County and the Coachella Valley of Riverside County. The power supply of the District consists of hydroelectric units on the All-American Canal and oil- and gas-fired generating facilities, as well as purchases of capacity and energy from other sources. In the twelve months ended December 31, 1988, the District experienced a peak demand of approximately 455.0 MW, generated 781,371 MWh and purchased 1,127,202 MWh.

Administration of the District is under the direction of a five-member Board of Directors. Electric rates are set by the Board of Directors after a series of public hearings and presentations to the city councils of the cities located within the District's service area. The District's electric rates are not subject to regulation by any California state agency and are not subject to approval by any Federal agency, but the District is subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

The following table summarizes the District's annual historical peak loads and resources for the twelve-month periods ended June 30, 1984 through 1988 and its projection of future peak loads and resources for the twelve-month periods ending June 30, 1989 through 1993:

The District
Peak Loads and Resources (MW)

	Historical					Projected				
	Twelve Months Ending June 30									
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Loads(1)	375.5	403.8	412.8	419.9	435.7	455.0	457.2	470.8	484.8	499.3
Resources(2):										
Thermal (Oil & Gas)	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0
Hydroelectric	43.0	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3
Project Entitlement	0.0	0.0	0.0	9.4	14.1	14.1	14.1	14.1	14.1	14.1
Other Purchases(3)	104.6	147.5	147.5	157.5	157.5	157.5	157.5	157.5	157.5	207.5
Subtotal	487.6	535.8	535.8	555.2	559.9	559.9	559.9	559.9	559.9	609.9
Less: Reserves(4)	44.4	42.2	43.5	43.1	45.5	48.4	48.7	50.7	52.8	55.0
Net Resources	443.2	493.6	492.3	512.1	514.4	511.5	511.2	509.2	507.1	554.9
Balance Available	67.7	89.8	79.5	92.2	78.7	56.5	54.0	38.4	22.3	55.6

(1) Projected annual peak loads are assumed to occur in July. The District is currently reviewing its projections of annual peak loads and has indicated that such projections may increase.

(2) Capacity at time of annual system peak.

(3) Includes purchases from Western Area Power Administration, EPE and participation in the Axis Steam Plant.

(4) Projected reserve requirements assumed to be 15% of load less firm purchases.

The following table summarizes the projected costs of power to the District of its Project Entitlement at the ANPP Switchyard:

Projected Annual Cost to the District of Power from the Authority Interest

($000)

	Twelve Months Ending June 30				
	1989	1990	1991	1992	1993
Project Entitlement Costs(1)	$7,008	$7,358	$7,430	$7,489	$7,607
Energy Delivered (000 MWh)(2)	79.2	87.6	77.7	86.4	90.5
Unit Cost (Mills/kWh)	88.5	84.0	95.6	86.7	84.1
Capacity Delivered (MW)(2)	13.8	13.8	13.8	13.8	13.8

(1) At the high voltage bus of the ANPP High Voltage Switchyard excluding the District's transmission cost. The District's Project Entitlement will be delivered over the Southwest Powerlink in which the District has acquired an ownership interest, as discussed in "The Authority Interest—Transmission of the Authority Interest."

(2) Amount available at the District's interconnection at the Imperial Valley Substation.

We have projected power supply costs for the District. This projection is based on the cost of the District's Project Entitlement, as projected herein, together with projections of the costs of power from other power supply resources available to be used to meet the District's loads.

Projected Power Supply Costs to the District

($000)

	Twelve Months Ending June 30				
	1989	1990	1991	1992	1993
Power Costs:					
Project Entitlement(1)	$ 7,008	$ 7,358	$ 7,430	$ 7,489	$ 7,607
Thermal (Gas and Oil)(2)	23,626	29,044	32,245	36,014	36,668
Hydroelectric Generation(3)	1,283	1,338	1,395	1,453	1,514
Other Purchased Power	42,138	43,400	44,127	47,433	60,838
Total Annual Power Supply Costs	$74,055	$81,140	$85,197	$92,389	$106,627
Total Energy Requirements (000 MWh)	1,935	1,993	2,052	2,114	2,177
Unit Power Supply Costs (Mills/kWh)	38.27	40.71	41.52	43.70	48.98

(1) Excludes transmission costs.

(2) Costs include fuel and other operation and maintenance costs at District plants.

(3) Operation and maintenance costs only.

Based on the projection of power costs from the District's Project Entitlement and on certain data supplied by the District and others, we have prepared a projection of operating results of the District's electric system for the twelve-month periods ending June 30, 1989 through 1993. In these projections, we show additional revenues to be obtained beyond those generated by the District's average charges for the calendar year 1987. We estimate an additional average annual increase in revenue requirements for the period 1989 through 1993 of approximately 3.4%. These additional revenues are projected to be obtained from the energy cost adjustment features of the existing rate structure associated with increases in the cost of purchased and generated energy.

The District is constructing major additions and improvements to its transmission system. A major portion of such additions and improvements will be used to transmit power for others which is expected to be available from existing and proposed geothermal and biomass generating plants in the District's service area. These geothermal and biomass generating plants, and the power output thereof, are to be owned by others. The District presently plans to finance, from its system revenues, the

portion of the transmission additions and improvements required to meet its load. The funds required for the construction of major transmission additions required to provide transmission service for others are being advanced by such parties. These advanced funds will be returned during the first eight to fifteen years of such service in annual amounts which will not exceed each parties' respective annual transmission service charges.

The District
Projected Operating Results

($000)

	Twelve Months Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1987 Average Charges(1)	$112,556	$115,933	$119,411	$122,993	$126,683
Additional Revenue Required(2)	7,367	10,539	12,731	20,584	28,404
Subtotal	$119,923	$126,472	$132,142	$143,577	$155,087
Miscellaneous Operating Revenues(3)	5,489	7,520	9,014	9,696	10,243
Other Income(4)	2,950	3,350	3,200	3,050	2,950
Total Projected Gross Revenues	$128,362	$137,342	$144,356	$156,323	$168,280
Operating Expenses:					
Power Production:					
Project Entitlement	$ 7,008	$ 7,358	$ 7,430	$ 7,489	$ 7,607
Thermal	23,626	29,044	32,245	36,014	36,668
Hydroelectric	1,283	1,338	1,395	1,453	1,514
Other Purchased Power(5)	42,138	43,400	44,127	47,433	60,838
Other Operation and Maintenance Expense	16,473	17,364	18,198	19,107	20,069
Total Projected Operating Expenses	$ 90,528	$ 98,504	$103,395	$111,496	$126,696
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 37,834	$ 38,838	$ 40,961	$ 44,827	$ 41,584
Debt Service	7,609	7,611	7,613	7,609	7,607
Balance for Other Purposes	$ 30,225	$ 31,227	$ 33,348	$ 37,218	$ 33,977

(1) Based on average revenues for all power sold in calendar year 1987, including energy cost adjustments.

(2) Projected additional revenue resulting from the District's Energy Cost Adjustment.

(3) Includes revenues for transmission of output of geothermal and biomass generating plants owned by others. Amounts shown include projected transmission service revenues prior to any return of funds advanced by others for transmission facility construction.

(4) Based on investment of funds at a 6.5% interest rate.

(5) Other Purchased Power includes purchases from EPE, Western, and participation in the Axis Steam Plant.

Cities of Riverside, Vernon, Azusa, Banning and Colton

The cities of Riverside, Vernon, Azusa, Banning and Colton are each municipal corporations existing under the laws of the State of California, each owning and operating an electric public utility for its citizens, providing electric service to virtually all of the electric customers within its city limits, which together encompass a total of approximately 128 square miles. The principal facilities of the cities' electric systems are sub-transmission and distribution lines aggregating approximately 1,619 circuit miles of transmission and, for the City of Riverside, 740 circuit miles of street lighting distribution as of June 30, 1988.

Electric rates for the City of Riverside are established by the Riverside Board of Public Utilities, subject to the approval of the Riverside City Council. Electric rates for the other cities are established

by the respective city councils. These electric rates are not subject to regulation by any California State agency. The cities of Riverside and Vernon, due to the magnitude of their energy sales, are subject to certain rate making provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The five cities operate their respective electric systems and obtain their bulk power supply in accordance with provisions of their respective Integrated Operations Agreements, as amended ("IOA"), which each city has executed with Edison. Each IOA provides, among other things, that the requirements of each city's electric system will be met by generating resources in which each such city has a contractual ownership interest and, to the extent required, by wholesale purchases from Edison.

At this time the cities of Riverside, Vernon, Azusa, Banning and Colton receive power and energy from their respective Project Entitlements in Unit 1, Unit 2 and Unit 3, Hoover Entitlements and short-term firm purchases and purchase interruptible energy from other utilities and governmental agencies when it is available at an economically attractive price and transmission is available. In addition, the City of Riverside has a 1.79% ownership interest, approximately 38.49 MW, in San Onofre Nuclear Generating Station, Units 2 and 3 ("San Onofre"). Unit 2 commenced commercial operation in October 1983 and Unit 3 commenced commercial operation in April 1984. The City of Riverside also has a 7.617% generation entitlement share in IPP (121.87 MW). The City of Riverside has entered into a power sales agreement with Deseret pursuant to which the City of Riverside has agreed to purchase 46.69 MW, plus losses which are to be determined between IPP and the Mona 345-kV bus, of firm capacity and associated energy. Riverside's contract also provides Deseret with first rights to supply the City of Riverside with certain economy and replacement energy. The capacity and energy from Deseret is currently available although it has not been integrated with Edison and is not subject to provisions of the IOA. The City of Vernon receives power and energy from its diesel units and a recently installed gas turbine. All remaining power and energy requirements for each of the five cities are purchased from Edison at wholesale rates.

The City of Banning has issued $2,570,000 of Certificates of Participation to fund a hydroelectric generating project which is anticipated to generate approximately 829 kW and 5,280 MWh annually. Additionally, the City of Vernon has issued $125,000,000 of Electric System Revenue Bonds to fund such City's Bear Butte hydroelectric, pumped storage project which is anticipated by the City to generate approximately 120 MW of peaking capacity and 205,500 MWh and 161,100 MWh annually during the high and low water years, respectively. The City further anticipates utilizing approximately 42 MW to meet a portion of its electric load with the balance of the project power sold to one or more publicly owned utilities. The project is presently in the design and engineering phase and is anticipated by the City to be in commercial operation during 1997.

As discussed previously, the City of Riverside has a 1.79% ownership interest in San Onofre. The cities of Riverside, Azusa, Banning and Colton have contracted to purchase from the Authority 3.0%, 4.0%, 2.0%, and 3.0%, respectively, of the Contingent Capacity and associated firm energy from the Authority Interest in the Hoover uprating project. The City of Riverside has contracted to purchase 7.617% of IPP capacity and energy. Riverside has a feasibility study participation percentage in White Pine Power Project. We have assumed herein that the City of Riverside's power and energy requirements above those produced by its Project Entitlement, its ownership interest in San Onofre Nuclear Generating Station Units 2 and 3, IPP purchases, its Hoover uprating project entitlement, Deseret power purchases and short-term firm purchases will be met by purchases from Edison through the IOA. We have further assumed herein that Vernon's, Azusa's, Colton's and Banning's power and energy requirements, above those produced by their respective Project Entitlements, Hoover uprating project entitlements and short-term firm and seasonal purchases, the City of Vernon's diesel generators and gas turbine unit and the City of Banning's hydroelectric generating project, will be met by purchases from Edison through their respective IOAs.

In addition to the cities' integrated resources and other resources, the cities have each executed contracts and agreements with other utilities for short term or seasonal capacity and energy. The combined capability of these purchases is approximately 227 MW and will be used to reduce capacity

and energy purchases from Edison. These purchases will not be integrated with Edison and therefore will not be subject to the provisions of their respective IOAs. Due to the large percentage of integrated resources and contract purchases relative to the cities' total requirements, the recent levels of purchases from Edison have decreased significantly from the levels experienced in the early 1980s.

The following table summarizes the fiscal year historical peak loads and resources for the cities of Riverside, Vernon, Azusa, Banning and Colton and the projected future peak loads and resources through 1993. The projected future peak loads and resources were provided by each of the respective cities.

Cities of Riverside, Vernon, Azusa, Banning and Colton
Peak Loads and Resources (MW)

	Historical					Estimated				
	Fiscal Year Ending June 30									
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Loads(1)	572.5	621.6	612.7	588.2	612.5	664.8	681.1	696.7	712.7	729.6
Resources:										
San Onofre Nuclear Generating Station(2)	39.4	39.4	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
Project Entitlement(3)	0	0	9.6	19.2	28.8	28.8	28.8	28.8	28.8	28.8
Intermountain Power Project(2)	0	0	60.9	118.9	121.9	121.9	121.9	121.9	121.9	121.9
Hoover Uprating Project	0	0	0	9.9	35.7	48.1	52.7	52.7	49.1	61.0
Deseret Power Purchase(2)	0	0	0	46.7	46.7	46.7	46.7	46.7	46.7	46.7
Other(4)	542.9	591.5	533.3	404.8	394.9	437.7	450.5	466.1	484.8	492.6
Subtotal	582.3	630.9	642.3	638.0	666.5	721.7	739.1	754.7	769.8	789.5
Less: Reserves and Losses(5)	9.8	9.3	29.6	49.8	54.0	56.9	58.0	58.0	57.1	59.9
Net Resources	572.5	621.6	612.7	588.2	612.5	664.8	681.1	696.7	712.7	729.6
Balance Available	0	0	0	0	0	0	0	0	0	0

(1) Non-coincidental.

(2) City of Riverside resource only.

(3) Project capacity shown at the date of commercial operation, which may not coincide wih the cities' peak loads.

(4) Includes the City of Vernon's diesel generators and gas turbine unit, the City of Banning's hydroelectric generating project and purchases as necessary to meet loads to be obtained from Edison or other sources.

(5) Reserves and losses associated with the San Onofre, IPP, Hoover uprating project, Deseret and the respective Project Entitlements. Capacity credit for these resources, under the respective Integrated Operations Agreements, is based on an assumed reserve requirement by Edison of 20% of the resource rated capability. The cities purchase capacity reserves from Edison. The Deseret Power Purchase is not an integrated resource under Riverside's Integrated Operations Agreement and is not subject to Edison's reserve requirements.

The following table summarizes the projected average cost of power to the cities of Riverside, Vernon, Azusa, Banning and Colton of their Project Entitlements.

Projected Annual Cost to Cities of Riverside, Vernon, Azusa, Banning and Colton
of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Project Entitlement Costs(1)	$14,536	$15,254	$15,401	$15,524	$15,765
Transmission Costs to Eldorado(2)	138	143	150	156	162
Transmission Costs to Point of Interconnection C(3)	345	356	368	376	388
Transmission Costs to the Cities' Points of Delivery(4)	373	388	402	415	431
Total Estimated Annual Costs	$15,392	$16,141	$16,321	$16,471	$16,746
Energy Delivered (000 MWh)	156.7	173.5	153.8	171.0	179.1
Average Unit Cost (Mills/kWh)	98.2	93.0	106.1	96.3	93.5
Capacity Delivered (MW)	27.3	27.3	27.3	27.3	27.3

(Footnotes on following page)

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) Based on the Transmission Service Agreements. Transmission costs escalated at 3.0% per year.

(4) Estimated transmission costs charged by Edison including scheduling and dispatching for the respective cities' Project Entitlements under provisions of their Integrated Operations Agreements.

We have projected the costs of power to the cities of Riverside, Vernon, Azusa, Banning and Colton for the period 1989 through 1993 assuming that these cities would purchase from Edison all power requirements not supplied from their respective Project Entitlements, Hoover uprating project entitlements and known short-term firm or seasonal purchases, with the exception of the cities of Riverside, Vernon and Banning. For the City of Riverside, we have included its ownership share of San Onofre, its entitlement from IPP and the capability of the Deseret Power Purchase. For the cities of Vernon and Banning we have included the respective production of Vernon's diesel generators and gas turbine unit and Banning's hydroelectric generating project. In accordance with their Integrated Operations Agreements, these cities will purchase power from Edison at Edison's partial requirements rates. In addition, with the exception of the Hoover uprating project entitlements, when a City Capacity Resource, such as its Project Entitlement, is not available, the cities shall purchase energy from some other source or purchase Contract Energy from Edison in the amount of energy capability associated with the capacity credit, less energy received from City Integrated Resources. For purposes of this report, we have assumed that all Contract Energy requirements are purchased from Edison, with the exception of the Western energy credits related to the Hoover uprating project which may be scheduled to supply a portion of these requirements and certain amounts available from short-term firm purchases.

Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, recent rate filings, and Edison's electric system resource plans and load forecasts. Edison resource plans which we have used in forecasting its wholesale rates include participation by some of its wholesale customers in the California-Oregon Transmission Project, as previously discussed under "Future Power Supply Resources". Inclusion of this potential participation by Edison's wholesale customers in either project does not have a substantial impact on the projection of Edison's power and energy rates.

Oil and gas prices have a direct impact on Edison rates. The oil price level used in the analyses of future Edison rates is based on an average cost of $18.54 per barrel in 1988 increasing at 4.2% per year through 1990 and at 5.7% per year after 1990. The natural gas price level is based on an average cost of $3.04 per million BTU in 1988 increasing at 4.2% per year through 1990 and at 5.7% per year after 1990.

On January 13, 1986 and again on June 5, 1987, the Cities signed settlement agreements with Southern California Edison Company which provided for changes in the wholesale partial requirements rates applicable to purchases by the Cities. The first settlement, Docket ER86-271, provided for a 1.9% increase over prior rates in effect, and was in effect from March 7, 1986 until May 31, 1987. On June 1, 1987, the second settlement rates, Docket ER87-483, went into effect and continue to be the rates in effect at the present time. Docket ER87-483 provided for a rate decrease of 8.9% from the Docket 86-271 rates.

Both settlements contained a provision for adjusting wholesale rates for the effects of the 1986 Tax Reform Act ("TRA"). Docket ER87-365 was established to adjust the Docket ER86-271 rates for the TRA. The Cities and Edison reached a settlement on August 26, 1988 with respect to the rate reduction required by the TRA which resulted in refunds of approximately $1,100,000 to the cities of Riverside, Azusa, Banning and Colton for service from March 1986 through May 1987 and March 1986 through June 1988 for the city of Vernon. These refunds are in addition to the partial refunds Edison paid in December 1987 of $1,156,000 associated with TRA changes. The TRA adjustment to Docket ER87-483 rates has not yet been prepared by Edison.

In projecting Edison rates, we have supplemented recent Edison filings and principles reached in the settlement agreements with the following assumptions: (1) FERC will allow Edison a 13.0% rate of

return on common equity for 1988 through 1989 and 13.5% in 1990 and thereafter; (2) the basic rate of annual inflation will be approximately 4.2% per year; (3) annual escalation for coal will be 5.7% per year; (4) operating expenses will escalate at 4.2% per year; and (5) the costs of construction will generally escalate at 5.2% per year. The forecast of Edison wholesale power costs results in estimated wholesale demand charges to Anaheim and Riverside which are essentially unchanged through 1993 and estimated wholesale energy charges which increase at an average rate of 3.7% per year through 1993. Such power cost increase projections include the effect of the declining load factor on the purchases to be made from Edison for the Cities of Anaheim and Riverside resulting from the addition of owned resources.

In November 1987, FERC issued an opinion and order in Edison's 1982 rate case. Corrections to Edison's 1982 rate case indicated in the final opinion and order may result in refunds of approximately $72.8 million, including interest through December 31, 1988, to the five cities for the periods from June 1982 through May 1984 when the 1982 rates were in effect. Edison has filed for a rehearing and FERC has yet to rule on such filing. Depending upon FERC's ruling and/or rehearing, the amount and timing of any such refund will be determined. We have not included any prospective refund resulting from the 1982 rate case in our analysis. For further information, please see discussion later in this section.

In November 1986, a FERC Administrative Law Judge issued an Initial Decision in Edison's 1984 rate case. Corrections to Edison's 1984 rate case indicated in the Initial Decision may result in refunds of approximately $32.6 million for the period from June 1984 through March 1986 when the 1984 rates were in effect. This Initial Decision is also under review by the FERC and the FERC has not yet issued a final order.

The Contract Energy cost is determined by multiplying Edison's cost of fuel for conventional oil-fired combustion turbine and combined-cycle generating resources measured in dollars per million BTU by the weighted heat rate of these generating resources measured in BTU per kilowatt-hour. This rate, plus a charge for certain other costs associated with fuel, is then adjusted for transmission losses to the cities' points of delivery. The cities have indicated that recent operations have required small amounts of Contract Energy at or below this cost from Edison or other resources.

Edison has provided testimony in a FERC proceeding that it recognizes that certain changes, which would be beneficial to these cities, should be made in the method of calculating Contract Energy costs under the provisions of the IOAs. On November 19, 1987, FERC issued an opinion and order which would (i) reduce the amount of Contract Energy which the cities would purchase from Edison; (ii) reduce the cost of such Contract Energy to the cities; and (iii) reduce the reserve obligations of the cities to the Edison control area in connection with capacity resources of the cities. Edison has requested a rehearing by FERC. A decision with respect to Edison's request has not been made by FERC. We have not included either such change in the method of calculating Contract Energy or the effects of the final opinion and order issued by FERC in our analysis.

Should a City Integrated Resource experience an extended outage, the city will be required to provide, or purchase from Edison, Replacement Capacity in accordance with its IOA. The cost of Replacement Capacity purchased from Edison, measured in dollars per kilowatt-day, is based on the costs of electric generating facilities installed during the five years just prior to the current year. However, the cities do not expect to be required to pay the cost of Replacement Capacity, except under unusual circumstances arising from extended outages of their Integrated Resources. Therefore, we have not considered the effects of Replacement Capacity costs on the cities' power supply costs.

Based upon the foregoing assumptions, our projection of Edison's wholesale power rates and the projected costs of the cities' respective Project Entitlements, the following tables show the projected power supply costs for the cities for a period from 1988 through 1993.

Projected Power Supply Costs to the City of Riverside

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Power Costs:					
Project Entitlement	$ 6,202	$ 6,502	$ 6,573	$ 6,633	$ 6,742
San Onofre	18,482	18,628	18,584	19,168	20,036
Intermountain Power Project(1)	51,288	55,529	57,581	59,645	60,705
Hoover Uprating Project	512	563	577	593	615
Deseret Power Purchase(2)	16,497	16,848	17,252	17,351	17,860
Credit from Surplus Sales(3)	(1,180)	(1,115)	(900)	(1,036)	(695)
Other Purchased Power(4)	19,511	19,672	23,652	25,981	28,440
Total Annual Power Supply Costs	$111,312	$116,627	$123,319	$128,335	$133,703
Total Energy Requirements (000 MWh)	1,386	1,428	1,470	1,513	1,556
Unit Power Supply Costs (Mills/kWh)	80.3	81.7	83.9	84.8	85.9

(1) Includes the projected annual cost of the Southern Transmission System transfer capability associated with the City of Riverside's IPP entitlement.
(2) Includes the projected annual cost of the excess transfer capability of the Southern Transmission System.
(3) Income derived from the sale of surplus energy generated by City Integrated Resources sold to Edison under the provisions of the IOA.
(4) Based on projected Edison energy and capacity rates and projected Edison Contract Energy costs and short-term firm purchases from other utilities.

Projected Power Supply Costs to the Cities of Vernon, Azusa, Banning and Colton

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Power Costs:					
Project Entitlement	$ 9,190	$ 9,639	$ 9,748	$ 9,838	$10,004
Hoover Uprating Project	553	608	623	639	661
Other Purchased Power*	68,813	66,001	70,339	74,585	77,344
Total Annual Power Supply Costs	$78,556	$76,248	$80,710	$85,062	$88,009
Total Energy Requirements (000 MWh)	1,604	1,621	1,635	1,649	1,667
Unit Power Supply Costs (Mills/kWh)	49.0	47.0	49.4	51.6	52.8

* Includes the City of Vernon's diesel generator and gas turbine production costs, the City of Banning's hydroelectric generating project production costs, short-term firm and seasonal purchases and Edison purchases based on projected Edison energy and capacity rates.

Based on the projected costs of power from their respective Project Entitlements and on certain data supplied by the cities of Riverside, Vernon, Azusa, Banning and Colton, we have prepared projections of operating results of their electric systems for the fiscal years ending June 30, 1989 through 1993. In these projections, we show increases in revenue requirements beyond the revenues generated at the cities' existing rates and estimate an average annual change in revenue requirements over the five-year period of approximately 4.5%, 1.3%, -0.7%, 0% and 1.8% for Riverside, Vernon, Azusa, Banning and Colton, respectively. Revenue requirements are based on covering projected operating expenses, including the cost of power from each city's Project Entitlement, debt service on bonds previously issued, where applicable, and on meeting the respective electric system's projected capital improvement program and other non-operating financial commitments.

City of Riverside
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges	$121,318	$124,952	$128,660	$132,378	$136,191
Revenue Adjustments(1)	22,457	16,663	11,894	5,082	3,004
Additional Revenue Required(2)	2,942	6,015	15,008	25,008	30,188
Subtotal	$146,717	$147,630	$155,562	$162,468	$169,383
Other Operating Revenues(3)	528	544	561	575	590
Surplus Sales Revenue(4)	1,180	1,115	900	1,036	695
Other Income(3)	3,260	3,260	3,260	3,260	3,260
Developers' Contributions(3)	2,271	1,882	2,039	1,844	1,879
Total Projected Gross Revenues	$153,956	$154,431	$162,322	$169,183	$175,807
Operating Expenses:					
Power Production:					
Project Entitlement(5)	$ 6,202	$ 6,502	$ 6,573	$ 6,633	$ 6,742
San Onofre Nuclear Generating Station	8,715	8,872	8,826	9,267	9,731
Intermountain Power Project(6)	51,288	55,529	57,581	59,645	60,705
Hoover Uprating Project	512	563	577	593	615
Deseret Power Purchase(7)	16,497	16,848	17,252	17,351	17,860
Other Purchased Power(8)	19,511	19,672	23,652	25,981	28,440
Other Operating Expenses(9)	20,760	21,656	22,591	23,568	24,592
Total Projected Operating Expenses	$123,485	$129,642	$137,052	$143,038	$148,685
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 30,471	$ 24,789	$ 25,270	$ 26,145	$ 27,122
Debt Service(10)	$ 13,256	$ 13,201	$ 13,156	$ 13,102	$ 13,087
Balance for Other Purposes(11)	$ 17,215	$ 11,588	$ 12,114	$ 13,043	$ 14,035

(1) Additional revenue projected by the City to be available from the Rate Stabilization account. Includes credits pursuant to the Plan for Disposition of Surplus Funds from IPP as elected by the City of Riverside.

(2) Additional revenues required primarily to pay the costs of future capital improvements to the City of Riverside's electric system and escalating purchased power costs.

(3) Includes interest income and miscellaneous income as projected by the City of Riverside.

(4) Revenue from the sale of surplus energy under the provisions of the City of Riverside's IOA.

(5) The City's share of projected annual costs of the Project including transmission to the Point of Interconnection C and projected costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(6) Includes payments for the Southern Transmission System associated with the transfer capability required for the City of Riverside's IPP entitlement.

(7) Includes payments for the excess transfer capability of the Southern Transmission System.

(8) Based on short-term purchases from other utilities and purchases from Edison at projected Edison rates under the provisions of the City of Riverside's IOA.

(9) Projected by the City of Riverside. Includes other operating expenses and equipment purchases.

(10) Net of capitalized interest.

(11) Includes transfer to the general fund and funds for transmission and distribution projects and approximately $1,194,000 of Southern Transmission Project construction funds billed by the Authority in fiscal year 1989.

City of Vernon
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges	$ 60,575	$ 60,575	$ 60,575	$ 60,575	$ 60,575
Additional Revenue Required(1)	(1,215)	(2,858)	(20)	2,562	4,066
Subtotal	$ 59,360	$ 57,717	$ 60,555	$ 63,137	$ 64,641
Other Operating Revenues	80	80	80	80	80
Other Income	6,300	6,550	6,813	7,088	7,378
Total Projected Gross Revenues	$ 65,740	$ 64,347	$ 67,448	$ 70,305	$ 72,099
Operating Expenses:					
Project Entitlement(2)	$ 5,651	$ 5,926	$ 5,990	$ 6,046	$ 6,146
Hoover Uprating Project	367	404	414	425	440
Other Purchased Power(3)	47,354	45,116	47,590	49,660	50,590
Other Operating Expenses(4)	9,500	9,975	10,474	10,997	11,547
Total Projected Operating Expenses	$ 62,872	$ 61,421	$ 64,468	$ 67,128	$ 68,743
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 2,868	$ 2,926	$ 2,980	$ 3,177	$ 3,376
Debt Service	0	0	0	0	0
Balance for Other Purposes(5)	$ 2,868	$ 2,926	$ 2,980	$ 3,177	$ 3,376

(1) Projected revenue increases required to cover all operating expenses, capital improvements and taxes.

(2) The City's share of projected annual costs of the Project including transmission to Point of Interconnection C and projected costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Includes the City's diesel generator and gas turbine production costs, short-term and seasonal purchases and purchases from Edison based on projected Edison rates under the provisions of its Integrated Operations Agreement.

(4) Includes projected expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses.

(5) Includes projected payments in lieu of taxes and capital additions to be funded from revenues.

City of Azusa
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges	$ 16,082	$ 16,735	$ 17,081	$ 17,436	$ 17,955
Additional Revenue Required(1)	(1,751)	(2,422)	(1,735)	(1,070)	(663)
Subtotal	$ 14,331	$ 14,313	$ 15,346	$ 16,366	$ 17,292
Other Operating Revenues	76	80	84	88	92
Other Income	0	0	0	0	0
Total Projected Gross Revenues	$ 14,407	$ 14,393	$ 15,430	$ 16,454	$ 17,384
Operating Expenses:					
Power Project Entitlement(2)	$ 1,177	$ 1,235	$ 1,250	$ 1,261	$ 1,283
Hoover Uprating Project	79	86	89	92	94
Other Purchased Power(3)	9,309	9,104	9,885	10,651	11,313
Other Operating Expenses(4)	1,986	2,075	2,168	2,266	2,368
Total Projected Operating Expenses	$ 12,551	$ 12,500	$ 13,392	$ 14,270	$ 15,058
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 1,856	$ 1,893	$ 2,038	$ 2,184	$ 2,326
Debt Service	0	0	0	0	0
Balance for Other Purposes(5)	$ 1,856	$ 1,893	$ 2,038	$ 2,184	$ 2,326

(1) Projected revenue increases required to cover all operating expenses, capital improvements and taxes.

(2) The City's share of projected annual costs of the Project including transmission to Point of Interconnection C and projected costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Based on short-term and seasonal purchases and purchases from Edison under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(4) Includes projected expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses.

(5) Includes projected payments to the General Fund, payments in lieu of taxes and capital additions to be funded from revenues.

City of Banning
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges	$ 6,963	$ 7,144	$ 7,325	$ 7,506	$ 7,697
Additional Revenue Required(1)	793	239	24	78	4
Subtotal	$ 7,756	$ 7,383	$ 7,349	$ 7,584	$ 7,701
Other Operating Revenues	120	130	140	140	150
Other Income	31	31	31	31	31
Total Projected Gross Revenues	$ 7,907	$ 7,544	$ 7,520	$ 7,755	$ 7,882
Operating Expenses:					
Project Entitlement(2)	$ 1,189	$ 1,247	$ 1,262	$ 1,274	$ 1,296
Hoover Uprating Project	43	48	49	49	51
Other Purchased Power(3)	4,070	3,616	3,561	3,735	3,761
Other Operating Expenses(4)	1,057	1,078	1,100	1,122	1,144
Total Projected Operating Expenses	$ 6,359	$ 5,989	$ 5,972	$ 6,180	$ 6,252
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 1,548	$ 1,555	$ 1,548	$ 1,575	$ 1,630
Debt Service	206	207	209	209	209
Balance for Other Purposes(5)	$ 1,342	$ 1,348	$ 1,339	$ 1,366	$ 1,421

(1) Projected revenue increases required to cover all operating expenses, capital improvements and taxes.

(2) The City's share of projected annual costs of the Project including transmission to Point of Interconnection C and projected costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Includes the production costs of the City's hydroelectric generating project, short-term and seasonal purchases and purchases from Edison based on projected Edison rates under the provisions of its Integrated Operations Agreement.

(4) Includes projected expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses.

(5) Includes projected payments in lieu of taxes and capital additions to be funded from revenues.

City of Colton
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges	$ 13,694	$ 14,354	$ 15,039	$ 15,764	$ 16,514
Additional Revenue Required(1)	(248)	(554)	144	911	1,585
Subtotal	$ 13,446	$ 13,800	$ 15,183	$ 16,675	$ 18,099
Other Operating Revenues	49	51	54	57	59
Other Income	0	0	0	0	0
Total Projected Gross Revenues	$ 13,495	$ 13,851	$ 15,237	$ 16,732	$ 18,158
Operating Expenses:					
Project Entitlement(2)	$ 1,173	$ 1,231	$ 1,246	$ 1,257	$ 1,279
Hoover Uprating Project	64	70	71	73	76
Other Purchased Power(3)	8,080	8,165	9,303	10,539	11,680
Other Operating Expenses(4)	2,423	2,545	2,672	2,805	2,946
Total Projected Operating Expenses	$ 11,740	$ 12,011	$ 13,292	$ 14,674	$ 15,981
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 1,755	$ 1,840	$ 1,945	$ 2,058	$ 2,177
Debt Service	98	100	97	96	98
Balance for Other Purposes(5)	$ 1,657	$ 1,740	$ 1,848	$ 1,962	$ 2,079

(1) Projected revenue increases required to cover all operating expenses, capital improvements, taxes and debt service.

(2) The City's share of projected annual cost of the Project including transmission to Point of Interconnection C and projected costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Based on short-term firm and seasonal purchases and purchases from Edison under the provisions of its Integrated Operations Agreement.

(4) Includes projected expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses and an assumed escalation rate of 5.0% per year.

(5) Includes payments in lieu of taxes and projected capital additions to be funded from revenues.

Cities of Burbank, Glendale and Pasadena

The cities of Burbank, Glendale and Pasadena are each municipal corporations existing under the laws of the State of California, owning and operating electric public utilities providing electric service to virtually all of the electric customers within their respective city limits.

Electric rates for each city are fixed by its City Council and are not subject to regulation by any California state agency. Each city is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978.

Burbank, Glendale and Pasadena supply electricity to their respective electric systems through a combination of oil- and gas-fired generating facilities located in the Los Angeles Basin, 34 MW of hydroelectric generation at the Hoover Power Plant and purchases from BPA and other utilities in the Northwest and Southwest. The City of Pasadena also purchases electric energy from the Azusa Hydroelectric Plant. In the twelve months ended June 30, 1988, the three cities generated an aggregate of 861,770 MWh of energy and purchased an aggregate of 2,224,939 MWh.

The 2.3% projected combined average annual peak load growth over the period 1989 to 1993 for the cities of Burbank, Glendale and Pasadena reflects their view of the population increase of the area

and the effect on consumption of conservation measures already implemented and those proposed, including the introduction, in some instances, of alternative energy resources.

The cities of Burbank, Glendale and Pasadena have entered into contracts to purchase a total of 9.484% (151.744 MW) of IPP base capacity and energy and 13.719% of the capacity and energy available under the Excess Power Sales Agreement which is presently projected to be approximately 46.221 MW. The cities of Burbank, Glendale and Pasadena have a feasibility study participation percentage totaling 5.61% in the White Pine Power Project. The cities of Burbank and Glendale each have a 3.85% ownership interest in the SEP. The City of Pasadena has a 2.3% ownership interest in the SEP. The following table summarizes the fiscal year historical peak loads and resources and projected future peak loads and resources through 1993 for the cities of Burbank, Glendale and Pasadena. The projected future peak loads and resources were provided by the cities of Burbank, Glendale and Pasadena.

Cities of Burbank, Glendale and Pasadena
Peak Loads and Resources (MW)

	Historical					Projected				
	Fiscal Year Ending June 30									
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Loads(1)	639	704	691	689	713	734	752	768	785	803
Resources(2):										
Basin Thermal (Oil and Gas)(3)	656	667	667	667	667	496	512	528	547	560
Hydroelectric	49	49	49	53	64	70	72	72	70	75
Project Entitlement(4)	0	0	10	10	19	29	29	29	29	29
Intermountain Power Project(5)	0	0	76	148	152	152	152	152	152	152
Other(6)	126	126	156	157	136	182	182	182	182	182
Total	833	844	958	1,035	1,038	929	947	963	980	998
Balance Available for Reserves and Losses	192	138	267	346	325	195	195	195	195	195

(1) Non-coincidental.

(2) Resources assumed available to meet peak loads.

(3) Includes those resources required to meet peak loads and planning reserve margin as provided by the cities of Burbank, Glendale and Pasadena.

(4) Project capacity shown at the date of commercial operation, which may not coincide with the cities' peak loads.

(5) Excludes purchases under the Excess Power Sales Agreement.

(6) Includes BPA peaking exchange through 1987, purchases under the Excess Power Sales Agreement, firm purchases from other utilities and additional requirements.

The following table summarizes the projected Project Entitlement cost of power to the cities of Burbank, Glendale and Pasadena.

Projected Annual Cost to the Cities of Burbank, Glendale and Pasadena of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Project Entitlement Costs(1)	$14,427	$15,138	$15,285	$15,408	$15,648
Transmission Costs of Power to Eldorado(2)	105	111	114	120	123
Transmission Costs to Point of Interconnection A(3)	123	126	132	135	138
Transmission Costs to the Cities	212	221	229	238	245
Total	$14,867	$15,596	$15,760	$15,901	$16,154
Energy Delivered (000 MWh) (4)	156.9	173.7	154.2	171.3	179.4
Average Unit Cost (Mills/kWh)	94.8	89.8	102.2	92.8	90.0
Capacity Delivered (MW) (5)	27.4	27.4	27.4	27.4	27.4

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) Based on the Transmission Service Agreements. Transmission costs escalated at 3.0% per year.

(4) Not reduced to reflect transmission losses to the cities' points of delivery. Based on the McCullough-Victorville Line 2 Transmission Agreements between the cities of Burbank and Glendale and the Department, the Victorville to Sylmar Switching Station Transmission Service Agreement between the City of Pasadena and the Department, and the 230 kV Interconnection and Transmission Agreement between the City of Pasadena and Edison.

(5) Project capacity shown at the date of commercial operation, which may not coincide with the cities' peak loads.

We have projected the power costs for the cities of Burbank, Glendale and Pasadena. These projections are based on the costs of the cities' Project Entitlements, as estimated herein, together with projections of the costs of power from the other power supply resources scheduled to be used to supply power to meet the cities' loads. For the purpose of this analysis, the costs of the resources required, but as yet unidentified, and the costs of operation of power plants owned by the cities of Burbank, Glendale and Pasadena, were provided by these Project Participants. The foregoing projections are based on power supply plans provided by these Project Participants. The cities of Burbank, Glendale and Pasadena are currently evaluating their power supply plans. In many cases, actual energy costs may differ when final plans, schedules and definitive pooling arrangements are developed.

Projected Power Supply Costs to the Cities of Burbank, Glendale and Pasadena

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Power Supply Costs:					
Project Entitlement	$ 14,867	$ 15,596	$ 15,760	$ 15,901	$ 16,154
Thermal (Gas and Oil)	36,111	38,314	40,884	44,180	48,296
Intermountain Power Project	67,036	72,528	75,148	77,755	79,114
Hoover Uprating Project	348	399	415	431	452
Other Purchased Power(*)	48,609	52,197	56,204	59,112	61,698
Total Annual Power Supply Costs	$166,971	$179,034	$188,411	$197,379	$205,714
Total Energy Requirements (000 MWh)	3,084	3,148	3,220	3,293	3,367
Unit Power Supply Costs (Mills/kWh)	54.1	56.9	58.5	59.9	61.1

* Includes each city's projected annual cost of power supply from other resources purchased to serve such city's annual requirements.

Based on the projected costs of power from their respective Project Entitlements and on certain data supplied by the cities of Burbank, Glendale and Pasadena, we have prepared projections of operating results of their electric systems for the fiscal years ending June 30, 1989 through 1993. In these projections, we show increases in revenue requirements beyond those generated by the cities' current rates and estimate an average annual increase in revenue requirements of 5.0%, 2.3%, and 3.6% for the cities of Burbank, Glendale and Pasadena, respectively. Required revenues are based on covering projected operating costs, including cost of power from each city's respective Project Entitlements, debt service on bonds previously issued and on meeting the respective city's projected improvement program and other non-operating financial commitments.

The City of Burbank
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sale of Electricity:					
At 1988 Average Charges(1)	$68,997	$70,446	$71,895	$73,413	$75,069
Additional Revenue Required(2)	5,001	8,690	16,007	18,601	20,695
Subtotal	$73,998	$79,136	$87,902	$92,014	$95,764
Other Operating Revenues	0	0	0	0	0
Other Income(3)	4,801	4,445	250	250	250
Total Projected Gross Revenues	$78,799	$83,581	$88,152	$92,264	$96,014
Operating Expenses:					
Power Production:					
Project Entitlement(4)	$ 4,957	$ 5,200	$ 5,255	$ 5,302	$ 5,386
Basin Thermal(5)	14,269	14,759	15,771	17,289	18,901
Intermountain Power Project(6)	23,838	25,791	26,723	27,651	28,134
Hoover Uprating Project	177	207	216	224	238
Other Purchased Power(5)(7)	15,683	17,385	18,775	19,512	20,194
Other Operating Expenses(8)	10,635	11,167	11,726	12,312	12,927
Total Projected Operating Expenses	$69,559	$74,509	$78,466	$82,290	$85,780
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 9,240	$ 9,071	$ 9,686	$ 9,974	$10,234
Debt Service	2,531	2,532	2,533	2,533	2,531
Balance for Other Purposes(9)	$ 6,709	$ 6,540	$ 7,153	$ 7,441	$ 7,703

(1) Based on average charge for all power sold in fiscal year ending June 30, 1988, including fuel cost adjustments.

(2) Projected additional revenue requirements to cover all operating expenses, capital additions, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments.

(3) Includes credits pursuant to the Plan for Disposition of Surplus Funds from IPP as elected by the City of Burbank for use during fiscal year 1989 and projected thereafter.

(4) Includes the City of Burbank's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(5) Reflects availability of economical outside purchases.

(6) Costs are projected at the load center. Excludes Excess Power Sales Agreement amounts.

(7) Includes purchases from Hoover Power Plant, payment for economy energy purchases, payment for purchases from the Northwest and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(8) Includes transmission and distribution, customer accounts and administrative and general expenses.

(9) Includes projected payments in lieu of taxes, capital additions to be funded from revenues and approximately $527,000 of Southern Transmission Project construction funds billed by the Authority in fiscal year 1989.

City of Glendale
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges(1)	$68,018	$69,806	$71,455	$73,073	$74,737
Additional Revenue Required(2)	(755)	1,717	4,004	7,213	8,985
Subtotal	$67,263	$71,523	$75,459	$80,286	$83,722
Other Operating Revenues	750	750	750	750	750
Other Income(3)	5,500	5,500	5,306	4,000	4,000
Total Projected Gross Revenues	$73,513	$77,773	$81,515	$85,036	$88,472
Operating Expenses:					
Power Production:					
Project Entitlement(4)	$ 4,957	$ 5,200	$ 5,255	$ 5,302	$ 5,386
Basin Thermal(5)	8,828	9,441	10,021	10,704	11,352
Intermountain Power Project(6)	12,054	13,041	13,512	13,980	14,225
Hoover Uprating Project	65	68	71	72	73
Other Purchased Power(5)(7)	19,519	20,708	22,294	23,618	25,079
Other Operating Expenses(8)	12,606	13,110	13,634	14,179	14,746
Total Projected Operating Expenses	$58,029	$61,568	$64,787	$67,855	$70,861
Total Projected Net Revenues Excluding Depreciation and Amortization	$15,484	$16,205	$16,728	$17,181	$17,611
Debt Service	4,162	4,162	4,168	4,168	4,154
Balance for Other Purposes(9)	$11,322	$12,043	$12,560	$13,013	$13,457

(1) Based on average charge for all power sold in the fiscal year ending June 30, 1988, including fuel cost adjustments.

(2) Projected additional revenue requirements to cover all operating expenses, capital additions, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments.

(3) Includes credits pursuant to the Plan for Disposition of Surplus Funds from IPP as elected by the City of Glendale for use during the fiscal year 1989 and projected thereafter.

(4) Includes the City of Glendale's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(5) Reflects availability of economical outside purchases.

(6) Costs are projected at the load center. Excludes Excess Power Sales Agreement amounts.

(7) Includes purchases from Hoover Power Plant, payment for economy energy purchases, firm capacity and energy purchases from BPA beginning in 1987 and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(8) Includes transmission and distribution, customer accounts and administrative and general expenses.

(9) Includes projected payments to general fund, capital additions to be funded from revenues and approximately $267,000 of Southern Transmission Project construction funds billed by the Authority in fiscal year 1989.

City of Pasadena
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1989	1990	1991	1992	1993
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1988 Average Charges(1)	$ 77,838	$ 79,116	$ 81,147	$ 83,070	$ 84,958
Revenue Adjustment	10,989	8,098	3,582	0	0
Additional Revenue Required (2)	(18,815)	7,885	9,221	14,544	16,578
Subtotal	$ 70,012	$ 95,099	$ 93,950	$ 97,614	$101,536
Other Operating Revenues	0	0	0	0	0
Other Income (3)	14,332	3,391	3,407	3,423	3,440
Total Projected Gross Revenues	$ 84,344	$ 98,490	$ 97,357	$101,037	$104,976
Operating Expenses:					
Power Production:					
Palo Verde Entitlement(4)	$ 4,953	$ 5,196	$ 5,250	$ 5,297	$ 5,382
Basin Thermal(5)	13,014	14,114	15,092	16,187	18,042
Intermountain Power Project(6)	31,144	33,696	34,913	36,124	36,755
Hoover Uprating Project	106	124	128	135	141
Other Purchased Power(5) (7)	13,406	14,105	15,135	15,981	16,424
Other Operating Expenses(8)	8,594	9,023	9,474	9,948	10,594
Total Projected Operating Expenses	$ 71,217	$ 76,258	$ 79,992	$ 83,672	$ 87,338
Total Projected Net Revenues Excluding Depreciation and Amortization	$ 13,127	$ 22,232	$ 17,365	$ 17,365	$ 17,638
Debt Service	3,848	3,778	3,717	3,410	3,361
Balance for Other Purposes(9)	$ 9,279	$ 18,454	$ 13,648	$ 13,955	$ 14,277

(1) Based on average charge for all power sold in the fiscal year ending June 30, 1988 including fuel cost adjustments.

(2) Projected additional revenue requirements to cover all operating expenses, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments. Revenues collected in excess of the amount required will be deposited in the City of Pasadena's rate stabilization fund to reduce the amount of additional revenues required in future years.

(3) Incudes credits pursuant to the Disposition of Surplus Funds from IPP as elected by the City of Pasadena for use during the fiscal year 1989.

(4) Includes the City of Pasadena's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(5) Reflects availability of economical outside purchases.

(6) Costs are projected at the load center. Excludes Excess Power Sales Agreement amounts.

(7) Includes hydroelectric purchases, payment for economy energy purchases, payments for purchases from the Northwest and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(8) Includes transmission and distribution, customer accounts and administrative and general expenses.

(9) Includes projected payments to general fund, capital additions to be funded from revenues and approximately $691,000 of Southern Transmission Project construction funds billed by the Authority in fiscal year 1989.

PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

The estimates and projections contained herein are based, in part, on the following information which was provided by the identified sources. While we believe these sources to be reliable and have no reason to believe such information is unreasonable, we have not independently verified such information.

1. Projections of the Department's power and energy requirements, resources and power supply costs, excluding costs of its Project Entitlement and IPP generation entitlements, were provided by the Department.
2. Projections of power and energy requirements for the cities of Riverside, Burbank, Glendale, Pasadena, Vernon, Azusa, Banning and Colton and the District were provided by those Project Participants.
3. Excluding their Project Entitlements, IPP generation entitlements and the Hoover uprating project, projections of resources for the cities of Burbank, Glendale and Pasadena were provided by those Project Participants.
4. Projections of capital expenditures and operation and maintenance expenses for the Department, and the cities of Riverside, Burbank, Glendale and Pasadena were provided by those Project Participants.
5. The District and the City of Vernon provided projections of their capital expenditures.
6. The financial advisor has provided us with assumed investment rates of 8.0% through fiscal year 1992 and 7.85% for fiscal year 1993 for the proceeds of Prior Series Bonds and the 1989 Bonds deposited in the Debt Service Reserve Account in the Debt Service Fund and the Reserve and Contingency Fund, and 7.0% for such proceeds deposited in all other funds.

In the preparation of our report, we have projected wholesale power and energy rates for Edison. Oil and gas prices have a direct impact on Edison rates. The oil price level used in the analyses of future Edison rates is based on an average cost of $18.54 per barrel in 1988 increasing at 4.2% per year through 1993 and at 5.7% per year after 1990. The natural gas price level is based on an average cost of $3.04 per million BTU in 1988 increasing at 4.2% per year through 1990 and at 5.7% per year after 1990. Additionally, we cannot presently determine to what extent Edison will be allowed to include CWIP in its wholesale electric rates. Edison has not included CWIP in its most recent rate settlement with the cities of Riverside, Vernon, Azusa, Banning and Colton. Our projections of Edison's wholesale electric rates do not include an allowance for CWIP in its rate base. We have not analyzed what impact, if any, the proposed merger, if approved, of SDG&E with Edison will have on Edison's operations or its wholesale electric rates.

Additionally, in the preparation of this report and the numbered opinions that follow, we have made certain assumptions with respect to conditions which may occur in the future. While we believe these assumptions are reasonable for the purpose of this report, they are dependent upon future events, and actual conditions may differ from those assumed. In making such assumptions, we have used and relied upon certain information provided to us by the Department, acting as the Authority's agent, the Project Participants, Edison and others. While we believe the sources to be reliable, we have not independently verified the information. To the extent that actual future conditions differ from those assumed herein or from the information provided to us by others, the actual results will vary from those projected. The principal assumptions made by us and the principal information related to such assumptions provided to us by others include the following:

1. Based on actual expenditures through November 30, 1988, APS's estimate of direct construction costs of the Project, and the Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project provided by the

Department, as the Authority's Agent, the cost of acquisition of the Authority Interest will be $465,170,000.

2. Operating costs of the Project were projected by APS with the exception of taxes.

3. Based on APS's projection, as adjusted by us, Unit 3 will have a plant factor of approximately 60% during the first cycle of operation and each unit will have a plant factor of approximately 65% during the second cycle of operation and 70% thereafter.

4. By such time as the on-site fuel storage facilities reach capacity, a national program for spent fuel disposal will have been implemented.

5. Existing environmental laws and regulations will not be modified to adversely affect the operation of the Project.

6. If additional permits, licenses and approvals are necessary to continue operating the Project, they will be received on a timely basis.

7. The variable cost of power from the Project will, in the future, maintain its same position relative to the variable cost of power from alternative resources which are now available to the Project Participants.

8. The cities of Riverside, Vernon, Azusa, Banning and Colton have integrated their respective Project Entitlements as a City Capacity Resource under their respective Integrated Operations Agreements with Edison.

9. Power and energy requirements of the cities of Vernon, Azusa, Banning and Colton, beyond that provided by their respective Project Entitlements and their respective Hoover uprating project entitlements, including Western energy credits, their respective short-term firm power purchases under contract or agreement, and the City of Vernon's diesel generators and the City of Banning's hydroelectric generating project, will be purchased from Edison in accordance with the terms of their respective Integrated Operations Agreements.

10. Power and energy requirements of the City of Riverside, beyond those provided by its Project Entitlement, San Onofre Nuclear Generating Station Units 2 and 3, IPP, Deseret and its Hoover uprating project entitlement, including Western energy credits, and short-term firm power purchases under contract or agreement will be purchased from Edison in accordance with the terms of its Integrated Operations Agreement.

11. With the exception of the Department and the cities of Burbank, Glendale and Pasadena, the Project Participants' participation in other potential resources or economy purchases which are not under contract but which may become available to such Project Participants during the projected period have not been included in the projected power costs or our projection of resources of the Project Participants.

12. Based on information provided by the Project Participants, the District, Glendale, Azusa and Colton will finance the projected costs of normal capital replacements and improvements, if any, to their electric systems from current revenues.

13. Transmission for each Project Participant's Project Entitlement will be provided in accordance with the agreements as discussed herein.

14. Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, recent rate filings, and Edison's electric system resource plans and load forecasts. Further, in projecting Edison rates, we have supplemented recent Edison filings with the following assumptions: (1) FERC will allow Edison a 13.0% rate of return on common equity in 1988 through 1990 and 13.5% in 1991 and thereafter; (2) the basic rate of annual inflation will be approximately 4.2% per year; (3) annual escalation for coal will be 5.7% per year; (4) operating expenses will escalate at 4.2% per year; and (5) the costs of

construction will generally escalate at 5.2% per year. The resulting wholesale energy charges paid by the cities of Azusa, Banning, Colton, Riverside, and Vernon to Edison would increase at approximately 3.7% per year for fiscal years 1988-1993.

15. The 1988 average revenue per unit of energy sales, based on 1988 revenues from the sales of electricity and total energy sales, as provided by all Project Participants with the exception of the Department, will continue at the same level for the projected energy sales over the period of fiscal years ending June 30, 1989 through 1993.

16. The existing ratemaking authority of the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District to establish rates for the purpose of providing necessary revenues for their respective electric utility systems will not be adversely modified.

17. The capital expenditures and operation and maintenance expenses for the cities of Azusa, Banning, Colton and Vernon will follow historical trends.

18. The operation and maintenance expenses for the District and the City of Vernon will follow historical trends.

OPINIONS

Based upon our studies and analyses, the considerations and assumptions in this report and the information supplied by the Project Participants, the Department, acting as the Authority's agent, and Edison with respect to the Authority's acquisition, construction and placing into operation of the Authority Interest, we are of the opinion that:

1. Financing by the Authority to provide funds to allow completion of the Authority Interest has been completed.

2. The projected cost of power from the Authority Interest is reasonable when compared with the cost of power expected from other long-term power supply resources which may be available to the Project Participants in the same time frame as the Project.

3. The Project Participants will continue to schedule the maximum amount of the production available from their respective Project Entitlements.

4. The projected revenue requirements from the sale of electricity for the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District during fiscal years ending June 30, 1989 through 1993 can reasonably be met.

Information appearing in the Official Statement which was taken from our report or which was specifically attributed to the Consulting Engineer is accurately presented in the Official Statement.

Respectfully submitted,

/s/ R. W. BECK AND ASSOCIATES

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PROJECT PARTICIPANTS

The information contained in this Appendix has been furnished to the Authority by the respective Project Participants. This Appendix presents information as of the respective dates set forth herein. Neither the Authority nor any Project Participant makes any representations regarding the accuracy of this information subsequent to such dates.

The Department of Water and Power of The City of Los Angeles

The Department of Water and Power of The City of Los Angeles (the "Department") is a separate proprietary agency controlling its own funds with full responsibility for meeting the water and electric requirements of its service area. There follows certain information concerning the Department prepared by the Department for inclusion in this appendix to the Official Statement. This information does not purport to cover all aspects of the Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement a copy of the most recent annual report and the most recent official statement prepared by the Department for the issuance of securities for its power system may be obtained from: B C Monk, Department of Water and Power, 333 South Beaudry, 18th Floor, Los Angeles, CA 90012.

Organization

The Department, the largest municipal utility in the United States, exists under and by virtue of the Charter of The City of Los Angeles adopted in January 1925, as amended. It provides water and electric services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.4 million. The electric properties and operations of the Department are referred to herein as the "Power System".

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners (the "Board"), traditionally selected from among prominent business, professional and civic leaders in the City. They are appointed for terms of five years each by the Mayor and confirmed by the City Council. The members of the Board serve without compensation except for an attendance fee of fifty dollars each for each Board meeting they attend, not to exceed two hundred fifty dollars in any calendar month. Certain matters regarding the administration of the Department also require the approval of the City Council.

The management and operation of the Department is under the direction of the General Manager and Chief Engineer, Paul H. Lane. Effective November 10, 1988, Norman E. Nichols became the Assistant General Manager and Chief Engineer and he will replace Mr. Lane upon his retirement March 31, 1989. The Power System is directed by the Assistant General Manager — Power. External affairs are under the guidance of the Assistant General Manager — External Affairs. Financial affairs are under the guidance of the Chief Financial Officer, and legal counsel is provided by the City Attorney and the Chief Assistant City Attorney for Water and Power.

The personnel functions of the Department are conducted in accordance with the civil service system established by the Los Angeles City Charter which is applicable to almost all Department employees. Under this system, appointments are made on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and Chief Engineer and certain other management positions are specifically exempted from the classified civil service under provisions of the Charter.

Wages and salaries paid all Department employees are fixed by the City Council. In accordance with a State Act (the Meyers-Milias-Brown Act) and a conforming Los Angeles City Ordinance (the Employee Relations Ordinance), fourteen bargaining units covering approximately 10,900 persons, or

96% of all Department employees, have been established since 1975. Seven labor or professional organizations represent the employees' bargaining units. In the bargaining process, memoranda of understanding are developed which set forth wages, hours, overtime and other terms and conditions of employment. After appropriate approval by the City Council, the memoranda are binding upon the Department, City Council and the respective employees' unions and organizations. Memoranda of Understanding have been entered into with the various bargaining units extending through September 30, 1988. Negotiations are currently in progress to reach new Memoranda of Understanding with such bargaining units.

The Power System

As of December 31, 1988 the Power System had a net dependable system capability of 7,280 megawatts ("MW") which is owned or operated generation. Steam electric generating capacity is equal to 73% of the System's total net capability, and owned hydroelectric generating capacity accounts for 20% of such capability. Purchases are made on a day to day or week to week basis that will alter these percentages. The portion of the hydroelectric generating capability that can be depended upon for carrying system load is determined by water flow conditions and system load characteristics. The Power System's depreciated properties are valued in excess of $3.0 billion, as of June 30, 1988.

Steam Generation: There has been a notable expansion in steam powered generation under a continuous, long-range program of planning and construction. The Power System's largest generating facility is the Haynes Generating Station with a total plant capacity of 1,570 MW, situated in the City of Long Beach, California. The Haynes Generating Station represents 22% of the Power System's overall capability.

Three additional fossil-fuel plants generate a total of 1,543 MW: the Valley Generating Station in the San Fernando Valley, the Harbor Generating Station in Wilmington and the Scattergood Generating Station situated near El Segundo. The third unit at Scattergood is presently operated under a permit which limits its output to 358 MW using natural gas as a fuel source. Studies are presently being conducted to determine if Unit 3 output can be increased to 460 MW.

The Department shares ownership in two coal-fired generating stations, Mohave in Southern Nevada and Navajo in Northern Arizona. The Department's share of Mohave is 20% and amounts to 316 MW of capacity. The Department's share of Navajo is 21.2% which amounts to 477 MW capacity. Additionally, the Department has a generation entitlement share in the Intermountain Power Project ("IPP") in Utah, which, together with the contractual arrangements, amount to 1,068 MW.

The Department obtained its 5.7% (217 MW) interest in the Palo Verde Nuclear Generating Station ("PVNGS"), Units 1, 2 and 3 on January 29, 1986 when PVNGS Unit 1 attained commercial operation. PVNGS Unit 2 attained commercial operation on September 18, 1986 and Unit 3 reached commercial operation on January 19, 1988. The Department also has a 3.96% (151 MW) generation entitlement share of PVNGS through the Southern California Public Power Authority ("Authority") ownership interest of 5.91%.

Natural gas, supplied by the Southern California Gas Company, is used as fuel for the Department's Los Angeles Basin steam plants whenever available and economical. Low-sulfur, low-ash residual oil is burned when gas is not used.

Hydroelectric Generation: The Department's major sources of hydroelectric capacity are Castaic Power Plant and its generation entitlement from Hoover Power Plant. Castaic Power Plant provides peaking capability only and is not a source of energy to meet base load requirements. An additional source of hydroelectric capability is provided by the Owens Gorge Hydroelectric Development, with an aggregate capacity of 119 MW. Situated on the northern rim of the Owens Valley in the Eastern High Sierra, this complex utilizes water resources of the Los Angeles-Owens River Aqueduct System. The utilization by the City of such water resources has been the subject of considerable controversy and is now the subject of litigation (see Item (5) under "Litigation"). Smaller hydroelectric facilities

are located north of the City along the Aqueduct in San Francisquito Canyon and at Van Norman and Franklin Reservoirs. The net plant capability of these smaller units under normal water conditions is 81 MW.

Purchased Capability: The Department purchases capacity and energy from Bonneville Power Administration ("BPA") and other Pacific Northwest utilities to be delivered over the Pacific DC Intertie ± 500-kV high-voltage DC line ("Intertie"). These purchases are used by the Department during on-peak hours in conjunction with other resources for economic system operation. In addition, purchases of economy energy are made from utilities in Nevada, Arizona, New Mexico, and Colorado.

System Capability and Power Production

Power Source	Type of Unit	Number of Units	Net Capability (MW)	% of Total Net Capability	Production in gWh(A) Twelve Months Ended June 30 1986	1987	1988	September 30 1988
Haynes	Oil/Gas	6	1,570	21.6				
Scattergood	Oil/Gas	3	716	9.8				
Valley	Oil/Gas	4	517	7.1				
Harbor	Oil/Gas	7	310	4.3				
Subtotal	Oil/Gas	20	3,113	42.8	7,207	5,492	6,179	6,463
					(31.5%)	(23.8%)	(25.2%)	(26.0%)
Navajo	Coal	3	477	6.6				
Mohave	Coal	2	316	4.3				
IPP(C)(D)	Coal	2	1,068	14.7				
Subtotal	Coal	7	1,861	25.6	5,972	9,643	12,516	12,648
					(26.1%)	(41.7%)	(51.0%)	(50.8%)
Palo Verde(E)	Nuclear	3	368	5.0				
Subtotal	Nuclear	3	368	5.0	116	795	979	1,062
					(0.5%)	(3.4%)	(4.0%)	(4.3%)
Castaic	Hydro	7	1,247(B)	17.1				
Owens Gorge, Owens Valley and Aqueduct	Hydro	22	200	2.8				
Subtotal	Hydro	29	1,447	19.9	3,808	2,855	1,801	1,048
					(16.6%)	(12.4%)	(7.3%)	(4.2%)
Purchases(F)			491	6.7	5,774	4,322	2,589	3,591(G)
Subtotal			491	6.7	(25.2%)	(18.7%)	(10.6%)	(14.4%)
Miscellaneous energy receipts					15	0	461	81
					(0%)	(0%)	(1.9%)	(0.3%)
Total		59	7,280	100.0	22,892	23,107	24,525	24,893
					(100.0%)	(100.0%)	(100.0%)	(100.0%)

(A) One Gigawatt-Hour (gWh) equals one million kWh.

(B) Castaic capability includes the State of California's contractual entitlement of up to 214 MW, with an average of 37 MW transferred to the State in December 1988, plus Edison's Supplier's Settlement entitlement of 200 MW except for a six-week period during the summer.

(C) IPP capability includes the Department's entitlement of 714 MW plus contractual purchase of 354 MW.

(D) This resource is a long-term firm purchase.

(E) Includes Department's ownership interest of 217 MW and long-term firm purchase through the Authority of 151 MW.

(F) As of June 1, 1987, the Department's Hoover entitlement of 491 MW is considered a long-term firm purchase.

(G) Includes 125 gWh of cogeneration.

Transmission and Distribution: Electricity from the Department's hydroelectric and steam power sources is delivered to customers over a complex, reliable transmission and distribution system. To deliver energy from generating plants to the customers, the Department owns and/or operates

approximately 17,700 miles of transmission and distribution circuits operating at voltages ranging from 120 to 1,000,000 volts.

In addition to utilizing its transmission system for its resources located in other states, the Department transmits energy for others through its system when surplus transmission capacity is available. As the operating agent of the Intertie, the Department transmits energy for the co-owners of the Intertie.

For a discussion of the Department's participation in the Mead-Phoenix DC Intertie Project see "Southern California Public Power Authority — Other Activities of the Authority" in the Official Statement to which this Appendix B is attached.

Power System Loads

As with most electric utilities in the United States, the Power System has experienced a marked decline in the rate of load growth since the early 1970s. The annual rate of growth of both system peak demand and net energy for load ("NEL"), the net system energy generated and purchased for Power System customers, was in the range of 7% to 8% for the twenty-year period through 1970. Growth in NEL continued at a slightly lower rate through 1972. In 1974, the Arab oil embargo and resulting mandatory curtailment program reduced the level of NEL to 1970 levels. A portion of this reduction, however, is attributed to the economic recession experienced during that period. Since 1974, the Power System's loads have reflected moderate increases resulting from both increased demand and economic recovery. The growth in the Power System's NEL averaged 2.3% for the period 1975-1988.

The estimated Power System load projection, dated September 1988, for the period through 2005 is summarized in the following table. The projected rate of growth is considerably below that experienced in the 1950s and 1960s. This reflects the modest rate of population growth within the City, the expected impact of higher consumer costs, and the implementation of demand-side management measures over the next twenty years. The variations in the indicated five-year compound growth rates reflect assumptions relative to the impact of conservation measures. The following table also shows the projected generating capacity in megawatts of the Power System through 2005.

Summary of Projected Power Resources and System Loads

	System Peak Demand		System Net Energy for Load			
Calendar Year	MW	Growth Rate(1)	gWh	Growth Rate(1)	Load Factor	Resources (MW)
1990	5,157	—	24,593	—	54.4%	7,443
1995	5,751	2.2%	27,417	2.2%	54.4%	7,575
2000	6,348	1.9%	30,554	2.2%	54.9%	8,281
2005	6,867	1.6%	32,853	1.5%	54.6%	8,904

(1) Five-Year Compound Annual Growth Rate.

Capital Additions and Financing Requirements

The Department's program of planning and construction to satisfy current power requirements and to meet future needs is continually being reviewed, updated and extended. Current estimates indicate that the Department will invest approximately $1,737 million in power generating and distributing facilities in the 5-year period which began July 1, 1988.

Following is a summary of the currently projected Power System capital program for the fiscal years 1988-89 through 1992-93 and the projected external financing requirements over the period.

Summary of Power System Capital Program and External Financing Requirements
(Millions of Dollars)

Fiscal Year ending June 30	Capital Program*	External Financing
1989	$ 354	$ 150
1990	379	235
1991	378	185
1992	326	120
1993	300	80
Total	$1,737	$ 770

* Net of reimbursements.

Major components of the capital program over the 1988-89 through 1992-93 period include the following:

- Transmission system improvements related to required base load generation additions totaling approximately $137 million.
- Capacity increases to the Intertie totaling approximately $28 million.
- Continuing system additions and betterments and load-related distribution system improvements totaling approximately $240 million annually.

Power System Additions

The Power System currently has adequate capacity to take care of its needs in the short-term. It faces a need, however, in the long-term for additional generation capacity to replace existing gas- and oil-fueled units as they reach their useful operating lives, to replace generating units being recalled and to meet the load growth presently expected. Consequently, the Department is engaged in or studying the following projects to provide additional capacity:

White Pine Power Project: The Department, in cooperation with White Pine County, Nevada, the California municipalities of Anaheim, Burbank, Glendale, Pasadena, Riverside, and several Nevada utilities, has begun studies to establish the feasibility of and proceed with the licensing activities necessary for constructing a coal-fired generating station near Ely, Nevada. This project would have a capability of approximately 1,500 MW. It is contemplated that White Pine County would own all, or a major portion of, and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the project. The project participants entered into agreements with White Pine County in the fall of 1980 for the purpose of conducting a feasibility study. The Department's entitlement percentage share for the feasibility study is approximately 39%. White Pine County issued notes in the principal amount of $19,929,000 for such purposes, all but $500,000 principal amount of which has been prepaid. The remaining $500,000 note matures December 31, 1992 and is payable from the proceeds of long- term bonds to be issued by White Pine County or from payments by the participants under such agreements on the basis of entitlement shares. The present commercial operation dates for the 750 MW generating units, if built, are in the mid-1990's.

Devers-Palo Verde #2 Transmission Line: The Department, the Imperial Irrigation District and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton along with the Southern California Edison Company ("Edison"), as project manager, have undertaken studies to

explore the feasibility of constructing a 500 kV AC transmission line. This proposed Devers-Palo Verde #2 transmission line, if built, will parallel the existing Devers-Palo Verde #1 transmission line from the PVNGS to Edison's Devers Substation, which is located west of Desert Hot Springs, California. The Department's participation rights in the proposed project total 30.7%, with an estimated total cost to the participants of $243 million. Edison has scheduled the project for completion in June, 1993.

On December 8, 1988, the California Public Utilities Commission ("CPUC") granted Edison a Certificate of Public Convenience and Necessity for this project. In its decision, the CPUC reserves the right to reevaluate its approval if the proposed Edison — San Diego Gas & Electric Company merger (CPUC Application 8-12-035: FERC Docket No. EC 89-5-000) is consummated or is still pending as of January 1, 1990. The decision notes that there may be no economic benefit from the line for Edison ratepayers if the merger is completed. Pursuant to an agreement with Edison, the Department has the right to construct this transmission line if Edison fails to commence construction before July 1, 1989. It is not clear what effect, if any, the above-described developments will have on the construction of this transmission line or the participation of the above-mentioned utilities.

Sylmar Expansion Project: The Department, the cities of Burbank, Glendale and Pasadena and Edison are participants in the Sylmar Expansion Project ("SEP") which provides an 1,100 MW expansion of the terminal capacity at the AC/DC converter station which is located at Sylmar, California. This project will increase the capacity of the Intertie from 2,000 MW to 3,100 MW. The Department is the project manager for the southern terminal of the Intertie and is responsible for the construction of the SEP. The Bonneville Power Administration ("BPA") is the project manager for the northern terminal and is responsible for a similar expansion at the northern converter station of the Intertie in Oregon. The Department estimates that the cost of the SEP will be $171,000,000. Construction is nearly complete and the SEP is currently in the testing phase. The SEP is anticipated to be completed in February 1989.

Utah-Nevada Transmission Project: Members of the Authority, together with several electric utilities providing service in Utah and Nevada, are considering constructing, owning and operating an electric transmission project to include facilities to be located in Utah and Nevada. This project, if undertaken and built, would be in operation in the mid-1990's. It is anticipated that, to the extent its members participate in and the Authority undertakes this project, the Authority will own and finance a portion of the project on behalf of its participating members, who would purchase transmission service or capability of the project from the Authority.

Long Term Power Purchase: The Department is in the process of consummating a long term system purchase from the Utah Power & Light Company ("Utah") consisting of an amount of capacity and energy equal to the amount of capacity and energy available to Utah from its remaining 4-percent entitlement in IPP. The Department will pay costs associated with Utah's entitlement in IPP, but the Department has not been assigned Utah's entitlement rights.

In addition to the projects described above, the Department is involved in preliminary studies relative to geothermal development and in purchasing electric energy from privately developed cogeneration projects.

Geothermal: In September 1981, the Department bid for and acquired leases from the Bureau of Land Management to develop the geothermal potential on three parcels in the Coso Known Geothermal Resource Area ("KGRA"). The Coso KGRA is located approximately 40 miles south of Lone Pine, in the Owens Valley. Three exploratory wells were drilled during the first half of 1985 to obtain information to assess the quality and viability of the resource. Two of the wells are successful and the third well is used for reinjection. Additional exploratory wells are being permitted. The probable reserves on the Department's leases are currently estimated to be in the 200 to 400 MW range. Development of the leases by outside parties is being considered.

Cogeneration: Cogeneration projects totaling 91 MW nameplate capacity are currently in operation within the Department's service area. Some of these projects are selling excess electric

energy to the Department under negotiated agreements. An additional estimated 160 MW of cogeneration are currently in active development and are expected to be operational by 1990.

Fuel Supply

The Department's Los Angeles Basin normal oil and gas requirements are estimated to range during the period 1988 through 1995 between 8 and 10 million equivalent barrels per year. Natural gas is expected to be available to supply 100% of these requirements during that period. Natural gas is currently supplied to the Department by the Southern California Gas Company; 18% is take-or-pay with the balance on a curtailable basis at the lowest priority level. The Department is developing a natural gas purchasing program to supply up to 50% of its future natural gas needs from independent spot market suppliers.

Although long-term fuel oil requirements are expected to be minimal, natural gas supply curtailments projected for winter 1988-89 will necessitate a fuel oil burn of approximately 3.7 million barrels. The Department has recently approved the purchase of additional fuel oil sufficient to meet this need.

The Department has terminated all long-term fuel oil contracts and expects to supply all requirements from short-term contracts as needed and anticipates no problem in meeting the requirements. The Department's existing fuel oil inventory of 2.5 million barrels can be used to protect the Department during adverse weather conditions. During periods in which the Department's natural gas purchase price exceeds its fuel oil purchase price, the Department has displaced natural gas with fuel oil to the extent possible.

Limitations on the use of natural gas as a utility boiler fuel under the Power Plant and Industrial Fuel Use Act of 1978 were repealed in August 1982. Regulations of the South Coast Air Quality Management District ("SCAQMD") have required the use of fuel oil with no more than a maximum sulfur content of 0.25% by weight. SCAQMD's rules also require the use of all available natural gas on any predicted or attained air pollution episode day. (See also "Environmental and Regulatory Factors", relative to additional limits on the sulfur content of fuel oil.)

Coal-fired steam-generated projects in which the Department has an ownership interest are supplied with coal under contracts.

Water

Water required for steam plant operations is secured from a number of sources. Three Los Angeles Basin steam plants, Harbor, Scattergood and Haynes, utilize the waters of the Pacific Ocean for power plant cooling purposes. A fourth Basin plant, the Valley Generating Station, utilizes groundwater pumped from the San Fernando Valley. The California Supreme Court has upheld the rights of The City of Los Angeles to the native waters of the San Fernando Basin, and to certain other contested water rights.

The Mohave and Navajo Generating Stations utilize water taken from the Colorado River for cooling purposes, the Navajo plant extracts water from Lake Powell, which was created by the construction of the Glen Canyon Dam. The rights to use such waters from the river rest upon the Colorado River compact, the decree of the U.S. Supreme Court in the case of *Arizona v. California*, and upon contracts entered into pursuant to the rights granted by such compact and decree. Certain small Indian tribes have announced claims to additional waters of the Colorado River beyond those granted in the decree, and the Navajo Indian Nation has indicated it will make substantial claims to the waters of the river. In December 1978, the United States and several Indian tribes along the Colorado River asked the United States Supreme Court to reopen the case of *Arizona v. California* to hear their claims of additional water rights over and beyond those previously granted. A Special Master was appointed to hear those claims, and on March 18, 1982 rendered a decision in favor of the Indian tribes. On March 30, 1983, the Supreme Court issued its decision which rejected to a large extent the Master's recommendations that the tribes be awarded additional water rights. However, the court deferred

certain claims to be determined by a lower federal court at a future time. Although the tribes may ultimately prevail on their claims in the future, the Department is confident that these pending matters, even if determined adversely to the Department, do not pose a threat to the operation of the generating stations.

Electric Rates

The Board is obligated by the City Charter and each Final Resolution pursuant to which the Department has issued revenue bonds or notes, to establish electric rates and collect charges in an amount sufficient to service the Department's Power System indebtedness and to meet its expenses of operation and maintenance. Rates are subject to the approval of the City Council by ordinance, but are not regulated by the Public Utilities Commission of California or by any other state agency.

Although its rates are not subject to approval by any federal agency, the Department is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978. The Department is operating in compliance with the Act. Following public hearings, an electric rate increase of 7.8% was effective October 1, 1988.

The Power System's electric rates ordinance contains an energy cost adjustment formula, under which the cost to the Department of fuel for generation of electric energy and purchased energy costs are recovered by direct adjustment to customers' bills.

Emergency Energy Curtailment Plan and Conservation

In 1973 the City Council enacted an Emergency Energy Curtailment Plan which mandated certain designated electricity conservation measures. The implementation of this plan was suspended in 1974 when the Department's fuel situation improved. However, the plan remains as part of the Municipal Code for possible future use. In addition, a revised and supplemented Plan, redesignated the Emergency Energy and Capacity Curtailment Plan of The City of Los Angeles, became effective on June 16, 1981.

The City Charter authorizes the Department to engage in and finance activities related to the conservation of electricity and water.

Operating Statistics

The Department's service area consists of Los Angeles City, where over 1.3 million customers are now served, and certain areas of Inyo and Mono counties in California, where over 4,500 customers are served. In the twelve months ending September 30, 1988, approximately 27% of the total energy sales were to residential customers, 70% to commercial and industrial customers, and the remainder to miscellaneous minor classifications. The portions of operating revenues from the two major customer classes were in the proportions of approximately 28% and 69%, respectively.

Operating Statistics	Twelve Months Ended September 30, 1988	Fiscal Year Ended June 30 1988	1987	1986
Net Energy for Load (Thousands of kWh)	23,867,750	23,701,912	22,792,990	22,262,629
Net Hourly Peak Demand (kW)	4,991,000	4,922,000	4,744,000	4,713,000
Annual Load Factor (%)	54.4	54.8	54.8	53.9
Electric Energy Generation, Purchases and Interchanges (Thousands of kWh)				
Generation (A)	21,221,621	21,475,102	18,784,271	17,103,208
Purchases	3,590,724	2,589,140	4,322,241	5,774,422
Miscellaneous Energy Receipts	80,697	460,549	0	14,750
Total Energy Production (A)	24,893,042	24,524,791	23,106,512	22,892,380

Operating Statistics	Twelve Months Ended September 30, 1988	Fiscal Year Ended June 30 1988	1987	1986
Less:				
Miscellaneous Energy Deliveries	136,669	151,370	92,814	137,803
Losses and System Uses	3,321,665	3,364,430	2,678,055	2,618,656
On-System Sales	21,434,708	21,008,991	20,335,643	20,135,921
Transactions Among Other Utilities for Department (Thousands of kWh)				
Purchases	0	0	0	101,520
Deliveries	0	0	0	101,520
Sales of Energy (Thousands of kWh)				
Residential	5,749,278	5,616,727	5,469,312	5,499,851
Commercial and Industrial	14,987,607	14,847,448	14,258,212	14,097,269
All Other	791,485	641,783	812,889	653,375
Total	21,528,370	21,105,958	20,540,413	20,250,495
Number of Customers — Average:				
Residential	1,121,987	1,116,806	1,092,912	1,078,074
Commercial and Industrial	185,570	184,969	180,245	177,717
All Other	2,832	2,828	2,763	6,181
Total	$ 1,310,389	$ 1,304,603	$ 1,275,920	$ 1,261,972
Operating Revenue(B):				
Residential	$ 447,994,000	$ 430,696,000	$ 388,730,000	$ 379,488,000
Commercial and Industrial	1,106,880,000	1,085,557,000	963,151,000	932,187,000
Street Lighting and Other	44,739,000	39,698,000	38,183,000	37,904,000
Total	1,599,613,000	1,555,951,000	1,390,064,000	1,349,579,000
Miscellaneous Revenues	15,006,000	14,077,000	13,377,000	8,555,000
Total	$1,614,619,000	$1,570,028,000	$1,403,441,000	$1,358,134,000
Average Revenue per kWh Sold:				
Residential	7.79¢	7.67¢	7.11¢	6.90¢
Commercial and Industrial	7.39¢	7.31¢	6.76¢	6.61¢
Average Annual kWh Use per Residential Customer	5,124	5,029	5,004	5,102

(A) Not including energy generated at Hoover Power Plant for plant use, and for the use of the United States Bureau of Reclamation, and the cities of Boulder City, Burbank, Glendale and Pasadena.

(B) Operating revenue amounts for twelve months ended September 30, 1988 are unaudited.

Environmental and Regulatory Factors

Environmental considerations and regulatory restrictions relative to the operation of the Power System's existing facilities, and to the location, design and construction of new facilities, may adversely affect the adequacy of electric service in the future.

The SCAQMD has adopted an "Emergency Episode Plan" ("Plan") which defines three so-called air quality Emergency Episode Stages and requires the Department to submit a plan demonstrating measures it will take during Stage I, Stage II and Stage III episodes. The Plan requires the Department to burn natural gas to the extent available, instead of fuel oil, during Stage I Episodes. During a Stage II or Stage III Episode, the Department must also reduce generation in power plants within the Los Angeles Basin by shifting generation to plants outside the basin to the extent consistent with health, safety and welfare. The Basin has never experienced a Stage III Episode.

In March 1980, the California State Air Resources Board ("ARB") adopted a rule providing for the reduction of emissions of nitrogen oxides ("NOx") from utility power plants in the South Coast Air Basin. The Department intervened in a lawsuit brought by Edison against the ARB challenging this new rule. Subsequently, negotiations among the parties produced a settlement which was implemented through a court ordered judgment on March 10, 1982. The basic terms of the settlement are (i) mandatory rescission of ARB's modified rule, thus avoiding the expenditure by the Department of approximately $257 million, and (ii) compliance by the Department with annual NOx emission limits

as provided in the settlement. The Power System has complied with the limits every year without installing additional NOx control equipment.

In February 1988, the SCAQMD proposed a rule which would require the installation of costly NOx control equipment on utility boilers and would nullify the settlement with the ARB. If adopted, the proposed rule could require the expenditure of up to $100 million per year in compliance costs. The Department is advocating a far less costly alternative in the current rulemaking.

In 1984, the Resources Conservation and Recovery Act and the Toxic Substance Control Act were amended by Congress to be more restrictive on the transportation, use, treatment, storage and disposal of hazardous materials and wastes including actual bans on certain existing hazardous material and waste handling practices. The California Legislature during 1987 and 1988 continued its active support of environmental legislation for the control of hazardous substances. The California State Water Resources Control Board and the State Department of Health Services continued their regulatory efforts to control transportation, treatment, storage, and disposal of hazardous substances. The full fiscal impact on Department operations cannot be determined at this time. Additionally, the Department has budgeted approximately $10 million to address underground storage of hazardous substances and surface impoundments to comply with California and Federal environmental legislation enacted in 1984 and 1985.

The President, in 1986, signed into law the Superfund Amendments and Reauthorization Act. In addition, current efforts by California and Federal agencies to investigate and improve Superfund sites may impact the Department as a result of previous disposal practices. Previously approved disposal methods or sites may become candidates for Superfund classification which may require substantial expenditures by the Department as a participant in the cleanup/remedial action required for the site.

The Service Area

The City of Los Angeles, encompassing an area of 465 square miles, is served exclusively by the Department. As indicated in the following chart, the population of the service area has risen from 102,479 at the turn of the century to an estimated 3.4 million residents as of January 1, 1988 to become the second largest city in the United States and the nucleus of the most populous County, Los Angeles County, in the nation.

Population Trends

Dec. 31 Year	City of Los Angeles	Metropolitan Area (Los Angeles County)
1900	102,479	170,298
1910	319,198	510,131
1920	576,673	936,455
1930	1,238,048	2,208,492
1940	1,504,277	2,785,643
1950	1,970,358	4,151,687
1960	2,481,595	6,042,431
1970	2,809,967	7,040,335
1980	2,968,574	7,477,421
1981	2,994,900	7,562,200
1982	3,011,300	7,630,500
1983	3,064,300	7,761,100
1984	3,105,300	7,861,300
1985	3,173,000	8,027,800
1986	3,251,500	8,246,200
1987	3,315,400	8,418,600
1988	3,361,500	8,555,900

Source: California Department of Finance and United States Bureau of the Census.

Note: For the decennial census years the population is as of April 1 and is from the United States Bureau of the Census while for the years 1981 through 1988 the population is as of January 1 and is from the California Department of Finance.

The U.S. Department of Commerce in the 1982 Annual Census of Manufacturers reported that the number of persons employed in manufacturing constituted about one-fourth of the area's labor force. Value added by manufacturers in 1982 aggregated over $40 billion, ranking the Los Angeles County area as California's largest Standard Metropolitan Statistical Area ("SMSA") in this respect, or 43 percent of the state total, having moved up from fifth place in 1947. During the interval from 1947 to 1982, a net gain of $28.1 billion in value added by manufacturing was achieved.

Los Angeles has important production facilities for most major branches of industry. It is the site of the largest industrial concentration in the Western United States, not only serving the local area and the region, but also participating in the national and international markets. In retail sales Los Angeles ranks second nationally as a city and first as a metropolitan area. With over 810 banks and branches, the Los Angeles SMSA is the leading financial center in the Western United States. The Nation's seven largest savings and loan associations are headquartered in the Los Angeles SMSA. In addition, Los Angeles leads in employment and payrolls of banks, savings and loan associations, insurance carriers and agents, and security and commodity brokers.

Litigation

There is no pending litigation relating to the Power System or the Department's operations or business pertaining thereto, except as hereinafter stated.

(1) An action was filed in the United States District Court for the Central District of California in October 1978 on behalf of black personnel against the Department and International Brotherhood of Electrical Workers, Local Union No. 18, containing broad general allegations of racial discrimination in employment practices, seeking declaratory, injunctive and "make whole" relief and requesting punitive damages and damages for emotional distress. An amended com-

plaint was filed by the plaintiffs which alleges racial discrimination throughout the government of The City of Los Angeles. In June 1981, the District Court limited the class of plaintiffs to those black craft employees of the Department specifically affected by the alleged discrimination and to those who can show that they have been personally damaged. The case was dismissed as to all other plaintiffs. In February, 1983, the District Court consolidated this case with another class action case (*Anderson, et al. v. Department of Water and Power, et al.*) which also alleges racial and ethnic discrimination by the Department, The City of Los Angeles and the Board of Civil Service Commissioners. The named plaintiffs in the latter class action are draftsmen, engineers, and architects who are challenging promotional testing on a Department-wide basis. Injunctive and monetary relief are sought. In May 1985, the class was certified. In March 1986, the plaintiffs' motion for partial summary judgment was denied. A second such motion was filed in November 1986 and was also denied in January 1987. In July 1988, the plaintiffs dismissed the *Anderson* lawsuit without prejudice, and reduced the scope of the *Worthen* action by means of another amended complaint to a declaratory relief action testing the Department's pay and position advancement procedures among clerical employees. The trial is set for April 11, 1989. (*Leon (formerly Worthen) et al. v. Department of Water and Power et al.*)

(2) Commencing in 1977-78, and again in 1984, the Navajo Indian Tribe adopted certain taxes affecting the operation of the Navajo and Mohave Generating Stations and the production of coal to be used at those stations. The generating station participants, including the Department, contested the taxing authority of the Navajo Indian Tribe in federal courts. In connection with renegotiation of the leases for operation of the two generating stations, all major issues involving the taxes have been settled and the renegotiated leases have been approved by the Secretary of the Interior. The settlement has resulted in an increase in the price of coal used to generate electricity from $17 per ton to $19 per ton. This increase has already been incorporated in the Department's energy cost adjustment.

In 1982 and 1983, the Hopi Tribe also adopted ordinances attempting to impose taxes on coal mined on its reservation for use at the two generating stations. However, the Secretary of the Interior, whose approval is required, vetoed the ordinances and no further action has been taken by the Tribe. If the Tribe enacts another such ordinance, it is expected that the participants will oppose it. (*Salt River Project Agricultural Improvement and Power District, et al. v. Navajo Tribe of Indians, et al.*)

(3) In October 1978 a major brush fire burned several homes and other structures in the Mandeville Canyon area of the City. Claims were consolidated in two lawsuits seeking $7.9 million in damages alleging maintenance of a dangerous condition in the operation of overhead electrical transmission lines. A further cause of action arising from the same facts was alleged in inverse condemnation. Trial took place in January and February 1983. On the issue of maintenance of a dangerous condition in the operation of overhead electrical transmission lines, the jury found for the Department. However, under the inverse condemnation theory, the Superior Court of Los Angeles County, ruling without a jury, found for the plaintiffs and granted damages in the amount of $10,600,000, which included prejudgment interest, costs and attorney's fees. Subsequently, the Superior Court also ruled in favor of the plaintiffs on the dangerous condition cause of action, notwithstanding the jury verdict. The Department appealed and obtained a writ from the Court of Appeal of the State of California staying enforcement of the judgment during the appeal. On July 31, 1985, the Court of Appeal affirmed the decision, with the exception of reversing the attorney's fee award. The Department filed a petition for hearing in the California Supreme Court which was denied. Therefore, the only issue which remained to be determined in the case was the question of attorney's fees, and the judgment (except for attorney's fees) has been paid. In November 1986, the Superior Court awarded attorney's fees of $2,116,000 to the plaintiffs. A dispute has arisen over payment of a portion of the attorney's fees and post-judgment interest which the Department contends is payable by those liability insurance companies that provided certain coverage for amounts in excess of $10.2 million at the time of the 1978 fire. The insurers refused to pay the

excess amounts due, and the Department has now filed suit against them. (*Aetna Life and Casualty Company, et al. v. Department of Water and Power, et al.*)

(4) On October 31, 1981, six residences were totally destroyed by fire in the Chatsworth area and, subsequently, damage claims have been received by the Department in an amount in excess of $5.2 million alleging the fire was caused by downed power lines resulting from strong winds. In September 1982 a complaint was filed seeking damages based on allegations of dangerous conditions, and inverse condemnation. Trial commenced in October 1986. In November 1986, the judge issued a preliminary ruling against the Department on inverse condemnation. The jury found in favor of the Department on the dangerous conditions cause of action, removing the potential for mental distress damages. The jury awarded the plaintiffs $1.371 million in damages on the inverse condemnation issue and the Superior Court of Los Angeles County also awarded attorney's fees and pre-judgment interest for a total award of approximately $2.8 million. The Department filed a Notice of Appeal in the California Court of Appeal in May 1987. (*Farrens, et al. v. Department of Water and Power.*)

(5) A petition for injunction and declaratory relief was filed in Superior Court of Mono County, seeking to require the Department's water diversions from four streams in the Mono Basin to cease or to be substantially decreased until such time as the water level in Mono Lake — a saline lake — reaches a higher level. About 15% to 20% of the City's water comes from the Mono Basin diversions, and if the plaintiffs were to prevail, there would be a decrease of hydroelectric generation capability. On a Department motion, the case was transferred to the Superior Court of Alpine County, and the Department filed an answer denying the allegations of the complaint. The Department has cross-complained against a number of parties, including the United States of America and the State of California, asserting water rights in the Mono Basin. Following a removal of the case to the federal courts, the non-federal causes of action were remanded to the state court system.

The State of California, joined by the Department, moved for summary judgment which motion was granted. The plaintiffs petitioned the California Supreme Court to review the lower court's decision and on February 17, 1983, the California Supreme Court issued an opinion which held that the plaintiffs could challenge the Department's existing water rights based upon the "public trust doctrine". The California Supreme Court's decision does not now limit any of the Department's water rights; however, it calls for a further hearing to weigh the interests of Mono Basin under the public trust doctrine against the City's needs which are served by the appropriative water rights system. This subsequent hearing or adjudication will result in a decision which could result in all, some or none of the City's water rights in the Mono Basin being curtailed. The plaintiffs moved in United States District Court for the Eastern District of California for an injunction to require the Department to maintain the lake level at 6,378 feet until August 1984, pending a resolution of the action. The present level is above that height. That motion for injunctive relief was held in abeyance while the District Court considered separate motion by the Department to remove the proceedings back to the Superior Court of Alpine County. In December 1984, the District Court issued a ruling removing all of the proceedings back to the Superior Court in Alpine County, except for an alleged federal common law nuisance for air pollution which it indicated it would retain. In October 1988, the United States Court of Appeals for the Ninth Circuit affirmed the removal of the proceedings to the Superior Court and held that the plaintiffs could not state a cause of action in federal court for common law nuisance based on air or water pollution.

In related matters that could also affect power generation from the Mono Basin, there are four lawsuits that have been filed that seek water releases below the Department's points of diversion on the Mono Basin creeks. The Department annually diverts approximately 100,000 acre feet per year (140 cfs) from the Mono Basin for water supply purposes and power generation purposes along the Aqueduct to Los Angeles. Any water required to be maintained in the four Mono Basin creeks diverted by the Department below the diversion dams is lost for both water supply and

power generation purposes. All of the following actions challenge the Department's continued right to divert the full flow of the four creeks:

(a) *Dahlgren, et al. v. Department of Water and Power.* This action, filed in November of 1984, in the Superior Court of Mono County seeks to have public trust balancing on Rush Creek resources below the Department's point of diversion. It also seeks to have mandatory fish flow releases below the diversion works dam. A preliminary injunction was issued in the action requiring the Department to release some 19 cfs below the diversion works pending trial. Currently, the case is off calendar pending the results of certain studies to be jointly carried on by the Department and the California Department of Fish and Game.

(b) *National Audubon Society v. State Water Resources Control Board* (the Department is the real party in interest) and *California Trout, Inc. v. State Water Resources Control Board* (the Department is the real party in interest). Both of these cases seek a writ of mandate to compel the State Board to revoke the City's licenses to divert waters of Lee Vining, Walker, Parker and Rush Creeks and not to reissue such licenses until the State Board establishes minimum fish flows below the diversion works on each of these creeks as allegedly required by the California Fish and Game Code. The *California Trout* action also seeks similar fish flow release for the Owens Gorge portion of the Owens River. These actions were heard in the Superior Court of Mono County in April of 1986 and both of the petitions for writ of mandate were denied. The plaintiffs sought appellate review of this trial court decision, and the appeal was briefed and argued before the California Court of Appeal. In February 1988, the California Court of Appeal ordered the case resubmitted due to its complexity.

In May 1988, the Court of Appeal reversed the lower court and ordered the Superior Court to issue a writ of mandate to the State Water Resources Control Board to conduct proceedings for revocation of the Department license to divert Mono Basin Creek water subject to be reissued if water for fish flow is maintained. The Department's petition for rehearing was granted and the Court of Appeal has now vacated the May 1988 decision. In January 1989 the Court of Appeal issued a new opinion ordering the Superior Court to mandate the State Water Resources Control Board to conduct proceedings to determine the water flow necessary below dams in the four creeks in Mono Basin to maintain fisheries. The Court of Appeal eliminated the Owens Gorge flow from consideration. Petition for review by the California Supreme Court is under consideration. (Two cases consolidated for hearing in the Court of Appeal on petition for mandate under *California Trout, Inc. v. Superior Court, Mono County.*).

(c) *Mono Lake Committee v. City of Los Angeles, et al.* This action, filed in August of 1986, is based upon the same legal theories as the *Dahlgren* case above, except that it seeks release on Lee Vining Creek, another of the creeks tributary to Mono Lake. A temporary restraining order required the Department to release 10 cfs down Lee Vining Creek below the diversion works. After a hearing, the Superior Court of Mono County issued a preliminary injunction requiring the Department to release approximately 4 cfs into lower Lee Vining Creek pending trial of the matter.

(6) A dispute with the State of California and other utilities over the contracts to supply the State Water Project with surplus electrical energy arose out of the continuing escalation of the price of fuel oil during the contract term. In 1979, the Department notified the State and other utilities of its intention to end its participation due to the commercial impracticability of continuing to provide the low-cost energy. In 1980, Southern California Edison Company and Pacific Gas & Electric Company brought lawsuits alleging breach of contract, with the former obtaining a preliminary injunction to prevent cessation of service pending the outcome of trial. The issuance of the injunction was conditioned on the plaintiffs posting a \$14 million bond; however, the plaintiffs subsequently stipulated with the Department to indemnify the Department in the event of a decision in the Department's favor without further posting of bond being required. The State of California has intervened in the lawsuit. The contract terminated on March

31, 1983. In early 1985, a motion for summary judgment was filed by the San Diego Gas & Electric Company (a co-defendant in the action) on the grounds that the case was moot, since the contract was terminated in 1983. That motion was denied. If the Department prevails in the lawsuit, it will be entitled to seek additional payment for providing the low-cost energy. The Board of Water and Power Commissioners and the City Council have approved settlement of the lawsuit which settlement has been approved by the Federal Energy Regulatory Commission ("FERC") and FERC has dismissed the entire action with prejudice. *(Southern California Edison Co.* v. *Department of Water and Power, et al.,* and *Pacific Gas & Electric Co. v. Department of Water and Power, et al.)* (2 cases)

(7) The Department is a party defendant in the action entitled *Salt River Pima-Maricopa Indian Community v. United States, et al.* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(8) The Department is a party defendant in the action entitled *A Tumbling T Ranches, et al. v. City of Phoenix, et al.* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(9) The Bonneville Power Administration (the "BPA") has acted in recent years to increase significantly the price of electric power and energy sold to its customers. The Department, together with other California cities, the California Public Utilities Commission and the California Energy Commission ("California Parties") has intervened in proceedings before FERC and has challenged the rate-setting methods used by the BPA in determining rate increases. FERC has determined it has certain limited jurisdiction to review the rate actions of the BPA. However, the BPA questioned the jurisdiction of FERC to decide certain issues and brought the matter before the United States Court of Appeals for the Ninth Circuit, the court of original jurisdiction for FERC review. On February 9, 1984, the Ninth Circuit upheld the determination of FERC regarding FERC's jurisdiction but ruled that the Ninth Circuit lacks jurisdiction to review FERC's interim approval of the BPA 1981 and 1982 non-regional rates. An administrative law judge for FERC rendered a decision in January 1985 on the 1981 rates essentially supporting the BPA decisions. A brief of exceptions has been filed by the California Parties. However, no final decision has yet been rendered by FERC. The Department has also challenged the setting of the 1983 and 1985 BPA rate before an administrative law judge of FERC. In addition, the Department has filed an action, together with other California utilities, against the BPA, in the United States District Court for the District of Columbia, challenging the ruling by FERC regarding a 1979 rate increase by the BPA. In May 1986, the Department filed an action in the United States Court of Appeals for the Ninth Circuit challenging BPA's reopening and changing of the 1985 rates without compliance with the hearing requirements of the Pacific Power Planning and Conservation Act. In April 1987, FERC ruled that the costs of construction, maintenance and decommissioning of the Washington Public Power Service nuclear plant could be passed on to the California utilities. This ruling affects the 1981-82 rates of BPA. FERC also ruled relative to the 1983 rates that there was no statutory prohibition against undue discrimination by BPA and further, that access to BPA transmission lines was not a rate issue and therefore FERC had no jurisdiction to decide it. In each of the rate proceedings, the Department has paid the interim BPA rates and seeks refunds based on the respective challenges. *(Central Lincoln People's Utility District v. Johnson, et al.* and *Department of Water and Power, et al. v. BPA.)*

(10) See "Litigation" in the Official Statement for a description of certain litigation, entitled *Thurston et al. v. Southern California Public Power Authority et al.*, concerning the Department's participation in the Southern California Public Power Authority interest in the Palo Verde Project.

(11) A lawsuit was filed in August 1982 by the State of Nevada in the United States District Court for the District of Nevada against the United States, the Western Area Power Administration and the California allottees of power from Hoover Dam seeking declaratory and injunctive relief, the principal aim of which is to obtain a declaration that the State of Nevada is entitled to one-third of the total electrical output of Hoover Dam from and after June 1, 1987 for a period of 50 years. The Department and other California allottees of Hoover Dam power who received 65%

of such power intend to resist vigorously this claim of the State of Nevada. The State of Arizona has intervened in this case, making a similar claim to that of the State of Nevada. A motion to intervene in the lawsuit filed by the California cities of Anaheim, Azusa, Banning, Colton and Riverside was granted. The litigation was placed off calendar and the parties entered into negotiations which culminated on August 17, 1984, when the President signed into law the Hoover Power Plant Act of 1984 in which a settlement of the above litigation was approved by Congress. The electric service contracts with all the allottees have now been executed, and the lawsuit has been dismissed. *(Nevada v. United States, et al.)*

(12) The Department is a party defendant in the action entitled *Long et al. v. Salt River Project, et al.* and *City of Phoenix, et al. v. John F. Long* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(13) In February 1986, litigation was initiated in the United States District Court for the District of Oregon by ASEA, Inc. ("ASEA"), the contractor for the design and construction of the AC/DC converter stations of the Southern Transmission System, against two of its subcontractors, CH2M Hill, Inc. and CH2M Hill Northwest, Inc., ("CH2M Hill Corporations") alleging that fraud and breaches of contract by such subcontractors damaged ASEA in connection with the Project as well as in connection with work that ASEA had separately contracted to perform for the Department at the Sylmar Converter Station, the southern terminus of the Intertie.

The CH2M Hill Corporations filed an answer and counter-claim against ASEA and its parent corporation, ASEA, A.B., alleging, among other things, that any injury so suffered by ASEA relating to the Project resulted from various acts including the decision to change the planned Southern Transmission System from a double bipole to a single bipole system. The CH2M Hill Corporations then filed a motion seeking to join the Department as a third-party defendant in this litigation. *(ASEA, Inc. v. CH2M Hill Northwest, Inc. et al.)*

ASEA was the prime contractor for IPA on a contract for about $270 million for the design and construction of converter stations for the Southern Transmission System portion of the IPP. The Department was the administrator of such contract for IPA. ASEA was also the prime contractor for the Sylmar Converter Station in connection with the upgrade of the Intertie. The defendants named in the Oregon District Court action, CH2M Hill Corporations, were subcontractors of ASEA in connection with both such contracts.

Shortly after the suit was filed, CH2M Hill, Inc. filed with the Department's Commission a claim for indemnity for its liability to ASEA as alleged in the District Court of Oregon, in an amount in excess of $24 million. Investigations of the claim by the Department disclosed that ASEA and CH2M Hill, Inc. may be liable to the Department and to IPA for compensatory damages in excess of $85 million and punitive damages of $50 million, and that ASEA sought in the Oregon District Court action to be reimbursed by its subcontractors for claims by IPA and the Department. Accordingly, the claim filed with the Department was rejected. An action was commenced by the Department on May 30, 1986, in the United States District Court for the Central District of California to recover such damages from ASEA and CH2M Hill, Inc. An additional related action was filed against IPA by ASEA in the United States District Court in Utah, and IPA has counterclaimed for damages in that action. In addition, CH2M Hill, Inc. has filed a third party complaint naming the Department as a defendant in the Oregon District Court action. As a consequence, the Department filed a motion with the Judicial Panel on Multidistrict Litigation to have the cases consolidated for pretrial in the United States District Court for the Central District of California which motion was granted. All cases have now been consolidated. A settlement agreement has been executed among IPA, ASEA and the Department. IPA and the Department have agreed to pay ASEA $9 million for contractor's work performed by ASEA (including interest and escalation) and $3.3 million in interest and escalation on late payments paid by IPA. Such payments were made in December 1987. ASEA, in return, has agreed to perform the contract work in question and fully indemnify IPA, the Department and the City of Los Angeles against all claims

Power System Summary of Financial Operations

	Twelve Months Ended September 30, 1988 (Unaudited)	Fiscal Year Ended June 30 1988	1987	1986
Operating Revenues				
Sales of Electric Energy:				
Residential	$ 447,994,000	$ 430,696,000	$ 388,730,000	$ 379,488,000
Commercial and Industrial	1,106,880,000	1,085,557,000	963,151,000	932,187,000
Street lighting and other	44,739,000	39,698,000	38,183,000	37,904,000
Miscellaneous	15,006,000	14,077,000	13,377,000	8,555,000
Total Operating Revenues	1,614,619,000	1,570,028,000	1,403,441,000	1,358,134,000
Operating Expenses				
Production:				
Fuel	245,815,000	228,499,000	219,944,000	348,069,000
Purchased power	491,513,000	470,957,000	355,975,000	203,116,000
Energy Cost	737,328,000	699,456,000	575,919,000	551,185,000
Other Production	42,824,000	41,348,000	38,279,000	37,452,000
Transmission and distribution	84,762,000	83,714,000	75,472,000	63,300,000
Maintenance	157,999,000	153,062,000	147,673,000	142,461,000
General	110,541,000	108,014,000	89,221,000	98,938,000
Less — Expenses charged to construction	(15,868,000)	(14,478,000)	(12,344,000)	(10,038,000)
Customer accounting	35,709,000	34,768,000	34,979,000	33,831,000
Customer services	6,007,000	5,806,000	3,926,000	3,456,000
Taxes on property outside the City	12,521,000	12,343,000	8,552,000	8,660,000
Contributions to retirement plan funds	87,534,000	88,215,000	92,198,000	79,800,000
Less — Contributions charged to construction	(20,233,000)	(20,511,000)	(22,323,000)	(17,785,000)
Total Operating Expenses (except Depreciation)	1,239,124,000	1,191,737,000	1,031,552,000	991,260,000
Operating Income before Depreciation	375,495,000	378,291,000	371,889,000	366,874,000
Allowance for funds used during construction	5,916,000	5,674,000	7,759,000	3,610,000
Other Income — net	18,166,000	18,037,000	19,754,000	27,984,000
Income before Depreciation and Interest	399,577,000	402,002,000	399,402,000	398,468,000
Debt Service				
Interest	103,058,000	101,669,000	96,139,000	96,784,000
Principal	68,116,000	67,916,000	61,526,000	84,996,000
Total Debt Service on bonds	171,174,000	169,585,000	157,665,000	181,780,000
Balance	228,403,000	232,417,000	241,737,000	216,688,000
Transfers to the City	72,256,000	70,182,000	67,913,000	64,353,000
Balance Available for Construction	$ 156,147,000	$ 162,235,000	$ 173,824,000	$ 152,335,000
Depreciation	$ 128,910,000	$ 124,004,000	$ 115,629,000	$ 107,419,000

with CH2M Hill, Inc. All parties have released claims related to this matter against each other. *(Department of Water and Power* v. *ASEA Inc.; ASEA Inc. v. CH2M Hill, Inc.; ASEA Inc.* v. *IPA).*

(14) In June 1985, an explosion at the Mohave Generating Station destroyed the control room and caused the deaths of several Mohave employees. The Department holds a 20% share pursuant to the Mohave Operating Agreement (the "Agreement") and would be liable for that portion of any settlement or judgment. Pursuant to the Agreement, Southern California Edison Company, the Project Manager, had obtained insurance for the participants covering up to a maximum of $30 million with a self-insured residual of $2 million (The Department's 20% share of which would be $400,000). The Department has received more than 30 claims from over 50 individuals and corporations seeking in excess of $70 million. The participants allege that they are immune from civil liability to the employees as employers pursuant to the workers compensation laws of California and Nevada. The Mohave participants are proceeding against the manufacturers for property damage in the amount of $123 million and indemnity. Litigation has commenced related to this incident. *(Russell C. Allen* v. *Bechtel Power Corp.)*

(15) The participants in the Palo Verde Nuclear Generating Station brought suit in the United States District Court for the District of Arizona seeking significant monetary damages for breach of contract by Combustion Engineering Incorporated because of the failure of a backup water supply system, which needed to be redesigned, resulting in delay of completion of the project. Combustion Engineering has cross-complained for significant monetary damages. The case has not yet been set for trial. *(Arizona Public Service Co., et al.* v. *Combustion Engineering Inc.)*

(16) Other claims and suits arising out of the ownership and operation of the Power System of the Department are pending against the Department for alleged deaths, personal injuries and property damage, and for alleged liabilities arising out of other matters, all of which are of a nature usually incident to the conduct of such a utility business. Until these claims and suits are disposed of, the Department's liability, if any, in these matters cannot be determined. Realistic evaluation of total exposure is complicated by the fact that California courts have adopted the rule of pure comparative negligence.

Financial

The following Summary of Financial Operations and Summary Balance Sheet have been prepared by the Department based upon audited financial statements and accounting records of the Power System for the fiscal years ended June 30, 1986 through 1988, and upon unaudited financial statements and accounting records for the twelve months ended September 30, 1988.

Under the provisions of the Charter of The City of Los Angeles, revenues of the Power System are deposited into the Power Revenue Fund. The Fund receives all revenues from the sale of power and all other commodities and services sold, furnished or supplied by the Department through its ownership, operation and management of all properties and facilities constituting the Power System, including all additions and betterments, and represents the source of payment, without priority, of all bonded indebtedness of the Power System, the necessary expenses of operating and maintaining the Power System, and all other obligations and indebtedness payable out of such Fund.

Power System Summary Balance Sheet

ASSETS

	September 30, 1988 (Unaudited)	June 30, 1988	June 30, 1987
Utility plant, at original cost, less accumulated provision for depreciation and amortization	$3,365,033,000	$3,324,924,000	$3,133,454,000
Current assets	691,984,000	579,824.000	567,353,000
Total	$4,057,017,000	$3,904,748,000	$3,700,807,000

CAPITALIZATION AND LIABILITIES

	September 30, 1988 (Unaudited)	June 30, 1988	June 30, 1987
Equity	$1,931,789,000	$1,890,526,000	$1,771,674,000
Long-term debt, excluding advance refunding bonds and portion due within one year	1,549,842,000	1,554,170,000	1,408,914,000
Current liabilities	575,386,000	460,052,000	520,219,000
Total	$4,057,017,000	$3,904,748,000	$3,700,807,000

Bonded indebtedness payable from the Power Revenue Fund as of September 30, 1988 was comprised of 54 issues of Electric Plant Revenue Bonds. The principal amount of the total bonded indebtedness outstanding at February 1, 1989 totaled $1,689,155,000.

In February and March 1981, the Department issued its first Electric Plant Short-Term Revenue Certificates. At February 1, 1989, $90,000,000 principal value of such certificates were outstanding.

Set forth on the following pages are the most recent financial statements of the Power System.

Report of Independent Accountants

Price Waterhouse
Simpson & Simpson

Los Angeles, California

August 31, 1988

To the Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles

In our opinion, the accompanying balance sheet and the related statements of income and retained income reinvested in the business and of cash flows present fairly, in all material respects, the financial position of the Power System of the Department of Water and Power of the City of Los Angeles at June 30, 1988, and the results of its operations and its cash flows for each of the two years in the period ended June 30, 1988, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Department's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

Price Waterhouse
Simpson & Simpson

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

STATEMENT OF INCOME

(In Thousands)

	Twelve Months ending September 30, 1988 (Unaudited)	Year ended June 30 1988	Year ended June 30 1987
Operating Revenues			
Residential	$ 447,994	$ 430,696	$ 388,730
Commercial and industrial	1,106,880	1,085,557	963,151
Other	59,745	53,775	51,560
Total operating revenues	1,614,619	1,570,028	1,403,441
Operating Expenses			
Fuel for generation	245,815	228,499	219,944
Purchased power	491,513	470,957	355,975
Energy costs	737,328	699,456	575,919
Other operation	331,276	326,876	299,408
Maintenance	157,999	153,062	147,673
Depreciation	128,910	124,004	115,629
Taxes on property outside the City	12,521	12,343	8,552
Total operating expenses	1,368,034	1,315,741	1,147,181
Operating Income	246,585	254,287	256,260
Other income — net	18,166	18,037	19,754
Income before debt expenses	264,751	272,324	276,014
Debt Expenses			
Interest on debt	103,831	102,437	96,926
Allowance for borrowed funds used during construction	(5,916)	(5,674)	(7,759)
Total debt expenses	97,915	96,763	89,167
Net Income	$ 166,836	$ 175,561	$ 186,847

STATEMENT OF RETAINED INCOME REINVESTED IN THE BUSINESS

Balance at beginning of year	$1,729,562	$1,680,322	$1,561,388
Net income for the year	166,836	175,561	186,847
	1,896,398	1,855,883	1,748,235
Less — Payments to the reserve fund of the City	72,256	70,182	67,913
Balance at end of year	$1,824,142	$1,785,701	$1,680,322

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

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

BALANCE SHEET

(In Thousands)

ASSETS	September 30, 1988 (Unaudited)	June 30, 1988
Utility Plant, at original cost		
Production	$1,748,703	$1,749,777
Transmission	563,479	561,178
Distribution	1,882,595	1,845,703
General	287,864	284,625
	4,482,641	4,441,283
Less — Accumulated depreciation	1,384,674	1,356,344
	3,097,967	3,084,939
Construction work in progress	244,703	215,435
Nuclear fuel, at amortized cost	22,363	24,550
Net utility plant	3,365,033	3,324,924
Current Assets		
Deposits with City Treasurer	172,705	179,170
Customer and other accounts receivable, less $2,500 allowance for losses	157,961	143,310
Receivable from Intermountain Power Project	94,573	—
Accrued unbilled revenue	103,015	88,782
Materials and supplies, at average cost	73,475	74,663
Fuel for generation	57,076	56,123
Prepayments and other current assets	33,179	37,776
Total current assets	691,984	579,824
Total assets	$4,057,017	$3,904,748

CAPITALIZATION AND LIABILITIES

Capitalization		
Equity		
Retained income reinvested in the business	$1,824,142	$1,785,701
Contributions in aid of construction	107,647	104,825
	1,931,789	1,890,526
Long-term debt	1,549,842	1,554,170
Total capitalization	3,481,631	3,444,696
Current Liabilities		
Long-term debt due within one year	52,845	53,545
Revenue certificates	90,000	90,000
Accrued interest	38,581	30,648
Accounts payable and accrued expenses	223,028	212,380
Over-recovered energy costs	57,382	57,552
Extension and other deposits	18,977	15,927
Other deferred credits	94,573	—
Total current liabilities	575,386	460,052
Commitments and Contingencies		
Total capitalization and liabilities	$4,057,017	$3,904,748

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

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

STATEMENT OF CASH FLOWS

(In Thousands)

	Twelve Months ending September 30, 1988 (Unaudited)	Year ended June 30 1988	Year ended June 30 1987
Cash Flows From Operating Activities:			
Net income	$ 166,836	$ 175,561	$ 186,847
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	140,720	135,558	125,734
Amortization of nuclear fuel	8,029	7,516	5,936
Allowance for borrowed funds used during construction	(5,916)	(5,674)	(7,759)
Changes in current assets and liabilities:			
Customer and other accounts receivable	(1,163)	(3,023)	(244)
Receivable from Intermountain Power Project	(94,573)	—	—
Accrued unbilled revenue	(4,895)	(4,247)	(806)
Materials and supplies	(6,821)	(11,654)	(1,189)
Fuel for generation	10,061	9,774	(4,078)
Deferred energy costs	4,464	8,928	17,856
Prepayments and other current assets	2,684	(7,509)	(18,659)
Accrued interest	3,962	4,191	(47)
Accounts payable and accrued expenses	3,636	(30,593)	(72,546)
Over-recovered energy costs	(27,210)	(15,644)	3,935
Extension and other deposits	1,369	(3,750)	2,228
Other deferred credits	94,573	—	—
Net cash provided by operating activities	295,756	259,434	237,208
Cash Flows From Financing Activities:			
Sale of revenue bonds	99,013	198,108	—
Sale of advance refunding bonds	—	—	47,312
Contributions in aid of construction	13,875	13,473	6,644
Reduction of long-term debt	(67,416)	(67,223)	(60,835)
Amount deposited in escrow account and offset against advance refunding bonds	—	—	(47,312)
Payments to the reserve fund of the City	(72,256)	(70,182)	(67,913)
Net cash provided by (used in) financing activities	(26,784)	74,176	(122,104)
Cash Flows From Investing Activities:			
Expenditures for plant and equipment	(347,256)	(328,870)	(313,465)
Deposits with City Treasurer:			
Net increase (decrease)	(78,284)	4,740	(198,361)
Beginning of year	250,989	174,430	372,791
End of year	$ 172,705	$ 179,170	$ 174,430
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$ 101,162	$ 100,435	$ 98,358

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

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

NOTES TO FINANCIAL STATEMENTS

(Data subsequent to June 30, 1988 are unaudited)

Note A — Summary of Significant Accounting Policies

The Department — The Department of Water and Power of the City of Los Angeles exists under and by virtue of the City Charter enacted in 1925 as a separate proprietary agency of the City. The Power System is responsible for the generation, transmission and distribution of electric power for sale in the City.

Financial statement presentation — The financial statements of the Power System are presented in conformity with generally accepted accounting principles, and substantially in conformity with accounting principles prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission except for the method of accounting for contributions in aid of construction described below. The Department is not subject to regulations of such commissions.

Utility plant — The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions and certain administrative and general expenses. Repairs and minor replacements are charged to maintenance expense. The original cost of property retired, plus removal cost, less salvage, is charged to accumulated depreciation.

Allowance for funds used during construction (AFUDC) — AFUDC represents the cost of borrowed funds used for the construction of new facilities. AFUDC is capitalized as part of the cost of utility plant and is credited to income as a reduction of debt expenses, but does not represent cash earnings. The average AFUDC rates were 7.7%, 7.9% and 8.8% for twelve months ending September 30, 1988, fiscal years 1988 and 1987, respectively.

Depreciation — Depreciation expense is computed by the straight-line method for all major projects completed after July 1, 1973 and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to this date is provided by the 5% sinking fund method based on estimated service lives. Depreciation provision as a percentage of average depreciable plant was 3.3%, 3.2% and 3.2% for twelve months ending September 30, 1988, fiscal years 1988 and 1987, respectively.

Nuclear fuel — Nuclear fuel is amortized and charged to Fuel for Generation in the Statement of Income on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the Department is charged one mill per kilowatt-hour on its share of electricity produced by the Palo Verde Nuclear Generating Station. The Department records this charge as a current year expense.

Nuclear decommissioning — Decommissioning of the Palo Verde Nuclear Generating Station, in which the Power System has an ownership interest, is projected to start sometime after 2027. The Power System is providing for its share of the estimated future decommissioning costs over the life of the nuclear power plant through annual charges to expense.

A Nuclear Decommissioning Fund has been established. The semi-annual deposits to the fund plus the interest earnings on the fund balance are expected to be sufficient to pay the Department's share of decommissioning costs.

Deposits with City Treasurer — Deposits with the City Treasurer included $149 million and $167 million at September 30, 1988 and June 30, 1988 which were invested in short-term securities under the

City Treasurer's pooled investment program, whereby available funds of the City and its independent operating departments are invested on a combined basis. These investments are valued at cost, which approximates market.

Fuel for generation — Coal inventories are stated at average cost. Fuel oil inventories are stated at cost, using the last-in, first-out method.

Contributions in aid of construction — Under the provisions of the City Charter, amounts received from customers and others for constructing utility plant are combined with retained income reinvested in the business to represent equity for purposes of computing the Power System's borrowing limits. Accordingly, contributions in aid of construction are shown in the accompanying balance sheet as an equity account and are not offset against utility plant. Depreciation for the related utility plant is expensed.

Revenues — Revenues consist of billings to customers for consumption of electric energy and include amounts resulting from an energy cost adjustment formula designed to permit the full recovery of energy costs. The Department projects these costs to establish the energy cost recovery component of customer billings and any difference between billed and actual energy costs, resulting in over- or under-recovery of energy costs, is adjusted in subsequent billings.

The Power System recognizes energy costs in the period incurred and accrues for estimated unbilled revenues for energy sold but not billed at the end of a fiscal year.

The Power System's rates are established by rate ordinance approved by the City Council. The Power System sells electric energy to other Departments of the City at regular rates provided in the ordinance.

Shared operating expenses — The Power System shares certain administrative functions with the Department's Water System. Generally, the costs of these functions are allocated on the basis of benefits provided to the Systems.

Debt expenses — Debt premium, discount and issue expenses are deferred and amortized to income over the lives of the related issues.

Statement of Cash Flows — During the year ended June 30, 1988, the Department implemented Statement of Financial Accounting Standards No. 95, "Statement of Cash Flows". Accordingly, fiscal year 1987 amounts have been restated to conform with the fiscal year 1988 presentation.

Note B — Revenue Certificates

At September 30, 1988 and June 30, 1988, the average interest rate of revenue certificates payable was 5.3% and 4.9% with various maturities of up to 154 and 242 days, respectively. The Department has an unsecured standby line of credit of $90 million which may be used if the certificates cannot be refinanced as they mature.

Note C — Jointly-owned Utility Plant

The Power System has an undivided interest in several electrical generating stations and transmission systems which are jointly-owned with other utilities. Each project participant has provided its portion of the total construction financing. The Power System's proportionate share of construction and improvement costs is included in its balance sheet at September 30, 1988 as follows (dollar amounts in millions):

Projects	Department Ownership Interest	Department Share of Capacity (megawatts)	Plant In Service Cost	Accumulated Depreciation	Construction Work In Progress
Palo Verde Nuclear Generating Station (Note G)	5.7%	209	$490	$ 22	$ 2
Navajo Steam Generating Station	21.2%	477	180	67	3
Mohave Coal Generating Station	20.0%	316	75	21	8
			745	110	13
Pacific Intertie DC Transmission System	40.0%	800	99	13	34
Other transmission systems	Various	—	69	14	1
			168	27	35
			$913	$137	$ 48

The Power System will incur certain minimum operating costs on the jointly-owned facilities, regardless of the amount of energy generated or the ability to take delivery of its share of energy generated. The proportionate share of these expenses is included in the appropriate categories of operating expenses.

Note D — Long-term Debt

Long-term debt outstanding at September 30, 1988, consisted of revenue bonds and notes due serially in varying annual amounts through 2028. Interest rates, which vary among individual maturities, averaged approximately 6.6% and 6.7% at September 30, 1988 and June 30, 1988. The revenue bonds generally are callable ten years after issuance. Scheduled annual principal maturities during the five years succeeding June 30, 1988 are $54 million, $52 million, $53 million, $55 million and $56 million, respectively.

In fiscal year 1987, the Power System sold advance refunding bonds totaling $48 million. Until the bonds to be refunded are called, interest on the advance refunding bonds is payable from interest earned on securities of the United States government purchased out of the proceeds of the sales and held in an escrow account with Citibank, N.A., New York. At September 30, 1988, $48 million of this escrow account has been offset against the advance refunding bonds in the accompanying balance sheet (during the twelve months ending September 30, 1988, there were no refunded bonds redeemed). After the monies in the escrow account are applied to redeem the bonds to be called, principally in 1994, interest on the advance refunding bonds will be payable from Power System revenues.

Note E — Shared Operating Expenses

Operating expenses shared with the Water System were $241 million, $256 million and $235 million for twelve months ending September 30, 1988, fiscal years 1988 and 1987, of which $168 million, $167 million and $153 million were allocated to the Power System.

Note F — Employee Benefits

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. Plan benefits are generally based on years of service, age at retirement and the employees' highest 12 consecutive months of salary before retirement. The

Department funds retirement plan costs on a level premium actuarial method as determined by the plan's independent actuary. For funding purposes, prior service costs relating to the plan are amortized generally over a 30-year period ending June 20, 2003.

The Power System was allocated approximately 76% of the plan's total costs for fiscal year 1987, and 74% for fiscal year 1986 amounting to $102 million and $91 million, respectively. As of June 30, 1987, the actuarially computed present value of accumulated retirement plan benefits attributable to the Power System aggregated $1,233 million, discounted at 8%, of which substantially all were vested.

In fiscal year 1988, the Department adopted the provisions of Statement of Financial Accounting Standards No. 87, "Employers' Accounting for Pensions". The adoption of this statement did not materially affect the Department's results of operations. As required by the new standard, retirement cost is determined using the projected unit credit actuarial cost method. Total benefit plan costs for fiscal year 1988 for the Power System include the following (amounts in millions):

Service cost	$ 35
Interest cost on projected benefit obligation	120
Actual return on plan assets	(31)
Net amortization and deferral	(37)
Net retirement plan cost	87
Disability and death benefit plan costs and administrative expenses	12
Total Benefit Plan Costs	$ 99

The plan's funded status at June 30, 1988 allocated to the Power System is as follows (amounts in millions):

Actuarial present value of benefit obligations:	
Vested benefits	$1,300
Non-vested benefits	5
Accumulated benefit obligation	1,305
Projected future compensation amount	227
Projected benefit obligation	1,532
Plan assets at fair value	1,163
Projected benefit obligation in excess of plan assets	369
Unrecognized net gain and effects of changes in assumptions	25
Unamortized net obligation at adoption of FAS 87	(322)
Accrued pension liability	$ 72

The projected benefit obligation at June 30, 1988 was determined using a discount rate of 8.25% and an assumed rate of increase in future compensation of 6%. The 1988 pension cost was determined using a long-term rate of return on plan assets of 8%. Plan assets consist primarily of corporate and government bonds, common stocks, mortgaged-backed securities and short-term investments.

In addition to the retirement plan, the Department provides certain health care benefits to active and retired employees. Health care costs are expensed as paid under a self-insured plan. The cost of providing such benefits to retired employees, net of employee contributions, amounted to $9 million and $7 million for fiscal years 1988 and 1987, respectively.

Note G — Commitments and Contingencies

Payments to the reserve fund of the City — Under the provisions of the City Charter, the Power System transfers funds at its discretion to the reserve fund of the City. Such payments are not in lieu of taxes and are recorded as distributions of retained income. The Department expects to make payments of $78 million in fiscal year 1989 from the Power System to the reserve fund of the City.

Long-term purchased power and transmission contracts — The Department has entered into a number of energy and transmission service contracts which involve substantial commitments. These include an agreement with the Intermountain Power Agency (IPA), a Utah State Agency, for purchase of energy from the Intermountain Power Project (IPP) for which the Power System has served as the project manager and operating agent. The Department's total interest in IPP includes a 44.6% "take or pay" obligation and an excess power contract for 18.2% for a total of 62.8%. The Department also has agreements with the Southern California Public Power Authority (SCPPA), a California Joint Powers Agency, for 67% of SCPPA's 5.9% entitlement (representing a net 4% participation) to the energy generated at the Palo Verde Nuclear Generating Station and for 59.5% in the capacity of the Southern Transmission System, which transmits energy from IPP in Utah to Southern California. Significant data related to these agreements, which are scheduled to expire from 2022 to 2027, at September 30, 1988 are as follows:

Contracts	Department Share of Capacity (megawatts)	Total Bonds Outstanding (millions)
Palo Verde Nuclear Generating Station (through SCPPA)	145	$1,030
Intermountain Power Project	1,004	$4,931
Southern Transmission System (for IPP power through SCPPA)	1,142	$ 999

All these agreements require the Power System to make certain minimum payments which are based upon debt service requirements. While these payments are fixed charges (of approximately $330 million in each of the next five years), the Department is also required to pay additional amounts (of approximately $120 million in each of the next five years) for operating and maintenance costs related to actual deliveries of energy under these agreements. Total payments under these contracts were approximately $320 million and $260 million in fiscal years 1988 and 1987, respectively. These aggregate purchased power costs are recovered through the energy cost recovery component of customer billings.

The Department also has a contract through 2017 with the U.S. Department of Energy for the purchase of available energy generated at the Hoover Power Plant. The Department's share of capacity at Hoover approximates 500 megawatts.

Nuclear insurance — As a participant in the Palo Verde Nuclear Generating Station, the Department could be subject to assessment of retrospective insurance premium adjustments in the event of a nuclear incident at Palo Verde or at any licensed nuclear reactor in the United States.

Litigation — A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, the uninsured liability under these actions would not materially affect the Power System's financial position as of September 30, 1988.

Note H — Receivable from Intermountain Power Project

As of July 1, 1988, an amendment to an IPA bond resolution provides for the use of surplus construction funds from IPP. As a purchaser of energy from IPP, the Department recorded a receivable of $109.5 million representing its share of such surplus funds. The funds are scheduled to be received in monthly installments of $5 million during the next two years and will be used to reduce the Department's future purchased power expense. At September 30, 1988, the receivable and related liability for purchased power credits (Other Deferred Credits) amounted to $94.5 million.

Imperial Irrigation District

There follows certain information concerning the Imperial Irrigation District and its Electric System, prepared by the Imperial Irrigation District for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Imperial Irrigation District annual report may be obtained from Charles Shreves, Imperial Irrigation District, P. O. Box 937, Imperial, California 92251.

Certain additional information relating to the Imperial Irrigation District may be found in Appendix A to the Official Statement under the caption "Project Participants — Imperial Irrigation District".

IMPERIAL IRRIGATION DISTRICT STATISTICS
(Electric System)

	Year Ended December 31				
	1983	1984	1985	1986	1987
Electric Plant:					
Net Utility Plant	$121,379,593	$139,371,493	$157,201,398	$168,851,876	$192,144,623
Miles of Lines:					
Transmission	996	1,021	1,037	1,052	1,062
Distribution	3,102	3,028	3,135	3,162	3,183
Bonded Indebtedness*	$ 65,670,000	$ 62,385,000	$ 59,630,000	$ 56,725,000	$ 53,650,000
Power Supply (MWh):					
Purchases	747,462	833,723	770,003	802,705	1,011,198
Generation	661,370	671,784	777,076	801,133	753,528
Customers:					
Residential	47,401	48,528	49,305	50,860	53,321
Commercial	8,643	8,872	9,064	9,336	9,699
Industrial	—	—	2	5	8
Other	1,866	1,891	2,072	2,288	2,333
Energy Sold (MWh):					
Residential	550,868	585,402	596,897	596,358	654,473
Commercial	588,849	625,246	654,446	700,476	768,927
Industrial	—	—	5,736	6,489	6,611
Other	105,778	113,713	123,235	122,261	129,117
Peak Demand (MW)	370	396	404	413	421
Summary of Operations:					
Operating Revenues:					
Electric Sales	$ 78,239,650	$ 80,557,097	$ 85,237,447	$ 87,423,666	$101,987,907
Other	1,078,707	936,069	1,060,434	2,328,001	3,251,900
Total	$ 79,318,357	$ 81,493,166	$ 86,297,881	$ 89,751,667	$105,239,807
Operating Expenses:					
Purchased Power	$ 28,558,349	$ 31,761,503	$ 28,444,068	$ 34,044,221	$ 44,183,895
Generation	19,317,963	17,104,826	20,863,459	15,508,235	18,160,602
Transmission and Distribution	4,761,773	3,728,458	3,793,897	4,779,486	4,885,137
Other	6,245,461	6,428,383	11,136,170	10,752,760	8,705,862
Total	$ 58,883,546	$ 59,023,170	$ 64,237,594	$ 65,084,702	$ 75,935,496
Other Income	2,914,399	4,823,493	4,938,001	4,060,405	4,701,054
Net Available for Depreciation and Debt Service	$ 23,349,210	$ 27,293,489	$ 26,998,288	$ 28,727,370	$ 34,005,365
Debt Service	$ 5,110,801	$ 8,865,071	$ 8,576,144	$ 7,646,561	$ 7,508,528

* $670,000 of bonds in 1983, together with certificates of participation.

City of Riverside

There follows certain information concerning the City of Riverside and its Electric System, prepared by the [illegible] Riverside for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operation and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report of the Electric System may be obtained from James H. Harmon, Assistant Director Finance/Administration, City of Riverside Utilities Department, Riverside City Hall, 3900 Main Street, Riverside, California 92522.

Certain additional information relating to the City's Electric System may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton".

CITY OF RIVERSIDE STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988
Electric Plant:					
Net Utility Plant	$133,085,067	$140,069,138	$144,521,455	$147,041,138	$143,292,568
Overhead Circuit Miles	615	618	623	634	638
Underground Circuit Miles	279	304	335	359	391
Street Lights	700	702	711	732	740
Bonded Indebtedness	$122,720,000	$121,740,000	$153,265,000	$154,344,425	$151,890,563
Power Supply (MWh):					
Purchases:					
Edison	929,425	892,973	803,388	196,679	20,775
Other	103,635	153,025	236,132	797,940	1,086,813
Generation	102,163	159,397	168,410	263,700	327,088
Customers:					
Residential	64,160	64,506	68,579	72,197	74,195(1)
Commercial	5,697	5,974	6,282	6,677	7,169
Industrial	220	243	301	330	193(1)
Other	173	255	252	150	148
Energy Sold (Millions of kWh):					
Residential	394	427	421	431	[illegible]
Commercial	227	249	265	279	[illegible]
Industrial	407	425	449	439	480
Other	35	40	38	42	41
Peak Demand (MW)	293	332	323	292	317
Summary of Operations:					
Operating Revenues:					
Electric Sales(2)	$ 87,515,668	$105,940,884	$102,228,610	$114,479,216	$117,096,320
Other	267,629	358,054	598,130	878,808	5,978,836
Total	$ 87,783,297	$106,298,938	$102,826,740	$115,358,024	$123,075,156
Operating Expenses:					
Purchased Power	$ 63,449,536	$ 74,775,376	$ 74,673,776	$ 71,467,899	$ 74,674,347
Generation(3)	2,977,642	6,904,059	4,928,039	5,497,642	6,621,657
Transmission	155,691	89,679	1,072,826	3,617,705	3,249,986
Distribution	2,615,052	2,661,077	2,662,753	3,153,755	3,442,635
Other	6,770,468	6,710,455	7,409,800	7,496,455	8,463,356
Total(4)	$ 75,968,389	$ 91,140,646	$ 90,747,194	$ 91,233,456	$ 96,451,981
Other Income	5,342,298	4,465,903	5,962,635	7,036,647	4,433,630
Net Available for Depreciation and Debt Service	$ 17,157,206	$ 19,624,195	$ 18,042,181	$ 31,161,215	$ 31,056,805
Debt Service	$ 6,465,383	$ 12,588,632	$ 13,213,347	$ 12,772,464	$ 13,183,758

(1) Approximately 150 customers were transferred from the industrial category to the residential category in 1988.

(2) Prior to 1987, the City of Riverside had in effect a Power Cost Adjustment Balancing Account that was utilized to recover or refund amounts related to changes in the cost of power. Electric Sales includes Power Cost Adjustments of ($4,469,473), $7,412,736 and ($5,271,833) for the years 1984, 1985 and 1986, respectively. In 1987 the Balancing Account was merged with the Rate Stabilization Account which is used to adjust revenues to match current operating expenses, of which power purchases are a major component.

(3) Includes transmission expenses associated with San Onofre energy.

(4) Does not include contributions to the City's General Fund of $4,991,000, $5,166,135, $5,537,627, $6,052,1[illegible] $6,497,891 for the years 1984 through 1988.

City of Vernon

There follows certain information concerning the City of Vernon and its Electric System, prepared by the City of Vernon for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent City of Vernon annual report may be obtained from Lewis Adams, City of Vernon, 4305 Santa Fe Avenue, Vernon, California 90058-0805.

Certain additional information relating to the City of Vernon may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF VERNON STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988(1)
Electric Plant:					
Net Utility Plant	$ 5,101,515	$ 6,659,377	$ 9,705,310	$14,002,321	$16,928,422
Miles of Lines:					
Transmission	13	13	13	13	13
Distribution	203	203	203	203	203
Bonded Indebtedness(2)	-0-	-0-	-0-	125,000,000	125,000,000
Power Supply (MWh):					
Purchases	1,056,149	1,097,271	1,141,562	1,140,518	1,142,258
Generation	4,394	9,357	9,547	11,171	14,720
Customers:					
Residential	31	30	31	30	30
Commercial	1,467	1,461	1,489	1,490	1,510
Industrial	507	497	497	471	460
Other	75	73	72	89	71
Energy Sold (MWh):					
Residential	127	125	125	123	124
Commercial	189,486	196,289	198,146	189,516	199,207
Industrial	795,114	882,199	888,563	929,471	909,377
Other	7,852	7,506	7,435	7,732	7,467
Peak Demand (MW)	191	192	193	193.9	190.0
Summary of Operations:					
Operating Revenues:					
Electric Sales	$62,675,177	$75,325,348	$77,475,949	$59,405,155	$60,609,597
Other	23,208	28,455	55,944	74,365	80,887
Total	$62,698,385	$75,353,803	$77,531,893	$59,479,520	$60,690,484
Operating Expenses:					
Power Supply	$59,912,567	$71,182,880	$68,177,475	$54,425,868	$56,446,107
Transmission and Distribution	1,219,056	1,304,003	3,147,383	3,758,562	3,418,463
Other	3,987,990	5,480,569	5,436,374	4,868,858	6,955,432
Total	$65,119,613	$77,967,452	$76,761,232	$63,053,288	$66,820,002
Net Available for Depreciation and Debt Service(3)	$(2,421,228)	$(2,613,649)	$ 770,661	$(3,573,768)	$(6,129,518)

(1) Unaudited data.

(2) Investment securities and funds sufficient to cover all principal and interest on these bonds have been set aside as security for such payment.

(3) Non-operating income, not included as revenues in the above table, for fiscal years 1984, 1985, 1986, 1987 and 1988 amounted to $4,441,275, $6,281,624, $7,223,868, $4,492,170 and $7,460,604, respectively.

City of Burbank

There follows certain information concerning the City of Burbank and its Public Service Department, prepared by the City of Burbank for inclusion in this Official Statement. This information does not purport to cover all aspects of the Public Service Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent City of Burbank annual report may be obtained from Ronald V. Stassi, Burbank Public Service Department, 164 West Magnolia Boulevard, Burbank, California 91503-0631.

Certain additional information relating to the City of Burbank's Public Service Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena".

CITY OF BURBANK STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988
Electric Plant:					
Net Utility Plant	$31,647,407	$43,575,791	$46,140,136	$45,486,166	$44,999,464
Miles of Lines:					
Transmission	53	53	53	53	53
Distribution	290	310	310	313	313
Bonded Indebtedness	$ 2,275,000	$ 1,775,000	$28,935,900	$31,540,000	$30,430,000
Power Supply (MWh):					
Purchases	641,650	735,780	798,110	769,117	727,610
Generation	289,313	237,396	183,432	239,641	328,011
Customers:					
Residential	37,718	37,955	38,340	38,876	39,804
Commercial	5,809	5,871	5,906	6,074	6,120
Industrial	152	164	174	179	182
Other	595	625	636	655	6[illegible]
Energy Sold (MWh):					
Residential	191,641	199,159	194,572	195,961	204,264
Commercial	197,580	203,270	212,471	213,690	225,462
Industrial	461,066	484,128	498,547	521,947	548,927
Other	32,336	34,899	32,441	30,178	31,781
Peak Demand (MW)	217	234	228	232	245
Summary of Operations:					
Operating Revenues:					
Electric Sales	$58,396,400	$63,187,391	$61,612,602	$63,923,886	$69,717,182
Other	—	—	—	—	—
Total	$58,396,400	$63,187,391	$61,612,602	$63,923,886	$69,717,182
Operating Expenses:					
Purchased Power	$17,325,363	$23,969,205	$25,614,532	$31,533,535	$33,194,530
Generation	24,256,054	20,114,796	15,566,895	11,728,335	15,009,064
Transmission and Distribution	4,023,795	3,991,955	4,318,848	4,136,617	5,820,003
Other	4,281,913	4,673,078	5,055,853	5,409,540	5,687,190
Total	$49,887,125	$52,749,034	$50,556,128	$52,808,027	$59,710,787
Net Available for Depreciation and Debt Service	$ 8,509,275	$10,438,357	$11,056,474	$11,115,859	$10,006,395
Debt Service	$ 791,573	$ 520,050	$ 3,214,750	$ 3,213,355	$ 3,523,894

City of Glendale

There follows certain information concerning the City of Glendale and its Public Service Department, prepared by the City of Glendale for inclusion in this Official Statement. This information does not purport to cover all aspects of the Public Service Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Glendale Public Service Department annual report may be obtained from Lawrence Silva of the Glendale Public Service Department, 119 North Glendale Avenue, Glendale, California 91206.

Certain additional information relating to the City of Glendale may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena."

CITY OF GLENDALE STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988*
Electric Plant:					
Net Utility Plant	$77,515,000	$80,366,530	$83,005,742	$93,578,382	$101,003,647
Miles of Lines:					
Transmission	72	72	72	73	75
Distribution	394	394	394	411	415
Bonded Indebtedness	$40,340,000	$38,555,000	$36,675,000	$34,695,000	$ 32,595,000
Power Supply (MWh):					
Purchases	670,898	737,207	760,393	766,668	759,613
Generation	191,065	154,557	134,684	147,484	201,835
Customers:					
Residential	57,946	58,463	59,378	61,347	63,896
Commercial	10,220	10,322	10,640	11,073	11,448
Industrial	118	120	124	126	126
Other	43	43	42	39	35
Energy Sold (MWh):					
Residential	273,481	292,175	283,416	284,836	297,276
Commercial	317,309	320,036	330,153	332,339	363,534
Industrial	192,838	201,351	208,467	208,677	202,734
Other	25,785	23,087	20,561	20,467	16,980
Peak Demand (MW)	208	232	232	225	228
Summary of Operations:					
Operating Revenues:					
Electric Sales	$52,904,556	$60,813,833	$60,807,695	$60,170,514	$ 68,159,028
Other	558,371	725,310	624,938	634,074	469,573
Total	$53,462,927	$61,539,143	$61,432,633	$60,804,588	$ 68,628,601
Operating Expenses:					
Purchased Power	$13,466,739	$20,965,103	$20,083,076	$22,138,546	$ 27,180,332
Generation	17,443,512	14,519,210	13,974,810	11,859,342	12,535,159
Transmission and Distribution	3,368,190	3,257,620	3,222,348	3,298,747	3,812,635
Other	6,109,702	6,256,801	6,602,221	8,285,448	8,442,380
Total	$40,388,143	$44,998,734	$43,883,455	$45,582,083	$ 51,970,506
Net Available for Depreciation and Debt Service	$13,074,784	$16,540,409	$17,549,178	$15,222,505	$ 16,658,095
Debt Service	$ 4,163,000	$ 4,162,000	$ 4,159,000	$ 4,156,000	$ 4,160,000

* Unaudited data.

City of Pasadena

There follows certain information concerning the City of Pasadena and its Power Department, prepared by the City of Pasadena for inclusion of this Official Statement. This information does not purport to cover all aspe[illegible] of the Power Department's business, operations and financial position. During the initial offering period for t[illegible] securities offered by this Official Statement, a copy of the most recent Pasadena Water and Power Departmen[illegible] annual report may be obtained from Pamela S. Wilson, Pasadena Water and Power Department, 150 South Robles Avenue, Suite 200, Pasadena, California 91101.

Certain additional information relating to the City of Pasadena may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena."

CITY OF PASADENA STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988*
Electric Plant:					
Net Utility Plant	$71,925,257	$77,647,390	$81,126,009	$87,170,197	$93,048,549
Miles of Lines:					
Transmission	85	86	86	86	86
Distribution	322	324	327	327	327
Electric Revenue Bonds	$23,000,000	$21,825,000	$40,229,220	$41,390,000	$39,635,000
Power Supply (MWh):					
Purchases	618,544	639,801	665,261	660,386	737,716
Generation	317,536	353,155	341,637	361,022	331,924
Customers:					
Residential	46,066	46,487	46,734	47,145	47,485
Commercial	6,305	6,443	6,533	6,623	6,8[illegible]
Industrial	675	705	720	745	7[illegible]
Other	169	169	169	173	173
Energy Sold (MWh):					
Residential	223,706	243,234	237,579	236,135	244,412
Commercial	126,223	131,603	131,547	131,181	136,432
Industrial	486,818	505,212	541,747	550,672	587,439
Other	44,081	42,687	45,469	43,774	46,993
Peak Demand (MW)	214	238	231	232	240
Summary of Operations:					
Operating Revenues:					
Electric Sales	$56,056,504	$60,473,076	$57,180,039	$61,228,605	$76,002,233
Other	—	—	—	—	—
Total	$56,056,504	$60,473,076	$57,180,039	$61,228,605	$76,002,233
Operating Expenses:					
Purchased Power	$15,886,535	$18,971,508	$20,040,770	$28,553,823	$40,701,733
Generation	22,978,336	22,644,602	18,501,579	13,219,859	15,455,471
Transmission and Distribution	2,737,958	3,237,410	3,352,469	3,159,343	3,549,894
Other	4,180,082	4,010,050	4,607,050	4,587,567	5,359,358
Total	$45,782,911	$48,863,570	$46,501,868	$49,520,592	$65,066,456
Net Available for Depreciation and Debt Service	$10,273,593	$11,609,506	$10,678,171	$11,708,013	$10,935,777
Debt Service	$ 2,303,732	$ 2,660,420	$ 3,685,249	$ 4,240,654	$ 4,582,3[illegible]

* Unaudited data.

ity of Azusa

There follows certain information concerning the City of Azusa and its Municipal Light Department, prepared by the City of Azusa for inclusion in this Official Statement. This information does not purport to cover all aspects of the Municipal Light Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Municipal Light Department annual report may be obtained from Joseph F. Hsu, Director of Utilities, Municipal Light Department, 777 No. Alameda Avenue, Azusa, California 91702-1395.

Certain additional information relating to the City's Municipal Light Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton".

CITY OF AZUSA STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988(1)
Electric Plant:					
Net Utility Plant	$ 3,372,374	$ 3,342,163	$ 3,467,896	$ 3,705,428	$ 4,234,424
Miles of Lines:					
Transmission	—	—	—	—	—
Distribution	125	130	131	139	144
Bonded Indebtedness	-0-	-0-	-0-	-0-	-0-
Power Supply (MWh):					
Purchases from Edison	163,570	170,460	177,768	185,713	196,436
Customers:					
Residential	10,536	10,621	11,207	11,157	11,640
Commercial	1,271	1,274	1,318	1,311	1,352
Industrial	35	33	34	34	34
Other	46	45	47	52	50
Energy Sold (MWh):					
Residential	50,503	52,715	53,133	53,961	56,530
Commercial	49,492	50,878	54,533	58,528	60,305
Industrial	52,500	53,347	56,992	64,542	67,988
Other	2,544	2,499	2,437	2,414	407
Peak Demand (MW)	40.2	44.5	43.1	44.0	46.9
Summary of Operations:					
Operating Revenues:					
Electric Sales	$14,878,100	$14,440,167	$15,511,655	$15,881,642	$16,029,926
Other(2)	329,577	36,743	93,316	154,080	121,256
Total	$15,207,677	$14,476,910	$15,604,971	$16,035,722	$16,151,182
Operating Expenses:					
Purchased Power	$10,099,838	$12,185,881	$12,606,258	$10,518,613	$10,163,535
Transmission and Distribution	530,691	595,488	607,089	1,231,667	1,350,785
Other	551,665	638,944	637,911	895,539	746,736
Total	$11,182,194	$13,420,313	$13,851,258	$12,645,819	$12,261,056
Net Available for Depreciation and Debt Service	$ 4,025,483	$ 1,056,597	$ 1,753,713	$ 3,389,903	$ 3,890,126

(1) Unaudited data.

(2) Does not include $783,791, $1,266,731 and $2,037,241 refunds from Edison for 1984, 1985 and 1986, respectively.

City of Banning

There follows certain information concerning the City of Banning's Electric System, prepared by the City of Banning for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report may be obtained from Timothy Dempsey, 176 East Lincoln Street, Banning, California 92220.

Certain additional information relating to the City's Public Utilities Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF BANNING STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988(1)
Electric Plant:					
Net Utility Plant	$2,174,670	$3,442,629	$3,724,741	$4,508,603	$6,754,667
Miles of Lines:					
Transmission	12	12	12	18	18
Distribution	84	87	89	89	89
Bonded Indebtedness	-0-	-0-	$1,250,000	$2,350,000	$2,300,000
Power Supply (MWh):					
Purchases from Edison	69,474	74,104	70,729	73,552	79,260
Customers:					
Residential	5,325	5,491	5,519	5,665	6,151
Commercial	600	595	600	626	66[illegible]
Industrial	6	6	6	5	[illegible]
Other	104	111	100	97	154
Energy Sold (MWh):					
Residential	28,003	30,040	30,157	31,119	30,045
Commercial	24,227	22,898	22,470	23,563	27,195
Industrial	10,368	12,151	10,749	10,071	8,433
Other	3,568	2,855	2,525	2,740	5,276
Peak Demand (MW)	18.1	18.3	18.6	18.7	18.6
Summary of Operations:					
Operating Revenues:					
Electric Sales	$5,867,683	$7,197,764	$6,760,732	$6,758,538	$6,473,552
Other	9,350	11,661	87,658	98,286	149,324
Total	$5,877,033	$7,209,425	$6,848,390	$6,856,824	$6,622,876
Operating Expenses:					
Purchased Power	$4,379,611	$5,311,922	$4,975,930	$4,563,230	$4,445,335
Transmission and Distribution	720,761	689,371	513,434	70,336	79,719
Other(2)	606,650	733,800	919,228	921,341	956,716
Total	$5,707,022	$6,735,093	$6,408,592	$5,554,907	$5,481,770
Net Available for Depreciation and Debt Service	$ 170,011	$ 474,332	$ 439,798	$1,301,917	$1,141,106
Debt Service(3)	—	$ 46,493	$ 164,270	$ 0	$ 30,000

(1) Unaudited data.

(2) Transfers to the City's General Fund are accounted for as an operating expense. Transfers for 1984, 1985, 1986, 1987 and 1988 amounted to $555,896, $630,000, $874,662, $913,415 and $891,716, respectively.

(3) Interest and Principal on Note for 1985; interest on Certificates of Participation thereafter.

City of Colton

There follows certain information concerning the City of Colton's Utility System, prepared by the City of Colton for inclusion in this Official Statement. This information does not purport to cover all aspects of the System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report may be obtained from Gale Drews, Utility Director, 650 North La Cadena, Colton, California 92324.

Certain additional information relating to the City may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF COLTON STATISTICS

	Year Ended June 30				
	1984	1985	1986	1987	1988*
Electric Plant:					
Net Utility Plant	$ 2,686,093	$ 3,086,734	$ 3,704,178	$ 4,432,230	$ 4,947,796
Miles of Lines:					
Transmission	1.5	1.5	1.5	1.5	2.3
Distribution	93	97	106	114	121
Bonded Indebtedness	$ 1,060,000	$ 1,035,000	$ 1,010,000	$ 975,000	$ 940,000
Power Supply (MWh):					
Purchases from Edison	136,396	138,749	143,247	162,738	186,769
Customers:					
Residential	8,172	8,312	9,811	11,043	12,037
Commercial	1,084	1,123	1,218	1,293	1,379
Industrial	11	11	11	10	10
Other	94	93	95	98	105
Energy Sold (MWh):					
Residential	41,996	42,636	43,690	52,158	61,236
Commercial	51,883	53,072	53,304	58,564	63,534
Industrial	29,420	29,710	29,753	29,897	32,423
Other	4,913	6,504	7,024	6,931	7,855
Peak Demand (MW)	30.2	35.2	34.6	39.4	40.2
Summary of Operations:					
Operating Revenues:					
Electric Sales	$10,744,457	$11,566,843	$11,853,772	$12,865,538	$14,312,140
Other	30,081	35,176	55,382	62,640	44,742
Total	$10,774,538	$11,602,019	$11,909,154	$12,928,178	$14,356,882
Operating Expenses:					
Purchased Power	$ 8,114,476	$ 9,540,786	$ 9,845,240	$10,452,914	$ 9,133,055
Transmission/Distribution	333,468	332,458	311,584	422,291	448,159
Other	1,202,698	1,231,201	1,360,597	1,752,112	1,859,442
Total	$ 9,650,642	$11,104,445	$11,517,421	$12,627,317	$11,440,656
Net Available for Depreciation and Debt Service	$ 1,123,896	$ 497,574	$ 391,733	$ 300,861	$ 2,916,226
Debt Service	$ 86,638	$ 90,342	$ 88,764	$ 97,120	$ 95,038

* Unaudited data.

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SUMMARIES OF CERTAIN DOCUMENTS

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SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE

The following is a summary of certain provisions of the Bond Indenture. This summary is not to be considered a full statement of the terms of the Bond Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Bond Indenture.

Pledge Effected by the Bond Indenture

Under the Bond Indenture, the Authority has pledged and assigned to the Trustee, for the benefit of the Bondholders, (1) the proceeds of the sale of the Bonds, (2) the Revenues, and (3) all Funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund), including the investments, if any, of the moneys therein, subject only to the provisions of the Bond Indenture permitting the application thereof for the purpose and on the terms and conditions set forth in the Bond Indenture (including application of the moneys on deposit in certain refunding escrow funds).

Nature of Obligation

The Bond Indenture provides that the principal and Redemption Price of, and interest on, the Bonds shall be payable solely from the Revenues and other funds pledged by the Authority under the Bond Indenture. The Bonds are not an obligation of the State of California or any public agency thereof, other than the Authority, or any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any Project Participant is pledged for the payment of the Bonds.

Application of Revenues

Revenues are pledged by the Bond Indenture to payment of principal and Redemption Price of and interest on the Bonds, subject to the provisions of the Bond Indenture permitting application for other purposes. The Bond Indenture establishes the following Funds and Accounts for the application of Revenues:

Funds	Held By
Construction Fund	Trustee
Revenue Fund	Trustee
Operating Fund	Trustee
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Bond Anticipation Note Fund	Trustee
Reserve and Contingency Fund	Trustee
Renewal and Replacement Account	
Decommissioning Account	
Reserve Account	
General Reserve Fund	Trustee

All Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

1. To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for Authority Operating Expenses or as a reserve for the acquisition of fuel or as a reserve for working capital, is equal to the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month. Such sum shall be paid to the Operating Fund as soon as practicable in each month after deposit of Revenues in the Revenue Fund, but not later than the last business day of such month. In addition, if the Supplemental Indenture authorizing a Series of Bonds so provides, amounts from the proceeds of such Bonds may be deposited in the Operating Fund and set aside as a reserve for the acquisition of fuel and as a reserve for working capital. At the requisition of the Authority, signed by an Authorized Authority Representative, amounts in the Operating Fund shall be paid out from time to time by the Trustee for reasonable and necessary Authority Operating Expenses. Additional amounts may be paid out from the appropriate separate Account in the Operating Fund to establish a revolving fund with a maximum balance of $250,000 for the payment of Authority Operating Expenses not conveniently paid as described in the previous sentence. The Bond Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiences in certain other funds established under the Bond Indenture with any balance to be deposited in the General Reserve Fund.

2. To the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such Accounts equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement, respectively. The Trustee will apply amounts in the Debt Service Account to the payment of principal of and interest on the Bonds. In addition, the Trustee may, and if directed by the Authority must, apply certain amounts in the Debt Service Account to the purchase or redemption of Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Trustee must pay out of the Debt Service Account the amount required for the redemption of Bonds called for redemption pursuant to sinking fund requirements, or maturing, on any redemption or maturity date.

In the event of the refunding of one or more Series of Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the Debt Service Account in the Debt Service Fund amounts accumulated therein with respect to Debt Service on the Bonds being refunded and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on the Series of Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the Series of Bonds being refunded shall be deemed to have been paid pursuant to the Bond Indenture, and (b) the amount remaining in the Debt Service Account after such withdrawal shall not be less than the requirement of such Account pursuant to the Bond Indenture.

Amounts in the Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account. Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account, is sufficient to pay in full all Outstanding Bonds in accordance with their terms, the funds on deposit in the Debt Service Reserve Account shall be transferred to the Debt Service Account. As long as the amount in the Debt Service Fund is sufficient to pay all then Outstanding Bonds in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in the Debt Service Reserve Account. Whenever moneys on deposit in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement, the excess will be deposited in the Revenue Fund.

Deposits from the Revenue Fund into the Debt Service Fund, the Bond Anticipation Note Fund, the Reserve and Contingency Fund and the General Reserve Fund are to be made as soon as practicable in each month after the deposit of Revenues into the Revenue Fund and the payment to the Operating Fund have been made for such month, but not later than the last business day of such month.

3. To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund shall equal all interest on Outstanding Bond Anticipation Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Bond Anticipation Note Fund to the payment of interest on Bond Anticipation Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Bond Anticipation Notes. However, if at any time the amounts in the Debt Service Account or the Debt Service Reserve Account are less than the amounts required by the Bond Indenture, and there is not on deposit in the General Reserve Fund or in the Renewal and Replacement Account or the Reserve Account in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Trustee shall transfer from the Bond Anticipation Note Fund the amount necessary to make up such deficiency.

4. To the Reserve and Contingency Fund, for credit to (a) the Renewal and Replacement Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget; (b) the Decommissioning Account, the amount, if any, provided for deposit therein for the then current month as set forth in the current Annual Budget; and (c) the Reserve Account, the amount, if any, provided for deposit therein during the then current month provided in the current Annual Budget.

Amounts in the Renewal and Replacement Account will be applied to the costs of Capital Improvements.

Amounts in the Decommissioning Account will be held as a reserve for the retirement from service, decommissioning or disposal of the generation facilities of the Project.

To the extent not provided for in the then current Annual Budget or by reserves in the Operating Fund or from the proceeds of Bonds, amounts in the Reserve Account will be applied to the costs of Capital Improvements to the extent amounts in the Renewal and Replacement Account are not sufficient therefor, and to the payment of extraordinary operation and maintenance costs of the Project, and contingencies.

If at any time the amounts in the Debt Service Account or in the Debt Service Reserve Account are less than the amounts required by the Bond Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Trustee will transfer from the Reserve Account and the Renewal and Replacement Account, in that order, the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account or the Reserve Account not required to meet any deficiencies in the Debt Service Fund or for any of the purposes for which such Accounts or the Decommissioning Account were established shall be transferred to the Operating Fund to the extent, if any, deemed necessary by the Authority to make up any deficiencies therein. Any remaining excess shall be deposited into the General Reserve Fund.

5. To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Trustee shall transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account the amount necessary to make up any deficiencies in required payments to said Accounts, (b) to the Debt Service Reserve Account the amount of any deficiency in such Account resulting from any transfer to the Debt Service Account, and (c) to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary (or all moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in payments to said Accounts.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above or not required by the Bond Indenture for the purchase or redemption of Bonds will upon determination of the Authority be applied to or set aside for any one or more of the following: (a) transfer to the Revenue Fund; (b) the purchase or redemption of any Bonds, and expenses and reserves in connection therewith; (c) Authority Operating Expenses or reserves therefor; (d) payments into any separate account or accounts established in the Construction Fund; (e) Costs of

Acquisition and Construction attributable to Capital Improvements or reserves therefor; (f) reduction in the cost of the Project power and energy to Project Participants under the Power Sales Contracts; (g) payment of principal of Bond Anticipation Notes; and (h) any other lawful purpose of the Authority related to the Project. Bonds purchased or redeemed with amounts in the General Reserve fund shall be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Construction Fund

The Bond Indenture establishes a Construction Fund, to be held by the Trustee, into which will be paid amounts required by the provisions of the Bond Indenture and any Supplemental Indenture and any moneys received for or in connection with the Project by the Authority, unless required to be otherwise applied as provided in the Bond Indenture. In addition, proceeds of insurance for physical loss or damage to the Project, including proceeds of any self-insurance fund, or of contractors' performance bonds pertaining to the period of construction of the Project will be paid into the Construction Fund. Within the Construction Fund, separate accounts will be established for (i) the Initial Facilities and (ii) any Capital Improvements, the costs of which are to be paid out of the Construction Fund.

The Trustee will pay, upon the requisitions of the Authority therefor, from the Construction Fund the Cost of Acquisition and Construction of the Project. Each such payment shall be made by the Trustee upon the filing by the Authority with the Trustee of a requisition for such payment, except that the Trustee will, during the construction of the Project, pay to the Authority a sum or sums aggregating not more than $250,000 to be used as a revolving fund. The Authority is to use the moneys in such revolving fund to pay such items of the Cost of Construction and Acquisition of the Project which cannot be conveniently paid through the filing with the Trustee prior to payment of requisitions by the Authority. Upon requisition by the Authority, the Trustee will, so long as the amount in such fund is less than $250,000, reimburse such fund by payments from the Construction Fund for expenses paid by the Authority.

Upon completion of the Initial Facilities or any Capital Improvements, the balance in the separate account in the Construction Fund established therefor not required to complete payment for the Cost of Acquisition and Construction of such Initial Facilities or Capital Improvements will be transferred to the Debt Service Reserve Account to the extent necessary to make the amount in such Account equal to the Debt Service Reserve Requirement, and the excess, if any, will be transferred to the General Reserve Fund for application to the retirement of Bonds by purchase or redemption. To the extent that other moneys are not available therefor, amounts in the Construction Fund will be applied, in priority to the other applications described above, to the payment of principal of and interest on Bonds when due.

Debt Service Reserve Requirement and Certain Other Definitions Pertaining to the Issuance of Bonds

Debt Service Reserve Requirement means, as of any date of calculation, an amount equal to the greatest amount of Adjusted Aggregate Debt Service for the then current or any future Fiscal Year; provided, however, that, for purposes of this definition, Adjusted Aggregate Debt Service shall be computed in accordance with the definition of said term given below with the exception that Aggregate Debt Service or Adjusted Debt Service with respect to a Series of Lender Bonds shall not be included in such computation unless the Supplemental Indenture authorizing such Series of Lender Bonds shall specify that such Aggregate Debt Service or Adjusted Debt Service shall be included in said computation; and provided further, that if such a computation shall include one or more Series of Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.

Adjusted Aggregate Debt Service means, as of any date of calculation and with respect to any period, the sum of (i) the sum of the amounts of Adjusted Debt Service during such period for all Series of Bonds and (ii) the Aggregate Debt Service during such period for all Series of Bonds not

included in the computation of Adjusted Debt Service on such date of calculation; provided, however, that in computing such Aggregate Debt Service, any particular Lender Bonds shall be deemed to bear at all times to the maturity thereof the Assumed Interest Rate applicable thereto.

Adjusted Debt Service means, with respect to any Series of Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Bonds for such period which would result if the Principal Installment for such Series due on the final maturity date of such Series were adjusted over the period specified pursuant to the next sentence so that the Bonds of such Series would have Substantially Equal Debt Service for each Fiscal Year of such period and that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal of and premium, if any, and interest on the Bonds of such Series in accordance with such adjustments and computing the interest component of Debt Service on the basis of the true interest cost actually incurred on such Series of Bonds (determined by the true, actuarial method of calculation). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on a date which shall be specified in the Supplemental Indenture authorizing such Series of Bonds, which date shall be not later than the earlier to occur of (i) 35 years after the date of such Bonds or (ii) the termination date of the Power Sales Contracts. For purposes of computing such true interest cost for any Series of Bonds containing Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.

Assumed Interest Rate means, as to any Lender Bonds with a Variable Interest Rate, the interest rate for such Bonds assumed for purposes of determining their maturity schedule, and as to any Lender Bonds not having a Variable Interest Rate, the stated interest rate for each such Lender Bond.

Lender Bonds means Bonds which: (i) are issued in exchange for Bond Anticipation Notes, (ii) are issued pursuant to the requirements of a lending or credit facility or agreement and (iii) will be held by a bank, trust company or similar financial institution, domestic or foreign. To the extent such Bonds are not included in the computation of the Debt Service Reserve Requirement, the Supplemental Indenture pursuant to which such Bonds are issued shall specify that such Bonds shall not have a lien on or pledge of or be payable from, any moneys on deposit in the Debt Service Reserve Account notwithstanding any other provision of the Bond Indenture to the contrary.

Substantially Equal Adjusted Aggregate Debt Service means, with respect to any period of similar Fiscal Years for all Series of Bonds, that the greatest Adjusted Aggregate Debt Service for any Fiscal Year in such period is not in excess of one hundred and twenty-five per cent of the Adjusted Aggregate Debt Service for any preceding Fiscal Year in such period.

Substantially Equal Debt Service means, with respect to any period of Years for any Series of Bonds, that the greatest Debt Service for any Year in such period is not in excess of one hundred and twenty-five per cent of the smallest Debt Service for any Year in such period; provided, however, that in computing Debt Service for the purpose of this definition, any particular Lender Bond shall be deemed to bear at all times prior to the maturity thereof the Assumed Interest Rate applicable thereto.

Certain Requirements of and Conditions to Issuance of Bonds

Bonds shall be authenticated by the Trustee pursuant to the Bond Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Trustee shall have received an Opinion of Bond Counsel to the effect that the Bonds of the Series being issued have been duly and validly authorized and issued and are valid and binding obligations of the Authority and as to certain other matters concerning the Bond Indenture.

(b) The Trustee shall have received the amount, if any, necessary for deposit in the Debt Service Reserve Account in the Debt Service Fund so that the balance in such Account shall equal the Debt Service Reserve Requirement calculated immediately after authentication and delivery of such Series of Bonds.

(c) Except in the case of Lender Bonds and Refunding Bonds, the Authority shall have certified that it is not in default in the performance of its agreements under the Bond Indenture.

The Bond Indenture also authorizes the issuance of Bonds known as "Initial Facilities Issue" to be issued in Series from time to time to pay all or a portion of the Cost of Acquisition and Construction of the Initial Facilities. Proceeds, including accrued interest, of each Series of Bonds of the Initial Facilities Issue are to be applied as determined by the Supplemental Indenture authorizing such Series.

The Bond Indenture also provides that Principal Installments will be established at the time of issuance for each Series of Bonds of the Initial Facilities Issue and each Series of Additional Bonds and Refunding Bonds so as to comply with the following:

(a) Principal Installments shall commence not later than the later of (A) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Bonds or (B) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which the Project Manager estimates that the last generation unit of the Project will first reach its Date of Firm Operation, and shall terminate not later than the date on which the Power Sales Contracts terminate.

(b) Such Principal Installments shall result in either (A) Substantially Equal Debt Service for the Bonds of such Series for the Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the last generating unit of the Project and for each Year thereafter to and including the final maturity date of such Series or (B) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Bonds then Outstanding, including such Series being issued, beginning however no earlier than the Fiscal Year immediately preceding the due date of the first Principal Installment to occur subsequent to the Date of Firm Operation of the last generating unit of the Project, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Bonds Outstanding immediately prior to the issuance of such Series being issued or the Fiscal Year immediately preceding the latest maturity of such Series being issued, whichever is earlier (using in the case of any Series of Bonds sold by competitive bidding a net effective interest rate for the Bonds of such Series as estimated by the Authority); provided, that, if the first Principal Installment for any Series of Bonds shall be less than 12 months after the date of issuance thereof, it shall be assumed, for purposes of this calculation, that interest accrued on such Series for the entire 12-month period preceding the first Principal Installment at the same rate as interest accrued for the actual portion of such period during which such Series of Bonds was Outstanding.

Additional Bonds

The Authority may issue one or more Series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition and Construction of any Capital Improvements upon compliance with the following in addition to the conditions to issuance described above:

(a) In the case of Additional Bonds being issued to finance the Cost of Acquisition and Construction of Capital Improvements which are determined necessary by the Board of Directors under the Power Sales Contracts to keep the Project in good operating condition or to prevent a loss of revenue therefrom or to prevent an increase in Authority Operating Expenses, the Trustee shall have received an opinion of the Consulting Engineer to such effect.

(b) In the case of Additional Bonds being issued to finance the Cost of Acquisition and Construction of Capital Improvements either required by any governmental agency having jurisdiction over the Project, required by the Participation Agreement or required by the Bond Indenture, the Trustee shall have received an Opinion of Bond Counsel to the effect that such Capital Improvements are either required by such governmental agency or are an obligation of

the Authority arising out of the Power Sales Contracts, the Participation Agreement or the Bond Indenture, respectively.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund all Outstanding Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Trustee pursuant to the Bond Indenture upon compliance with certain requirements and conditions, including the receipt by the Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Bonds to be redeemed plus the amount required to pay principal on refunded Bonds not to be redeemed together with accrued interest on such Bonds or (ii) Investment Securities in such amounts and having such terms as required by the Bond Indenture to pay the principal or Redemption Price, if applicable, and interest due on the redemption date or maturity date, as the case may be.

Notice of Redemption

The Bond Indenture requires the Trustee to give notice of any redemption of the Bonds by publication once a week for at least two successive weeks in newspapers customarily published at least once a day for at least five days (other than legal holidays) in each calendar week in the English language and of general circulation, respectively, in Los Angeles, California and in the Borough of Manhattan, City and State of New York. The first such publication is required to be made not less than 30 days nor more than 60 days prior to the redemption date. The Trustee is also required to mail a copy of such notice not less than 25 days before the redemption date to the holders of any registered Bonds which are to be redeemed, but failure to do so will not affect the validity of any redemption.

Interchangeability

Bonds in coupon form, upon surrender thereof at the principal corporate trust office of the Trustee, acting as Bond Registrar pursuant to the Bond Indenture, with all unmatured coupons attached, may, at the option of the holder thereof, be exchanged for an equal aggregate principal amount of fully registered Bonds of the same Series and maturity and of any authorized denominations.

Bonds in fully registered form, upon surrender thereof at the principal corporate trust office of the Bond Registrar with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the registered owner or his duly authorized attorney, may, at the option of the registered owner thereof, be exchanged for an equal aggregate principal amount of Bonds in coupon form, of the same Series and maturity with appropriate coupons attached, or of Bonds in registered form of the same Series and maturity and of any other authorized denomination.

In all cases in which the privilege of exchanging the Bonds or transferring the registered Bonds is exercised, the Authority shall execute and the Trustee shall authenticate and deliver the Bonds in accordance with the provisions of the Bond Indenture. For every such exchange or transfer of the Bonds, the Authority or the Bond Registrar may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer. Neither the Authority nor the Bond Registrar shall be required to transfer or exchange any Bond (a) for a period of 20 days next preceding an interest payment date or next preceding any selection of the Bonds to be redeemed or thereafter until after the first publication or mailing of any notice of redemption or (b) if such Bond has been called for redemption.

Investment of Certain Funds and Accounts

The Bond Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund and the Bond Anticipation Note Fund, subject to the terms of agreements relating to the issuance of Bond

Anticipation Notes, must, be invested to the fullest extent practicable in Investment Securities. The Bond Indenture provides that such investments will mature no later than such times as shall be necessary to provide moneys when needed for payments from such Funds and Accounts and provides specific limitations on the term of investments for moneys in certain Funds and Accounts.

Interest (net of the return of accrued interest paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds or Accounts, other than the Construction Fund, will be paid into the Revenue Fund except that interest shall be paid into the Construction Fund to the extent provided in the Supplemental Indenture authorizing the first Series of Bonds issued under the Bond Indenture. Interest on moneys or investments in each separate account in the Construction Fund will be held in such account for the purposes thereof.

The Trustee may deposit moneys in all Funds and Accounts held under the Bond Indenture in banks or trust companies organized under the laws of any state of the United States or national banking associations ("Depositaries"). All moneys held under the Bond Indenture by the Trustee or any Depositary must be (1) either (a) continuously and fully insured by the Federal Deposit Insurance Corporation, or (b) continuously and fully secured by lodging with the Trustee or any Federal Reserve Bank, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive, of the definition of "Investment Securities" having a market value (exclusive of accrued interest) not less than the amount of such moneys, and (2) held in such other manner as may then be required by applicable Federal or State of California laws and regulations and applicable state laws and regulations of the state in which the Trustee or such Depositary is located, regarding security for the deposit of trust funds; provided, however, that it shall not be necessary for the Trustee or any Paying Agent to give security for the deposit of any moneys held in trust by it and set aside by it for the payment of principal or Redemption Price of or interest on any Bonds or for the Trustee or any Depositary to give security for any moneys which are represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Bond Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized cost of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest. Such computations shall be determined as of January 1 and July 1 in each year.

Encumbrances; Disposition of Properties

The Authority will not issue bonds, notes, debentures or other evidences of indebtedness, other than the Bonds, payable out of or secured by a pledge or assignment of the Revenues or other moneys, securities or funds held or set aside by the Authority, the Trustee or the Paying Agents under the Bond Indenture, nor will it create, or cause to be created any lien or charge thereon, except, to the extent permitted by law, (1) evidences of indebtedness (a) payable out of moneys in the Construction Fund as part of the Cost of Acquisition and Construction of the Project or (b) payable out of, or secured by a pledge and assignment of, Revenues to be derived on and after the discharge of the pledge of Revenues provided in the Bond Indenture or (2) Bond Anticipation Notes issued in accordance with the provisions of the Bond Indenture.

The Authority may, however, acquire, construct or finance through the issuance of its bonds, notes or other evidences of indebtedness any facilities which do not constitute a part of the Project for the purposes of the Bond Indenture and may secure such bonds, notes or other evidences of indebtedness by a mortgate of the facilities so financed or by a pledge of, or other security interest in, the revenues therefrom or any lease or other agreement with respect thereto or any revenues derived from such lease or other agreement; provided that such bonds, notes or other evidences of indebtedness shall not be payable out of or secured by the Revenues or any Fund or Account held under the Bond Indenture and neither the cost of such facilities nor any expenditure in connection therewith or with the financing thereof shall be payable from the Revenues or from any such Fund or Account.

The Authority will not sell, lease, mortgage or otherwise dispose of any part of the Project, except for sales or exchanges of property or facilities (1) which are not useful in the operation of the Project, or (2) for which the proceeds received are, or the fair market value of the subject property (as certified by an Authorized Authority Representative) is, less than $100,000, or (3) as to which the Consulting Engineer certifies that the ability of the Authority to comply with the rate covenant described under the caption "Rate Covenant" below will not be impaired. The proceeds of any such transaction not used to acquire other property necessary or desirable for the operation of the Project will be deposited in the General Reserve Fund.

The Authority will not lease or make contracts or grant licenses for the operation or use of, or grant easements or any other rights with respect to, any part of the Project, which would (1) impede the operation of the Project and (2) impair or adversely affect the rights or security of Bondholders under the Bond Indenture. If the depreciated costs of the subject property exceeds $500,000, the Consulting Engineer must certify that the proposed action of the Authority does not result in a breach of the above mentioned conditions. Any payments to the Authority in connection with any such transaction will constitute Revenues.

Rate Covenant

The Authority covenants in the Bond Indenture that as long as any Bonds are Outstanding it will have good right and lawful power to establish and collect rates and charges with respect to the use of the capability of the Project and the sale of the capacity, output or service thereof, subject to the terms of the Project Agreements. The Authority covenants in the Bond Indenture that it will at all times establish and collect rates and charges for the use of the capability of the Project or the sale of the output, capacity or service of the Project which provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all the following:

(a) Authority Operating Expenses during such Fiscal Year;

(b) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(c) The amount, if any, to be paid during such Fiscal Year into the Debt Service Reserve Account in the Debt Service Fund;

(d) The amount, if any, to be paid during such Fiscal Year into the Bond Anticipation Note Fund;

(e) The amount to be paid during such Fiscal Year into the Reserve and Contingency Fund for credit to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account therein; and

(f) All other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

The Authority will not furnish any use, output, capacity, or service of the Project free of charge to any person, firm or corporation, public or private, and the Authority will enforce the payment of any and all accounts owing to the Authority by reason of its ownership and operation of the Project by discontinuing such use, output, capacity, or service or by filing suit therefor as soon as practicable after 120 days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Power Sales Contracts and Project Agreements

The Trustee covenants that it will collect and deposit in the Revenue Fund all amounts payable to it under the Power Sales Contracts or otherwise payable to it pursuant to any contract for use of the capability of the Project or the sale of the output, capacity or service of the Project or any part thereof. The Authority will enforce the provisions of the Power Sales Contracts and duly perform its covenants and agreements thereunder, and will not agree to or permit any rescission of or amendment to, or otherwise take any action under or in connection with, the Power Sales Contracts which would reduce

the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights or security of Bondholders under the Bond Indenture.

The Authority will enforce the provisions of the Project Agreements and duly perform its covenants and agreements thereunder. The Authority will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Project Agreements which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Bondholders under the Bond Indenture; however, the Authority is not thereby prohibited from amending any Power Sales Contract with respect to Points of Delivery.

Annual Budget

The Authority will file with the Trustee an Annual Budget prepared in accordance with the Power Sales Contracts for each Fiscal Year commencing with the Fiscal Year which begins on the earliest of (i) the date to which all interest is capitalized with respect to all Bonds and Bond Anticipation Notes, (ii) the date which is one year prior to the first Principal Installment date for any Bonds, or (iii) the Date of Firm Operation of the first generating unit to be placed in service. The Annual Budget will set forth the estimated Revenues and Authority Operating Expenses of the Project, by month for such Fiscal Year and shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the Revenue Fund, the Operating Fund, including provision for any general reserve for Authority Operating Expenses and the estimated amount to be deposited in the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account in the Reserve and Contingency Fund and the requirements, if any, for the amounts estimated to be expended from each Fund and Account. The Authority shall review quarterly its estimates set forth in the Annual Budget and in the event such estimates do not substantially correspond with the actual Revenues, Authority Operating Expenses or other requirements, the Authority shall adopt an amended Annual Budget for the remainder of such Fiscal Year. The Authority is also required to adopt such an amended Annual Budget if there are at any time during such Fiscal Year extraordinary receipts or payments of unusual costs. The Authority may also at any time in accordance with the provisions of the Power Sales Contracts, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Insurance

The Authority will at all times keep or cause to be kept the properties of the Project which are of an insurable nature and of the character usually insured by those constructing or operating properties similar to the Project insured against loss or damage by fire and from other causes customarily insured against and in such amounts as are usually obtained. The Authority will also use its best efforts to maintain or cause to be maintained any additional or other insurance which the Authority deems necessary or advisable to protect its interests and those of the Bondholders. If any useful portion of the Project is damaged or destroyed, the Authority shall diligently prosecute the reconstruction or replacement thereof, unless the Authority decides not to so repair or replace. The proceeds of any insurance, including the proceeds of any self-insurance fund, paid on account of damage or destruction (other than any business interruption loss insurance) unless held and applied under the Participation Agreement, shall be held by the Trustee and applied, to the extent necessary, to pay the costs of reconstruction or replacement. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund unless otherwise required by the Participation Agreement.

Accounts and Reports

The Authority will keep or cause to be kept proper and separate books of records and accounts relating to the Project and each Fund and Account established by the Bond Indenture and relating to the costs and charges under the Power Sales Contracts. Such books, together with all other books and papers of the Authority relating to the Project, will at all times be subject to the inspection of the

Trustee and the Holders of an aggregate of not less than 5% in principal amount of Bonds then Outstanding.

The Authority will file annually with the Trustee an annual report for each Fiscal Year, accompanied by an Accountant's Certificate, relating to the Project, including a statement of assets and liabilities as of the end of such Fiscal Year, a statement of Revenues and Authority Operating Expenses, a statement of receipts and disbursements with respect to Funds and Accounts established by the Bond Indenture, and a statement as to the existence of any default under the provisions of the Bond Indenture.

The Authority will cause the Consulting Engineer to file with it and the Trustee after each three year period a report or survey with respect to the operation and maintenance of the properties constituting the Project, the making of necessary and proper renewals and replacements thereof and the status of the Annual Budget and any construction budget of the Project.

The Authority will notify the Trustee forthwith of any Event of Default or default in the performance of any provision of the Bond Indenture. The Authority will file annually with the Trustee a certificate of an Authorized Authority Representative stating whether, to the best of the signer's knowledge and belief, the Authority has complied with its covenants and obligations in the Bond Indenture and whether there is then existing an Event of Default or other event which would become an Event of Default upon the lapse of time and if any such default or Event of Default so exists, specifying the same and the nature and the status thereof.

The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of the Bond Indenture will be available for inspection of Bondholders at the office of the Trustee and will be mailed to each Bondholder who files a written request therefor with the Trustee. The Trustee may charge each Bondholder requesting such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

Extension of Payment of Bonds and Coupons

The Authority covenants in the Bond Indenture that it will not extend or assent to the extension of the maturity of any of the Bonds or the time of payment of any of the coupons or claims for interest. If the maturity of any of the Bonds or the time for payment of such coupons or claims for interest is extended, such Bonds, coupons or claims for interest shall not be entitled, in the case of any default under the Bond Indenture, to the benefit of the Bond Indenture or any payment out of Revenues, Funds or the moneys held by the Trustee or by any Paying Agent (except moneys held in trust for the payment of particular Bonds, coupons or claims for interest) except upon the prior payment of the principal of all Bonds Outstanding the maturity of which has not been extended and of the portion of accrued interest on the extended Bonds which is not represented by such extended coupons or claims for interest.

Amendments and Supplemental Indentures

Any of the provisions of the Bond Indenture may be amended by the Authority by a Supplemental Indenture upon the consent of the Holders of at least two-thirds in principal amount in each case of (1) all Bonds then Outstanding and (2) if less than all of the several Series of Outstanding Bonds are affected, the Bonds of each affected Series; excluding, in each case, from such consent, and from the Outstanding Bonds, the Bonds of any specified Series and maturity if such amendment by its terms will not take effect so long as any of such Bonds remain Outstanding. Any such amendment may not permit a change in the terms of any Sinking Fund Installment or the terms of redemption or maturity of the principal of or interest on any Outstanding Bond or make any reduction in principal, Redemption Price or interest rate without the consent of each affected Holder, or reduce the percentages of consents required for a further amendment.

The Authority may adopt (without the consent of any Holders of the Bonds or the Trustee) Supplemental Indentures to close the Bond Indenture against, or impose additional limitations upon,

issuance of Bonds or other evidences of indebtedness; to authorize Bonds of a Series; to add to the restrictions contained on the Bond Indenture; to add to the covenants of the Authority contained in the Bond Indenture; to confirm any security interest or pledge under the Bond Indenture; to authorize the establishment of a fund or funds for self-insurance; and to modify any of the provisions of the Bond Indenture in any other respect if such modification shall be, and be expressed to be, effective only after all Bonds then Outstanding cease to be Outstanding and all Bonds authenticated and delivered after the adoption of such Supplemental Indenture specifically refer to such Supplemental Indenture in the text of such Bonds. The Authority may adopt Supplemental Indentures which shall be effective upon the consent of the Trustee (without the consent of any Holders of the Bonds) to cure any ambiguity; supply any omission or correct any defect or inconsistent provision in the Bond Indenture; or to clarify matters or questions arising under the Bond Indenture and not contrary to or inconsistent with the Bond Indenture.

Notwithstanding any other provision of the Bond Indenture, certain provisions of the supplemental indentures authorizing the issuance of certain refunding Bonds may not be amended or supplemented in any manner if such amendment or supplement adversely affects the interest of the holders of such Bonds in the respective Escrow Funds or in any other manner.

Trustee; Paying Agents

The Trustee may at any time resign on 60 days' written notice to the Authority. Such resignation will take effect on the date specified in such notice, or, if a successor Trustee has been appointed by the Authority with the approval of the Bondholders pursuant to the Bond Indenture prior to such date, such resignation will take effect immediately upon the appointment of such successor. The Trustee may at any time be removed by the Holders of a majority in principal amount of the Bonds then Outstanding. Successor Trustees may be appointed by the Holders of a majority in principal amount of Bonds then Outstanding, and failing such an appointment the Authority shall appoint a successor to hold office until the Bondholders act. The Trustee and each successor Trustee, if any, must be a bank, trust company or national banking association doing business and having its principal office in either New York, New York, Chicago, Illinois, Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $50,000,000, if there be such an entity willing and able to accept appointment. The Bond Indenture requires the appointment by the Authority of one or more Paying Agents (which may include the Trustee).

Pursuant to the Bond Indenture, the Trustee, prior to the occurrence of an Event of Default and after the curing of all Events of Default which may have occurred, undertakes to perform only such duties as are specifically set forth in the Bond Indenture. If an Event of Default has occurred and has not been cured, the Trustee shall exercise such of the rights and powers vested in it by the Bond Indenture, and use the same degree of care and skill in their exercise, as a prudent man would exercise or use under the circumstances in the conduct of his own affairs. Subject to the above, neither the Trustee nor any Paying Agent shall be liable in connection with the performance of its duties under the Bond Indenture except for its own negligence, misconduct or default.

The Authority is required to pay to each Fiduciary reasonable compensation for all services rendered under the Bond Indenture and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its duties under the Bond Indenture. Each Fiduciary has a lien on any and all funds held by it under the Bond Indenture securing its rights to compensation. The Authority also agrees to indemnify and save each Fiduciary harmless against any liabilities which it may incur in the exercise and performance of its powers and duties under the Bond Indenture, and which are not due to its negligence, misconduct or default.

Defeasance

If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to the Holders of all Bonds and coupons the principal or Redemption Price, if applicable, and interest due or to become due thereon, at the times and in the manner stipulated therein and in the Bond Indenture, then the lien of the Bond Indenture and all covenants, agreements and other obligations of the Authority to the

Bondholders, shall thereupon cease, terminate and become void and be discharged and satisfied. In such event, the Trustee shall cause an accounting for such period or periods as shall be requested by the Authority to be prepared and filed with the Authority and, upon the request of the Authority shall execute and deliver to the Authority all such instruments as may be desirable to evidence such discharge and satisfaction, and the Fiduciaries shall pay over or deliver, as directed by the Authority, all moneys or securities held by them pursuant to the Bond Indenture which are not required for the payment of principal or Redemption Price, if applicable, on Bonds or payment of coupons not theretofore surrendered for such payment or redemption. If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to the Holders of all Outstanding Bonds of a particular Series, or of a particular maturity within a Series, and the coupons appertaining thereto the principal or Redemption Price, if applicable, and interest due or to become due thereon, at the times and in the manner stipulated therein and in the Bond Indenture, such Bonds shall cease to be entitled to any lien, benefit or security under the Bond Indenture, and all covenants, agreements and obligations of the Authority to the Holders of such Bonds shall thereupon cease, terminate and become void and be discharged and satisfied.

Bonds or coupons or interest installments for the payment or redemption of which moneys shall have been set aside and shall be held in trust by the Paying Agents (through deposit pursuant to the Bond Indenture of funds for such payment or redemption or otherwise) at the maturity or redemption date thereof shall be deemed to have been paid within the meaning and with the effect expressed in the above paragraph. All Outstanding Bonds of any Series, or of any maturity within a Series, and all coupons appertaining to such Bonds shall prior to the maturity or redemption date thereof be deemed to have been paid within the meaning and with the effect expressed in the above paragraph if (a) in case any of said Bonds are to be redeemed on any date prior to their maturity, the Authority shall have given to the Trustee irrevocable instructions accepted in writing by the Trustee to publish as provided in the Bond Indenture notice of redemption of such Bonds on said date, (b) there shall have been deposited with the Trustee either moneys in an amount which shall be sufficient, or Investment Securities (including any Investment Securities issued or held in book-entry form on the books of the Department of the Treasury of the United States) the principal of and the interest on which when due will provide moneys which, together with the moneys, if any, deposited with the Trustee at the same time, shall be sufficient, to pay when due the principal or Redemption Price, if applicable, and interest due and to become due on said Bonds on or prior to the redemption date or maturity date thereof, as the case may be, and (c) the Authority shall have given the Trustee in form satisfactory to it irrevocable instructions to publish, as soon as practicable, at least twice, at an interval of not less than seven days between publications, in the Authorized Newspapers a notice to the Holders of such Bonds and coupons that the deposit required by (b) above has been made with the Trustee and that said Bonds and coupons are deemed to have been paid in accordance with the Bond Indenture and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal or Redemption Price, if applicable, on said Bonds. Neither Investment Securities nor moneys deposited with the Trustee pursuant to the Bond Indenture nor principal or interest payments on any such Investment Securities shall be withdrawn or used for any purpose other than, and shall be held in trust for, the payment of the principal or Redemption Price, if applicable, and interest on said Bonds; provided that any cash received from such principal or interest payments on such Investment Securities deposited with the Trustee, (A) to the extent such cash will not be required at any time for such purpose, as determined by the Trustee, shall be paid over upon the direction of the Authority as received by the Trustee, free and clear of any trust, lien, pledge or assignment securing said Bonds or otherwise existing under the Bond Indenture, and (B) to the extent such cash will be required for such purpose at a later date, shall, to the extent practicable, be reinvested in Investment Securities maturing at times and in amounts sufficient to pay when due the principal or Redemption Price, if applicable, and interest to become due on said Bonds, on or prior to such redemption date or maturity date thereof, as the case may be, and interest earned from such reinvestments shall be paid over as received by the Trustee, free and clear of any lien, pledge or security interest securing said Bonds or otherwise existing under the Bond Indenture. For the purposes of defeasance, Investment Securities shall mean

and include only such securities as are described in clause (i) of the definition of "Investment Securities" in the Bond Indenture which shall not be subject to redemption prior to their maturity other than at the option of the holder thereof.

Any request, consent, revocation of consent or other instrument which the Bond Indenture may require or permit to be signed and executed by the Bondholders may be in one or more instruments of similar tenor, and shall be signed or executed by such Bondholders in person or by their attorneys appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney, or (ii) the holding by any person of the Bonds or coupons appertaining thereto, shall be sufficient for any purpose of the Bond Indenture (except as otherwise therein expressly provided) if made in accordance with the Bond Indenture, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable.

Events of Default and Remedies

Events of Default specified in the Bond Indenture include failure to pay principal or Redemption Price of any Bond when due; failure to pay any interest installment on any Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; and default for 120 days after written notice thereof from the Trustee or the Holders of not less than 10% in principal amount of the Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Bond Indenture or in the Bonds. Upon the happening of any such Event of Default the Trustee or the Holders of not less than 25% in principal amount of the Bonds then Outstanding may declare the principal of and accrued interest on all Bonds then Outstanding due and payable (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, the Authority will, if demanded by the Trustee, (1) account, as if it were the trustee of an express trust, for all Revenues and other moneys, securities and funds pledged or held under the Bond Indenture, and (2) cause to be paid over to the Trustee (a) forthwith, all moneys, securities and funds held by the Authority in any Fund under the Bond Indenture and (b) as received, all Revenues. The Trustee will apply all moneys, securities, funds and Revenues received during the continuance of an Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Trustee and Paying Agents, (2) to the payment of Authority Operating Expenses, and (3) to the payment of interest and principal or Redemption Price on the Bonds without preference or priority of interest over principal or principal over interest, unless the principal of all Bonds has not been declared due and payable, in which case first to the payment of interest and second to the payment of principal or Redemption Price on those Bonds which have become due and payable in order of their due dates, and if the amount available shall not be sufficient for such payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the Project.

If an Event of Default has occurred and has not been remedied the Trustee may, or on request of the Holders of not less than 25% in principal amount of Bonds Outstanding must, proceed to protect and enforce its rights and the rights of the Bondholders under the Bond Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Bond Indenture or in aid of the execution of any power granted in the Bond Indenture or any remedy granted under the Act, or for an accounting against the Authority, as if it were trustee of an express trust, or in the enforcement of any other legal or equitable rights, as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Bond Indenture. The Trustee may, and upon the request of the Holders of a majority in principal amount of the Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Bond Indenture or to preserve or protect the interests of the Trustee and of the Bondholders.

No Bondholder will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Bond Indenture or the execution of any trust under the Bond Indenture or for any remedy under the Bond Indenture, unless (1) such Bondholder previously has given the Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Bonds then Outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity either to exercise its powers under the Bond Indenture, the Act or the laws of the State of California or to institute such suit, action or proceeding, (3) there have been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (4) the Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Bond Indenture provides that nothing therein or in the Bonds affects or impairs the Authority's obligation to pay the Bonds and interest thereon when due or the right of any Bondholder to enforce such payment of his Bonds.

The Holders of not less than a majority in principal amount of Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability or would be unjustly prejudicial to Bondholders not parties to such direction.

The Insurer shall be deemed to be the Holder of any Bonds for which the Insurer has issued a municipal bond insurance policy.

Notice of Default

Notice of the occurrence of any Event of Default will be given to each registered owner of Bonds then Outstanding and to each Holder of coupon Bonds who shall have filed with the Trustee within two years preceding the mailing of such notice an address for notices.

Unclaimed Moneys

Any moneys held by a Fiduciary in trust for the payment of any of the Bonds or coupons which remain unclaimed for six years after the date when such Bonds have become due and payable, either at their stated maturity dates or by call for redemption, shall, at the written request of the Authority and after meeting certain publication requirements, be repaid to the Authority, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Bondholders shall look only to the Authority for the payment of such Bonds and coupons.

SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS

The following is a summary of certain provisions of the Power Sales Contracts entered into between the Authority and each of the Project Participants. Except as described in this summary, all of the Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Power Sales Contracts and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in the Official Statement have the meanings set forth in the Power Sales Contracts.

Entitlement to Capacity

During the Start-up Period and any Base Load Period of any generating unit of the Project, each Project Participant is obligated to take delivery of its Project Entitlement Share of the product of the Authority Percentage multiplied by the Net Energy Generation of such generating unit. After the Date of Firm Operation of each generating unit of the Project, each Project Participant is entitled to schedule for its account capacity and energy of each generating unit of the Project up to the amount obtained by multiplying its Project Entitlement Share by the Authority Percentage and the Available

Generating Capability of each generating unit of the Project; provided that such scheduling shall not reduce the Project Participant's obligations described in the preceding sentence. A Project Participant may arrange to dispose of capacity or energy from the Project to which it is entitled, but any such arrangements will not affect its obligations under its Power Sales Contract. The delivery of capacity and energy from the Generating Station will be scheduled by (or on behalf of) the Authority and the Project Participants in advance with the Operating Agent and accounted for on the basis of such advance schedules. Whenever any Project Participant schedules for its account capacity and energy from a generating unit of the Project, the Agent, acting on behalf of the Authority, unless otherwise established under the Participation Agreement, shall additionally schedule for each Project Participant a percentage of the Zero Net Load as effective during the period that such generating unit is operated to meet such schedule, equal to the product of the Project Participant's Project Entitlement Share multiplied by the Authority Percentage. The capacity and energy of the Project shall be scheduled or controlled by the Project Participants under practices and procedures approved by the Board of Directors, subject to the provisions of the Participation Agreement.

Nature of Obligation

Each Project Participant is obligated to make the payments required under its Power Sales Contract solely from the revenues of its electric system as a cost of purchased electric capacity and energy and an operating expense. Each such Project Participant has covenanted to include in its annual power system budget for each fiscal year during the term of its Power Sales Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such Power Sales Contract. The Project Participants' obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective Power Sales Contracts are not subject to reduction or offset if the Project is not operating or operable (or has been completed) or if its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the Project Participants' payment obligations under the Power Sales Contracts are not subject to any reduction or offset and are not conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

Term

The Power Sales Contracts shall constitute a binding obligation of the parties thereto from and after the effective date and the term of such Power Sales Contracts shall end on October 31, 2030 or such later date as all Bonds and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made, unless terminated sooner in accordance with provisions for termination or amendment described below.

Required Payments

For a discussion on Monthly Power Costs and the payment obligations of the respective Project Participants with respect thereto, see "Security and Sources of Payment for the Bonds — Power Sales Contracts".

Rate Covenants of Project Participants

Each Project Participant has covenanted in its Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

The Board of Directors

The Authority is administered by a Board of Directors comprised of the chief executive officer (or his designee) of the electric utility of each member of the Authority. The Project Participants are entitled to participate in Project matters in accordance with voting rights given to them as members of the Authority. See "Southern California Public Power Authority — Organization and Management" in the Official Statement. The Authority, through its Board of Directors, has the following duties and responsibilities, among others: (1) provide liaison among the Project Participants, (2) attempt to resolve any disputes among the Authority, the Project Participants, the Agent, and the Project Manager or the Operating Agent relating to the Project, (3) review, modify and approve (i) the practices and procedures to be followed by the Project Participants relating to the scheduling and controlling of capacity and energy from the Project, (ii) all Capital Improvements and the budgets therefor and provisions for financing thereof, (iii) all amendments and supplements to the Project Agreements and (iv) the Project's insurance program, (4) approve all consultants or advisors on financial and legal matters that may be retained by the Authority, (5) approve the issuance of each series of Bonds and evidences of indebtedness issued in anticipation of the issuance of Bonds and (6) perform other functions provided for in the Power Sales Contracts and the other Project Agreements.

Restrictions on Disposition

A Project Participant may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that (i) the Project Participant assigns its interest under its Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Project Participant under the Power Sales Contract, (ii) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency, (iii) an independent engineer selected by the Authority delivers an opinion that such purchaser or lessee is reasonably able to charge and collect rates and charges required to meet its obligations under the Power Sales Contract, (iv) it is determined by the Board of Directors that the disposition will not adversely affect the value of such Power Sales Contract as security for the Bonds and (v) Bond Counsel has rendered an opinion that such disposition will not adversely affect the Federal Tax Exemption.

Defaults and Remedies

The failure of a Project Participant to perform any of its obligations, including the obligation to make required payments, under its Power Sales Contract will constitute a default. In the event of a default or inability to perform by a Project Participant under its Power Sales Contract, the Authority may proceed to enforce the Project Participant's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity, or if a payment due under the Power Sales Contract remains unpaid when due, the Authority may, upon 120 days' written notice to the Project Participant, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Project Participant while the default continues. Except as a result of a transfer of the defaulting Project Participant's rights to delivery of capacity and energy and the use of Project facilities described below, the discontinuance of delivery of capacity and energy to, and the use of Project facilities by, a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Power Sales Contract. In the event the delivery of capacity and energy to, and use of Project facilities by, a Project Participant in default is discontinued, the Authority shall transfer to all other Project Participants which are not in default and which so request, a pro rata portion of the defaulting Project Participant's rights to delivery of capacity and energy and use of Project facilities. In the case of such a transfer, the Project Participants accepting additional rights to delivery of capacity and energy and use of Project facilities shall assume the defaulting Project Participant's obligations with respect to the rights which are transferred to them. In the event less than all of a defaulting Project Participant's rights to delivery of capacity and energy and use of Project facilities are transferred to non-defaulting Project Participants, the Authority shall, to the

extent possible, dispose of such remaining rights on the best terms readily available, and in such a manner as, in the opinion of Bond Counsel, does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Bonds. The obligation of the defaulting Project Participant to the Authority shall be reduced to the extent that the Authority receives payments with respect to the rights of such Project Participant which are transferred.

Termination or Amendment

As long as any Bonds issued under the Bond Indenture are outstanding or until provision has been made for the payment of any Bonds outstanding in accordance with the Bond Indenture, the Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the Bonds or which will impair or adversely affect the rights of the holders of the Bonds. Each Power Sales Contract also provides that the Authority may not, without the consent of each of the Project Participants, amend or supplement the Bond Indenture (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Project Participants under the Power Sales Contracts or to be to the disadvantage of the Project Participants or to result in increased Monthly Power Costs to the Project Participants.

Contracts Subject to Bond Indenture

It has been recognized by the Project Participants in the Power Sales Contracts that the Authority, in planning, financing, acquiring, constructing and operating the Project, must comply with the requirements of the Bond Indenture and the other Project Agreements and all licenses, permits and regulatory approvals necessary therefor, and the Project Participants have therefore agreed that the Power Sales Contracts are subject to the provisions of the Bond Indenture and the other Project Agreements and such licenses, permits and approvals.

SUMMARY OF CERTAIN PROVISIONS OF THE PARTICIPATION AGREEMENT

The following is a summary of certain provisions of the Arizona Nuclear Power Project Participation Agreement, as amended (the "Participation Agreement"). This summary is not to be considered a full statement of the terms of the Participation Agreement and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Participation Agreement.

Definitions

Arizona Nuclear Power Project: One or more nuclear steam electric Generating Units, together with all facilities, structures and Nuclear Fuel used or to be used therewith or related thereto, including the Nuclear Plant Site, all facilities and rights-of-way for the collection, transportation, treatment, storage and disposal of water required for Construction Work, Operating Work and Capital Improvements and for rail access wherever such facilities and rights-of-way are located, but excluding the ANPP High Voltage Switchyard(s), and all transmission facilities connected thereto, which may be revised from time to time by the Administrative Committee.

Base Load Period: Any period of time during which any Generating Unit is scheduled to be operated to achieve and maintain its then Maximum Generating Capability.

Date of Firm Operation: The date with respect to each Generating Unit on which the Engineering and Operating Committee determines it to be reliable as a source of Power and on which such Generating Unit can reasonably be expected to operate steadily at any load up to its Target Capacity.

Fuel Assembly: An integral unit of fabricated Nuclear Fuel prepared for insertion into a Reactor, including all hardware incorporated in such integral unit.

Generating Unit: A complete system of ANPP for generating electricity, including without limitation, the nuclear steam supply system and its containment, resident Fuel Assemblies, the turbine-generator, all auxiliary structures, system facilities and equipment necessary for or useful in the operation of the unit and any structures, systems, facilities and equipment shared with any other Generating Unit at the Nuclear Plant Site, such as the radioactive waste treatment systems, fire protection systems, water supply and treatment systems.

Generation Entitlement Share: The percentage entitlement of each Participant to the Net Energy Generation and to the Available Generating Capability.

Nuclear Fuel Agreement: Any agreement entered into by the Project Manager or the Operating Agent relating to the purchase, sale, lease, transfer, disposition, storage, transportation, mining, conversion, milling, enrichment, processing, fabrication and reprocessing of any Nuclear Fuel for use in, used in or removed from a Reactor.

Project Agreements: The Participation Agreement, any Construction Agreement, any Nuclear Fuel Agreement, but excluding any Nuclear Fuel Agreements concerning uranium concentrates to which all Participants are not parties, and any agreements between the Participants or any of them and any third party for land, land rights or water rights for ANPP, as such agreements are originally executed or as they may thereafter be supplemented or amended and any other agreements as the Participants agree to designate as Project Agreements.

Start-Up Period: The period with respect to each Generating Unit commencing with the date on which the first Fuel Assembly is inserted into the Generating Unit's Reactor and terminating with its Date of Firm Operation.

Target Capacity: The nominal generating capacity established by the Administrative Committee for each Generating Unit. The initial nominal generating capacity for each Generating Unit is 1,270 megawatts electrical.

The Agreement

Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico and El Paso Electric Company have entered into the Participation Agreement, as amended, pursuant to which each of them and the Authority as Participants will accept, acquire and own undivided interests as tenants in common in the Arizona Nuclear Power Project (the "ANPP") and all Project Agreements in proportion to its Generation Entitlement Shares, excluding (i) the Option and Purchase of Effluent Agreement, dated April 23, 1973, except to the extent only that such agreement governs the rights and obligations for the purchase and delivery of wastewater effluent required for Construction Work, Operating Work and Capital Improvements and (ii) any Project Agreement which by its terms establishes an ownership interest or rights of any Participant in the subject matter thereof which differs from its Generation Entitlement Shares under the Participation Agreement.

Energy Entitlements

The Participation Agreement does not constitute a joint venture. Each Participant is responsible for its own covenants, obligations and liabilities.

During the Start-Up Period and any Base Load Period, each Participant shall schedule and be obligated to take delivery of its Generation Entitlement Share. At all times after the Date of Firm Operation, each Participant shall be entitled to schedule generation of power and energy from each Generating Unit up to the amount of its Generation Entitlement Share of the available operating capacity of such Generating Unit and shall be entitled to receive all energy attributable thereto for its account in accordance with the provisions of the Participation Agreement, and each Participant shall be obligated to provide its own reserve requirements. Whenever any Participant schedules for its account power from a Generating Unit, the Operating Agent, unless otherwise established by the

Administrative Committee, shall additionally schedule for each Participant a percentage, equal to its Generation Entitlement Share of the available operating capacity of each Generating Unit, of the Zero Net Load effective during the period that such Generating Unit is operated to meet such schedule.

Administration

Arizona Public Service Company has been designated the Project Manager for construction and Operating Agent for operation and maintenance of the ANPP, and is responsible, as agent for the Participants, for the construction, operation and maintenance of the ANPP. For purposes of Project direction, three (3) committees are established as follows:

1. *Administrative Committee:* responsible, among other things, for providing liaison among the Participants; providing liaison among the Participants and the Project Manager and the Operating Agent with respect to progress, performance and completion of construction and operation of the ANPP; acting on certain recommendations of the Project Manager or the Operating Agent; acting upon disputes among the Participants arising under the Project Agreements; providing general supervision of the other committees established under the Participation Agreement; and for reviewing and acting upon issues and problems referred to it by another committee.

2. *Engineering and Operating Committee:* responsible, among other things, for providing liaison between the Participants and the Project Manager with regard to the construction of ANPP; establishing the Date of Firm Operation for each Generating Unit; acting upon the recommendations of the Operating Agent concerning the operation of the ANPP or the making of Capital Improvements, including among other things, the annual capital expenditures budget, annual manpower tables and budget and the annual operation and maintenance budget; developing a plan providing for coordination between the Participants, Federal, State and local authorities in the event of an abnormal occurrence at the plant site minimizing exposure of the public to radiation.

3. *Auditing Committee:* responsible, among other things, for developing accounting and auditing procedures, including the development of procedures for making forecasts and requests for funds; making periodic audits of the records maintained for the ANPP and establishing the minimum amounts for the Construction Account and the Operating Account.

Actions Pending Resolution of Disputes

If a dispute arises which is not resolved by the Administrative Committee or the higher authorities within the Participant's organizations, then, pending the resolution of the dispute by arbitration or judicial proceedings, the Project Manager or Operating Agent shall proceed with Construction Work, Operating Work or Capital Improvements in a manner consistent with the Project Agreements. If a dispute arises between any of the Participants under the Project Agreements, any Participant may call for submission of the dispute to binding arbitration.

Interconnections and Transmission Lines

Power and Energy generated by ANPP shall be delivered to the Participants by means of (i) one or more ANPP High Voltage Switchyards to be constructed and (ii) such high voltage transmission lines as the Participants or any of them determines to construct, operate and maintain to interconnect ANPP with either existing or planned transmission systems owned or to be owned, and operated, by one or more Participants or any other party with whom any Participant has or will have a right to interconnect according to the principles established in the Participation Agreement.

Construction, Operation and Maintenance Costs

The Operating Agent will establish a separate Operating Account for the payment of all costs of operation and Capital Improvements of the ANPP. Each Participant shall advance payments to the Operating Account on the basis of bills it receives which reflect such Participant's share of the costs of

Operating Work and Capital Improvements determined in accordance with the terms of the Participation Agreement. All payments due under any Nuclear Fuel Agreement, and for operating emergencies, shall be advanced to the Operating Account as required by each Participant. Each Participant is obligated to advance funds to the Operating Agent to make payments of operating and maintenance costs when due.

During the construction period each Participant is obligated to advance to the Project Manager its share of funds required for construction for deposit to the Construction Account. Each Participant shall pay weekly in advance its share (equal to its Generation Entitlement Share) of all construction costs in accordance with monthly forecasts of estimated weekly expenses prepared by the Project Manager. Upon completion of all construction, the Project Manager will prepare a final completion report of all costs of construction and the Participants will make such payments or adjustments as required so that the costs of construction are shown on the basis of ownership interests.

If a Participant shall dispute any portion of any amount specified in a request for the funds, the Participant shall make the total payment specified in the request pending a protest of such payment. If it is determined that a Participant has made advances which are greater or less than its share of the costs, the difference shall be paid or refunded to such Participant.

Transfer of Interest

Each Participant shall have the right to transfer or assign all or part of its Generation Entitlement Share, together with an equal interest in the ownership of ANPP and in the Project Agreements, to any person or entity engaged in the generation, transmission or distribution of energy. Each Participant shall also have the right, in certain circumstances, to mortgage or create security interests in, and sell and leaseback, its Generation Entitlement Share and other interests, in connection with its financing of ANPP.

Operating Emergency

The Operating Agent will advise the Participants when an emergency occurs, and shall submit an estimate of expenses required to restore the availability of each Generating Unit affected. If the uninsured costs of restoration exceed 10% of the original costs, the Operating Agent shall obtain the approval of the Administrative Committee before committing any expenses. The Operating Agent, however, may incur any expense which in its sole discretion it deems necessary to protect the health and safety of the public.

Damage to Project

If ANPP or any portion thereof should be damaged or destroyed to the extent that the costs of repairs or reconstruction is estimated to be less than 150% of the aggregate amount of Project Insurance coverage carried and covering the cost of such repairs or reconstruction, then the Project Manager or the Operating Agent shall cause such repairs or reconstruction to be made so that ANPP is restored to substantially the same general condition, character or use as existed prior to such damage or destruction and the Participants shall share the costs of such repairs or reconstruction in the proportion to their Generation Entitlement Share.

If ANPP or any portion thereof should be damaged or destroyed to the extent that the costs of repairs or reconstruction are estimated to be 150% or more of the aggregate amount of Project Insurance coverage carried and covering the cost of such repairs or reconstruction, then upon agreement of all Participants the Project Manager or the Operating Agent shall cause such repairs or reconstruction to be made as may be agreed and the Participants shall share the costs of such repairs or reconstruction in proportion to their Generation Entitlement Share; provided, however, that should all of the Participants not agree to restore or reconstruct the damaged portion of ANPP, but some of the Participants nevertheless desire to do so, then any Participant who does not agree to restore or reconstruct shall sell its share and ownership interest in ANPP to the remaining Participants for a price

equal in amount to its share in the salvage value thereof. The Participants agreeing to repair or reconstruct such Generating Unit shall share the costs of repair or reconstruction in the proportion that the share of each bears to the total shares of such Participants.

Term of Agreement

The contract became effective September 1, 1973 and extends for a period of 50 years from its effective date or 40 years from the date on which the last Generating Unit can be reasonably expected to operate continuously at its Target Capacity, whichever is later.

Defaults and Covenants

In the event of a Default by any Participant of any obligation, including the obligation to make payments when due, under the Project Agreements the non-defaulting parties shall remedy such default, either by advancing the necessary funds and/or commencing to render the necessary performance. Each non-defaulting party agrees to contribute to such remedy in the ratio of its Generation Entitlement Share to the total of the Generation Entitlement Shares of all non-defaulting parties. The defaulting party, upon notice by a non-defaulting party of a default or alleged default under the Project Agreements, shall remedy such default or alleged default, and shall pay promptly upon demand to each non-defaulting party the total amount of money, if any, together with interest thereon, paid by each such non-defaulting party. If the defaulting party disputes the default, it shall pay the disputed payment or perform the disputed obligation but may do so under protest, in which event the matter in dispute is to be submitted to arbitration and if so submitted the decision of the arbitrator or board of arbitrators shall be binding upon the parties.

DEBT SERVICE REQUIREMENTS

(Accrual Basis)

Fiscal Year Ending June 30	Prior Series Bonds*		1989 Bonds		Combined Total Debt Service
	Principal	Interest	Principal	Interest	
1989	$ 13,870,000	$ 69,466,943	$ 500,000	$ 4,032,024	$ 87,868,967
1990	14,745,000	61,716,499	510,000	10,644,005	87,615,504
1991	15,790,000	60,674,687	535,000	10,613,405	87,613,092
1992	16,955,000	59,507,411	575,000	10,580,770	87,618,181
1993	18,255,000	58,205,278	605,000	10,545,120	87,610,398
1994	19,710,000	56,754,629	645,000	10,507,005	87,616,634
1995	18,080,000	55,135,720	3,930,000	10,465,725	87,611,445
1996	17,580,000	53,701,752	6,120,000	10,214,205	87,615,957
1997	11,115,000	52,310,408	14,375,000	9,816,405	87,616,813
1998	13,900,000	51,488,696	13,360,000	8,867,655	87,616,351
1999	17,475,000	50,473,795	11,695,000	7,972,535	87,616,330
2000	17,260,000	49,167,826	14,010,000	7,177,275	87,615,101
2001	22,975,000	47,884,329	9,580,000	7,177,275	87,616,604
2002	24,640,000	46,222,687	10,245,000	6,506,675	87,614,362
2003	26,440,000	44,415,139	10,250,000	6,506,675	87,611,814
2004	32,610,000	42,550,814	6,695,000	5,763,550	87,619,364
2005	36,345,000	40,239,401	5,265,000	5,763,550	87,612,951
2006	38,910,000	37,673,168	5,635,000	5,395,000	87,613,168
2007	35,430,000	34,960,326	12,225,000	5,000,550	87,615,876
2008	37,840,000	32,556,171	13,075,000	4,144,800	87,615,971
2009	40,405,000	29,988,312	13,990,000	3,229,550	87,612,862
2010	43,200,000	27,189,881	14,975,000	2,250,250	87,615,131
2011	41,880,000	24,170,244	20,360,000	1,202,000	87,612,244
2012	36,285,000	21,237,844	28,890,000	1,202,000	87,614,844
2013	38,840,000	18,686,299	28,890,000	1,202,000	87,618,299
2014	46,450,000	15,930,276	24,030,000	1,202,000	87,612,276
2015	49,730,000	12,644,952	24,040,000	1,202,000	87,616,952
2016	79,120,000	9,121,864	0	0	88,241,864
2017	83,560,000	4,685,912	0	0	88,245,912
Totals	$ 909,395,000	$1,168,761,258	$ 295,005,000	$ 169,184,004	$2,542,345,262

* Excludes the Refunded Bonds.

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PROPOSED FORM OF BOND COUNSEL OPINION REGARDING 1989 BONDS

Upon delivery of the 1989 Bonds in definitive form, Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel, proposes to render its final approving opinion with respect to such Bonds in substantially the following form:

(Closing Date)

Board of Directors
Southern California Public Power Authority
613 East Broadway
Glendale, California 91205

Gentlemen:

We have examined (i) a record of proceedings relating to the issuance of $295.005,000 aggregate principal amount of Power Project Revenue Bonds, 1989 Refunding Series A (the "Bonds"), of Southern California Public Power Authority (the "Authority"), a public entity of the State of California; (ii) the Power Sales Contracts hereinafter referred to; and (iii) such other matters of law as we have deemed necessary to enable us to render the opinions expressed herein. The Bonds are issued under and pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), and under and pursuant to the Indenture of Trust, dated as of July 1, 1981, by and between the Authority and First Interstate Bank of California, as trustee, as amended and supplemented by the First Supplemental Indenture of Trust, dated as of August 1, 1982, and as supplemented by the Tenth Supplemental Indenture of Trust (the "Tenth Supplemental Indenture"), dated as of January 1, 1989 (such Indenture of Trust as heretofore amended and supplemented being herein called the "Indenture").

The Bonds will mature on the dates and in the principal amounts, and bear interest at the respective rates per annum, shown below.

Due July 1	Amount Maturing	Interest Rate	Due July 1	Amount Maturing	Interest Rate
1989	$ 500,000	5.80%	2001	$ 9,580,000	7.00%
1990	510,000	6.00	2002	10,245,000	0.00
1991	535,000	6.10	2003	10,250,000	7.25
1992	575,000	6.20	2004	6,695,000	0.00
1993	605,000	6.30	2007	23,125,000	7.00
1994	645,000	6.40	2010	42,040,000	7.00
1995	3,930,000	6.40	2011	20,360,000	0.00
1996	6,120,000	6.50	2012	28,890,000	0.00
1997	14,375,000	6.60	2013	28,890,000	0.00
1998	13,360,000	6.70	2014	24,030,000	0.00
1999	11,695,000	6.80	2015	24,040,000	5.00
2000	14,010,000	0.00			

The Bonds are dated, and shall bear interest from, January 15, 1989, except as otherwise provided in the Indenture. Interest on the Bonds is payable on January 1 and July 1 in each year, commencing July 1, 1989. The Bonds are subject to redemption prior to maturity in the manner and upon the terms set forth in the Indenture. The Bonds are in fully registered form without interest coupons in denominations of $5,000 or any integral multiple thereof, are interchangeable and transferable as provided in the Indenture and are lettered as provided for each maturity in the Indenture and numbered from one upward within each maturity.

The Bonds are issued to provide moneys to advance refund the Refunded Bonds (as defined in the Tenth Supplemental Indenture) all of which were issued to finance a portion of the Cost of Acquisition and Construction of the Initial Facilities (as defined in the Indenture) and to pay certain costs of issuance related to the Bonds. The Authority reserves the right to issue additional bonds under the Indenture on the terms and conditions and for the purposes stated in the Indenture. Under the provisions of the Indenture all such bonds may rank equally as to security and payment with the Authority's Outstanding (as defined in the Indenture) Power Project Revenue Bonds, 1982 Series A and B, 1983 Series A, 1984 Series A, 1985 Refunding Series A and B, 1986 Refunding Series A and B, and 1987 Refunding Series A (the "Prior Series Bonds") and the Bonds.

The Authority has entered into ten separate Power Sales Contracts (the "Power Sales Contracts") with the following purchasers (the "Purchasers") of capability of the Project (as defined in the Indenture): Department of Water and Power of The City of Los Angeles (the "Department"), Imperial Irrigation District, and the Cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton.

We are of the opinion that:

1. The Authority is duly created and validly existing under the provisions of the Act and has good right and lawful authority under the Act to acquire and construct the Initial Facilities and provide for the operation and maintenance thereof.

2. The Authority has the right and power under the Act to enter into the Indenture, and the Indenture has been duly and lawfully authorized by the Authority, is in full force and effect in accordance with its terms and is valid and binding upon the Authority and enforceable in accordance with its terms, and no other authorization for the Indenture is required. The Indenture creates the valid pledge which it purports to create of (i) the proceeds of the sale of the Bonds and any other parity bonds issued under the Indenture, (ii) the Revenues (as defined in the Indenture), and (iii) all funds established by the Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund) including the investments, if any, thereof, subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture.

3. The Authority is duly authorized and entitled to issue the Bonds, and the Bonds have been duly and validly authorized and issued by the Authority in accordance with the Constitution and statutes of the State of California, including the Act, and the Indenture. The Bonds constitute valid and binding obligations of the Authority as provided in the Indenture, are enforceable in accordance with their terms and the terms of the Indenture and are entitled to the benefits of the Act and the Indenture. The Bonds are not an obligation of the State of California, any public agency thereof (other than the Authority), or any member of the Authority or any Purchaser and neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any member of the Authority or any Purchaser is pledged for the payment of the Bonds. The Bonds rank equally as to security and payment with the Prior Series Bonds.

4. The Authority has the right and power to enter into and carry out its obligations under the Power Sales Contracts and has duly authorized, executed and delivered the Power Sales Contracts which constitute valid and binding agreements of the Authority enforceable in accordance with their terms.

5. Under the Constitution and laws of the State of California, each Power Sales Contract constitutes a valid and binding agreement of the Purchaser party thereto enforceable in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid, binding and enforceable nature of such Power Sales Contracts: (i) the legal existence or formation of any Purchaser or the incumbency of any official or officer thereof; (ii) any local or special acts or any ordinance, resolution or other proceedings of any Purchaser, including, without limitation, any

proceedings relating to the negotiation or authorization of any Power Sales Contract or the execution, delivery or performance thereof (except that we have examined the ordinances pursuant to which the respective Power Sales Contracts were authorized by the respective Purchasers); (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Purchaser; (iv) any judicial order, judgment or decree in a proceeding to which any Purchaser is a party; or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Purchaser of its Power Sales Contract. The Authority has received, independent from this opinion, opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts rendered by legal counsel to the respective Purchasers.

6. The Internal Revenue Code of 1986 (the "Code"), establishes certain requirements which must be met subsequent to the issuance and delivery of the Bonds for interest thereon to be and remain excluded from Federal gross income. Non-compliance with such requirements could cause the interest on the Bonds to be included in Federal gross income retroactive to the date of issuance of the Bonds. These requirements include, but are not limited to, provisions which prescribe yield and other limits within which the proceeds of the Bonds and other amounts are to be invested and require that certain investment earnings on the foregoing must be rebated on a periodic basis to the Treasury Department of the United States. Pursuant to the Indenture, the Authority has covenanted to maintain the exclusion from Federal gross income of the interest on the Bonds.

In our opinion, under existing law, interest on the Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the aforementioned covenant, interest on the Bonds is excluded from gross income for Federal income tax purposes.

We are further of the opinion that under existing statutes, regulations, rulings and court decisions, the Bonds are not "specified private activity bonds" within the meaning of Section 57(a)(5) of the Code and, therefore, interest on the Bonds will not be treated as a preference item for purposes of computing the alternative minimum tax imposed by Section 55 of the Code. However, we note a portion of the interest on the Bonds owned by corporations may be subject to the Federal alternative minimum tax, which is based in part on adjusted net book income or adjusted current earnings.

7. We are further of the opinion that the difference between the principal amount of the Bonds maturing on July 1 in each of the years 2000, 2002, 2004, 2007, 2010, 2011, 2012, 2013, 2014 and 2015, respectively (the "Discount Bonds"), and the initial offering price to the public (excluding bond houses, brokers or similar persons or organizations acting in the capacity of underwriters or wholesalers) at which price a substantial amount of such Discount Bonds of the same maturity was sold constitutes original issue discount which is excluded from Federal gross income to the same extent as interest on the Bonds. Further, such original issue discount accrues actuarially on a constant interest rate basis over the term of each Discount Bond and the basis of each Discount Bond acquired at such initial offering price by an initial purchaser of such Discount Bonds will be increased by the amount of such accrued original issue discount.

8. The Authority has paid (within the meaning of the Indenture) the Redemption Price and interest due and to become due on the Refunded Bonds, at the times and in the manner stipulated therein and in the Indenture, and the Refunded Bonds are no longer Outstanding. Except for the rights of the holders of the Refunded Bonds to payments from the Escrow Fund established by the Tenth Supplemental Indenture, the Refunded Bonds have ceased to be entitled to any lien, benefit or security under the Indenture, and all covenants, agreements and obligations of the

Authority to the holders of the Refunded Bonds have ceased, terminated, become void and been discharged and satisfied.

The opinions expressed in paragraphs 2, 3, 4 and 5 hereof are qualified to the extent that the enforceability of the Indenture, the Bonds and the Power Sales Contracts, respectively, may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights generally or as to the availability of any particular remedy.

We have examined the executed Bond in registered form numbered R-1, and in our opinion the form of such Bond and its execution are regular and proper.

On July 27, 1982, three individual plaintiffs filed an action entitled *Thurston et al. v. Southern California Public Power Authority et al.* in the Superior Court for the County of Los Angeles against the Authority, the Department and other unnamed defendants. In this action, the plaintiffs have (i) raised certain issues concerning the validity and legality of revenue bonds (which could include the Bonds) proposed to be issued to finance the acquisition and construction by the Authority of an interest in the Palo Verde Project, and certain terms and provisions thereof, and (ii) alleged, among other things, that under the Constitution and statutes of the State of California and/or the Los Angeles City Charter, the obligations undertaken by the Department under its Power Sales Contract constitute (a) a debt requiring approval of the voters of the City under the Constitution of the State of California, which vote was not obtained, (b) a pledge of the Department's revenues in violation of the Los Angeles City Charter and (c) unsound or unlawful business practices, an unsound business venture or are otherwise illegal. As to the issues raised by the plaintiffs concerning the validity and legality of such revenue bonds and certain terms and provisions thereof, described in (i) above, we are of the opinion that such issues are without merit. As to the issues raised by the plaintiffs concerning the obligations undertaken by the Department under its Power Sales Contract, described in (ii) above, the Los Angeles City Attorney is rendering his opinion to the effect that such issues are without merit.

Very truly yours,

MUDGE ROSE GUTHRIE ALEXANDER & FERDON

APPENDIX F

Department of Water and Power the City of Los Angeles

February 2, 1989

Board of Directors
Southern California Public Power Authority
613 East Broadway
Glendale, California 91205

Gentlemen:

In connection with the Department's purchase from the Southern California Power Public Authority (the "Authority") of a 67% entitlement to the output of the Authority Interest in the Palo Verde Nuclear Generating Station, the Department has conducted certain studies and analyses which have included projections with respect to, among other things, the estimated cost of power from Authority Interest as contained in the Report of the Consulting Engineer set forth as Appendix A to the Official Statement to which this letter is attached (the "Official Statement"), the estimated cost and availability of oil and natural gas, future load growth in The City of Los Angeles, and the estimated future power system revenue requirements necessary to satisfy its cost of such purchase. The Department has also compared the projected cost of power from the Authority Interest with the projected cost of power from its existing facilities.

Based upon these studies and analyses, we are of the opinion that:

1. The Department's share of the output from the Authority Interest will, over time, be economically beneficial to the Department in displacing base load oil- and natural gas-fired generation in the Los Angeles basin;

2. The projected cost of power to the Department from the Authority Interest makes such power economically attractive in the long term to the Department when compared with the projected price levels of oil and natural gas and with the projected cost of power from other alternative resources which may be available to the Department; and

3. For the period through June 30, 1993, the Department's electric system revenues will be sufficient to enable it to pay the Authority all amounts payable under the Department's Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, the Department's power system revenues.

Respectfully submitted,

DEPARTMENT OF WATER AND POWER
OF THE CITY OF LOS ANGELES

By: /s/ ELDON A. COTTON
Assistant General Manager — Power

By: /s/ NORMAN J. POWERS
Chief Financial Officer

111 North Hope Street, Los Angeles, California ☐ *Mailing address:* Box 111, Los Angeles 90051
Telephone: (213) 481-4211 *Cable address:* DEWAPOLA

Municipal Bond Insurance Policy

AMBAC Indemnity Corporation
c/o CT Corporation Systems
222 W. Washington Ave., Madison, WI 53703
Administrative Office:
One State Street Plaza, New York, NY [redacted]

Issuer:

Policy Number: [redacted]

Bonds:

Premium:

AMBAC

AMBAC Indemnity Corporation (AMBAC) A Wisconsin Stock Insurance Company

in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to the United States Trust Company of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of Bondholders, that portion of the principal of and interest on the above-described debt obligations (the "Bonds") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer.

AMBAC will make such payments to the Insurance Trustee within 5 days following notification to AMBAC of Nonpayment. Upon a Bondholder's presentation and surrender to the Insurance Trustee of such unpaid Bonds or appurtenant coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Bondholder the face amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, AMBAC shall become the owner of the surrendered Bonds and coupons and shall be fully subrogated to all of the Bondholder's rights to payment.

In cases where the Bonds are issuable only in a form whereby principal is payable to registered Bondholders or their assigns, the Insurance Trustee shall disburse principal to a Bondholder as aforesaid only upon presentation and surrender to the Insurance Trustee of the unpaid Bond, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to the Insurance Trustee, duly executed by the Bondholder or such Bondholder's duly authorized representative, so as to permit ownership of such Bond to be registered in the name of AMBAC or its nominee. In ca[redacted] where the Bonds are issuable only in a form whereby interest is payable to registered Bondholders or their assigns, [redacted] Insurance Trustee shall disburse interest to a Bondholder as aforesaid only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Bond and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to the Insurance Trustee, duly executed by the claimant Bondholder or such Bondholder's duly authorized representative, transferring to AMBAC all rights under such Bond to receive the interest in respect of which the insurance disbursement was made. AMBAC shall be subrogated to all of the Bondholders' rights to payment on registered Bonds to the extent of the insurance disbursements so made.

SPECIMEN

As used herein, the term "Bondholder" means any person other than the Issuer who, at the time of Nonpayment, is the owner of a Bond or of a coupon appertaining to a Bond. "Due for Payment", when referring to the principal of Bonds, is when the stated maturity date or a mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity; and, when referring to interest on the Bonds, is when the stated date for payment of interest has been reached. "Nonpayment" means the failure of the Issuer to have provided sufficient funds to the paying agent for payment in full of all principal of and interest on the Bonds which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Bonds prior to maturity. This Policy does not insure against loss of any redemption, prepayment or acceleration premium which at any time may become due in respect of any Bond, nor against risk other than Nonpayment.

In witness whereof, AMBAC has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon AMBAC by virtue of the counter-signature of its duly authorized representative.

President

AMBAC INDEMNITY CORPORATION
CORPORATE
SEAL
WISCONSIN

Stephen D. Cooke
Secretary

Effective Date:

Authorized Representative [redacted]

UNITED STATES TRUST COMPANY OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Cynthia Chaney
Authorized Officer

Form # 66-0003 (11/87)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

REPORT WITH FINANCIAL STATEMENTS
AND SUPPLEMENTAL FINANCIAL INFORMATION

June 30, 1988 and 1987

400 South Hope Street
Los Angeles, CA 90071-2889

Telephone 213 236 3000

Price Waterhouse

Report of Independent Accountants

September 2, 1988

To the Board of Directors of
Southern California Public
Power Authority

In our opinion, the accompanying combined balance sheet and the related combined statements of operations and of cash flows present fairly the financial position of the Southern California Public Power Authority (Authority) at June 30, 1988 and 1987, and the results of its operations and its cash flows for the years then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying separate balance sheets and the related separate statements of cash flows of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project and Mead-Phoenix Project, and the separate statements of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project present fairly the financial position of each of the Projects at June 30, 1988, and their cash flows and the results of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project for the year, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceeding year. Our examination of these statements was made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

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

Price Waterhouse

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED BALANCE SHEET

(In thousands)

	June 30, 1988					
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Total	June 30, 1987 Total
ASSETS						
Utility plant						
Production	$ 600,458				$ 600,458	$ 368,755
Transmission	5,988	$ 656,773			662,761	636,546
General	81	18,724			18,805	18,126
	606,527	675,497			1,282,024	1,023,427
Less - Accumulated depreciation	34,224	38,064			72,288	34,072
	572,303	637,433			1,209,736	989,355
Construction work in progress	2,028	912		$12,600	15,540	236,512
Nuclear fuel, at amortized cost	31,330				31,330	36,415
Net utility plant	605,661	638,345		12,600	1,256,606	1,262,282
Special funds						
Investments	221,918	150,768	$26,970	1,843	401,499	412,547
Advance to Intermountain Power Agency		20,161			20,161	20,981
Advances for capacity and energy, net			6,009		6,009	3,064
Interest receivable	2,204	855	264		3,323	5,223
Cash			684	14	698	546
	224,122	171,784	33,927	1,857	431,690	442,361
Accounts receivable	836				836	5,587
Materials and supplies	6,528				6,528	
Costs recoverable from future billings to participants	42,967	71,776	(95)		114,648	84,310
Deferred costs						
Unamortized debt expenses, less accumulated amortization of $36,164 and $28,178 in 1988 and 1987	210,841	161,546	1,159	54	373,600	386,802
Other deferred costs	1,309				1,309	1,542
	212,150	161,546	1,159	54	374,909	388,344
	$1,092,264	$1,043,451	$34,991	$14,511	$2,185,217	$2,182,884
LIABILITIES						
Long-term debt	$1,028,965	$ 998,578	$34,294	$ 100	$2,061,937	$2,087,332
Current liabilities						
Long-term debt due within one year	13,095	2,260		14,048	29,403	
Accrued interest	37,573	38,611	689	351	77,224	77,180
Accounts payable and accrued expenses	12,631	4,002	8	12	16,653	18,372
	63,299	44,873	697	14,411	123,280	95,552
Commitments and contingencies						
	$1,092,264	$1,043,451	$34,991	$14,511	$2,185,217	$2,182,884

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED STATEMENT OF OPERATIONS

(In thousands)

	Year ended June 30, 1988				
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Total	Year ended June 30, 1987
Operating revenues					
Sales of electric energy	$85,828		$2,530	$ 88,358	$52,015
Sales of transmission services		$ 82,332		82,332	40,617
Total operating revenues	85,828	82,332	2,530	170,690	92,632
Operating expenses					
Nuclear fuel	9,042			9,042	7,259
Other operation	13,313	8,750	1,131	23,194	17,264
Maintenance	6,388	3,159		9,547	6,274
Depreciation	18,241	19,975		38,216	30,732
Expense charged to projects during construction	(520)			(520)	(370)
Total operating expenses	46,464	31,884	1,131	79,479	61,159
Debt expenses					
Interest on debt, net	72,961	63,983	1,304	138,248	148,941
Allowance for borrowed funds used during construction	(16,699)			(16,699)	(40,498)
Net debt expense	56,262	63,983	1,304	121,549	108,443
Total expenses	102,726	95,867	2,435	201,028	169,602
Costs recoverable from future billings to participants	$(16,898)	$(13,535)	$ 95	$(30,338)	$(76,970)

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED STATEMENT OF CASH FLOWS

(In thousands)

	Year ended June 30, 1988					
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Total	Year ended June 30, 1987 Total
Cash flows from operating activities:						
Sales of electric energy	$ 85,828		$ 2,530		$ 88,358	$ 52,015
Sales of transmission services		$ 82,332			82,332	40,617
Expenses of operations	(102,726)	(95,867)	(2,435)		(201,028)	(169,602)
Adjustments to arrive at net cash provided by (used for) operating activities:						
Depreciation and amortization	27,283	19,975			47,258	37,187
Other, net	10,388	6,752			17,140	17,775
Changes in current assets and liabilities:						
Interest receivable	(451)	2,113	238		1,900	(677)
Accounts receivable	2,023	2,662	66		4,751	(155)
Materials and supplies	(6,528)				(6,528)	
Other assets	232	68	54		354	23,206
Accrued interest	119				119	(14,947)
Accounts payable and accrued expenses	(1,639)	774	(816)		(1,681)	1,544
Net cash provided by (used for) operating activities	14,529	18,809	(363)		32,975	(13,037)
Cash flows from investing activities:						
Payments for construction of facility	(15,378)	(25,307)			(40,685)	(72,590)
Advances for capacity and energy, net			(2,945)		(2,945)	
Payments for feasibility study				$(1,061)	(1,061)	(771)
Purchases of investments	(1,082,161)	(1,821,388)	(149,058)	(4,479)	(3,057,086)	(2,149,158)
Proceeds from sale of investments	1,082,472	1,827,066	153,050	5,546	3,068,134	2,234,397
Refund from (advance to) Intermountain Power Agency		820			820	(20,981)
Net cash provided by (used for) investing activities	(15,067)	(18,809)	1,047	6	(32,823)	(9,103)
Cash flows from financing activities:						
Proceeds from sale of refunding bonds						679,434
Proceeds from sale of revenue bonds						34,293
Payment for bond issue costs						(107,549)
Payment for defeasance of revenue bonds						(508,703)
Payment of bond anticipation notes						(75,000)
Net cash provided by financing activities						22,475
Net increase (decrease) in cash	(538)		684	6	152	335
Cash at beginning of year	538			8	546	211
Cash at end of year	$ -	$ -	$ 684	$ 14	$ 698	$ 546
Cash paid during the year for interest (net of amount capitalized)	$58,328	$77,221	$2,757	$ -	$138,306	$121,113

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

NOTES TO FINANCIAL STATEMENTS

NOTE A - Organization and purpose:

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

The members have the following participation percentages in the Authority's interest in the four projects:

Participant	Palo Verde	Southern Transmission System	Hoover Uprating	Mead-Phoenix
City of Los Angeles	67.0%	59.5%		61.2%
City of Anaheim		17.6	42.6%	15.0
City of Riverside	5.4	10.2	31.9	6.0
Imperial Irrigation District	6.5			
City of Vernon	4.9			3.0
City of Azusa	1.0		4.2	.6
City of Banning	1.0		2.1	.6
City of Colton	1.0		3.2	.6
City of Burbank	4.4	4.5	16.0	5.0
City of Glendale	4.4	2.3		5.0
City of Pasadena	4.4	5.9		3.0
	100.0%	100.0%	100.0%	100.0%

Note A - Organization and purpose:
(Continued)

Palo Verde Project - The Authority, pursuant to an assignment agreement dated as of August 14, 1981 with the Salt River Project Agricultural Improvement and Power District, purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). As of July 1, 1981, ten participants had entered into power sales contracts with the Authority to purchase the Authority's share of PVNGS capacity and energy. Units 1, 2 and 3 of the Palo Verde Project began commercial operation in January and September 1986, and January 1988, respectively.

Southern Transmission System Project - The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has agreed to make payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), a transmission line which will provide for the transmission of energy from the Intermountain Power Project (IPP) in Utah to Southern California. The Authority entered into an agreement also dated as of May 1, 1983 with six of its participants pursuant in which each member assigned its entitlement to capacity of STS to the Authority in return for the Authority's agreement to make payments-in-aid of construction to IPA. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles, a member of the Authority, has served as project manager and operating agent of IPP.

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

NOTE A - Organization and purpose:
(Continued)

Construction is scheduled for completion by September 1992. The Authority will have an 18.68% interest in the contingent capacity of the Hoover Uprating Project. Several "uprated" generators of the Hoover Uprating Project have commenced commercial operations since June 1987.

Mead-Phoenix Project - The Authority has also studied the feasibility of constructing the proposed Mead-Phoenix DC Intertie Project (Mead-Phoenix Project), a transmission line from Arizona to Nevada. The Authority's present interest in the Mead-Phoenix Project is 93.75%. The feasibility study is substantially complete and present plans call for the Authority to decide whether to continue with the project in fiscal year 1989.

NOTE B - Summary of significant accounting policies:

The Authority maintains its records substantially in accordance with accounting principles and methods prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by such commissions.

Utility plant - All expenditures, including general administrative and other overhead expenses, payments-in-aid of construction, interest net of related investment income, deferred cost amortization and the fair value of test power generated and delivered to the participants are capitalized as utility plant construction work in progress until a facility begins commercial operation.

The Authority's share of costs associated with PVNGS is included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service life of thirty-five years. Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982,

NOTE B - Summary of significant accounting policies:
(Continued)

the Authority is charged one mill per kilowatt-hour on its share of electricity produced by PVNGS. The Authority records this charge as a current year expense.

The costs associated with STS are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thrity-five years.

Advances for capacity and energy - Advance payments to USBR for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by USBR billings to participants for energy and capacity.

Nuclear decommissioning - Decommissioning of PVNGS is projected to start sometime after 2027. The Authority is providing for its share of the estimated future decommissioning costs over the life of the nuclear power plant through annual charges to expense.

A Nuclear Decommissioning Fund was established in 1986. The deposits to the fund plus the interest earnings on the fund balances are expected to be sufficient to pay the Authority's share of the decommissioning costs.

Deferred costs - Deferred costs are shown net of accumulated amortization. Unamortized debt issue costs, including the cost of refunding, are amortized over the terms of the respective issues. Other deferred costs are amortized generally over five years.

Investments - Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities. These investments are stated at amortized cost. As discussed in Note C, all of the investments are restricted as to their use.

NOTE B - Summary of significant accounting policies:
(Continued)

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

Debt expenses - Debt expenses include interest on debt, the amortization of bond premiums and discounts, debt issue and refunding costs. Income from investments is recorded as a reduction of debt expense.

Statement of Cash Flows - During the year ended June 30, 1988, the Authority adopted Statement of Accounting Standards No. 95, "Statement of Cash Flows". Accordingly, fiscal year 1987 items have been restated to conform with the fiscal year 1988 presentation.

NOTE C - Special funds:

The Bond Indentures for three of the four projects require the following special funds to be established to account for the Authority's receipts and disbursements. The moneys and investments held in these funds are restricted in use to the purposes stipulated in the bond indentures. A summary of these funds follows:

NOTE C - Special funds:
(Continued)

Fund	Held by	Purpose
Construction	Trustee	To disburse funds for the acquisition and construction of the Project
Debt Service	Trustee	To pay interest and principal related to the Revenue Bonds
Revenue	Trustee	To initially receive all revenues and disburse them to other funds
Operating	Trustee	To pay operating expenses
Reserve and Contingency	Trustee	To pay capital improvements and make up deficiencies in other funds and, in the case of the Palo Verde Project, accumulate funds for decommissioning
General Reserve	Trustee	To make up any deficiencies in other funds
Advance Payments	Trustee	To disburse funds for the cost of acquisition of capacity

Special funds, in thousands, were as follows:

	June 30,			
	1988		1987	
Project	Carrying Value	Market	Carrying Value	Market
Palo Verde	$224,122	$231,950	$224,520	$235,136
STS	171,784	171,139	180,395	192,319
Hoover Uprating	33,927	33,609	34,528	34,217
Mead-Phoenix	1,857	1,860	2,918	2,918
	$431,690	$438,558	$442,361	$464,590

NOTE C - Special funds:

(Continued)

Palo Verde Project - The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Construction Fund-Initial Facilities Account	$ 48,666	$ 38,454
Debt Service Fund -		
Debt Service Account	63,780	67,711
Debt Service Reserve Account	90,050	90,235
Bond Anticipation Note Fund	30	30
Revenue Fund	735	1
Operating Fund	11,155	15,739
Reserve and Contingency Fund	9,706	8,169
General Reserve Fund		4,181
Total Special Funds	$224,122	$224,520

Southern Transmission System Project - The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Construction Fund - Initial Facilities Account	$ 10,310	$ 18,638
Debt Service Fund -		
Debt Service Account	41,086	38,623
Debt Service Reserve Account	89,079	91,192
Revenue Fund	1	1
Operating Fund	7,239	6,249
General Reserve Fund	3,908	4,711
Total Special Funds	$151,623	$159,414

During fiscal year 1987 the Authority advanced to IPA $20,981,000 for their proportionate share of certain operating and capital requirements associated with STS. During fiscal year 1988 the advance was reduced to $20,161,000.

NOTE C - Special funds:

(Continued)

Hoover Uprating Project - The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1988	June 30, 1987
Advance Payments Fund	$23,244	$27,277
Operating Working Capital Fund	340	
Debt Service Fund		
Debt Service Account	714	932
Debt Service Reserve Account	3,620	3,255
Total Special Funds	$27,918	$31,464

At June 30, 1988 the Authority had advances to USBR amounting to $6,009,000.

Mead-Phoenix Project - At June 30, 1988 and 1987, the balance in the Development Fund was $1,857,000 and $2,918,000 of which substantially all were invested in securities of the United States Government.

NOTE D - Long-term debt:

Palo Verde Project - To finance the purchase and construction of the Authority's share of the Palo Verde Project, the Authority issued Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of July 1, 1981 (Bond Indenture), as amended and supplemented. Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Palo Verde Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond

NOTE D - Long-term debt:
(Continued)

Indenture and (3) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject to the provisions of the Palo Verde Project Bond Indenture providing for the application thereof.

All outstanding Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal year 1998 for the 1982 Series A Bonds, 1999 for the 1982 Series B Bonds and the 1983 Series A Bonds, 2001 for the 1984 Series A Bonds and the 1985 Series A Bonds, 2005 for the 1985 Series B Bonds and 2003 for the 1986 Series A Bonds, the 1986 Series B Bonds and the 1987 Series A Bonds. Scheduled principal maturities for the Palo Verde Project during the five fiscal years following June 30, 1988 are $13,095,000 in 1989, $13,870,000 in 1990, $14,745,000 in 1991, $15,790,000 in 1992 and $16,955,000 in 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 7.2% and 8.4%, respectively.

Southern Transmission System Project - To finance payments-in-aid of construction to IPA for construction of STS the Authority issued Transmission Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of May 1, 1983 (Bond Indenture), as amended and supplemented. Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to STS (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture; subject to the provisions of the Bond Indenture providing for the application thereof.

NOTE D - Long-term debt:
(Continued)

All outstanding Transmission Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal year 2000 for the 1984 Series A Bonds, 2001 for the 1984 Series B Bonds and the 1985 Series A Bonds, 2003 for the 1986 Series A Bonds and 2002 for the 1986 Series B Bonds. Scheduled principal maturities for STS during the five fiscal years following June 30, 1988 are $2,260,000 in 1989, $3,785,000 in 1990, $7,945,000 in 1991, $8,485,000 in 1992 and $9,115,000 in 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 7.7%.

Hoover Uprating Project - To finance advance payments to USBR for application to the costs of the Hoover Uprating Project, the Authority issued Hydroelectric Power Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of March 1, 1986 (Bond Indenture). Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1988 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) the proceeds from the sale of the bonds, (2) all revenues from sales of energy to participants (see Note E), (3) interest or other receipts derived from any moneys or securities held pursuant to the Bond Indenture and (4) all funds established by the Indenture of Trust (except for the Interim Advance Payments Account in the Advance Payment Fund); subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Hydroelectric Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

NOTE D - Long-term debt:
(Continued)

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal year 2002 for the 1986 Series A Bonds. No principal maturities of bonds outstanding at June 30, 1988 are scheduled for fiscal years 1989 through 1993. The effective interest rate on outstanding debt during fiscal years 1988 and 1987 was 8.0% and 8.1%, respectively.

The Authority estimates that the total financing requirements for its interest in the Hoover Uprating Project will approximate $34 million, of which substantially all will be expended for payments for capacity and associated firm energy and the acquisition of entitlements to capacity.

Mead-Phoenix Project - At June 30, 1988, the Authority had borrowed $14,148,000 to finance the feasibility study and development costs of the Mead-Phoenix Project. This loan bears interest at approximately 67% of the prime rate; however, the interest rate cannot exceed 12%. The average interest rate on this loan was 5.9% and 5.2% during fiscal years 1988 and 1987, respectively.

The proceeds of the loan were deposited in a Development Fund for which the lender is the trustee and can only be used for payment of Mead-Phoenix Project development costs, costs of issuance of the loan, including general and administrative expenses of the Authority related to the Mead-Phoenix Project, and loan principal and interest.

The feasibility study is substantially complete and present plans call for the Authority to decide whether to continue with the project in fiscal year 1989.

On April 6, 1988, the Authority adopted a note retirement plan. The plan involves voluntary payments by each participant of its proportionate share of the liability with respect to the loan. The Authority intends to repay all but $100,000 during fiscal year 1989.

NOTE D - Long-term debt:
(Continued)

Refunding bonds - During fiscal year 1987, the proceeds from the sale of $707,275,000 of Power Project Refunding Bonds were used to advance refund $630,120,000 of previously issued bonds. In connection therewith, the net proceeds of the refunding bonds have been invested in securities of the United States Government, the principal and interest from which will be sufficient to fund the remaining principal, interest and call premium payments on the refunded bonds until the stated first call dates of the respective issues. Accordingly, all amounts related to the refunded bonds have been removed from the balance sheets and the cost of refunding the debt is included in unamortized debt expenses. At June 30, 1988 the aggregate amount of debt considered to be extinguished was $1,875,050,000.

NOTE E - Power sales and transmission service contracts:

The Authority has sold its entitlement to the output of the Palo Verde Project pursuant to power sales contracts with ten participants (see Note A). Under the terms of the contracts, the participants are entitled to power output from the Palo Verde Nuclear Generating Station and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Power Project Revenue Bonds and other debt, whether or not the Palo Verde Project or any part thereof has been completed, is operating or operable, or its output is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2030 and, as long as any Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

The Authority has entered into transmission service contracts with six participants of STS (see Note A). Under the terms of the contracts, the participants are entitled to transmission service utilizing STS and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance

NOTE E - Power sales and transmission service contracts:
(Continued)

expenses and debt service on Transmission Project Revenue Bonds and other debt, whether or not STS or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2027 and, as long as any Transmission Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

In March 1986, the Authority entered into power sales contracts with six participants of the Hoover Uprating Project (see Note A). Under the terms of the contracts, the participants are entitled to capacity and associated firm energy of the Hoover Uprating Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service whether or not the Hoover Uprating Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The contracts expire in 2018 and as long as the Hydroelectric Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

NOTE F - Costs recoverable from future billings to participants:

Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. Those expenses, according to generally accepted accounting principles, which are not included as "costs" are deferred to such periods as they are intended to be recovered through billings.

NOTE G - Commitments and contingencies:

As a participant in the PVNGS, the Authority could be subject to assessment of retroactive insurance premium adjustments in the event of a nuclear incident at the PVNGS or at any other licensed reactor in the United States.

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

INDEX TO SUPPLEMENTAL FINANCIAL INFORMATION

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED SCHEDULE OF LONG-TERM DEBT
AT JUNE 30, 1988
(In thousands)

	Series	Date of Sale	Effective Interest Rate	Maturity on July 1	Total
Palo Verde Project Revenue and Refunding Bonds	1982A	8/13/82	10.9%	1988 to 2017	$ 26,325
	1982B	11/12/82	7.7%	1988 to 2017	44,445
	1983A	4/ 8/83	8.8%	1988 to 2017	36,015
	1984A	7/18/84	10.3%	1990 to 2004	24,090
	1985A	5/22/85	8.7%	1988 to 2014	12,515
	1985B	7/ 2/85	9.1%	1988 to 2017	101,815
	1986A	3/13/86	8.2%	1988 to 2015	157,645
	1986B	12/16/86	7.2%	1988 to 2017	354,630
	1987A	2/11/87	6.9%	1988 to 2017	352,645
					1,110,125
Southern Transmission System Project Revenue and Refunding Bonds	1984A	2/ 9/84	9.3%	1990 to 2004	65,945
	1984B	10/17/84	10.2%	1990 to 2000	18,770
	1985A	8/15/85	8.9%	1989 to 2021	121,620
	1986A	3/18/86	8.0%	1988 to 2021	371,720
	1986B	4/29/86	7.5%	1988 to 2023	480,010
					1,058,065
Hoover Uprating Project Revenue Bonds	1986A	8/13/86	8.1%	1993 to 2017	34,435
Mead-Phoenix Bank Loan					14,148
Total Principal Amount					2,216,773
Less: Unamortized Bond Discount -					
Palo Verde Project Revenue and Refunding Bonds					68,065
Southern Transmission System Project Revenue and Refunding Bonds					57,227
Hoover Uprating Power Project Revenue Bonds					141
Total Unamortized Bond Discount					125,433
Total Long-Term Debt Less Unamortized Bond Discount					$2,091,340

Bonds which have been refunded are excluded from this schedule.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1988	June 30, 1987
ASSETS		
Utility plant		
Production	$ 600,458	$ 368,755
Transmission	5,988	3,512
General	81	58
	606,527	372,325
Less - Accumulated depreciation	34,224	15,983
	572,303	356,342
Construction work in progress	2,028	224,809
Nuclear fuel, at amortized cost	31,330	36,415
Net utility plant	605,661	617,566
Special funds		
Investments	221,918	222,229
Interest receivable	2,204	1,753
Cash		538
	224,122	224,520
Accounts receivable	836	2,859
Materials and supplies	6,528	
Costs recoverable from future billings to participants	42,967	26,069
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $18,643 and $13,698 in 1988 and 1987	210,841	218,503
Other deferred costs	1,309	1,542
	212,150	220,045
	$1,092,264	$1,091,059
LIABILITIES		
Long-term debt	$1,028,965	$1,039,335
Current liabilities		
Long-term debt due within one year	13,095	
Accrued interest	37,573	37,454
Accounts payable and accrued expenses	12,631	14,270
	63,299	51,724
Commitments and contingencies		
	$1,092,264	$1,091,059

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year ended June 30, 1988	1987
Operating revenue		
Sales of electric energy	$ 85,828	$ 51,949
Operating expenses		
Nuclear fuel	9,042	7,259
Other operation	13,313	10,162
Maintenance	6,388	3,192
Depreciation	18,241	12,643
Expense charged to projects during construction	(520)	(370)
Total operating expenses	46,464	32,886
Debt expenses		
Interest on debt, net	72,961	78,290
Allowance for borrowed funds used during construction	(16,699)	(40,498)
Net debt expense	56,262	37,792
Total expenses	102,726	70,678
Costs recoverable from future billings to participants	$(16,898)	$(18,729)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year ended June 30, 1988	1987
Cash flows from operating activities:		
Sales of electric energy	$ 85,828	$ 51,949
Expenses of operations	(102,726)	(70,678)
Adjustments to arrive at net cash provided by operating activities:		
Depreciation and amortization	27,283	19,098
Other, net	10,388	9,723
Changes in current assets and liabilities:		
Interest receivable	(451)	515
Accounts receivable	2,023	2,560
Materials and supplies	(6,528)	
Other assets	232	
Accrued interest	119	(4,529)
Accounts payable and accrued expenses	(1,639)	5,055
Net cash provided by operating activities	14,529	13,693
Cash flows from investing activities:		
Payments for construction of facility	(15,378)	(55,131)
Purchases of investments	(1,082,161)	(1,124,179)
Proceeds from sale of investments	1,082,472	1,176,515
Net cash used for investing activities	(15,067)	(2,795)
Cash flows from financing activities:		
Proceeds from sale of refunding bonds		679,434
Payment for bond issue costs		(106,289)
Payment for defeasance of revenue bonds		(508,703)
Payment of bond anticipation notes		(75,000)
Net cash used for financing activities		(10,558)
Net increase (decrease) in cash	(538)	340
Cash at beginning of year	538	198
Cash at end of year	$ -	$ 538
Cash paid during the year for interest (net of amount capitalized)	$58,328	$43,819

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS
IN FUNDS REQUIRED BY THE BOND INDENTURE

YEAR ENDED JUNE 30, 1988
(In thousands)

	Construction Fund Initial Facilities Account	Debt Service Fund	Bond Anticipation Note Fund	Revenue Fund	Operating Fund	Reserve & Contingency Fund	General Reserve Fund	Total
Balance at June 30, 1987	$38,234	$157,906	$29		$15,575	$8,478	$4,178	$224,400
Additions								
Investment earnings	2,335	14,896	1	$ 82	1,323	1,040	6	19,683
Sales	1,896			85,716				87,612
Other income	58				59			117
Transfer of interest payment		102,906						102,906
Transfer of investments	8,458				(2,563)	(1,724)	(4,171)	
Transfer of investment earnings	5,597	(14,630)	(1)	11,112	(1,308)	(764)	(6)	
Transfer of sales receipts		71,680		(99,488)	19,038	3,880	4,890	
Miscellaneous transfers	1,453	(66)		2,996	250	264	(4,897)	
Total	19,797	174,786	-	418	16,799	2,696	(4,178)	210,318
Deductions								
Construction expenditures	5,489					845		6,334
Operating expenditures					18,046			18,046
Fuel costs	2,920				591			3,511
Interest		178,052						178,052
Property tax	1,332				2,665			3,997
Financing costs	141							141
Interest on investment purchases	14	22			15	18		69
Premium on investment purchases	368	244				628		1,240
Total	10,264	178,318			21,317	1,491		211,390
Balance at June 30, 1988	$47,767	$154,374	$29	$ 418	$11,057	$9,683	$ -	$223,328

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,204 and $1,753 at June 30, 1988 and 1987, nor do they include total amortized net investment premiums of $1,724 and $1,632 at June 30, 1988 and 1987.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1988	June 30, 1987
ASSETS		
Utility plant		
Transmission	$ 656,773	$ 633,034
General	18,724	18,068
	675,497	651,102
Less - Accumulated depreciation	38,064	18,089
	637,433	633,013
Construction work in process	912	
Net utility plant	638,345	633,013
Special funds		
Investments	150,768	156,446
Advance to Intermountain Power Agency	20,161	20,981
Interest receivable	855	2,968
	171,784	180,395
Accounts receivable		2,662
Costs recoverable from future billings to participants	71,776	58,241
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $16,910 and $13,999 in 1988 and 1987	161,546	167,084
	$1,043,451	$1,041,395
LIABILITIES		
Long-term debt	$ 998,578	$ 999,556
Current liabilities		
Long-term debt due within one year	2,260	
Accrued interest	38,611	38,611
Accounts payable and accrued expenses	4,002	3,228
	44,873	41,839
Commitments and contingencies		
	$1,043,451	$1,041,395

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year ended June 30, 1988	1987
Operating revenue		
Sales of transmission services	$ 82,332	$ 40,617
Operating expenses		
Other operation	8,750	7,036
Maintenance	3,159	3,082
Depreciation	19,975	18,089
Total operating expenses	31,884	28,207
Debt expenses		
Interest on debt, net	63,983	70,651
Total expenses	95,867	98,858
Costs recoverable from future billings to participants	$(13,535)	$(58,241)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year ended June 30, 1988	1987
Cash flows from operating activities:		
Sales of transmission services	$ 82,332	$ 40,617
Expenses of operations	(95,867)	(98,858)
Adjustments to arrive at net cash provided by (used for) operating activities:		
Depreciation and amortization	19,975	18,089
Other, net	6,752	8,052
Changes in current assets and liabilities:		
Interest receivable	2,113	(690)
Accounts receivable	2,662	(2,649)
Other assets	68	23,157
Accrued interest		(11,107)
Accounts payable and accrued expenses	774	(4,335)
Net cash provided by (used for) operating activities	18,809	(27,724)
Cash flows from investing activities:		
Payments for construction of facility	(25,307)	(14,395)
Purchases of investments	(1,821,388)	(933,018)
Proceeds from sale of investments	1,827,066	996,118
Refund from (advance to) Intermountain Power Agency	820	(20,981)
Net cash provided by (used for) investing activities	(18,809)	27,724
Net increase (decrease) in cash		
Cash at beginning of year		
Cash at end of year	$ -	$ -
Cash paid during the year for interest	$77,221	$77,294

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS
IN FUNDS REQUIRED BY THE BOND INDENTURE

YEAR ENDED JUNE 30, 1988
(In thousands)

	Construction Fund-Initial Facilities Account	Debt Service Fund	Revenue Fund	Operating Fund	General Reserve Fund	Total
Balance at June 30, 1987	$18,480	$126,864		$6,237	$ 4,584	$156,165
Additions						
Investment earnings	987	20,407	$ 143	479	416	22,432
Sales			82,255			82,255
Transfer of interest payment		85,841				85,841
Transfer of investments	11,295				(11,295)	
Transfer of investment earnings		(6,392)	2,505	(479)	4,367	1
Transfer of funds	3,307	(6,416)	(2,647)		5,762	6
Transfer of sales receipts		72,408	(82,256)	9,848		
Miscellaneous receipts	2,948					2,948
Total	18,537	165,848	-	9,848	(750)	193,483
Deductions						
Payments-in-aid of construction and administrative costs	26,921					26,921
Operating expenditures				8,855		8,855
Interest		163,061				163,061
Interest on investment purchases		505				505
Premium on investment purchases		14				14
Total	26,921	163,580		8,855		199,356
Balance at June 30, 1988	$10,096	$129,132	$ -	$7,230	$ 3,834	$150,292

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $855 and $2,968 at June 30, 1988 and 1987, nor do they include total amortized net investment discounts of $477 and $281 at June 30, 1988 and 1987.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1988	June 30, 1987
ASSETS		
Special funds		
Investments	$26,970	$30,962
Interest receivable	264	502
Cash	684	
	27,918	31,464
Accounts receivable		66
Advances for capacity and energy, net	6,009	3,064
Cost recoverable from future billings to participants	(95)	
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $102 and $49 in 1988 and 1987	1,159	1,212
	$34,991	$35,806
LIABILITIES		
Long-term debt	$34,294	$34,293
Current liabilities		
Accrued interest	689	689
Accounts payable and accrued expenses	8	824
	697	1,513
Commitments and contingencies		
	$34,991	$35,806

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year ended June 30, 1988	1987
Operating revenues		
Sales of electric energy	$2,530	$66
Operating expenses		
Capacity charges	235	13
Energy charges	652	53
Other operation	244	
Total operating expenses	1,131	66
Debt expenses		
Interest on debt, net	1,304	
Total expenses	2,435	66
Cost recoverable from future billings to participants	$ 95	$-

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In Thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Cash flows from operating activities:		
Sales of electric energy	$ 2,530	$ 66
Expenses of operations	(2,435)	(66)
Adjustments to arrive at net cash provided by (used for) operating activities:		
Changes in current assets and liabilities:		
Interest receivable	238	(502)
Accounts receivable	66	(66)
Accrued interest		689
Other assets	54	49
Accounts payable and accrued expenses	(816)	824
Net cash provided by (used for) operating activities	(363)	994
Cash flows from investing activities:		
Payments for construction of facility	(2,945)	(3,064)
Purchases of investments	(149,058)	(85,662)
Proceeds from sale of investments	153,050	54,699
Net cash provided by (used for) investing activities	1,047	(34,027)
Cash flows from financing activities:		
Proceeds from sale of revenue bonds		34,293
Payment for bond issue costs		(1,260)
Net cash provided by financing activities		33,033
Net increase in cash	684	
Cash at beginning of year		
Cash at end of year	$ 684	$ -
Cash paid during the year for interest	$2,757	$ -

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE

FOR THE YEAR ENDED JUNE 30, 1988
(In thousands)

	Advance Payments Fund	Interim Advance Payments Fund	Revenue Fund	Operating Fund	Operating Working Capital Fund	Debt Service Account	Debt Service Reserve Account	Total
Balance at June 30, 1987	$25,242	$2,243				$ 941	$3,253	$31,679
Additions								
Investment earnings	2,185	373	$ 3		$ 17	72	296	2,946
Sales			2,596					2,596
Transfer of investments	(3,915)	3,915						
Transfer of investment earnings	738	(410)	(3)		(17)	(26)	(282)	
Transfer of sales receipts			(2,596)	$66		2,530		
Miscellaneous transfers	(3,136)	2,424			340		372	
Total	(4,128)	6,302	-	66	340	2,576	386	5,542
Deductions								
Advances for capacity and energy		4,448						4,448
Payments for capacity and energy charges				66				66
Administrative expenditures	921							921
Interest						2,757		2,757
Interest on investment purchases							14	14
Premium on investment purchases	439	16				46	1	502
Total	1,360	4,464		66		2,803	15	8,708
Balance at June 30, 1988	$19,754	$4,081	$ -	$-	$340	$ 714	$3,624	$28,513

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $264 and $466 at June 30, 1988 and 1987, nor do they include total amortized net investment premiums of $858 and $676 at June 30, 1988 and 1987.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MEAD-PHOENIX PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1988	June 30, 1987
ASSETS		
Utility plant		
Construction work in progress	$12,600	$11,703
Special funds		
Investments	1,843	2,910
Cash	14	8
	1,857	2,918
Deferred charges		
Unamortized debt expenses, less accumulated amortization of $509 and $432 in 1988 and 1987	54	3
	$14,511	$14,624
LIABILITIES		
Long-term debt	$ 100	$14,148
Current liabilities		
Long-term debt due within one year	14,048	
Accrued interest	351	426
Accounts payable and accrued expenses	12	50
	14,411	476
Commitments and contingencies		
	$14,511	$14,624

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MEAD-PHOENIX PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year ended June 30, 1988	Year ended June 30, 1987
Cash flows from operating activities:	$ -	$ -
Cash flows from investing activities:		
Payments for feasibility study	(1,061)	(771)
Purchases of investments	(4,479)	(6,299)
Proceeds from sale of investments	5,546	7,065
Net cash provided by (used for) investing activities	6	(5)
Cash flows from financing activities:	-	-
Net increase (decrease) in cash	6	(5)
Cash at beginning of year	8	13
Cash at end of year	$ 14	$ 8

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1988	Commission File Number 0-296

El Paso Electric Company

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	74-0607870 (I.R.S. Employer Identification No.)
303 North Oregon Street, El Paso, Texas (Address of principal executive offices)	79901 (Zip Code)

Registrant's telephone number, including area code: 915-543-5711

None of the registrant's securities is registered pursuant to Section 12(b) of the Act.

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

Common Stock, no par value
(Title of Class)

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 ____.

As of February 28, 1989, the aggregate market value of the voting stock held by non-affiliates of the registrant was $398,355,968.

As of February 28, 1989, there were outstanding 35,138,192 shares of Common Stock, no par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the annual meeting of its shareholders to be held in May 1989 are incorporated by reference into Part III of this report.

DEFINITIONS

The following abbreviations or acronyms used in this report are defined below:

Abbreviations or Acronyms	Terms
AFUDC	Allowance for Funds Used During Construction
AIP	Arizona Interconnection Project
APS	Arizona Public Service Company
BP John	B.P. John Furniture Company, a subsidiary of PasoTex
Border Steel	Border Steel Rolling Mills, Inc., a subsidiary of PasoTex
Common Plant or Common Facilities	Facilities at or related to the Palo Verde Station that are common to all three Palo Verde Units
Community	Salt River Pima-Maricopa Indian Community
Company	El Paso Electric Company
CWIP	Construction Work in Progress
DOE	United States Department of Energy
EnerServ	EnerServ Products, Inc., a subsidiary of PasoTex
FERC	Federal Energy Regulatory Commission
FL&R	Franklin Land & Resources, Inc., a subsidiary of the Company
Four Corners	Four Corners Project or Four Corners Plant
IID	Imperial Irrigation District, an irrigation district in Southern California
Internally Generated Cash	As defined in Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources"
KV	Kilovolt
KW	Kilowatt(s)
KWH	Kilowatt-hour(s)
MW	Megawatt(s)
MWH	Megawatt-hour(s)
NASDAQ	National Association of Securities Dealers Automated Quotations System
New Mexico Commission	New Mexico Public Service Commission
NRC	Nuclear Regulatory Commission
Palo Verde Station or Palo Verde Project or Palo Verde or PVNGS	Palo Verde Nuclear Generating Station
PasoTex	PasoTex Corporation, a subsidiary of the Company
PNM	Public Service Company of New Mexico
RGEC	Rio Grande Electric Cooperative, Inc.
SCE	Southern California Edison Company
SFAS	Statement of Financial Accounting Standard
SRP	Salt River Project Agricultural Improvement and Power District
Texas Commission	Public Utility Commission of Texas
TNP	Texas-New Mexico Power Company
Tribe	Navajo Indian Tribe
Westwood	Westwood Lighting Group, Inc., a subsidiary of PasoTex
1989 Proxy Statement	Company's definitive proxy statement for the annual meeting of shareholders to be held in May 1989

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PART I

PART II

PART III

PART IV

* The information required by this Item has been omitted from this Annual Report to Shareholders.

PART I

Item 1. Business

General

The Company was incorporated in Texas in 1901. Its principal business is the generation and distribution of electricity through an interconnected system to approximately 230,000 customers in El Paso, Texas and in an area in the Rio Grande Valley in West Texas and Southern New Mexico. The Company's principal executive offices are located at 303 North Oregon Street, El Paso, Texas 79901 (telephone 915-543-5711).

The Company's service area extends approximately 110 miles northwesterly from El Paso to the Caballo Dam in New Mexico and approximately 120 miles southeasterly from El Paso to Van Horn, Texas. The service area has an estimated population of 724,000, including approximately 590,000 people in the metropolitan area of El Paso. Copper smelting and refining, oil refining, garment manufacturing, cattle raising and agriculture are important industries in El Paso, which is also an important transportation and distribution center. At December 31, 1988, the Company's largest retail customers included a copper refinery, a smelter, and a steel fabricator in El Paso (the latter being an indirect subsidiary of the Company), and important military installations, namely the U.S. Army Air Defense Center at Ft. Bliss in El Paso and the White Sands Missile Range and Holloman Air Force Base in New Mexico. The Company derives a significant portion of its operating revenues from wholesale power sales. See "Rates and Regulation — Rate Matters — FERC."

The Company's major franchises are with the cities of El Paso, Texas and Las Cruces, New Mexico, such franchises expiring in 2001 and 1993, respectively. The franchises contain no express renewal provisions. Although the City of Las Cruces is currently reviewing alternative sources, the Company believes, but has no assurance, that the franchises will be renewed.

During 1988, approximately 63% of the Company's operating revenues were derived from Texas, 20% from New Mexico and 17% from FERC wholesale customers. Sales to (i) residential customers, (ii) small commercial and industrial customers, (iii) large commercial and industrial customers and (iv) public authorities accounted for approximately 36%, 34%, 12% and 18%, respectively, of the Company's operating revenues from retail sales. In 1988, IID, a wholesale customer, accounted for 11.4% of utility operating revenues. No retail customer accounted for more than 3% of utility operating revenues. The effect of seasonal sales by quarter are insignificant to the Company's annual operating revenues, but the third quarter of each calendar year traditionally contributes more than 25% of annual revenues due to the climate in the Company's service area. See Note M of Notes to Consolidated Financial Statements.

The Company attained an all-time total system peak load of 1,002 MW on August 22, 1988. In 1987, the Company's total system peak load was 975 MW. In 1988 and 1987, the native system peak load was 840 MW and 820 MW, respectively. The Company periodically makes long-range projections of system peak load and estimates future sources of power that may be used to supply the system requirements. The projected annual peak load growth rate for the Company's service area during the 1989-1998 time period is approximately 3%.

The Company had 1,191 employees as of December 31, 1988. Approximately 28% of the employees are covered by a collective bargaining agreement that expires in February 1991.

In addition to its electric utility operations, the Company has various subsidiaries which engage in unregulated, non-utility businesses. See "Non-Utility Operations" and Note N of Notes to Consolidated Financial Statements.

Company Conditions

The Company has not generated in the recent past, nor will it generate in 1989, sufficient Internally Generated Cash to meet its cash requirements for preferred and common stock dividends, construction, redemptions of debt and preferred stock and regulatory deferrals, and, accordingly, the Company will continue to be required to finance such requirements to the extent not met by Internally Generated Cash. Management has defined Internally Generated Cash, for purposes of its cash planning and financing requirements, as "net cash (used for) provided by operating activities" before the effect of "Palo Verde deferred costs" and "phase-in plan deferrals", all as reflected in the Consolidated Statement of Cash Flows set forth in Item 8 of this report. Internally Generated Cash is used as a measure for planning purposes because it recognizes the necessity of financing deferrals, which are scheduled to be collected in cash in the future, pursuant to regulatory order.

As explained in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources," the Company intends to meet its financing requirements through short-term borrowings, extension or long-term refunding of debt maturities during this time period and possible sales of non-utility assets. The Company will require third party consents or renegotiation of certain financial covenants in order to accomplish the needed refunding and extension of long-term debt, which the Company believes, but has no assurance, it will be able to obtain.

In declaring its first quarter 1989 dividend of $.38 per share of common stock, the Company cautioned that the level of future dividend payment was uncertain and would depend on earnings, cash flow and other factors. The Company expects 1989 income from continuing operations to be significantly lower than that reported in 1988. The Company, in general, anticipates that future results of operations will be significantly affected by the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 and may continue to be significantly affected by the factors described in "Results of Operations." The Company is, therefore, currently reevaluating its dividend policy, including consideration of the possible reduction or omission of dividends for the foreseeable future in light of such anticipated lower income and management's assessment of future results of operations, the Company's existing liquidity needs and restrictions on financing, and difficulties imposed by regulatory uncertainties, including the uncertainty regarding the timing and method of inclusion in Texas rates of the Company's investment in Palo Verde Unit 3.

For further information regarding the above matters, see "Rates and Regulation — Rate Matters" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Rates and Regulation

Regulatory Authorities

Texas. The rates and services of the Company in Texas municipalities are regulated by those municipalities and in unincorporated areas by the Texas Commission. The Texas Commission has exclusive de novo appellate jurisdiction to review municipal orders and ordinances regarding rates and services, and its decisions are subject to judicial review.

New Mexico. The New Mexico Commission has authority over the Company's rates and services in New Mexico, the issuance of securities by the Company and other matters affecting the operations of the Company, including the Company's diversification activities. See "Non-Utility Operations."

FERC. The Company is subject to regulation by the FERC in certain matters, including rates for wholesale power sales and the issuance of securities. In addition, Congress has enacted energy legislation which, among other things, establishes national standards for consideration by state regulatory agencies in determining utility rates and imposes other requirements on the operations of utilities, including the Company. Under certain circumstances, the FERC may order interconnection, wheeling and pooling.

NRC. The Palo Verde Station is subject to the jurisdiction of the Nuclear Regulatory Commission ("NRC"), which has authority to issue permits and licenses and to regulate nuclear facilities in order to protect the health and safety of the public from radiation hazards and to conduct environmental

reviews pursuant to the National Environmental Policy Act. Before any nuclear power plant can become operational, an operating license from the NRC is required. The NRC has granted facility operating licenses for Unit 1, Unit 2 and Unit 3 for terms of forty years each beginning December 31, 1984, December 9, 1985 and March 25, 1987, respectively. See "Utility Construction Program — Palo Verde Station" and "Facilities — Palo Verde Station."

Rate Matters

Texas

March 1988 Rate Order

On March 30, 1988, the Texas Commission adopted a rate moderation plan to phase-in Palo Verde Units 1 and 2 into Texas rates. The plan is based on a stipulated settlement proposed in October 1987 by the Company and most of the parties to the Company's 1987 Texas rate case. Texas rates, based on the final order, were implemented on April 22, 1988.

The rate moderation plan adopted by the Texas Commission is intended to comply with SFAS No. 92, *Regulated Enterprises — Accounting for Phase-in Plans,* and provides for a series of increases in the Company's annual Texas retail base rates over a period of four years. The Company received a cash increase of approximately $21 million in the first twelve months of the plan ($8.6 million net of fuel savings and miscellaneous revenues), and the Company will receive an additional cash increase in each of the following three twelve-month periods. With respect to each of these four twelve-month periods, to the extent the Company's approved cost-of-service exceeds the cash increase provided for that period, the unrecovered revenue requirements will be deferred for cash collection in later years of the plan. The initial cost-of-service base rate increase established in the 1988 rate case was $46 million, compared with the $21 million cash rate relief provided under the plan. On a percentage basis, Texas base rates increased by 13.7% in the first year of the plan (3.6% net of fuel savings and miscellaneous revenues). The revenues deferred for collection in later years of the plan are scheduled to be recovered within ten years. The Company is allowed under the plan to request additional increases after the fourth year, if necessary to recover all deferred revenues within the ten year period. Although such increases may be necessary, the Company has not formally requested any additional increases. See "1988 Rate Case" below.

All construction prudence issues directly related to Palo Verde Units 1 and 2 and Common Plant, and any effect which Unit 1 and 2 construction issues might have had on Unit 3, were settled by the Texas Commission's March 1988 rate order. Issues relating to the prudence of the Company's decisions with respect to its initial and continuing investment in Palo Verde were also resolved insofar as they affect regulatory treatment of Units 1 and 2. In the settlement of these issues, the Company agreed, in October 1987, to an after-tax regulatory disallowance of approximately $24.4 million of the Company's investment in PVNGS (less than 2% of such investment). The Company recorded the disallowance, which did not require cash, in 1987. All issues relating to excess capacity with respect to Units 1 and 2 were resolved among the stipulating parties for the life of the phase-in period.

Three participants in the 1987 rate case who were not parties to the stipulated settlement have appealed the Commission's order. Their appeals were filed in May 1988, and no further action has taken place on such appeals to date. A final judicial determination on such appeals is not expected this year. Management anticipates that the Commission's order will be upheld.

1988 Rate Case

On October 14, 1988, the Company filed its first annual cost-of-service request pursuant to the Texas rate moderation plan and requested an increase of approximately $39 million in base revenues, including a 14% return on common equity, and approximately $6 million in fuel revenues, for a total increase of $45 million. Under the terms of the plan, the Company is allowed a cash increase in base revenues of approximately $7 million. The difference between such cash increase and any increase in base revenues ordered by the Texas Commission will be deferred for collection in later years of the

plan. Hearings were held in January and February 1989. The hearing examiner's report is expected in early April and a final order later that month.

Intervening parties to the case have recommended increases in base revenues which are less than $39 million. The Texas Commission staff has recommended a total increase in base revenues of approximately $22 million. The Company's net income in 1989 will be adversely affected if, and to the extent, that the final rate order adopts a base revenue increase of less than $39 million. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations." Included in the staff recommendations are certain adjustments to the deferred asset balances, which, if ordered, would cause approximately $20 million of write-offs of amounts currently reflected in the Company's 1988 consolidated balance sheet. The Company strenuously opposes the proposed adjustments and other portions of the staff's recommendations which, in the Company's opinion, are without merit. Management believes, but cannot predict with certainty, that the Texas Commission will not adopt the staff's recommendation for adjustments to the deferred asset balances. However, if the adjustment were adopted, the Company would seek appropriate legal remedies, including an appeal of the case through the courts.

In its filing, the Company included an analysis of the expected overall effects of the rate moderation plan for the full ten-year period. As originally anticipated under the rate moderation plan, the Company was to receive increases of 4% in the second year of the plan and 3.5% in each of the third and fourth years of the plan, with base rates to remain level after the fourth increase. The increases had been forecasted on an expected average jurisdictional unit rate to the Company from its forecasted sales. While base revenues in the pending case will increase 4%, or approximately $7 million, average jurisdictional unit rates will be 5.682¢, rather than the 5.936¢ per KWH originally planned, due to changes in customer consumption patterns. Cash collections, therefore, are not expected to be realized at the same level as originally anticipated for the growth which the Company has experienced, resulting in greater deferred revenues and contributing to the need for additional increases in base rates after the fourth increase to accomplish full recovery of the deferrals within the ten year term of the plan. To increase cash flow, the Company is evaluating alternatives to address the unit rate situation, including a possible request that the original average unit rate path be reestablished. The Company may seek to renegotiate the matter with all the parties to the stipulation and may ask the Texas Commission to rule on the proper rate setting methodology, either in a separate hearing or in the Company's next annual cost-of-service filing under the plan. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Unit 3

Although Unit 3 achieved commercial operation in January 1988, it will not meet present Texas in-service criteria for inclusion in rate base until completion of the AIP transmission facilities presently scheduled for the end of 1989. Until then, Unit 3 is being accounted for, insofar as the Texas jurisdictional portion is concerned, as plant under construction, and the Company is capitalizing all Texas jurisdictional costs of owning, operating and maintaining Unit 3. During 1989, the Company plans to request an accounting deferral order from the Texas Commission which will allow the Company to defer the costs of owning, operating and maintaining Unit 3 (excluding an allowance for earnings on shareholders' investment) from the date that Unit 3 meets the Texas in-service criteria until the Company's request for inclusion of Unit 3 in rate base can be filed and ruled upon by the Texas Commission. The Company believes, but cannot predict with certainty, that the Texas Commission will rule favorably on the matter. In the event that an accounting deferral order is not obtained from the Texas Commission, the Company would be required to expense the costs related to Unit 3 beginning in early 1990, which would adversely affect net income. The Company plans to file the Unit 3 case in the second quarter of 1990 and presently anticipates a final order by the end of 1990.

Certain issues relating to the prudence of construction costs specifically incurred with respect to Unit 3, and the prudence of the Company's decisions with respect to its investment in Palo Verde insofar as they affect regulatory treatment of Unit 3, relating to events occurring after the 1978

issuance of a certificate of convenience and necessity for Palo Verde by the Texas Commission, and any possible issues of excess generating capacity relating to Unit 3 are, under the terms of the rate moderation plan, reserved for decision in the Unit 3 case.

Although the timing and method of inclusion of Unit 3 costs in Texas rates cannot be predicted with certainty, management believes the ultimate resolution of the remaining issues of prudence relating to Unit 3 will not result in a material disallowance of the costs incurred. If any excess generating capacity were to be found by the Texas Commission relating to Unit 3, management believes the amount of any resulting exclusion from rate base would likely be temporary and would be restored to rate base in future rate proceedings to permit full recovery of substantially all of the Company's Texas jurisdictional investment in Unit 3. Management believes that inclusion of Unit 3 in Texas rates may require rate moderation, as was the case with Units 1 and 2. The Company's current planning for cash requirements contemplates inclusion of Unit 3, on a phased-in basis, in Texas rates beginning in April 1991. However, any exclusion from rate base by the Texas Commission based on a finding of excess capacity or an increase in rates substantially lower than presently contemplated would have an adverse impact upon the Company's future income and Internally Generated Cash and could substantially increase financing requirements. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Sale and Leaseback Transactions

The Company has entered into certain sale and leaseback transactions involving Palo Verde Units 2 and 3. See "Utility Construction Program — Palo Verde Station." The Texas Commission's March 1988 rate order included in rates the lease payments attributable to Unit 2, to the extent of the book value of the plant sold and leased back, plus all related taxes. As required by statute, the Company filed a report of its Unit 2 sale and leaseback transactions with the Texas Commission. When adopting the rate moderation plan, the Texas Commission included the effect of the Unit 2 transactions in rates because rates recognizing the transactions in such case would not exceed those under traditional ratemaking methodology. However, the Texas Commission specifically reserved a ruling on the question of whether the transactions were in the public interest and should be reflected in rates in the future in lieu of such traditional methodology. As part of the Company's October 14, 1988 rate filing, the Company requested a ruling from the Texas Commission on whether the transactions were in the public interest. The Texas Commission is also currently evaluating the Company's sale and leaseback transactions involving a portion of Palo Verde Unit 3. A hearing was held on the Unit 3 transaction during December 1988, and a hearing examiner's report is expected during the spring of 1989. Were it to find the Palo Verde sale and leaseback transactions not to be in the public interest, the Texas Commission might choose to disregard the transactions in favor of traditional rate making methodology in setting rates related to the respective generating plants. The Company believes the transactions benefit both ratepayers and shareholders, and, accordingly, the Company believes, but cannot predict with certainty, that the transactions will be found to be in the public interest.

1987 Rate Case Expenses

In August 1988, the Company filed to recover approximately $11 million of expenses incurred by the Company in litigating the 1987 rate case. In its March 1988 rate order, the Texas Commission ordered a separate docket to be convened to consider such expenses. Hearings were held in October 1988, and a hearing examiner's report is expected shortly, with a final order during the second quarter of 1989. The Company has requested that it be allowed to recover its expenses by means of a surcharge to its Texas customers. Expenses related to the determination of prudence of the construction of the Palo Verde Station have been requested to be capitalized in rate base and recovered over the life of the Station with a return on the unamortized amount. Management believes, but cannot predict with certainty, that the Company will receive full recovery of these expenses.

Prior Rate Case Appeals

The Company's appeals of the orders in its 1984 and 1985 rate cases are in the process of being settled without any consequences to the Company.

Fuel

In Texas, the Company is entitled to recover its fuel costs by means of a fixed fuel factor approved by the Texas Commission. The fuel factor is reviewed and approved in each rate case filed by the Company, and the Texas Commission has the authority to order fuel reconciliation, which requires a hearing, on its own initiative. The Company will file a fuel reconciliation proceeding in the near future and anticipates hearings commencing in mid-1989.

New Mexico

In March 1987, the Company entered into a stipulated settlement with certain jurisdictional New Mexico parties which provided for a rate moderation plan for the Company's New Mexico jurisdiction. In May 1987, the New Mexico Commission issued its final order adopting such rate moderation plan. The approved plan provides for (i) continued full inclusion in the Company's rate base of the capital costs of Palo Verde Unit 1 and one-third of Palo Verde Common Plant and inclusion in rate base of certain transmission facilities, (ii) recovery of the New Mexico portion of equity AFUDC attributable to Unit 3 in rates as cost-of-service, amortized over a period ending December 31, 1994, subject to acceleration based upon recoupment of the cost-of-service revenue deferrals described in the following clause, (iii) increases in rates of 3% on a total cents per kilowatt-hour basis in 1987, 3% in base rates no sooner than one year after the 1987 increase and an additional 3% in base rates no sooner than one year after the second 3% increase, with any deficiency in revenue requirements resulting from this rate path being deferred for collection in later years (base rates to be held constant after the third increase until the earlier of December 31, 1994 or the full recoupment of such deferrals and the New Mexico portion of equity AFUDC attributable to Unit 3), (iv) recovery in rates of the lease payments on Unit 2 to the extent of the book value of plant sold and leased back, as well as all related taxes, (v) agreement by the Company that, except for the New Mexico portion of equity AFUDC attributable to Unit 3, neither the capital costs of Palo Verde Unit 3, one-third of Palo Verde Common Plant, a proportionate share of certain Palo Verde transmission facilities nor any Unit 3 operating expenses will at any time be requested for inclusion in the Company's rate base or requested for any cost-of-service treatment insofar as the New Mexico jurisdiction is concerned. Under the New Mexico rate moderation plan, Palo Verde Unit 3 may be used to serve New Mexico load, but such power will be priced as purchased power at the rate of the most economic source of power available at that time. The New Mexico Commission's adoption of the rate moderation plan resolves any possible issue related to the prudence of the planning, management and construction of Palo Verde and settles any possible issue of excess generating capacity through 1993. Based upon present planning analysis, the Company does not expect to have excess generating capacity insofar as its New Mexico jurisdiction is concerned.

The first of the three scheduled rate increases under the New Mexico rate moderation plan was approved in November 1987 and provided an annual increase in the Company's New Mexico base rates of $9.9 million, or $5.0 million in total revenues, net of fuel savings. Actual revenues to be collected by the Company pursuant to the phase-in of the approved increase aggregated $6.6 million of base revenues, or $1.8 million in total revenues, net of fuel savings. The difference between the approved base revenue increase of $9.9 million and the implemented increase of $6.6 million is, under the terms of the plan, deferred for collection in later years of the plan.

In November 1987, the Company filed for the second increase of approximately $5.5 million under the plan. Under the phase-in provisions of the plan, the increase was limited to 3%, or $1.7 million, with the balance to be deferred. On October 3, 1988, the Commission adopted and approved in its entirety a stipulation on revenue requirements and tariff-schedule-rate design for the case. Under the terms of the stipulation, the Company was authorized to implement its cash increase in base rates under the

rate moderation plan of $1.5 million, although the stipulation provided for a zero increase in non-fuel base revenue requirements. The stipulation also allowed for $1.2 million of fuel expense related to Palo Verde Unit 2 to be capitalized as a cost-of-service deferral. New rates in New Mexico became effective on November 4, 1988.

The Company expects to file for the third increase allowed under the plan early in the second quarter of 1989. Hearings are expected to be held in the later half of 1989, with rates to become effective early in the first quarter of 1990.

As stated above, the New Mexico rate moderation plan provides that neither the capital costs of Palo Verde Unit 3, one-third of Common Plant nor a proportionate share of certain Palo Verde transmission facilities (aggregating approximately $54.1 million) nor any Unit 3 operating expenses, including the lease payments attributable to that portion of Unit 3 sold and leased back on December 31, 1987, will at any time be included in the Company's rates or receive any cost-of-service treatment in the New Mexico jurisdiction. The costs related to the New Mexico portion of Unit 3 will need to be recovered through economy, off-system sales of power. Although the current market price for economy, off-system sales of electricity is not sufficient to cover current operating expenses related to Unit 3, including lease payments related to the portion of Unit 3 sold and leased back, the Company believes, based upon current forecasts of plant operating performance, power demand and alternative fuel prices that, over the estimated remaining life of the Unit, the Company will recover its costs related to the New Mexico portion of Unit 3.

SFAS No. 92, issued in August 1987 and effective for financial statements for fiscal years beginning after December 15, 1987, establishes specific criteria to be met by a phase-in plan in order for costs deferred for future recovery by the regulator to be capitalized for financial reporting purposes. The rate moderation plan approved in New Mexico does not currently meet such criteria because, under the existing terms of the plan, any portion of cost-of-service deferrals not recouped prior to December 31, 1994 will not be recovered through rates in New Mexico. The Company, however, has filed to amend the plan to meet the criteria of SFAS No. 92 and believes that such amendment will be approved by the New Mexico Commission. Hearings on the Company's application are anticipated to start in the second quarter of 1989. The ability of the Company to continue to report for financial statement reporting purposes amounts equal to the difference between the approved revenue requirements and implemented rates is dependent upon approval of the amendment.

Fuel. In its New Mexico jurisdiction, the Company is entitled to recover its fuel costs through a fuel factor approved by the New Mexico Commission. The rate moderation plan approved in New Mexico provides that the fuel factor will be fixed each year during the life of such plan, with such fuel factor to remain in effect for one year unless the New Mexico Commission orders fuel reconciliation due to material over or under recovery of fuel costs.

FERC

The Company's sales for wholesale power make up a significant portion of the Company's operating revenues. During 1988 and 1987, approximately 17% of the Company's electric operating revenues resulted from such sales. Rate tariffs currently applicable to FERC wholesale customers contain appropriate fuel and purchased power cost adjustment provisions designed to recover those costs in excess of costs included in base rates. Although rates to wholesale customers require FERC approval, the Company and its wholesale customers usually establish such rates through negotiations subject to such FERC approval.

In March 1986, the Company filed for increased rates for service to three wholesale customers, IID, TNP and RGEC. The requested increase amounted to approximately $32 million, utilizing a forecasted 1986 test period. In May 1986, the Company was allowed to implement a portion of the increased rates under suspension. The Company subsequently entered into settlement agreements with each of these customers. The FERC approved the settlements with IID and RGEC on March 30, 1987.

The settlement with IID is based upon a long-term firm power sales agreement providing for the sale of 100 megawatts of firm capacity to IID beginning in 1987 and continuing through April 2002. In addition, the agreement calls for contingent capacity of 50 megawatts to be made available to IID beginning in 1992 and continuing through April 2002. The settlement agreement with IID settles any possible issue of the prudence of the construction costs of PVNGS and of excess generating capacity. The Company and IID are currently negotiating the impact that the sale and leaseback of a portion of Unit 3 has on the demand charges during the term of the contract.

The settlement agreement with TNP is based upon a revised firm power sales agreement with TNP. As part of the settlement of the rate increase request, the Company and TNP settled an arbitration with respect to the contractual level of reserve demand under the Company's prior sales agreement with TNP. The revised firm power sales agreement with TNP provides for firm power sales to TNP ranging from 43 megawatts to 79 megawatts, beginning in 1987 and continuing through 2002, with negotiated demand charge rates for such power.

On December 29, 1987, the FERC approved with modifications the settlement with TNP. The FERC refused to bind itself to certain contractual provisions contained in the settlement. TNP and the Company requested a rehearing by the FERC on its order and asked the FERC to allow the Company to place the agreed rates for 1988 in effect. On May 2, 1988, the FERC granted the petition for rehearing. TNP and the Company have subsequently modified the stipulation to address the FERC's concerns, and the FERC approved such stipulation. The Company and TNP have also agreed on the impact of the sale and leaseback of Unit 3 on the demand charges during the term of the contract.

The Company and RGEC have agreed to a 10-year contract based on a flat rate during the life of the contract.

Palo Verde Performance Standards

In New Mexico, the Company is subject to performance standards for operation of the Palo Verde units. The standards measure performance on the basis of all three units viewed as an entity. These standards set designated levels of capacity factors (the ratio of actual generation to maximum possible generation) at the Palo Verde Station. If the capacity factors exceed the maximum standard (75 percent), the Company is rewarded based upon the additional fuel costs avoided, calculated on the basis of the Company's weighted average fuel and purchased power costs (other than Four Corners, Palo Verde and purchases from Southwestern Public Service Company). If the capacity factors fall below the minimum standard (60 percent), the Company is penalized based upon the additional fuel costs incurred using the same formula. If performance falls between the minimum and maximum standards, no consequences result. For the period most recently completed, performance at Palo Verde has not resulted in a penalty or a reward. The Company expects to file a performance standards case in Texas in the second quarter of 1989.

Utility Construction Program

The Company's estimated construction costs for 1989 through 1992 set forth in the table below are approximately $190.5 million in cash and approximately $27.9 million in related AFUDC, net of deferred tax. The estimated costs were prepared as of February 22, 1989. For a number of reasons, actual costs may vary from the construction program estimates set forth below. Such estimates are reviewed and modified from time to time to reflect changed conditions.

	1989	1990	1991	1992
		(In thousands)		
Production:				
PVNGS(1)	$ 11,100	$11,500	$ 6,700	$ 6,100
PVNGS Deferred Costs(2)	22,500	—	—	—
Other	3,600	2,200	1,700	1,700
Transmission:				
PVNGS	400	—	—	—
AIP	25,000	—	—	—
Other	500	1,900	3,100	3,900
Distribution	23,900	20,000	13,100	13,000
General Plant	3,200	7,800	3,700	3,900
AFUDC(3):				
PVNGS(2)	23,300	600	400	300
AIP	4,600	—	—	—
Other	1,200	1,000	400	400
Deferred Tax on AFUDC(4)	(3,900)	(200)	(100)	(100)
Total	$115,400	$44,800	$29,000	$29,200

(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources — Nuclear Fuel."

(2) Includes the Texas jurisdictional costs of owning, operating and maintaining Unit 3, which the Company will continue to capitalize until Unit 3 meets present Texas in-service criteria. Subsequent to the in-service date for ratemaking purposes, the Company anticipates deferring such costs, which are expected to aggregate approximately $34.7 million and $11.1 million for 1990 and 1991, respectively, pursuant to an accounting deferral order that the Company will request from the Texas Commission. See "Rates and Regulation — Rate Matters — Texas — Unit 3."

(3) AFUDC has been calculated using an estimated accrual of 10.56%. Certain amounts of construction work in progress ("CWIP") have been previously allowed in the Company's rate base, and the appropriate amounts have been excluded from the CWIP balance used as a basis for calculating AFUDC. AFUDC on major projects has been compounded on a semiannual basis.

(4) Deferred tax is provided on the borrowed portion of AFUDC and will effectively reduce plant to a net amount for ratemaking and depreciation purposes.

The Company is nearing completion of construction of the Arizona Interconnection Project ("AIP"), which involves the installation of a new 345 KV transmission line and associated substation equipment along a 313-mile path originating at Springerville Generating Station in Springerville, Arizona, and terminating at the Rio Grande Power Plant in Dona Ana County, New Mexico (northwest of El Paso). The AIP will enable the Company to import low cost energy from the Arizona-New Mexico power grid, enhance system reliability and access its full PVNGS nuclear capacity entitlement. Through construction of the AIP, the Company will be better equipped to meet future strategic generating resource mix requirements and will continue to benefit from economy energy purchases. See "Rates and Regulation — Rate Matters — Texas — Unit 3."

Net utility plant at December 31, 1983, was $1,230,428,000. Gross additions to plant, including CWIP, for the five years ended December 31, 1988, totaled $906,047,000 (the largest portion of which was $673,000,000 for PVNGS). Net utility plant at December 31, 1988 (which reflects the sales of plant

in the Palo Verde sale and leaseback transactions), was $1,260,843,000 (including capitalized nuclear fuel of approximately $54,081,000 leased from a nuclear fuel trust). See "Energy Sources — Nuclear Fuel."

The Company does not expect to construct additional base load generating facilities during this century. With the exception of AIP, the Company's major construction activities for this century are complete.

Palo Verde Station

The Company has a 15.8% interest in the three 1,270 MW nuclear generating units and Common Plant at the Palo Verde Station near Phoenix, Arizona (owned as to Unit 1 and approximately 60% of Unit 3, and leased as to Unit 2 and approximately 40% of Unit 3). The participants in the Palo Verde Project include the Company and six other utilities: Arizona Public Service Company, Southern California Edison Company, Public Service Company of New Mexico, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District and the Los Angeles Department of Water and Power. Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units. APS serves as Operating Agent for the Palo Verde Station. In February 1977 and November 1978, respectively, the New Mexico Commission and the Texas Commission issued Certificates of Convenience and Necessity for the Company's participation in Palo Verde Station.

The table below sets forth the actual costs incurred by the Company through December 31, 1988, for the construction of PVNGS (including the cost of start-up and testing and the Company's share of the cost of related switchyard and transmission facilities), and the Company's estimate of the cumulative cost of construction through the completion of PVNGS. The table includes capitalized ownership, operating and maintenance expenses related to the Texas jurisdictional portion of Unit 3, but does not include the Company's share of the estimated cost of nuclear fuel. See "Energy Sources — Nuclear Fuel". The table also does not reflect a regulatory disallowance write-off of approximately $38.3 million. The estimated costs were prepared as of February 22, 1989. See "Rates and Regulation — Rate Matters."

	Actual Costs Through December 31, 1988	Estimated Cumulative Costs Through December 31, 1989	1990	1991
Nuclear Plant	$ 999,200	$1,032,800	$1,044,300	$1,051,000
Related AFUDC	511,100	534,100	534,700	535,100
Transmission Lines and Switchyard	32,200	32,600	32,600	32,600
Related AFUDC	11,300	11,600	11,600	11,600
Deferred Tax on AFUDC	(105,400)	(108,500)	(108,600)	(108,600)
Total	$1,448,400	$1,502,600	$1,514,600	$1,521,700

The above table includes approximately $653.4 million in aggregate book value of the undivided interests involved in the Unit 2 and Unit 3 sale and leaseback transactions in which the related leases are accounted for as operating leases. Such book value no longer appears as an asset of the Company.

Sales and Leasebacks. In August and December 1986, the Company sold and leased back all of its 15.8% undivided interest in Unit 2 and one-third of its interest in certain Common Plant at Palo Verde for approximately $684.4 million cash. In December 1987, the Company sold and leased back approximately 39.5% of its undivided 15.8% interest in Unit 3 for approximately $250 million cash. For a description of the terms and provisions of these transactions, see Note E of Notes to Consolidated Financial Statements.

Approximately $258.2 million of the proceeds from the Palo Verde sales and leasebacks have been used to redeem long-term, secured debt, consisting of approximately $108.2 million of first mortgage bonds and $150 million of bank debt secured by second mortgage bonds. Approximately $112 million of the proceeds have been used to fund the Company's diversification program. See "Non-Utility Operations." The Company has used approximately $564.2 million of the proceeds to pay taxes related to the sales and leasebacks, retire short-term obligations, make preferred stock redemptions, repurchase common stock, and fund construction, rate moderation, dividend and working capital requirements as well as for other general corporate purposes. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Facilities

General

As described below, the Company currently has a net generating capacity of 1,497 MW, consisting of 246 MW at Rio Grande, 478 MW at Newman, 69 MW at Copper, an entitlement of 104 MW from Four Corners and an entitlement of 600 MW from Palo Verde Units 1, 2 and 3.

Rio Grande Power Station

Rio Grande, located in New Mexico adjacent to the city of El Paso, consists of three steam-electric generating units which have an aggregate capability of 246 MW when operating entirely on natural gas. When interstate natural gas at the station is curtailed, the units operate primarily on fuel oil, which increases operating and maintenance expenses. See "Energy Sources."

Newman Power Station

Newman, located in El Paso, consists of three steam-electric units with an aggregate capability of 266 MW and one combined-cycle unit with a capability of 212 MW. The units regularly operate on natural gas, but are also capable of operating on fuel oil. If they were to operate entirely on fuel oil, operating and maintenance costs would increase and capacities would be lower. See "Energy Sources."

Copper Power Station

Copper, consisting of a 69 MW combustion turbine capable of operating on fuel oil or natural gas and used for peaking purposes, was placed in service in June 1980 on a leased site in El Paso. The station has been classified under the Fuel Use Act as an existing facility, which allows the station to burn natural gas. Since such classification, the station has operated primarily on intrastate natural gas. See "Energy Sources — Natural Gas."

Four Corners Project

The Company has an undivided 7% interest in Units 4 and 5 at Four Corners located in northwestern New Mexico. Each of the coal-burning generating units have a 739 MW capability. For emergencies each Unit is rated at 784 MW. Both units are located adjacent to a surface-mined supply of coal and are jointly owned by the Company, APS (which is the Operating Agent for Four Corners), Tucson Electric Power Company, PNM, SCE and SRP. The Company's entitlement of 104 MW is used for the Company's base load to the maximum extent possible.

The Four Corners Plant is located on land held under easements from the Federal Government and also under a lease from the Tribe, the enforcement of which might require Congressional consent. The risk with respect to the enforcement of these easements and of the lease is not deemed by the Company to be material. The Company is dependent, however, in some measure upon the willingness and ability of the Tribe to protect these properties and honor its commitments. Certain of the transmission lines and almost all of the contracted coal sources for the Four Corners Plant are located on the Tribe's reservation.

The participants in Four Corners are defendants in a suit filed by the State of New Mexico in March 1975 in state district court in New Mexico, against the United States of America, the City of Farmington, New Mexico, the Secretary of the Interior as Trustee for the Navajo and other Indian tribes, and certain other defendants. The suit seeks adjudication of the water rights of the San Juan River Stream System in New Mexico, which, among other things, supplies the water used at Four Corners. No trial date has been set in this matter. An agreement reached with the Tribe in 1985 provides that if the Four Corners Plant loses a portion of its rights in the adjudication, the Tribe will provide sufficient water from its allocation to offset the loss.

The Company owns a 230-mile 345 KV transmission line from Newman to Albuquerque, New Mexico, at which point the Company's entitlement from Four Corners is delivered from 150 miles of transmission lines owned by PNM. This 345 KV transmission line regularly carries power from Four Corners and provides a major interconnection with the other five participants in Four Corners. The Company also owns an undivided interest in a 200-mile 345 KV transmission line from Newman across southern New Mexico to Greenlee, Arizona. This line provides the Company with interconnection capability with Tucson Electric Power Company's system and for the Company's entitlement from Four Corners and also provides added stability, flexibility, and reliability to the Company's system. The Company and Tucson Electric Power Company have entered into an interconnection agreement which includes emergency transmission service.

Palo Verde Station

For information regarding the Company's interest in the Palo Verde Station, see "Rates and Regulation" and "Utility Construction Program." For a description of nuclear fuel acquisition, see "Energy Sources — Nuclear Fuel."

Both groundwater and surface water in areas of Arizona important to the operation of the Palo Verde Station have been the subject of inquiries, claims and legal proceedings which will require a number of years to resolve.

In connection with the construction and operation of the Palo Verde Station, APS, as Operating Agent for Palo Verde, has entered into contracts with certain municipalities granting the right to purchase effluent for cooling purposes at Palo Verde. The validity of the primary effluent contract has been challenged in a suit by the Salt River Pima-Maricopa Indian Community (the "Community") against the United States Department of the Interior (the Federal agency alleged to have jurisdiction over the use of such effluent) and additional defendants, including APS and the Company. The portion of the action challenging the effluent contract has been stayed while the Community litigates its claims against the Department of the Interior and other defendants for wrongful exclusion from SRP, a Federal reclamation project. On October 21, 1988, federal legislation was enacted conforming to the requirements of a proposed settlement that would terminate this case without affecting the validity of the primary effluent contract. Congress, however, has not yet appropriated the Federal money necessary to effectuate the settlement. Moreover, appropriation of approximately $3 million by the Arizona state legislature and approval by the court in the Lower Gila River Watershed litigation (see below) are required before the settlement will become final. The Company is unable to predict when such appropriations will be made, when, or if, the required court approval will be obtained, or when the settlement will become final.

In November 1982, certain operators of farms located in the vicinity of the Palo Verde site filed a lawsuit in Maricopa County Superior Court claiming prior rights to effluent to be delivered to Palo Verde under the primary and secondary effluent contracts. In January 1984, the Operating Agent for Palo Verde joined with another Palo Verde participant in bringing an action in an Arizona state court against the plaintiffs in the foregoing lawsuit and an owner of land in the river basin from which the effluent to be received under the primary contract is alleged to be derived, seeking a declaratory judgment as to rights to effluent under Arizona law. This declaratory judgment action was consolidated in the Arizona state court with the lawsuit filed in November 1982. In October 1985, the state court

ruled in favor of the Palo Verde participants in these consolidated lawsuits, holding that the effluent contracts are neither void, unenforceable, nor enjoinable for the reasons raised in the consolidated lawsuits by the parties adverse to the Palo Verde participants (the "Adverse Parties"). The Adverse Parties appealed that decision to the Arizona Court of Appeals. APS and certain Palo Verde participants, including the Company, cross-appealed. On December 17, 1986, the consolidated appeals and cross-appeals were transferred to the Arizona Supreme Court, and oral argument was heard on February 20, 1987. Subsequently, three of the five Supreme Court Justices removed themselves from the case, and a rehearing of oral argument occurred on February 16, 1988. A decision by the Arizona Supreme Court is still pending.

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. Palo Verde is located within the geographic area subject to the summons, and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. APS, as Operating Agent for Palo Verde, 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 and, alternatively, seek confirmation of such rights. No trial date has been set in this matter.

Although the foregoing matters remain subject to further evaluation, APS, as Operating Agent for Palo Verde, has advised the Company that APS expects that the described litigation will not have a materially adverse impact on the operation of the Palo Verde generating units.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability payments resulting from nuclear energy hazards to the full $7.7 billion limit of liability under Federal law, as modified by legislation passed by Congress in August of 1988. 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. The maximum assessment per reactor under the retrospective assessment program for each nuclear incident is approximately $66 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% ownership interest in the three Palo Verde Units, the Company's maximum potential assessment per incident is approximately $31.3 million, with an annual payment limitation of $4.74 million. The insureds under this liability insurance include the Palo Verde participants and "any other person or organization with respect to his legal responsibility for damage caused by the nuclear energy hazard."

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $1.725 billion, a substantial portion of which must first be applied to decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchase of power resulting from the accidental outage of any of the three Palo Verde Units if such outage exceeds 21 weeks.

NRC Matters. On several occasions, including during 1988, the NRC has proposed and assessed civil penalties for various violations at PVNGS that have been categorized as problems of Severity Level III or lesser severity (on a scale of I to V in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions"). In addition, the NRC is currently evaluating possible enforcement action relating to alleged violations of NRC regulations in connection with the reactor start-up of PVNGS Unit 1 in May 1988.

Palo Verde Unit 3 experienced an unscheduled outage on March 3, 1989, and Palo Verde Unit 1 experienced an unscheduled outage on March 5, 1989. Both of these units remain out of service and, pursuant to Confirmatory Action Letters from the NRC dated March 7, 1989, and March 8, 1989, the NRC is requiring APS to successfully complete certain procedures and obtain NRC approval prior to restarting either unit. The required Unit 1 procedures include confirming that the atmospheric dump valves, emergency lighting, and steam bypass control system are operable, and developing a plan for investigation of a recent circuit breaker failure. The required Unit 3 procedures include developing and presenting to the NRC a plan for investigating the atmospheric dump valves and all valves and

dampers which recently failed to automatically activate. Unit 3 began its planned refueling outage on March 8, 1989, and that outage is scheduled to continue for over 70 days. The timing of the Unit 1 refueling outage, which is scheduled to begin on April 8, 1989, is currently under review.

On March 15, 1989, Palo Verde Unit 2 was removed from service by APS to test the atmospheric dump valves. On March 28, 1989, the NRC notified APS that it will require APS to successfully complete certain procedures and obtain NRC approval prior to restarting Unit 2.

The Company cannot currently predict the duration of the Palo Verde outages or the financial or regulatory impact, if any, if such outages continue for an extended period of time.

Decommissioning Plan and Fund. For information regarding the obligations of the Company to plan and fund, over the service life of Palo Verde, its share of the estimated costs to decommission Palo Verde, see Note D of the Notes to Consolidated Financial Statements. The Company believes that all costs associated with nuclear plant decommissioning will be recoverable through rates.

Environmental Matters

The Company's operations are subject to stringent environmental protection measures imposed under federal and state laws and regulations, some of which have required substantial expenditures for pollution control technology. Units 4 and 5 at Four Corners have operated for several years under variances from the New Mexico Environmental Improvement Division (the "NMEID") relating to the emission of nitrogen oxides. The most recent variance was granted on December 18, 1987, to allow adequate time for the installation of additional equipment intended to achieve compliance with existing emissions limitations without adverse operational impacts. The variance was granted through September 30, 1989 for Unit 4, and September 30, 1991 for Unit 5. The total cost for the retrofit of the new burners and associated modifications for Units 4 and 5 is estimated to be approximately $38,000,000, of which the Company's share would be approximately $2,660,000.

Revisions to environmental laws and regulations continue to be proposed and adopted at federal, state and local levels. Pursuant to the Federal Clean Air Act Amendments of 1977, the EPA has adopted regulations, applicable to certain Federally-protected areas, that address visibility impairment which can be reasonably attributed to specific sources. Although some state implementation plans have been revised to implement these regulations, further revisions are being considered by some states. The EPA may also adopt regulations to deal with visibility impairment resulting from regional haze. In addition, amendments to the Clean Air Act have been proposed which are intended to address problems of "acid rain," toxic air pollutants, and the nonattainment of national ambient air quality standards. Along with other members of the electric utility industry, the Company is continuing its involvement in proceedings before the United States Congress, state legislatures, federal and state regulatory agencies, and the courts concerning revisions to environmental laws and regulations. The Company cannot accurately predict at this time the financial and operational impacts resulting from such revisions.

Energy Sources

General

Since 1984, the Company's energy mix has generally consisted of natural gas, coal and purchased power. Beginning in 1986, uranium became a part of the Company's energy mix, decreasing the importance of purchased power. This, in combination with lower natural gas costs, resulted in decreases in the Company's average yearly system energy cost. The following table lists the percentage contribution of coal, gas, uranium and purchased power to the total energy mix of the Company and the average cost to the Company in cents per KWH.

	Coal		Gas		Uranium		Purchased Power	
	Percent of Energy Mix	Average Cost	Percent of Energy Mix	Average Cost	Percent of Energy Mix	Average Cost	Percent of Energy Mix	Average Cost
1984	16%	.83¢	46%	4.00¢	—%	—¢	38%	2.64¢
1985	11	1.02	28	3.81	—	—	61	2.80
1986	13	1.01	30	2.36	7	.98	50*	2.30
1987	14	1.04	32	2.10	12	.96	42*	2.04
1988	13	1.00	30	2.21	40	1.06	17	2.47

* Prior to rate making treatment of the Company's investment in Palo Verde as described in "Rates and Regulation," the Company included under purchased power the major portion of energy generated by Palo Verde.

For a discussion of the recovery by the Company of its fuel costs, either in base rates or through fuel adjustment clauses, see Note A of Notes to Consolidated Financial Statements.

The Company's local generating units are subject to the requirements of the Fuel Use Act, as amended (the "FUA"). Under such Act, the Company may continue to burn natural gas in its existing generating units for the life of the units, subject to compliance with a DOE approved energy conservation plan filed by the Company in 1982. In early 1988, the Company filed its final update to the conservation plan. In the future, under Section 712 of the FUA, the Company will be required to file annual statements that it is in compliance with its conservation plan. The Company will continue its conservation programs in the areas of customer assistance, public information and operating efficiency.

Natural Gas

The Company is supplied with natural gas from both interstate and intrastate pipeline systems. The interstate pipeline owned by El Paso Natural Gas ("EPNG") is interconnected with the Company's Rio Grande Station. EPNG transports spot natural gas and contract commodity gas to the Rio Grande Station. Meridian Oil & Hydrocarbons ("Meridian") supplies both intrastate and spot natural gas to the Company's Newman and Copper Stations.

In 1988, the majority of the Company's interstate natural gas requirements consisted of spot natural gas supplied by various suppliers. In December 1987, the Company's commodity gas contract with EPNG terminated and the Company began negotiating a new gas contract with EPNG. Pending numerous regulatory issues that EPNG currently has pending before the FERC, the Company and EPNG expect to reach a new agreement in 1989. In the interim, EPNG continues to transport spot natural gas on behalf of El Paso Electric Company and provide commodity gas (as required) to the Company under the original Certificate of Service filed with the FERC.

The intrastate natural gas requirements at Copper and Newman are supplied pursuant to an intrastate natural gas contract with El Paso Hydrocarbons (a subsidary of Meridian) and transported by its subsidiary El Paso Gas Transportation Company. This contract was amended in 1986, lowering the Company's take-or-pay requirements, resulting in greater flexibility and allowing maximization of the use of inexpensive economy purchased power and generation from Palo Verde. In addition,

interstate natural gas can be supplied to Newman Units 1, 2, 3 and 4, which allows for a back-up natural gas supply when operational constraints on the intrastate gas system dictate the need for an alternate fuel supply.

During 1988, the Company experienced only slight supply curtailments on its interstate system due to the shortage of natural gas caused by severe winter weather conditions in various parts of the nation. The impacts of the curtailments were minimal because the Company was able to shift load to other generating plants or purchase economy power. The Company does not expect any significant curtailments during 1989 with respect to either interstate or intrastate gas supplies.

Coal

APS, the Operating Agent for the Four Corners Plant, purchases coal to fuel such plant from coal suppliers with long-term leases of coal reserves owned by the Tribe. Such coal supplier is currently disputing the Tribe's ability to assess certain taxes against it. Any collection from the coal supplier of these taxes would increase the Company's coal costs in an amount that the Company does not deem material.

The Company believes that sufficient reserves of low sulfur coal (the sulfur content of which is currently running 0.8%) have been committed to the two units of Four Corners in which the Company has an undivided interest to continue operating such units for their useful lives. Prices paid for coal supplied from reserves dedicated under the existing contract have been stable, although applicable contract clauses permit escalations under certain conditions. In addition, major price increases from time to time could result from contract renegotiation.

Nuclear Fuel

The fuel cycle for the Palo Verde Station is comprised of the following stages: (1) the mining and milling of uranium ore to produce uranium concentrates; (2) the conversion of uranium concentrates to uranium hexafluoride; (3) the enrichment of uranium hexafluoride; (4) the fabrication of fuel assemblies; (5) the utilization of fuel assemblies in reactors; and (6) the storage of spent fuel and the disposal thereof. Arrangements have been made to obtain quantities of uranium concentrate anticipated to be sufficient, if certain contract options are exercised, to meet operational requirements through 1997. Spot purchases on the open market will be made as appropriate in lieu of any uranium which might be obtained pursuant to the contract options. The Palo Verde participants have also contracted for a significant portion of the conversion services required through 1992. The Palo Verde participants, including the Company, have an enrichment services contract with DOE that obligates DOE to furnish the enrichment services required for the operation of the three Palo Verde units over a term expiring in November 2014. In addition, existing contracts will provide fuel assembly fabrication services for at least ten years from the operation date of each Palo Verde unit and, if options are exercised, for approximately twelve additional years.

Spent fuel storage facilities at Palo Verde have sufficient capacity to store all fuel expected to be discharged from normal operation of all of the Palo Verde units through at least the year 2003. Pursuant to the Nuclear Waste Policy Act of 1982 (the "Act"), DOE is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. The NRC, pursuant to the Act, also requires all operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. APS, as Operating Agent, on behalf of itself and the other Palo Verde participants, including the Company, has executed a spent fuel disposal contract with DOE. The Act also obligates DOE to develop the facilities necessary for the permanent disposal of all spent fuel generated and to be generated by domestic power reactors and to have the first such facility in operation by 1998 under prescribed procedures. In December 1987, Congress passed the Nuclear Waste Policy Amendments Act of 1987, substantially changing the Act by, among other things, decreasing to one the number of sites to be initially considered for permanent disposal facilities. In June 1988, DOE reported that such permanent disposal facilities will not be in operation until 2003

and, under DOE's current criteria for shipping allocation rights, Palo Verde is scheduled to begin spent fuel shipments to the DOE permanent disposal facilities in 2010. The Company believes that alternative interim spent fuel storage methods will be available for use by Palo Verde until DOE's scheduled shipments from Palo Verde begin.

Pursuant to the Participation Agreement among the participants in the Palo Verde Station, the Company has an undivided interest in nuclear fuel purchased and to be purchased in connection with the operation of Units 1, 2 and 3 of the Station. The Company has a nuclear fuel purchase commitment with an independent trust. The trust's financing is based upon a letter of credit with a three-year term which is annually extended by one year if notice to the contrary is not given to the trust by the issuing bank. The letter of credit is currently scheduled to expire on January 8, 1992. The trust purchases nuclear fuel and incurs all costs in connection with the acquisition of the fuel and related materials for use by the Company at Palo Verde. The Company has the option of either purchasing the fuel from the trust or purchasing the heat generated by the fuel at prices established to reimburse the trust for all the costs incurred in connection with acquisition of the fuel. The Company is required to elect one of these options for each batch of nuclear fuel. The Company has elected the heat purchase option as the basis for payment for the first fuel loads for Palo Verde Units 1, 2 and 3 and for the first fuel reloading at Palo Verde Unit 1 and presently intends to elect the heat purchase option as the basis for payment for future fuel reloadings. Quarterly heat payments at the established prices began in the first quarter of 1986 for Palo Verde Unit 1, the first quarter of 1987 for Unit 2 and the second quarter of 1988 for Unit 3. At December 31, 1988, the aggregate investment of the trust in such nuclear fuel and related materials was approximately $91,500,000, including approximately $67,100,000 for fuel loaded at Palo Verde Units 1, 2 and 3.

Executive Officers of the Registrant

Name	Age	Current Position and Business Experience
David H. Wiggs, Jr.	41	President and Chief Executive Officer since March 1989; President and Chief Operating Officer from January 1988 to March 1989; for more than 5 years prior to January 1988 a partner in Kemp, Smith, Duncan & Hammond, counsel for the Company.
William J. Johnson	47	Senior Vice President and Chief Financial Officer since January 1988; Vice President from May 1984 to January 1988; Treasurer from December 1986 to February 1988; Chief Financial Officer since December 1986 and Controller from May 1978 to December 1986.
Charles Mais	57	Senior Vice President since June 1986; Vice President from December 1978 to June 1986.
William W. Royer	44	Senior Vice President since January 1988; Vice President from December 1985 to January 1988; Treasurer from December 1983 to December 1986 and General Counsel from March 1981 to February 1988.
Ignacio R. Troncoso	42	Senior Vice President since January 1988; Vice President from May 1982 to January 1988.
Joseph E. Wasiak	57	Senior Vice President since January 1988; Vice President from February 1986 to January 1988; Assistant Vice President from May 1984 to February 1986 and for more than 5 years prior thereto served in various managerial and supervisory capacities with the Company.
Lawrence M. Downum, Jr.	50	Vice President since December 1983 and for more than 5 years prior thereto served in various managerial and supervisory capacities with the Company.
James P. Maloney	57	Vice President since February 1986; Assistant to the President from October 1985 to February 1986; Commanding General of Fort Bliss, Texas from June 1982 to August 1985.

Name	Age	Current Position and Business Experience
Gary R. Hedrick	34	Treasurer since February 1988; Vice President, Treasurer and Chief Financial Officer of PasoTex Corporation from December 1986 to February 1988; Treasurer of Franklin Land & Resources, Inc. from November 1986 to February 1988; for more than 5 years prior thereto served in various managerial and supervisory capacities with the Company.
Gordon M. Heggem	62	Controller since May 1987; and for more than 5 years prior thereto Manager of General Accounting.
Eduardo A. Rodriguez	33	Corporate Secretary since February 1989; General Counsel since February 1988; Assistant General Counsel from December 1984 to February 1988; Assistant Secretary from June 1986 to February 1989 and Staff Counsel from November 1981 to December 1984.
Billye E. Bostic	58	President of PasoTex, the Company's investment subsidiary, since December 1986; Vice President of FL&R since April 1982; Executive Vice President of the Company from May 1982 until December 1986. Mr. Bostic will retire at March 31, 1989, and thereafter will serve as a consultant to the Company under a one-year consulting agreement, subject to renewal by mutual agreement.

The executive officers of the Company are elected no less often than annually and serve at the discretion of the Board of Directors.

Non-Utility Operations

The Company engages in unregulated, non-utility operations through its wholly owned subsidiary, FL&R, and through PasoTex, which is 65% owned by FL&R and 35% owned by the Company. Although the non-utility operations themselves are not subject to regulation (other than certain reporting requirements), the Company's funding of its diversification program and transactions among the Company and its affiliated interests are subject to the regulation of the New Mexico Commission. The New Mexico Commission authorized the Company to invest up to $120 million in PasoTex, such funding level representing the net after-tax gain from the Unit 2 sales and leasebacks.

For financial information regarding the Company's non-utility operations, see Note N of Notes to Consolidated Financial Statements.

PasoTex

The Company has invested approximately $112 million of the proceeds from the Unit 2 sale and leaseback transactions in PasoTex, which was established primarily for the purpose of investing such funds to earn a return to offset the portion of the Unit 2 lease payments not recoverable through rates. See Note E of Notes to Consolidated Financial Statements. A secondary objective for PasoTex is to stimulate economic activity and power consumption in its service area by investing in local business and industry and bringing new industrial and commercial business into the Company's service area, thereby providing new jobs and economic development and broadening the base of the Company's utility customers, which should result in lower KWH fixed costs for the Company's utility operations.

PasoTex invested $65 million in certain non-publicly held preferred stocks issued by two savings and loan institutions. PasoTex subsequently sold, at cost, $17.5 million of such preferred stock to the Company. The proceeds from such sale were invested in a note payable by FL&R to a bank, which note is secured by real estate which constitutes part of FL&R's discontinued operations. The Company has been required to write down its $5 million preferred stock investment in one of the savings and loan institutions to $2 million due to adjustments in the equity account of such institution. See Note F of Notes to Consolidated Financial Statements.

PasoTex has invested the balance of its funds principally for the acquisition of controlling or sole ownership interests in a marketer of oil country tubular goods, a specialty steel products manufacturer and two furniture and accessory manufacturers. To a lesser extent, PasoTex has invested in certain financing transactions and has provided working capital financing to certain of its subsidiaries. The following discussion relates primarily to PasoTex's two significant subsidiaries, each of which contributed at least 10% of the Company's consolidated revenues for the year ended December 31, 1988.

Oil Country Tubular Goods. EnerServ Products, Inc. ("EnerServ") is 100% owned by PasoTex. EnerServ end finishes and markets oil country tubular goods ("OCTG"), which consist of steel casing and tubing used in the drilling and completion of oil and gas wells. EnerServ's principal executive offices and end-finishing facilities are located in Houston, Texas. EnerServ's results of operations predominantly depend upon the level of demand for OCTG, which demand is generally related to the domestic market for crude oil and natural gas. Given the current price of oil, demand for OCTG is expected to be weak in 1989.

The marketing of oil country tubular goods is a highly fragmented and competitive industry with many companies engaged in the business, none of which is dominant. EnerServ's marketing competitors include larger companies with greater financial resources, larger staffs and a greater inventory of OCTG. Competition in the industry is principally based upon product quality and price. The OCTG business is typically cyclical in nature, but it has experienced an unprecedented downturn since 1982.

EnerServ, primarily through its wholly-owned subsidiary, Pipeco, Inc. ("Pipeco"), markets its product principally to end users, including major oil companies, independent oil and gas operators and contract drillers concentrated in Texas, Louisiana, Oklahoma and New Mexico. No marketing customer accounted for 10% or more of EnerServ's consolidated revenues for the year ended December 31, 1988. At March 1, 1989, Pipeco's sales force consisted of 14 full-time salesmen.

The principal raw material essential to EnerServ's marketing business is steel, which is currently readily available. EnerServ's foreign sources of supply are, however, subject to disruption. Historically, Pipeco has purchased substantial product from foreign suppliers. Reliance on foreign supply involves inherent uncertainties, including foreign exchange fluctuations and restrictions on the quantity of pipe imported. However, Pipeco has developed reliable domestic supply sources.

EnerServ's Tubular Services division ("Tubular Services") (which, like its competitors, is licensed by the American Petroleum Institute) heat treats and end finishes OCTG. Historically, a substantial portion of the plain end pipe end finished by Tubular Services has been produced by foreign manufacturers. In past years, the depressed domestic drilling industry had a materially adverse effect on Tubular Services' end finishing business.

EnerServ, through its ownership of Pipeco, owns a substantial amount of the OCTG which Tubular Services end finishes, along with OCTG owned by independent oil field distributors and manufacturers of OCTG, which deliver unfinished casing and tubing to Tubular Services.

No single end finishing customer accounted for more than 10% of EnerServ's consolidated revenues in 1988. Tubular Services' primary competitors are numerous other independent end finishers, some of which have greater financial resources and larger staffs. In addition, several large manufacturers of OCTG end finish their own products.

EnerServ warrants to its customers that its end finishing work meets American Petroleum Institute standards, and EnerServ believes that its claims history relating to nonconforming product is below industry norms.

Historically, the amount of EnerServ's backlog of unfilled end finishing orders has not been significant in relation to annual sales.

EnerServ experiences customary practices relating to working capital items. Inventory, however, may fluctuate and requires working capital financing, which is subject to the same restrictions on

financing described in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Compliance by EnerServ with Federal, state and local provisions which have been enacted or adopted regarding the discharge of materials into the environment, or otherwise relating to the protection of the environment, in the opinion of management, would have no material effect upon EnerServ's capital expenditures, earnings, or competitive position.

At March 1, 1988, EnerServ employed 142 persons, none of whom are represented by any union, and management of EnerServ considers its relationship with its employees to be satisfactory. The work force, most of which consists of hourly employees, fluctuates with the level of activity at the end finishing operations.

Specialty Steel Products Manufacturing. Border Steel Rolling Mills, Inc. ("Border Steel"), an 80% owned subsidiary, operates a mini mill which produces construction-grade steel in the form of reinforcing bars ("rebar") for the Southwest construction markets, fabricated rebar and other specialized mill products. Border Steel also produces grinding balls and grinding rods for the copper mining industry and cold finished bars. Its major raw material is scrap metal which is supplied from various sources throughout the southwestern United States. Management believes that supplies are adequate in quantity and quality to support Border Steel's projected operations for 1989. Border Steel certifies its products to meet American Society for Testing and Materials chemical and physical property standards. Previously, Border Steel has not incurred a product liability claim, and none are pending.

Border Steel's sales are approximately 80% to the construction industry, 9% specialty industrial and 11% to the mining industry. On January 1, 1989, Border Steel had a backlog of approximately 37% of the 1989 projected volume in the form of construction contracts for fabricated rebar.

The 1988 sales of fabricated rebar sold on contract grew to more than 50% of Border Steel's gross revenues. Industry practice dictates that a percentage of total payments on construction contracts be retained until construction is complete. The extended payment terms provided under these contracts have resulted in significantly increased working capital needs compared to previous years.

In December 1988, Border Steel's board of directors approved a $12 million program to modernize the steel making operation, increasing capacity by 50% and contemplated to increase profitability through unit cost reduction and additional volume. The program requires financing. See "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Border Steel employs over 600 people, of which approximately 450 are covered by various union contracts.

Regulations relating to the discharge of materials into the environment have affected Border Steel in the past. A claim filed against Border Steel in 1988 under the Texas Solid Waste Disposal Act was settled upon Border Steel's agreement to renovate certain disposal facilities. All facility renovations have been completed in accordance with engineering plans approved by the Texas Water Commission. Border Steel is not aware of any further environmental claims and believes it is in substantial compliance with all environmental regulations.

Border Steel competes with various steel producers and fabricators from the Southwest, West Coast, Pacific Northwest and the Rocky Mountain area. Competition is significant and revolves around product price, quality and availability. Border Steel's customer base is diversified, and some of Border Steel's competitors have greater resources. No single customer generates more than 10% of total gross revenues.

Furniture and Accessories Manufacturing. B. P. John Furniture Company, Inc. ("B. P. John"), 100% owned by PasoTex, is a manufacturer of low to medium-priced bedroom and dining room furniture. B. P. John was purchased by PasoTex in December 1987. It is presently located in Santa Ana, California, but current plans call for the relocation of B. P. John to the southern New Mexico area in

1989. The expected cost of such relocation and construction of a new manufacturing facility is estimated at approximately $12 million to $15 million, which will require financing. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations." B. P. John presently employs approximately 600 people.

Westwood Lighting Group, Inc. ("Westwood"), 50% owned by PasoTex, is an industry leader in the manufacture, distribution and sale of zinc-cast brass-plated portable lamps. PasoTex acquired its interest in Westwood in July 1987 and completed the relocation of Westwood to the El Paso/Juarez, Mexico area in late 1988.

FL&R

The principal assets of FL&R are real estate investments in downtown El Paso which include a luxury hotel and an office and parking building. The primary objective in making these investments was to initiate and promote revitalization of downtown El Paso and thereby stimulate economic and industrial development and electric power consumption in the service area. Although these properties are believed to have good long-term potential, they currently operate at a loss and will continue to have a detrimental effect on the Company's earnings and cash flow. Accordingly, the Company has decided to discontinue the real estate operations of FL&R and sell these investments. The Company has made provision in 1988 for the expected losses on the sale of the investments, including provision for expected operating losses during the phase-out period of the investments. See Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Non-Utility Operations."

FL&R has also invested in certain preferred stocks and partnerships for the leasing of assets to third parties. Substantially all of the assets of FL&R have been pledged to secure its various borrowings. FL&R borrows independently from third parties, without recourse to the Company (except for certain borrowings pursuant to the Company's nuclear fuel and fuel oil financing arrangements) for the purposes of its various investments and activities.

Utility Operating Statistics

	December 31, 1988	1987	1986
Utility Operating Revenues (In thousands):			
Retail:			
Residential	$ 112,957	$ 103,232	$ 103,428
Commercial and industrial, small	105,166	95,766	98,543
Commercial and industrial, large	35,575	32,976	37,821
Sales to public authorities	57,240	51,493	50,872
Provision for refund	(1,641)	(3,019)	(10,006)
Other	4,891	1,573	2,149
	314,188	282,021	282,807
Wholesale:			
Sales for resale	67,919	55,242	35,302
Total utility operating revenues	$ 382,107	$ 337,263	$ 318,109
Number of customers (End of year):			
Residential	209,550	204,102	198,002
Commercial and industrial, small	21,069	20,582	20,115
Commercial and industrial, large	39	41	39
Other	2,548	2,509	2,309
Total	233,206	227,234	220,465
Average annual use and revenue per residential customer:			
KWH	6,025	5,846	5,719
Revenue	$ 546.13	$ 511.48	$ 530.86
Average revenue per KWH:			
Residential	9.07¢	8.75¢	9.28¢
Commercial and industrial, small	7.52	7.28	7.78
Commercial and industrial, large	5.10	5.19	5.74
Energy supplied, net, KWH (In thousands):			
Generated	4,904,854	3,186,967	2,422,514
Purchased and interchanged	969,793	2,264,955	2,437,875
Total	5,874,647	5,451,922	4,860,389
Energy sales, KWH (In thousands):			
Retail:			
Residential	1,246,081	1,179,812	1,114,177
Commercial and industrial, small	1,397,913	1,316,198	1,267,129
Commercial and industrial, large	697,758	635,448	658,521
Sales to public authorities	908,238	860,852	809,619
	4,249,990	3,992,310	3,849,446
Wholesale:			
Sales for resale	1,271,366	1,087,444	641,858
Total sales	5,521,356	5,079,754	4,491,304
Losses and company use	353,291	372,168	369,085
Total	5,874,647	5,451,922	4,860,389
Native system:			
Peak load, KW	840,000	820,000	790,000
Net generating capacity for peak, KW	1,497,000	1,297,000	1,103,000
Load factor	63.0%	61.5%	61.6%
Total system:			
Peak load, KW	1,002,000	975,000	938,000
Net generating capacity for peak, KW	1,497,000	1,297,000	1,103,000
Load factor	67.3%	64.4%	59.9%

Item 2. Properties

The principal properties of the Company are described in Item 1 of this report, and such descriptions are incorporated herein by reference thereto. Transmission lines are located either on private rights-of-way, easements or on streets or highways by public consent. Reference is made to Note I of Notes to Consolidated Financial Statements for information regarding encumbrances against the principal properties of the Company and its subsidiaries.

Item 3. Legal Proceedings

First Service Life Litigation

Pending Actions Involving the Company. On September 26, 1988, the Company filed a declaratory judgment action in the 345th Judicial District Court, Travis County, Texas, against First Service Life Insurance Company, a life insurance company organized under the laws of the Cayman Islands ("First Service"), and R. B. Ashworth, as Conservator for the affairs of First Service under the Texas Insurance Code (the "Conservator"), for a determination that (i) the Company has legal, valid, duly perfected and enforceable security interests in certain collateral granted to the Company by First Service to secure annuities purchased by the Company from First Service, the present balance of which is approximately $20 million (the Company's original annuity investment purchased from First Service being $70 million); and (ii) that events of default have occurred under the collateral security documents pertaining to such annuities which entitle the Company to enforce such security interests. In late May 1988, the Company notified First Service that First Service was in default under the annuities and the collateral agreements and that the Company intended to enforce its security interests. The Conservator, who was appointed by the Texas Commissioner of Insurance in early June 1988, notified the Company that First Service might not be in default, expressed doubt as to the validity and enforceability of the security interests held by the Company and demanded that the Company return to the Conservator all of the collateral and desist and refrain from proceeding with enforcement of the security interests and other interference with the conservatorship and the conservatorship proceedings.

On September 29, 1988, the Conservator, in conjunction with his answer and denial of the Company's declaratory judgment action, countersued the Company on behalf of First Service and two affiliated corporations, First Service Life, a Turks and Caicos corporation ("FSL"), and Knickerbocker Life Insurance Company ("Knickerbocker"), for actual damages of at least $50 million, plus punitive damages of at least $300 million. The Conservator's counterclaim seeks (i) a temporary and permanent injunction against the Company's enforcement of its security interests in the collateral, (ii) an accounting from the Company as to all payments and transfers of property to the Company from First Service with respect to the Company's annuities, (iii) a declaratory judgment that the Company's security interests are illegal and unenforceable under the Texas Insurance Code and that the sale and purchase of the annuities was an illegal transaction under the Texas Insurance Code by a company doing insurance business in Texas without authorization and (iv) disgorgement by the Company of all payments received on its annuities and all collateral therefor. The counterclaim alleges several causes of action against the Company including principally fraud, conversion and breach of duty of good faith and fair dealing (based upon an alleged affiliate or "insider" relationship between the Company and First Service).

On December 1, 1988, a receiver (the "Receiver") was appointed for First Service by the 53rd Judicial District Court of Travis County, Texas, and on December 13, 1988, the Receiver in his capacity for First Service was substituted as a party for the Conservator in the above-described litigation. On January 18, 1989, the Receiver was appointed as receiver for FSL as well. The Conservator remains a party to the above-described litigation in its capacity as conservator for Knickerbocker.

Although only preliminary discovery has been conducted, the Company's legal counsel, Small, Craig & Werkenthin, Austin, Texas, has reviewed the basic facts of the case with management and other parties familiar with various aspects of the transactions involved in the litigation, examined

documents and records of the Company and other parties which relate to such transactions and evaluated the allegations against the Company made in the counterclaim. Based upon its preliminary evaluation and investigation of the case to date, and subject to the results of discovery, counsel believes that it is more likely than not that the outcome of the litigation will be favorable to the Company.

The Company believes that the collateral for its annuities is approximately equal in value to the present balance of annuities and that the Company's security interests in the collateral are valid and enforceable, and the Company intends to recover the amounts owed to it on the annuities through enforcement of its rights to the collateral. The Company strongly denies the allegations of the counterclaim, believes the counterclaim is without merit and intends to vigorously defend against it. The Company has made no provision for loss with respect to the annuities or for the effects, if any, of the ultimate outcome of the litigation. Effective April, 1988 the Company discontinued the accrual of interest income on the annuities.

Threatened Litigation. The Company has been notified by other parties who allegedly purchased annuities from First Service (the "Other Annuitants") that the Other Annuitants intend to institute litigation against the Company seeking damages for money allegedly lost by the Other Annuitants on their annuities. The allegations of the Other Annuitants against the Company include allegations that the Company acted in concert with principals and agents of First Service in connection with misrepresentations by such agents of First Service and that the Company exercised control over the affairs of First Service and managed First Service to serve the interest of the Company to the detriment of the interests of policyholders of First Service, including the Other Annuitants. The Other Annuitants further allege that the collateral granted by First Service to the Company for the Company's annuity investment, and the payments received by the Company on its annuities from First Service, constitute fraudulent transfers and preferences and violations of the Texas Insurance Code and the Texas Deceptive Trade Practices Act. The Other Annuitants claim damages totaling approximately $2.4 million plus interest on their annuities and attorneys' fees. No suit against the Company has been filed by the Other Annuitants.

The Company vigorously denies any liability to the Other Annuitants and believes their claims are without merit. Based upon counsel's limited evaluation and investigation in connection with the Company's suit against the Conservator (and now the Receiver) described above, and subject to the preliminary nature of the claims made by the Other Annuitants, counsel believes that it is more likely than not that, if litigation were instituted by the Other Annuitants on the basis of the claims set forth in their notices to the Company, the ultimate outcome of such litigation would be favorable to the Company.

There are numerous parties who purchased annuities from First Service, not included within the group of the Other Annuitants, who may assert additional claims similar in nature to the claims asserted by the Other Annuitants, against the Company. These claims, if asserted, could result in additional suits against the Company.

Suit Against Directors of First Service. On February 3, 1989, the Receiver filed suit in the 345th Judicial District Court, Travis County, Texas, against certain individuals who were alleged to be directors of First Service and/or FSL, including Billye E. Bostic, President of PasoTex and formerly Executive Vice President and Chief Financial Officer of the Company.

The Receiver alleges that First Service engaged in the sale of annuities in Texas without authorization to do so and that such actions constituted illegal insurance transactions under the Texas Insurance Code. The Receiver further alleges that the alleged illegal sale of annuities by First Service constitutes a breach by the directors of First Service of their fiduciary duty to exercise due care in the management of the affairs of First Service and/or FSL and resulted in unspecified losses to First Service. The suit seeks actual damages of at least $33 million and, in addition, exemplary damages of at least double the actual damages. Discovery has not commenced.

Mr. Bostic has advised the Company that he denies that he served as a director of First Service or FSL during the period of the alleged activities complained of, denies any liability in respect of the Receiver's suit and intends to vigorously defend against it. Mr. Bostic is represented by counsel separate from the Company's counsel in the First Service litigation. Mr. Bostic is entitled to indemnity with respect to the Receiver's suit to the extent indemnification is afforded by the Company to all of its officers and directors with respect to service on certain outside boards.

Because the Receiver's suit has only been recently filed and no discovery has commenced, counsel for Mr. Bostic is unable to express an opinion as to the ultimate outcome of the suit. No provision for loss, if any, is included in the 1988 consolidated financial statements.

Other Legal Proceedings

Information regarding legal proceedings relating to Palo Verde, Four Corners, rates and regulation and environmental matters is described under the subcaptions "Rates and Regulation," "Facilities" and "Environmental Matters" under "Business" in Item 1 of this report and is incorporated herein by reference thereto.

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Company's Common Stock is traded in the over-the-counter market and quoted on the NASDAQ National Market System. The high and low sale prices for the Company's Common Stock, as reported by NASDAQ, and the quarterly dividends per share paid by the Company, for the periods during 1987 and 1988 indicated below, were as follows:

	Sale Price		
	High	Low	Dividends
1987			
First Quarter	$21⅝	$18¾	$0.38
Second Quarter	18¾	16½	0.38
Third Quarter	17½	15¼	0.38
Fourth Quarter	16⅞	13⅛	0.38
1988			
First Quarter	16⅝	14⅛	0.38
Second Quarter	16⅜	14⅜	0.38
Third Quarter	16¼	15⅛	0.38
Fourth Quarter	16⅛	13⅜	0.38

At February 27, 1989, there were 43,535 holders of record of the Company's Common Stock.

The Company's Restated Articles of Incorporation and the First Mortgage Indenture and certain of the supplemental indentures relating to the various series of First Mortgage Bonds contain restrictions as to the payment of dividends on the Common Stock of the Company and as to the purchase or retirement of capital stock of the Company. At December 31, 1988, the retained earnings available for dividends on the Common Stock under the most restrictive of those provisions was approximately $186,380,000. For information regarding the Company's current re-evaluation of its dividend policy, see Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Item 6. Selected Financial Data

As of and for the years ended December 31:

	1988	1987	1986	1985	1984
		(In thousands except per share data)			
Operating revenues:					
Utility	$ 382,107	$ 337,263	$ 318,109	$ 339,591	$ 329,015
Non-utility	256,617	105,719	153	6,444	5,553
Total	$ 638,724	$ 442,982	$ 318,262	$ 346,035	$ 334,568
Income from continuing operations before cumulative effect of change in accounting method	$ 69,787	$ 48,830	$ 98,715	$ 111,903	$ 108,286
Income from continuing operations before cumulative effect of change in accounting method per weighted average shares of common stock	1.64	1.02	2.41	2.84	2.88
Dividends declared per share of common stock	1.52	1.52	1.52	1.49	1.43
Total assets	1,975,159	2,275,573	2,194,418	1,919,060	1,690,109
Additions to utility plant, net of allowance for equity funds used for construction	73,567	56,679	136,598	169,437	167,297
Long-term, financing and capital lease obligations and preferred stock — redemption required	$ 746,851	$ 888,328	$ 947,631	$ 971,228	$ 803,577

Included in income from continuing operations before the cumulative effect of change in accounting method for the year ended December 31, 1987 is a provision of approximately $11,413,000, net of tax, for realized and unrealized losses sustained in 1987 on the Company's investment in marketable securities, primarily in connection with the stock market break on October 19, 1987 and a $24,400,000 after-tax non-cash regulatory write-off of plant costs, recorded by the Company in connection with the settlement of its 1987 Texas Rate Case.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Liquidity and Capital Resources

Although the Company's construction requirements have decreased significantly with the completion of the Palo Verde construction program, this decrease has been offset by cash requirements related to regulatory deferrals and current maturities of financing incurred for Palo Verde construction costs. The Company has not generated in the recent past, nor will it generate in 1989, sufficient Internally Generated Cash to meet its cash requirements for preferred and common stock dividends, construction, redemptions of debt and preferred stock and regulatory deferrals and, accordingly, will continue to be required to finance such requirements to the extent not met by Internally Generated Cash. Management has defined Internally Generated Cash, for purposes of its cash planning and financing requirements, as "net cash (used for) provided by operating activities" before the effect of "Palo Verde deferred costs" and "phase-in plan deferrals", all as reflected in the Consolidated

Statement of Cash Flows set forth under Item 8. Internally Generated Cash is used as a measure for planning purposes because it recognizes the necessity of financing deferrals, which are scheduled to be collected in cash in the future, pursuant to regulatory order.

1989 Cash Requirements. The Company's 1989 financing requirements will be greater than originally anticipated principally as a result of (i) lower than anticipated cash revenue from the Company's rate moderation plans, based on the growth in KWH sales that has occurred (see Part I, Item 1 — "Rates and Regulation — Rate Matters — Texas — 1988 Rate Case"); (ii) higher than expected operating and maintenance expenses, particularly at Palo Verde; (iii) higher than anticipated working capital requirements; (iv) the inability to consummate the planned redemption of the First Service Life investment annuities (see Part I, Item 3 — "Legal Proceedings — First Service Life Litigation"); and (v) the investment in a non-liquid asset (see "Part I, Item 1 — Non-Utility Operations — PasoTex").

The Company's cash requirements for 1989 are expected to aggregate approximately $290.6 million, comprised of construction requirements of approximately $67.7 million; long-term debt maturities and preferred stock redemptions of $106.8 million; regulatory deferrals and Palo Verde Unit 3 capitalized costs of $52.0 million; and common and preferred stock dividend requirements of $64.1 million (assuming no change in dividend level). The Company expects to meet approximately $139.3 million of these requirements with cash on hand at December 31, 1988 and Internally Generated Cash expected for 1989. The balance of the 1989 cash requirements of approximately $151.3 million (assuming no change in dividend level) will need to be financed. See "Non-Utility Cash Requirements" below.

Management intends to meet its financing requirements during 1989 through short-term borrowings, extension and long-term refunding of debt maturities during this time period and possible sales of non-utility assets. The Company will require third party consents or renegotiation of certain financial covenants (see discussion below) in order to accomplish the needed refunding and extension of long-term debt, which the Company believes, but has no assurance, it will be able to obtain.

Restrictions on Financing. External financing by the Company in 1989 will be affected by several factors. Short-term debt financing by the Company is regulated by the FERC and is restricted by the terms and provisions of the transaction documents for the Unit 2 sales and leasebacks. At December 31, 1988 and March 31, 1989, consolidated short-term debt totaled approximately $69.9 million and $104.9 million, respectively. Under the Unit 2 transaction documents, the Company and its subsidiaries may not issue, assume or become liable for short-term debt, without the consent of the equity participants in those transactions, if, after giving effect to such issuance, assumption or becoming liable, consolidated short-term debt would exceed a specified percentage of consolidated capitalization (as defined). At March 31, 1989, the Company and its subsidiaries could, under the Unit 2 provisions, incur approximately $159 million of additional short-term debt. However, under present FERC authorization, the Company itself, without inclusion of the subsidiaries, is limited to an aggregate of $200 million of short-term debt outstanding at any one point in time through December 31, 1989.

The Company intends to secure a committed revolving line of credit facility of up to $250 million to provide for its short-term borrowing needs. In that connection, the Company will seek FERC authorization to increase, through December 31, 1991, the authorized level of short-term debt to $250 million. The Company has commenced negotiations with bank lenders and believes that it will be able to obtain a satisfactory committed revolving line of credit facility and that the FERC will grant the to be requested increase in the Company's authorized level of short-term debt. The provisions of the Unit 2 transaction documents described above apply to the incurrence of short-term debt on a consolidated basis. Depending upon the short-term borrowing requirements of the Company and the amount of short-term debt of the Company's subsidiaries outstanding, the Company may need the consent of the Unit 2 equity participants, or renegotiation of such short-term debt incurrence test, if the Company were to require the full borrowing availability of such revolving line of credit facility. At March 31, 1989, the Company maintained informal lines of credit totaling approximately $150.6 million.

The Unit 2 sale and leaseback transaction documents also restrict the incurrence of long-term debt by the Company and its subsidiaries. Under the provisions of those documents, neither the Company nor its subsidiaries may, without the consent of the equity participants in those transactions, issue, assume or become liable for long-term debt if, after giving effect to such issuance, assumption or becoming liable, consolidated long-term debt (as defined) would exceed a specified percentage of consolidated capitalization (as defined) or the ratio of the Company's consolidated net income to interest and rental payment charges (as defined) would be less than a specified ratio.

The Company does not presently meet the above long-term debt incurrence tests, and, therefore, the Company and its subsidiaries are presently precluded from issuing or refunding (and in the case of certain issues, extending) long-term debt without the consent of the Unit 2 equity participants. The Company anticipates that it will be required to either refund or extend the maturities of all or substantially all of its long-term debt maturing during the 1989 through 1992 time period. The Company, therefore, would be required to obtain either the consents of the Unit 2 equity participants to such refundings and extensions or renegotiate the incurrence of debt tests with the equity participants in a manner that would permit the Company to accomplish the needed refundings and extensions. The Company believes, but has no assurance, that it will be able to obtain either the needed consents from the Unit 2 equity participants or successfully renegotiate the incurrence of the long-term debt test.

Contemporaneously with the consummation of the Unit 3 sale and leaseback transactions, the Company and the equity investors in the Unit 2 sale and leaseback transactions agreed to modifications of the documents for those transactions. As required by the modifications, the Company in May 1988 provided the six equity investors in the August 1986 Unit 2 sale and leaseback transactions with bank letters of credit, in the aggregate amount of approximately $155 million and having a term expiring not earlier than December 31, 1991, in support of the equity portion of rent under the related lease.

In addition, as part of the modifications, the Company agreed to certain financial covenants with each of the eight equity investors in the Unit 2 sale and leaseback transactions. The covenants require the Company to retire approximately $187 million of long-term debt maturing through February 1991; the ratio of the Company's consolidated net income to interest and rental payment charges, determined as of June 30, 1991, to be not less than a specified ratio; and the Company's consolidated long-term and short-term debt, determined as of June 30, 1991, to be not in excess of specified percentages of consolidated capitalization. If the Company fails to meet such financial tests as of June 30, 1991, the equity investor can, in lieu of exercising remedies under the related lease, including drawing on the letter of credit, elect to require that the letter of credit be renewed for successive one year periods until such financial covenants are met as of June 30 in a subsequent year. Although the Company is not required to meet the financial tests imposed by the covenants until as of June 30, 1991, the Company expects to seek renegotiation of the financial tests as part of the renegotiated terms and provisions that the Company intends to seek from the Unit 2 equity investors with respect to the long-term debt incurrence test described above. The Company believes, but has no assurance, that such renegotiations will be successful.

The letter of credit agreements providing for the letters of credit issued to the Unit 2 and Unit 3 equity participants and one other bank credit agreement providing for an $11.5 million loan to the Company's leveraged employee stock ownership plan require the Company to maintain for each fiscal quarter, on a rolling 12-month basis, a coverage of earnings to interest and rental payments of a specified ratio (the "fixed charge ratio"). Although the Company will not know with certainty until it has results for the first quarter 1989 (which are expected in late April), the Company does not expect to meet the fixed charge ratio required under the letter of credit agreements and the bank credit agreement for the 12-month period ending March 31, 1989 and has so notified the banks. The Company believes, but has no assurance, that it will be able to negotiate a satisfactory amendment to the fixed

charge ratio which will avoid any default that otherwise could be declared for failure to meet the fixed charge ratio for such period. If the letter of credit banks were to declare such a default, the letter of credit banks then could terminate the letters of credit issued to the Unit 2 and Unit 3 equity participants. The Company has the right and obligation, under the transaction documents for the Unit 2 and Unit 3 sales and leasebacks, to replace the letters of credit with complying letters of credit. Failure to replace such letters of credit within the required time period would permit the equity participants to draw on the letters of credit, prior to termination by the banks, and declare the facility leases for the sales and leasebacks in default. See Note E of Notes to Consolidated Financial Statements.

1990-1992 Cash Requirements. Cash requirements presently scheduled for the period 1990-1992 consist of redemptions of debt and preferred stock of $200.1 million; construction requirements of $100.3 million; and common and preferred dividends (assuming no change in dividend level and required redemptions of preferred stock) of $185.4 million. Additional cash requirements, to the extent not met by Internally Generated Cash, including continuing regulatory deferrals, will depend upon a number of factors, including subsequent rate increases providing adequate cash and revenue rate relief pursuant to rate moderation plans, interest rates, load growth, and the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 by the Texas Commission. See Part I, Item 1 — "Rates and Regulations — Rate Matters — Texas — Unit 3" and "Non-Utility Cash Requirements" below.

The ability of the Company to meet its cash requirements beyond 1989 will depend primarily upon the ability of the Company to refund and extend long-term debt. The Company is evaluating its non-utility operations and may determine to sell certain of those operations or the related assets. If the Company determines to pursue any such sales of assets, proceeds from any such sales could significantly reduce the level of external financing required during 1989 through 1992.

Reevaluation of Dividend Policy. The Company paid a first quarter dividend of $.38 per share of common stock (an aggregate of $13,352,513) on March 15, 1989. In declaring the first quarter dividend, the Company cautioned that the level of future dividend payment was uncertain and would depend on earnings, cash flow and other factors. As discussed under "Results of Operations" below, the Company expects a reduction in 1989 income from continuing operations compared to the level in 1988. The Company, in general, anticipates that future results of operations will be significantly affected by the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 and may continue to be significantly affected by the factors described in "Results of Operations." The Company is currently reevaluating its dividend policy, including consideration of the possible reduction or omission of dividends for the foreseeable future, in light of such anticipated lower income and management's assessment of future results of operations, the Company's existing liquidity needs and restrictions on financing, and the uncertainity regarding the timing and method of inclusion in Texas rates of the Company's investment in Unit 3. See "Rates and Regulation — Rate Matters — Texas — Unit 3" in Part I, Item 1. The Company's ultimate decision regarding future dividends will have a significant effect upon the level of financing required to meet cash requirements.

Other Restrictions — Restated Articles of Incorporation; Mortgage Indentures. The Company's Restated Articles of Incorporation provide that, unless consented to by the holders of preferred stock, additional shares of preferred stock may not be issued unless certain tests are met with respect to (i) net earnings of the Company available for preferred dividends, (ii) after- tax earnings available for interest, amortization and preferred dividends and (iii) the sum of junior stock capital and, if the Company so elects, surplus. The most restrictive of said tests, (i) above, would not have permitted the issuance of any new shares of preferred stock at December 31, 1988.

In addition, the Company's Restated Articles of Incorporation provide that, unless consented to by the holders of preferred stock, the aggregate of unsecured long-term debt shall not exceed 10% of the total of the Company's outstanding secured debt, capital and surplus. At December 31, 1988, the

Company would have been permitted to issue approximately $33.6 million in additional unsecured long-term debt.

The Company's First Mortgage Indenture permits the issuance of additional first mortgage bonds to the extent of 60% of the value of unfunded net additions to the Company's utility property, provided net earnings available for interest during a recent twelve-month period were at least twice the annual interest requirements on all bonds to be outstanding and on all prior lien debt. At December 31, 1988, unfunded net additions totaled $320.8 million, which was sufficient, with the inclusion of $106.1 million in bond credits, to permit the issuance of approximately $298.6 million principal amount of new bonds. However, net earnings available for interest would restrict the issuance of new bonds (assuming an interest rate of 11.375%) to approximately $214.2 million principal amount.

The Company's Second Mortgage Indenture permits the issuance of additional second mortgage bonds on the basis of 40% of the value of unfunded net additions to utility property. At December 31, 1988, unfunded net additions totaled approximately $26.6 million, which was sufficient, with the inclusion of $170 million in bond credits, to permit the issuance of approximately $180.6 million principal amount of additional second mortgage bonds.

Non-Utility Cash Requirements. The Company cannot, without the approval of the New Mexico Commission, make capital contributions or loans to or investments in its subsidiaries. In addition, the terms and provisions of certain of the Company's financing agreements, including the bank letter of credit agreements for the Palo Verde sales and leasebacks, restrict capital contributions, loans and other investments by the Company in its subsidiaries. As a result, the financing requirements of the Company's subsidiaries must be met from cash on hand in the subsidiaries, their internally generated cash flows and their ability to borrow externally without recourse to the Company. The subsidiaries are subject to the incurrence of debt restrictions affecting the Company, discussed above, as those tests are applied on a consolidated basis. During 1988, the subsidiaries had a net cash requirement for operations of approximately $13 million due primarily to increases in working capital which were financed principally from short-term borrowings under revolving credit lines.

The subsidiaries' non-operating cash requirements for 1989 and 1990 consist primarily of $4.8 million for scheduled retirement of long-term debt and $12 million for plant expansion and improvements at Border Steel. The Company's current projections indicate that these cash requirements will be met through the subsidiaries' internally generated cash flows from operations, funds on hand and short-term borrowings. The operations of the subsidiaries, however, are subject to substantially different uncertainties than are the utility operations. Accordingly, management is unable to predict whether the subsidiaries' cash flow projections will be fully realized. The Company currently plans to relocate its B.P. John subsidiary's manufacturing operations to the southern New Mexico area in 1989, at an expected cost of approximately $12 million to $15 million, which will require financing. Additionally, the Company may decide to generate cash through sales of substantial subsidiary assets, which would affect the subsidiaries' and the Company's financing requirements. See Part I, Item 1 — "Non-Utility Operations."

Results of Operations

Income from continuing operations before the cumulative effect of change in accounting method, after preferred stock dividend requirements of $12,259,000, aggregated $57,528,000 for the year ended December 31, 1988, or $1.64 per share of common stock. Comparable results for the year ended December 31, 1987, after adjusting for the effect of the regulatory disallowance and investment losses, aggregated $71,737,000 applicable to common stock, or $2.03 per share of common stock. Additionally, management believes that income from continuing operations in 1989 will be significantly lower than the 1988 level. The principal reasons for the anticipated decline relate to less investment income resulting from the use of invested cash for the requirements set forth under "Liquidity and Capital Resources" above and additional interest expense due to anticipated short-term borrowing requirements. Additionally, the Company's 1989 net income will be further adversely impacted if, and to the extent that, the Texas Commission in the pending Texas rate case adopts a base revenue increase of

less than the $39 million increase requested by the Company. See Part I, Item 1 — "Rates and Regulation — Rate Matters — Texas — 1988 Rate Case."

Future results of operations will be signficantly affected by the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 and may continue to be significantly affected by the substantial reductions in regulatory earning assets, which result from the sale and leaseback transactions; the regulatory treatment afforded the lease payments; the Texas jurisdiction regulatory disallowance of $38 million recorded in 1987; and the New Mexico jurisdiction deregulation of approximately $54.1 million of Unit 3 investment, together with current operating costs attributable to the deregulated portion of Unit 3 substantially exceeding related revenues from off-system sales of electricity.

The Company continued to experience increases in electric sales and customer growth in its service area during 1988. Native system sales increased from 3,992,310 megawatt-hours of electricity in 1987 to 4,249,990 megawatt-hours in 1988, an increase of 6.5%. Total system sales increased 8.7% in 1988 compared with 1987. Customers were added to the Company's service area at an annual rate of approximately 3% in both 1987 and 1988. The Company achieved record peak demands in 1988, recording an all-time total system peak load of 1,002 megawatts on August 22, 1988, which was a 2.8% increase over 1987's record peak of 975 megawatts. The Company's 1988 native system peak demand of 840 megawatts, which was also a new record, was a 2.4% increase from the previous record of 820 megawatts set in 1987. The projected annual peak load growth rate for the Company's service area during the 1989-1998 time period is approximately 3%. Some industrial power users in the Company's service area have announced that they are considering cogeneration as an alternative to purchasing electricity from the Company. The Company does not currently anticipate that cogeneration will be a significant factor affecting its operations.

The following comparisons of results for 1988 to 1987 and 1987 to 1986 should be read in conjunction with the above information concerning expectations for 1989 results of operations.

<u>Utility</u>

The primary reasons for increases (decreases) in results of operations for the year ended December 31, 1988 compared to the year ended December 31, 1987 and the year ended December 31, 1987 compared to the year ended December 31, 1986 are as follows:

Operating Revenues:

Base revenues increased for 1988 over 1987 approximately $42,500,000 due primarily to an increase in KWH sales (volume) to all three jurisdictions and an increase in base revenues resulting from rate increases for Texas and New Mexico which were effective in April 1988 and November 1987, respectively. Base revenues increased for 1987 over 1986 approximately $23,100,000 due to an increase in KWH sales (volume), which was partially offset by a decrease in base rates for Texas customers and a change in sales mix. Base revenues from wholesale customers increased by $3,100,000 and $11,400,000 for 1988 over 1987 and 1987 over 1986, respectively, due primarily to an increase in KWH sales (volume).

Fuel revenues for 1988 over 1987 increased approximately $2,300,000 due to an increase in fuel costs. Fuel revenues for 1987 over 1986 decreased approximately $3,900,000 due to a decrease in the average cost of fuel and purchased and interchanged power.

Operating Expenses:

Fuel expense increased in 1988 over 1987 approximately $20,900,000 due to an increase in the average cost of nuclear fuel and natural gas and volume of nuclear fuel and natural gas consumed. Fuel expense for 1987 over 1986 increased approximately $7,000,000 due to an increase in volume of nuclear fuel and natural gas consumed. The increase in 1987 was offset in part by a decrease in the average cost of natural gas.

Purchased and interchanged power decreased in 1988 compared to 1987 and 1987 compared to 1986 by approximately $22,300,000 and $9,900,000, respectively, due to increased economy sales of electricity to others of $12,800,000 and $4,000,000, respectively and decreased purchases from other utilities as a result of increased power available from Palo Verde. Economy sales to others was approximately $19,700,000 and $6,900,000 in 1988 and 1987, respectively. The decrease in 1988 compared to 1987 was also due to a decrease in the amount of Palo Verde power accounted for as purchased power due to placing Units 1 and 2 in service. However, the decrease in 1987 compared to 1986 was partially offset by the major portion of Palo Verde power being accounted for as purchased power expense.

	1988 over 1987	1987 over 1986
	(In thousands)	
Palo Verde costs	$ 50,576	$ 49,330
Palo Verde costs deferred and capitalized	8,212	(34,173)
Phase-in plan deferrals	(16,935)	(529)
	41,853	14,628
Other	5,444	12,824
Total	$ 47,297	$ 27,452

Other operating and maintenance expenses increased in 1988 over 1987 due to increased expensing of Palo Verde costs and decreased Palo Verde costs deferred and capitalized with a resulting increase in phase-in plan deferrals. Increased expensing of Palo Verde costs resulted from expensing all costs related to the New Mexico and FERC portions of Unit 3 beginning in January 1988 and expensing all costs related to the New Mexico portion of Unit 2 beginning in November 1987 and expensing all cost related to the Texas portion of Units 1 and 2 beginning in May 1988. A principal portion of such Palo Verde costs consisted of lease expense on Units 2 and 3. Palo Verde costs deferred and capitalized decreased due to the discontinuance of deferrals on the Texas jurisdictional portion of Units 1 and 2 beginning in May 1988, partially offset by capitalizing the Texas portion of Unit 3 beginning in February 1988.

Other operating and maintenance expenses increased in 1987 over 1986 due to increased expensing of Palo Verde costs partially offset by Palo Verde costs deferred and capitalized. Increased expensing of Palo Verde costs resulted from placing in commercial operation Unit 1 in February 1986 and Unit 2 in September 1986. Palo Verde costs deferred increased due to deferring the Texas and New Mexico jurisdictional portions of Palo Verde Units 1 and 2 and related common facilities. See Note C of Notes to Consolidated Financial Statements.

Depreciation and Amortization Expenses:

Depreciation increased in 1988 over 1987 due to depreciating the Texas jurisdictional portion of Palo Verde Unit 1 and Common Plant beginning in May 1988 and the New Mexico and FERC jurisdictional portion of Palo Verde Unit 3 beginning in February 1988. Depreciation increased in 1987 over 1986 due to depreciating the New Mexico and FERC jurisdictional portion of Palo Verde Unit 1 and Common Plant beginning in March 1986 and a portion of Palo Verde Unit 2 beginning in October 1986.

Amortization expense increased in 1988 over 1987 due to amortization of a New Mexico deferred debit effective January 1988 and Palo Verde deferred costs beginning in May 1988 and November 1988 for Texas and New Mexico, respectively.

AFUDC:

AFUDC decreased in 1988 compared to 1987 because of the sale of approximately 39.5% of Palo Verde Unit 3 in December 1987, which resulted in decreased cumulative construction and Palo Verde deferred cost balances accruing AFUDC. Additionally, AFUDC decreased due to discontinuing

accounting recognition of allowance for equity funds used during construction on Palo Verde deferred costs related to Units 1 and 2 pursuant to SFAS No. 92. AFUDC decreased in 1987 compared to 1986 due to decreased cumulative construction and Palo Verde deferred cost balances accruing AFUDC due to the sale of Palo Verde Unit 2 in the second half of 1986.

Consolidated

Investment Income:

Investment income increased in 1988 compared to 1987 due to a higher average investment return and increased income related to an investment in a partnership partially offset by decreased average investment balances. Investment income decreased in 1987 compared to 1986 due to realized and unrealized losses incurred on the Company's investments in marketable securities.

Other Income, Net:

Other income, net, increased in 1988 compared to 1987 due to decreased depreciation on plant held for future use which was fully depreciated in May 1988. Other income, net, decreased in 1987 compared to 1986 due to a gain, in 1986, on the sale of real property with no comparable gain in 1987 and an increase in other miscellaneous nonoperating expenses.

Interest on Long-Term and Financing and Capital Lease Obligations:

Interest on long-term and financing and capital lease obligations decreased in 1988 over 1987 due principally to the early redemption of the 16.20% Series First Mortgage Bonds in February 1988 and the redemption of a floating rate note in the first quarter of 1988. Interest on long-term and financing and capital lease obligations decreased in 1987 over 1986 due principally to the early redemption of the 16.35% Series First Mortgage Bonds in May 1987. The decrease was partially offset by the interest on a financing obligation relating to one sale and leaseback transaction involving Palo Verde Unit 2.

Other Interest Expense:

Other interest expense decreased in 1988 over 1987 due to margin interest incurred in 1987 with no comparable expense in 1988 and a decrease in the interest on fuel overrecovery and the average short-term debt outstanding. The decrease was partially offset by an increase in subsidiary interest expense related to subsidiaries acquired in the third quarter of 1987. Other interest expense increased in 1987 over 1986 due to margin interest incurred in 1987 with no comparable expense in 1986 and an increase in the interest on fuel overrecovery balances and accumulated provision for rate refund.

Interest Capitalized and Deferred:

Interest capitalized increased in 1988 over 1987 due to the capitalized interest on Palo Verde deferred costs and increased interest related to nuclear fuel lease obligations and an increase in interest deferred on a portion of a financing obligation relating to one sale and leaseback transaction involving Palo Verde Unit 2. For 1987 over 1986, interest capitalized increased due to interest deferred on a portion of a financing obligation relating to one sale and leaseback transaction involving Palo Verde Unit 2 and increased interest related to nuclear fuel lease obligations.

See Note A of Notes to Consolidated Financial Statements for a discussion of SFAS No. 96 — Accounting for Income Taxes.

Effects of Inflation:

In contrast to the analysis of increases in base revenues included at the beginning of "Results of Operations," it is sometimes difficult, in the case of operation and maintenance expenses, to distinguish between effects of volume increases and rises in unit costs (which, for purposes of this discussion, are all attributed to inflationary pressures).

Price changes in fuel costs are passed through to FERC customers pursuant to fuel cost adjustment provisions. Fuel price changes in the Company's Texas and New Mexico jurisdictions require fuel reconciliation hearings for the over or under recovery of fuel costs. There are a number of other major expense items such as maintenance costs, payroll costs and other operating costs that are beyond the scope of the fuel reconciliation hearings in the Texas and New Mexico jurisdictions and the fuel cost adjustment provisions for the FERC customers. Inflationary pressures on these items have given rise to earnings attrition between general rate increases. See "Rates and Regulation" in Part I, Item 1. As the Company increases its short-term borrowings, as discussed under Liquidity and Capital Resources above, inflationary pressures could also affect the Company through the cost of such short-term debt.

Non-Utility Operations:

Non-utility operating income from continuing operations increased approximately $7.6 million from 1987 to 1988. This resulted from inclusion of a full year's operations during 1988 of subsidiaries which were purchased in the third and fourth quarters of 1987, and increased volume in sales of OCTG and specialty steel products, partially offset by approximately $4.5 million of moving and start-up expenses incurred in the move of Westwood Lighting Group, Inc. to the El Paso area. The 1988 results of subsidiary operations may not be indicative of future performance due to the possible economic changes in the industries in which the subsidiaries operate, moving and start-up costs to be incurred by B. P. John Furniture Co., and planned capital and operational improvements planned for certain subsidiaries. See Note N of Notes to Consolidated Financial Statements in regard to segment information and discontinued operations.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

The Shareholders and Board of Directors
El Paso Electric Company:

We have audited the accompanying consolidated balance sheets of El Paso Electric Company and Subsidiaries as of December 31, 1988 and 1987, and the related consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 1988. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of El Paso Electric Company and Subsidiaries at December 31, 1988 and 1987, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1988 in conformity with generally accepted accounting principles.

As discussed in Note K of Notes to Consolidated Financial Statements, the Company is a defendant in a lawsuit and, pursuant to indemnity provisions, is contingently liable with respect to a related lawsuit in which a former executive officer of the Company is one of the defendants. The ultimate outcome of such litigation cannot presently be determined. Accordingly, no provision for any liability that may result upon adjudication of either lawsuit has been made in the accompanying consolidated financial statements.

As discussed in Note A of Notes to Consolidated Financial Statements, the Company changed its method of accounting for unbilled revenues in 1987.

PEAT MARWICK MAIN & CO.

El Paso, Texas
March 24, 1989

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 1988	December 31, 1987
	(In thousands)	
Utility plant (Notes C, D and E):		
Electric plant in service	$1,150,233	$1,089,804
Less accumulated depreciation and amortization	201,547	171,708
Net plant in service	948,686	918,096
Construction work in progress	258,076	228,314
Nuclear fuel under capital leases net of amortization of $78,599,000 and $37,550,000, respectively	54,081	68,848
Net utility plant	1,260,843	1,215,258
Non-utility property, at cost net of accumulated depreciation	48,800	104,353
Assets held for sale (Note N)	17,317	—
Investments (Note F)	85,416	307,073
Current assets:		
Cash and temporary investments	9,853	300,061
Other short-term investments (Note F)	100,903	15,602
Accounts receivable, principally trade, net	91,341	76,562
Inventories	81,793	50,888
Prepayments and other	35,714	34,595
Total current assets	319,604	477,708
Deferred charges and other assets:		
Palo Verde deferred costs (Notes C and D)	126,413	102,662
Phase-in plan deferrals (Note C)	29,497	529
Other	87,269	67,990
Total deferred charges and other assets	243,179	171,181
Total assets	$1,975,159	$2,275,573

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31, 1988	December 31, 1987
	(In thousands)	
Capitalization (Notes G, H and I):		
Common stock, no par value, 40,000,000 shares authorized. Issued and outstanding 35,075,309 and 34,972,180 shares, respectively	$ 335,767	$ 334,299
Retained earnings	198,131	239,320
Common stock equity	533,898	573,619
Preferred stock, cumulative, no par value, 2,000,000 shares authorized:		
Redemption required	108,460	110,610
Redemption not required	14,198	14,198
Long-term obligations	514,078	639,777
Financing and capital lease obligations (Note E)	124,313	137,941
Total capitalization	1,294,947	1,476,145
Current liabilities:		
Current maturities and planned redemptions of long-term and financing and capital lease obligations (Note I)	137,177	115,782
Notes payable and commercial paper (Note B)	69,947	174,176
Accounts payable, principally trade	40,465	37,299
Taxes accrued (Note J)	11,538	30,498
Interest accrued	17,254	22,458
Other	38,032	37,148
Total current liabilities	314,413	417,361
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note J)	35,473	40,180
Accumulated deferred investment tax credit (Note J)	129,949	131,540
Deferred gain on sales and leasebacks (Note E)	182,806	189,978
Allowance for loss on discontinued operations (Note N)	11,520	—
Other	6,051	20,369
Total deferred credits and other liabilities	365,799	382,067
Commitments and contingencies (Notes C, D, E, K and L)		
Total capitalization and liabilities	$1,975,159	$2,275,573

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

For the years ended December 31, 1988, 1987 and 1986
(In thousands except per share data)

	1988	1987	1986
Operating revenues:			
Utility	$382,107	$337,263	$318,109
Non-utility	256,617	105,719	153
	638,724	442,982	318,262
Operating expenses:			
Utility:			
Fuel	72,187	51,297	44,285
Purchased and interchanged power	23,917	46,199	56,068
	96,104	97,496	100,353
Other	132,533	74,250	48,819
Maintenance	20,195	14,246	11,696
Depreciation and amortization	34,254	21,162	19,186
Phase-in plan deferrals (Note C)	(17,464)	(529)	—
Non-utility costs and expenses	246,332	103,002	1,049
Taxes:			
Federal income taxes (Note J)	8,101	15,656	28,629
Other	25,130	22,136	19,404
	545,185	347,419	229,136
Operating income	93,539	95,563	89,126
Other income (deductions):			
Allowance for equity funds used during construction	13,065	31,941	49,595
Phase-in plan deferred return (Note C)	11,504	—	—
Regulatory disallowance of plant costs (Note C)	—	(38,323)	—
Investment income:			
Realized and unrealized investment gains (losses) (Note F)	811	(17,644)	—
Other	19,744	31,133	14,223
Other, net	(2,763)	(3,142)	(1,953)
Federal income taxes applicable to other income (Note J):			
Regulatory disallowance of plant costs	—	13,937	—
Other	(6,944)	497	(5,690)
	35,417	18,399	56,175
Income before interest charges	128,956	113,962	145,301
Interest charges (credits):			
Interest on long-term and financing and capital lease obligations	71,911	79,933	83,905
Other interest	8,975	14,553	4,939
Interest capitalized and deferred	(13,304)	(6,896)	(3,999)
Allowance for borrowed funds used during construction	(8,413)	(22,458)	(38,259)
	59,169	65,132	46,586
Income from continuing operations before cumulative effect of change in accounting method	69,787	48,830	98,715
Discontinued operations (Note N):			
Loss from discontinued real estate operations, net of income taxes of $4,772, $5,559 and $2,709, respectively	(9,464)	(8,062)	(3,101)
Provision for loss on disposal of real estate operations, including provision of $11,520 for operating losses during phase-out period, net of income taxes of $18,522	(35,954)	—	—
	(45,418)	(8,062)	(3,101)
Income before cumulative effect of change in accounting method	24,369	40,768	95,614
Cumulative effect of change in accounting method (Note A)	—	4,240	—
Net income	24,369	45,008	95,614
Preferred stock dividend requirements	12,259	12,892	14,185
Net income applicable to common stock	$ 12,110	$ 32,116	$ 81,429
Net income per weighted average shares of common stock:			
Income from continuing operations before cumulative effect of change in accounting method	$ 1.64	$ 1.02	$ 2.41
Discontinued operations	(1.29)	(0.23)	(0.09)
Cumulative effect of change in accounting method	—	0.12	—
Total	$ 0.35	$ 0.91	$ 2.32

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

For the years ended December 31, 1988, 1987 and 1986
(In thousands except per share data)

	1988	1987	1986
Retained earnings at beginning of year	$239,320	$264,016	$236,042
Add:			
Net income	24,369	45,008	95,614
	263,689	309,024	331,656
Deduct:			
Cash dividends:			
Preferred stock	12,259	12,892	14,185
Common stock	53,254	53,795	53,327
Capital stock expense	45	165	128
Purchase of Company common stock	—	2,852	—
	65,558	69,704	67,640
Retained earnings at end of year	$198,131	$239,320	$264,016
Dividends declared per share of common stock	$ 1.52	$ 1.52	$ 1.52
Weighted average number of common shares outstanding	35,029,975	35,422,043	35,106,903

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 1988, 1987 and 1986

	1988	1987	1986
		(In thousands)	
Cash Flows From Operating Activities:			
Net income	$ 24,369	$ 45,008	$ 95,614
Adjustments for non-cash items:			
Depreciation and amortization	33,475	22,788	22,699
Amortization of nuclear fuel	22,527	4,368	2,926
Deferred income taxes and investment tax credit, net	13,269	20,085	44,799
Allowance for equity funds used during construction	(13,065)	(31,941)	(49,595)
Provision for rate refund	(13,921)	668	13,315
Increase in other deferred items	(13,076)	(17,980)	(7,350)
Discontinued operations, net of related income taxes	35,954	—	—
Regulatory disallowance of plant costs	—	38,323	—
Accounts receivable	(16,321)	(10,978)	4,335
Inventories	(13,593)	(9,624)	324
Prepayments and other current assets	(4,299)	(8,649)	(13,544)
Accounts payable	(973)	14,883	(6,656)
Taxes accrued	(18,960)	(73,094)	(26,663)
Interest accrued	(5,204)	(954)	6,587
Other current liabilities	884	(5,773)	4,544
Other operating activities	(505)	3,424	6,189
Palo Verde deferred costs	(22,227)	(55,157)	(22,442)
Phase-in plan deferrals	(28,968)	(529)	—
Net cash (used for) provided by operating activities	(20,634)	(65,132)	75,082
Cash Flows From Investing Activities:			
Additions to utility plant	(86,632)	(88,620)	(186,193)
Allowance for equity funds used during construction	13,065	31,941	49,595
Proceeds from sales and leasebacks	—	250,000	597,000
Sale of nuclear fuel in process to trust	—	28,460	—
Proceeds from sale of assets	2,509	831	5,922
Additions to non-utility property	(14,738)	(8,306)	(21,200)
Non-utility acquisitions, net of cash received	—	(43,609)	—
Proceeds from sale of investments	5,551	39,776	31,577
Purchase of long-term investments	(5,000)	(57,606)	(80,351)
Other investing activities	(39)	(4,004)	421
Net cash (used for) provided by investing activities	(85,284)	148,863	396,771
Cash Flows From Financing Activities:			
Issuances of common stock	1,468	1,482	12,767
Proceeds from long-term obligations	10,289	28,000	184,531
Redemption and repurchase of securities	(2,150)	(19,085)	(14,940)
Dividends paid	(65,513)	(66,687)	(67,512)
Redemption of long-term obligations	(153,527)	(137,293)	(86,884)
Net increase (decrease) in short-term obligations	(104,229)	140,006	(27,242)
Other financing activities	(2,327)	(165)	(128)
Net cash (used for) provided by financing activities	(315,989)	(53,742)	592
Net increase (decrease) in cash and temporary investments	(421,907)	29,989	472,445
Cash and temporary investments at beginning of year	532,663	502,674	30,229
Cash and temporary investments at end of year	$ 110,756	$532,663	$502,674
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 19,427	$ 50,088	$ 12,150
Interest on borrowed money	63,678	72,777	70,741
Non-cash transactions			
Capitalization of nuclear fuel and related obligation	26,282	48,439	3,999

For the purposes of this statement, all temporary cash investments with a maturity of three months or less are considered cash equivalents.

See accompanying notes to consolidated financial statements.

Change in Accounting Method

Prior to January 1, 1987, the Company recognized utility revenues when billed. To provide a better matching of the Company's revenues from kilowatt-hour sales with the related costs, effective January 1, 1987, the Company changed its method of accounting to record estimated revenues from sales of electricity for services provided subsequent to monthly billing cycle dates but prior to the end of the accounting period. The cumulative effect of this accounting change as of January 1, 1987, net of income taxes of $2,827,000, increased net income and net income per share for the year ended December 31, 1987 by $4,240,000 and $.12, respectively. The pro forma effect on net income for the year ended December 31, 1987 of applying the new method of accounting retroactively is not material.

Fuel Cost Adjustment Provisions

The Company's Texas and New Mexico retail customers are presently being billed under fixed fuel factors approved by the Texas Commission and the New Mexico Commission. The Texas fuel factor set in the Company's last rate case will remain in effect until the earlier of the Company's next general rate case or a Commission ordered fuel reconciliation. In the Texas jurisdiction and New Mexico jurisdiction, the Company's fixed fuel factor is subject to reduction if the utility materially over-recovers its allowable fuel costs under its existing fuel factor.

Rate tariffs currently applicable to FERC jurisdictional customers contain appropriate fuel and purchased power cost adjustment provisions designed to recover the Company's fuel and purchased power costs.

Federal Income Taxes and Investment Tax Credits

Deferred income taxes are provided as a result of timing differences in reporting income and expense items for financial statement and income tax purposes.

With respect to investment tax credit generated by the Company, such investment tax credit utilized is deferred and amortized to income, once such related properties are considered "operational" by the Company's regulatory authorities, over the estimated average remaining useful lives of the Company's fixed assets directly or indirectly involved in the generation and transmission of electricity.

Statement of Financial Accounting Standards No. 96, "Accounting for Income Taxes," was issued by the Financial Accounting Standards Board in December 1987. Statement 96 requires a change from the deferred method to the asset and liability method of accounting for income taxes.

Under the asset and liability method, deferred income taxes are recognized for the tax consequences of "temporary differences" by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Statement 96, as amended, is effective for fiscal years beginning after December 15, 1989. The Company may recognize the cumulative effect of a change in accounting principle upon adoption of Statement 96 or restate prior period financial statements to conform to the provisions of the Statement. The Company currently plans to implement Statement 96 in the year ending December 31, 1990 and has not yet decided upon the method of adoption.

The Company estimates that adoption of Statement 96 will result in a reduction in the balance of accumulated deferred income tax liability and the creation of a liability to the Company's ratepayers for the effect on regulated assets and liabilities of the reduction of the Federal statutory income tax rate from 46% to 34% as provided for by the Tax Reform Act of 1986. This reduction in accumulated deferred income taxes will be partially offset by the effect of new temporary differences resulting from

EL PASO ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

General

El Paso Electric Company (the Company) maintains its accounts in accordance with the Uniform System of Accounts prescribed for electric utilities by the FERC. The subsidiaries are not regulated companies. The Company reports its regulated utility operations pursuant to SFAS No. 71 — Accounting for the Effects of Certain Types of Regulation, as amended.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Utility Plant and Non-utility Property

Utility plant and non-utility property are stated at original costs, and depreciation is provided on a straight-line basis at annual rates which will amortize the undepreciated cost of depreciable property over the estimated remaining service lives. The average annual depreciation rate used by the Company for utility plant other than the Palo Verde Station was 3.43% in 1988, 1987 and 1986. The average annual depreciation rate for the portions of the Palo Verde Station for which the Company is providing depreciation was 2.50% for New Mexico and FERC jurisdictions in 1988, 1987 and 1986 and 2.62% for the Texas jurisdictional portion which began in April 1988.

The Company and its subsidiaries charge the cost of repairs and minor replacements to the appropriate operating expense accounts and capitalize the cost of renewals and betterments. The cost of depreciable utility plant retired or sold and the cost of removal, less salvage, are charged to accumulated depreciation.

The Company is amortizing nuclear fuel under the units of heat production method.

AFUDC

The Company's applicable regulatory bodies, FERC, the New Mexico Commission and the Texas Commission, generally provide for the capitalizing of AFUDC, which is defined as an amount which includes the net cost during a period of construction of borrowed funds used for construction purposes plus a reasonable rate on other funds when so used. While AFUDC results in an increase in the cost of utility plant under construction, with a corresponding increase in income, it is not current cash income. AFUDC, net of certain tax effects, is normally recovered in cash over the service life of utility plant in the form of increased revenue collected as a result of higher depreciation expense.

The Company records AFUDC during the construction period of utility plant and, in 1987 and 1986, additionally recorded AFUDC, pursuant to regulatory order, on utility plant placed in-service but pending regulatory treatment in rate base, as well as on operating costs deferred during the same period. See Note D of Notes to Consolidated Financial Statements.

The amount of AFUDC is determined by applying an accrual rate to the balance of certain CWIP and deferred costs. In this connection, the FERC has promulgated procedures for the computation (a prescribed formula) of the accrual rate. The weighted average accrual rate was 11.1%, 11.4% and 11.5% for 1988, 1987 and 1986, respectively. The Company compounds AFUDC on major construction projects semiannually. Prior to May 1988, certain amounts of CWIP have been allowed in the Company's rate base or have been made the basis of extraordinary cash rate relief, and the appropriate amounts have been excluded from the CWIP balance used as a base for calculating AFUDC.

Statement 96, such as allowance for equity funds used during construction and accumulated deferred investment tax credits. The portion of the regulated liability created by Statement 96 relating to certain temporary differences (i.e. accelerated depreciation) will be recorded as long-term and be amortized over the remaining life of the assets giving rise to the temporary difference. In general, the Company believes that the effect of adoption of Statement 96 as it relates to the Company's regulated utility operations will have no impact upon earnings or retained earnings.

The application of Statement 96 to the non-utility, unregulated operations of the Company is not expected to have a significant effect on earnings or retained earnings at the time of adoption.

Statement of Cash Flows

In 1988, the Company adopted SFAS No. 95 — Statement of Cash Flows, which sets forth standards for cash flow reporting and requires the presentation of a statement of cash flows in place of the statement of sources of funds invested in utility plant and other plant. Consolidated statements of sources of funds invested in utility plant and other plant for 1987 and 1986 have been restated to reflect the implementation of SFAS No. 95.

Reclassification

Certain amounts in the consolidated financial statements for 1987 and 1986 have been reclassified to conform with the 1988 presentation.

B. Liquidity

Although the Company's construction requirements have decreased significantly with the completion of the Palo Verde construction program, this decrease has been offset by cash requirements related to regulatory deferrals and current maturities of financing incurred for Palo Verde construction costs. The Company has not generated in the recent past, nor will it generate in 1989, sufficient Internally Generated Cash to meet its cash requirements for preferred and common stock dividends, construction, redemptions of debt and preferred stock and regulatory deferrals and, accordingly, will continue to be required to finance such requirements to the extent not met by Internally Generated Cash. Management has defined Internally Generated Cash, for purposes of its cash planning and financing requirements, as "net cash (used for) provided by operating activities" before the effect of "Palo Verde deferred costs" and "phase-in plan deferrals", all as reflected in the Consolidated Statement of Cash Flows. Internally Generated Cash is used as a measure for planning purposes because it recognizes the necessity of financing deferrals, which are scheduled to be collected in cash in the future, pursuant to regulatory order.

1989 Cash Requirements. The Company's 1989 financing requirements will be greater than originally anticipated principally as a result of (i) lower than anticipated cash revenue from the Company's rate moderation plans, based on the growth in KWH sales that has occurred (see Note C of Notes to Consolidated Financial Statements); (ii) higher than expected operating and maintenance expenses, particularly at Palo Verde; (iii) higher than anticipated working capital requirements; (iv) the inability to consummate the planned redemption of the First Service Life investment annuities (see Note K of Notes to Consolidated Financial Statements); and (v) the investment in a non-liquid asset (see Note N of Notes to Consolidated Financial Statements).

The Company's cash requirements for 1989 are expected to aggregate approximately $290.6 million, comprised of construction requirements of approximately $67.7 million; long-term debt maturities and preferred stock redemptions of $106.8 million; regulatory deferrals and Palo Verde Unit 3 capitalized costs of $52.0 million; and common and preferred stock dividend requirements of

$64.1 million (assuming no change in dividend level). The Company expects to meet approximately $139.3 million of these requirements with cash on hand at December 31, 1988 and Internally Generated Cash expected for 1989. The balance of the 1989 cash requirements of approximately $151.3 million (assuming no change in dividend level) will need to be financed. See "Non-Utility Cash Requirements" below.

Management intends to meet its financing requirements during 1989 through short-term borrowings, extension and long-term refunding of debt maturities during this time period and possible sales of non-utility assets. The Company will require third party consents or renegotiation of certain financial covenants (see discussion below) in order to accomplish the needed refunding and extension of long-term debt, which the Company believes, but has no assurance, it will be able to obtain.

Restrictions on Financing. External financing by the Company in 1989 will be affected by several factors. Short-term debt financing by the Company is regulated by the FERC and is restricted by the terms and provisions of the transaction documents for the Unit 2 sales and leasebacks. At December 31, 1988 and March 31, 1989, consolidated short-term debt totaled approximately $69.9 million and $104.9 million, respectively. Under the Unit 2 transaction documents, the Company and its subsidiaries may not issue, assume or become liable for short-term debt, without the consent of the equity participants in those transactions, if, after giving effect to such issuance, assumption or becoming liable, consolidated short-term debt would exceed a specified percentage of consolidated capitalization (as defined). At March 31, 1989, the Company and its subsidiaries could, under the Unit 2 provisions, incur approximately $159 million of additional short-term debt. However, under present FERC authorization, the Company itself, without inclusion of the subsidiaries, is limited to an aggregate of $200 million of short-term debt outstanding at any one point in time through December 31, 1989.

The Company intends to secure a committed revolving line of credit facility of up to $250 million to provide for its short-term borrowing needs. In that connection, the Company will seek FERC authorization to increase, through December 31, 1991, the authorized level of short-term debt to $250 million through December 31, 1991. The Company has commenced negotiations with bank lenders and believes that it will be able to obtain a satisfactory committed revolving line of credit facility and that the FERC will grant the to be requested increase in the Company's authorized level of short-term debt. The provisions of the Unit 2 transaction documents described above apply to the incurrence of short-term debt on a consolidated basis. Depending upon the short-term borrowing requirements of the Company and the amount of short-term debt of the Company's subsidiaries outstanding, the Company may need the consent of the Unit 2 equity participants, or renegotiation of such short-term debt incurrence test, if the Company were to require the full borrowing availability of such revolving line of credit facility. At March 31, 1989, the Company maintained informal lines of credit totaling approximately $150.6 million.

The Unit 2 sale and leaseback transaction documents also restrict the incurrence of long-term debt by the Company and its subsidiaries. Under the provisions of those documents, neither the Company nor its subsidiaries may, without the consent of the equity participants in those transactions, issue, assume or become liable for long-term debt if, after giving effect to such issuance, assumption or becoming liable, consolidated long-term debt (as defined) would exceed a specified percentage of consolidated capitalization (as defined) or the ratio of the Company's consolidated net income to interest and rental payment charges (as defined) would be less than a specified ratio.

The Company does not presently meet the above long-term debt incurrence tests, and, therefore, the Company and its subsidiaries are presently precluded from issuing or refunding (and in the case of certain issues, extending) long-term debt without the consent of the Unit 2 equity participants. The Company anticipates that it will be required to either refund or extend the maturities of all or substantially all of its long-term debt maturing during the 1989 through 1992 time period. The

required redemptions of preferred stock) of $185.4 million. Additional cash requirements, to the extent not met by Internally Generated Cash, including continuing regulatory deferrals, will depend upon a number of factors, including subsequent rate increases providing adequate cash and revenue rate relief pursuant to rate moderation plans, interest rates, load growth, and the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 by the Texas Commission. See Note C of Notes to Consolidated Financial Statements and "Non-Utility Cash Requirements" below.

The ability of the Company to meet its cash requirements beyond 1989 will depend primarily upon the ability of the Company to refund and extend long-term debt. The Company is evaluating its non-utility operations and may determine to sell certain of those operations or the related assets. If the Company determines to pursue any such sales of assets, proceeds from any such sales could significantly reduce the level of external financing required during 1989 through 1992.

Reevaluation of Dividend Policy. The Company paid a first quarter dividend of $.38 per share of common stock (an aggregate of $13,352,513) on March 15, 1989. In declaring the first quarter dividend, the Company cautioned that the level of future dividend payment was uncertain and would depend on earnings, cash flow and other factors. As discussed in the first and second paragraphs of Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations", the Company expects a reduction in 1989 income from continuing operations compared to the level in 1988. The Company, in general, anticipates that future results of operations will be significantly affected by the timing and method of inclusion in Texas rates of the Company's investment in Unit 3 and may continue to be significantly affected by the factors described in the first and second paragraphs of Part II, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations." The Company is currently reevaluating its dividend policy, including consideration of the possible reduction or omission of dividends for the foreseeable future, in light of such anticipated lower income and management's assessment of future results of operations, the Company's existing liquidity needs and restrictions on financing, and the uncertainty regarding the timing and method of inclusion in Texas rates of the Company's investment in Unit 3. See Note C of Notes to Consolidated Financial Statements. The Company's ultimate decision regarding future dividends will have a significant effect upon the level of financing required to meet cash requirements.

Other Restrictions — Restated Articles of Incorporation; Mortgage Indentures. The Company's Restated Articles of Incorporation provide that, unless consented to by the holders of preferred stock, additional shares of preferred stock may not be issued unless certain tests are met with respect to (i) net earnings of the Company available for preferred dividends, (ii) after-tax earnings available for interest, amortization and preferred dividends and (iii) the sum of junior stock capital and, if the Company so elects, surplus. The most restrictive of said tests, (i) above, would not have permitted the issuance of any new shares of preferred stock at December 31, 1988.

In addition, the Company's Restated Articles of Incorporation provide that, unless consented to by the holders of preferred stock, the aggregate of unsecured long-term debt shall not exceed 10% of the total of the Company's outstanding secured debt, capital and surplus. At December 31, 1988, the Company would have been permitted to issue approximately $33.6 million in additional unsecured long-term debt.

The Company's First Mortgage Indenture permits the issuance of additional first mortgage bonds to the extent of 60% of the value of unfunded net additions to the Company's utility property, provided net earnings available for interest during a recent twelve-month period were at least twice the annual interest requirements on all bonds to be outstanding and on all prior lien debt. At December 31, 1988, unfunded net additions totaled $320.8 million, which was sufficient, with the inclusion of $106.1 million in bond credits, to permit the issuance of approximately $298.6 million principal amount of new bonds.

Company, therefore, would be required to obtain either the consents of the Unit 2 equity participants to such refundings and extensions or renegotiate the incurrence of debt tests with the equity participants in a manner that would permit the Company to accomplish the needed refundings and extensions. The Company believes, but has no assurance, that it will be able to obtain either the needed consents from the Unit 2 equity participants or successfully renegotiate the incurrence of debt test.

Contemporaneously with the consummation of the Unit 3 sale and leaseback transactions, the Company and the equity investors in the Unit 2 sale and leaseback transactions agreed to modifications of the documents for those transactions. As required by the modifications, the Company in May 1988 provided the six equity investors in the August 1986 Unit 2 sale and leaseback transactions with bank letters of credit, in the aggregate amount of approximately $155 million and having a term expiring not earlier than December 31, 1991, in support of the equity portion of rent under the related lease.

In addition, as part of the modifications, the Company agreed to certain financial covenants with each of the eight equity investors in the Unit 2 sale and leaseback transactions. The covenants require the Company to retire approximately $187 million of long-term debt maturing through February 1991; the ratio of the Company's consolidated net income to interest and rental payment charges, determined as of June 30, 1991, to be not less than a specified ratio; and the Company's consolidated long-term and short-term debt, determined as of June 30, 1991, to be not in excess of specified percentages of consolidated capitalization. If the Company fails to meet such financial tests as of June 30, 1991, the equity investor can, in lieu of exercising remedies under the related lease, including drawing on the letter of credit, elect to require that the letter of credit be renewed for successive one year periods until such financial covenants are met as of June 30 in a subsequent year. Although the Company is not required to meet the financial tests imposed by the covenants until as of June 30, 1991, the Company expects to seek renegotiation of the financial tests as part of the renegotiated terms and provisions that the Company intends to seek from the Unit 2 equity investors with respect to the long-term debt incurrence test described above. The Company believes, but has no assurance, that such renegotiations will be successful.

The letter of credit agreements providing for the letters of credit issued to the Unit 2 and Unit 3 equity participants and one other bank credit agreement providing for an $11.5 million loan to the Company's leveraged employee stock ownership plan require the Company to maintain for each fiscal quarter, on a rolling 12-month basis, a coverage of earnings to interest and rental payments of a specified ratio (the "fixed charge ratio"). Although the Company will not know with certainty until it has results for the first quarter 1989 (which are expected in late April), the Company does not expect to meet the fixed charge ratio required under the letter of credit agreements and the bank credit agreement for the 12-month period ending March 31, 1989 and has so notified the banks. The Company believes, but has no assurance, that it will be able to negotiate a satisfactory amendment to the fixed charge ratio which will avoid any default that otherwise could be declared for failure to meet the fixed charge ratio for such period. If the letter of credit banks were to declare such a default, the letter of credit banks then could terminate the letters of credit issued to the Unit 2 and Unit 3 equity participants. The Company has the right and obligation, under the transaction documents for the Unit 2 and Unit 3 sales and leasebacks, to replace the letters of credit with complying letters of credit. Failure to replace such letters of credit within the required time period would permit the equity participants to draw on the letters of credit, prior to termination by the banks, and declare the facility leases for the sales and leasebacks in default. See Note E of Notes to Consolidated Financial Statements.

1990-1992 Cash Requirements. Cash requirements presently scheduled for the period 1990-1992 consist of redemptions of debt and preferred stock of $200.1 million; construction requirements of $100.3 million; and common and preferred stock dividends (assuming no change in dividend level and

However, net earnings available for interest would restrict the issuance of new bonds (assuming an interest rate of 11.375%) to approximately $214.2 million principal amount.

The Company's Second Mortgage Indenture permits the issuance of additional second mortgage bonds on the basis of 40% of the value of unfunded net additions to utility property. At December 31, 1988, unfunded net additions totaled approximately $26.6 million, which was sufficient, with the inclusion of $170 million in bond credits, to permit the issuance of approximately $180.6 million principal amount of additional second mortgage bonds.

Non-Utility Cash Requirements. The Company cannot, without the approval of the New Mexico Commission, make capital contributions, loans to or investments in its subsidiaries. In addition, the terms and provisions of certain of the Company's financing agreements, including the bank letter of credit agreements for the Palo Verde sales and leasebacks, restrict capital contributions, loans and other investments by the Company in its subsidiaries. As a result, the financing requirements of the Company's subsidiaries must be met from cash on hand in the subsidiaries, their internally generated cash flows and their ability to borrow externally without recourse to the Company. The subsidiaries are subject to the incurrence of debt restrictions affecting the Company, discussed above, as those tests are applied on a consolidated basis. During 1988, the subsidiaries had a net cash requirement for operations of approximately $13 million due primarily to increases in working capital which were financed principally from short-term borrowings under revolving credit lines.

The subsidiaries' non-operating cash requirements for 1989 and 1990 consist primarily of $4.8 million for scheduled retirement of long-term debt and $12 million for plant expansion and improvements at Border Steel. The Company's current projections indicate that these cash requirements will be met through the subsidiaries' internally generated cash flows from operations, funds on hand and short-term borrowings. The operations of the subsidiaries, however, are subject to substantially different uncertainties than are the utility operations. Accordingly, management is unable to predict whether the subsidiaries' cash flow projections will be fully realized. The Company currently plans to relocate its B. P. John subsidiary's manufacturing operations to the southern New Mexico area in 1989, at an expected cost of approximately $12 million to $15 million, which will require financing. Additionally, the Company may decide to generate cash through sales of substantial subsidiary assets, which would affect the subsidiaries' and the Company's financing requirements. See Note N of Notes to Consolidated Financial Statements.

C. Rate Matters

Texas

On March 30, 1988, the Texas Commission adopted a rate moderation plan to phase-in Palo Verde Units 1 and 2 into Texas rates. The plan is based on a stipulated settlement proposed in October 1987 by the Company and most of the parties to the Company's 1987 Texas rate case. Texas rates, based on the final order, were implemented on April 22, 1988.

The rate moderation plan adopted by the Texas Commission is intended to comply with SFAS No. 92, *Regulated Enterprises — Accounting for Phase-in Plans*, and provides for a series of increases in the Company's annual Texas retail base rates over a period of four years. The Company received a cash increase of approximately $21 million in the first twelve months of the plan ($8.6 million net of fuel savings and miscellaneous revenues), and the Company will receive an additional cash increase in each of the following three twelve-month periods. With respect to each of these four twelve-month periods, to the extent the Company's approved cost-of-service exceeds the cash increase provided for that period, the unrecovered revenue requirements will be deferred for cash collection in later years of the plan. The initial cost-of-service base rate increase established in the 1988 rate case was $46 million, compared with the $21 million cash rate relief provided under the plan. On a percentage basis, Texas base rates increased by 13.7% in the first year of the plan (3.6% net of fuel savings and miscellaneous

revenues). The revenues deferred for collection in later years of the plan are scheduled to be recovered within ten years. The Company is allowed under the plan to request additional increases after the fourth year, if necessary to recover all deferred revenues within the ten year period. Although such increases may be necessary, the Company has not formally requested any additional increases. See "1988 Rate Case" below.

All construction prudence issues directly related to Palo Verde Units 1 and 2 and Common Plant, and any effect which Unit 1 and 2 construction issues might have had on Unit 3, were settled by the Texas Commission's March 1988 rate order. Issues relating to the prudence of the Company's decisions with respect to its initial and continuing investment in Palo Verde were also resolved insofar as they affect regulatory treatment of Units 1 and 2. In the settlement of these issues, the Company agreed, in October 1987, to an after-tax regulatory disallowance of approximately $24.4 million of the Company's investment in PVNGS (less than 2% of such investment). The Company recorded the disallowance, which did not require cash, in 1987. All issues relating to excess capacity with respect to Units 1 and 2 were resolved among the stipulating parties for the life of the phase-in period.

Three participants in the 1987 rate case who were not parties to the stipulated settlement have appealed the Commission's order. Their appeals were filed in May 1988, and no further action has taken place on such appeals to date. A final judicial determination on such appeals is not expected this year. Management anticipates that the Commission's order will be upheld.

1988 Rate Case. On October 14, 1988, the Company filed its first annual cost-of-service request pursuant to the Texas rate moderation plan and requested an increase of approximately $39 million in base revenues, including a 14% return on common equity, and approximately $6 million in fuel revenues, for a total increase of $45 million. Under the terms of the plan, the Company is allowed a cash increase in base revenues of approximately $7 million. The difference between such cash increase and any increase in base revenues ordered by the Texas Commission will be deferred for collection in later years of the plan. Hearings were held in January and February 1989. The hearing examiner's report is expected in early April and a final order later that month.

Intervening parties to the case have recommended increases in base revenues which are less than $39 million. The Texas Commission staff has recommended a total increase in base revenues of approximately $22 million. The Company's net income in 1989 will be adversely affected if, and to the extent, that the final rate order adopts a base revenue increase of less than $39 million. See Note B of Notes to Consolidated Financial Statements. Included in the staff recommendations are certain adjustments to the deferred asset balances, which, if ordered, would cause approximately $20 million of write-offs of amounts currently reflected in the Company's 1988 consolidated balance sheet. The Company strenuously opposes the proposed adjustments and other portions of the staff's recommendations which, in the Company's opinion, are without merit. Management believes, but cannot predict with certainty, that the Texas Commission will not adopt the staff's recommendation for adjustments to the deferred balances. However, if the adjustment were adopted, the Company would seek appropriate legal remedies, including an appeal of the case through the courts.

In its filing, the Company included an analysis of the expected overall effects of the rate moderation plan for the full ten-year period. As originally anticipated under the rate moderation plan, the Company was to receive increases of 4% in the second year of the plan and 3.5% in each of the third and fourth years of the plan, with base rates to remain level after the fourth increase. The increases had been forecasted on an expected average jurisdictional unit rate to the Company from its forecasted sales. While base revenues in the pending case will increase 4%, or approximately $7 million, average jurisdictional unit rates will be 5.682¢, rather than the 5.936¢ per KWH originally planned, due to changes in customer consumption patterns. Cash collections, therefore, are not expected to be realized at the same level as originally anticipated for the growth which the Company has experienced, resulting in greater deferred revenues and contributing to the need for additional

increases in base rates after the fourth increase to accomplish full recovery of the deferrals within the ten year term of the plan. To increase cash flow, the Company is evaluating alternatives to address the unit rate situation, including a possible request that the original average unit rate path be reestablished. The Company may seek to renegotiate the matter with all the parties to the stipulation and may ask the Texas Commission to rule on the proper rate setting methodology, either in a separate hearing or in the Company's next annual cost-of-service filing under the plan. See Note B of Notes to Consolidated Financial Statements.

Unit 3 Although Unit 3 achieved commercial operation in January 1988, it will not meet present Texas in-service criteria for inclusion in rate base until completion of the AIP transmission facilities presently scheduled for the end of 1989. Until then, Unit 3 is being accounted for, insofar as the Texas jurisdictional portion is concerned, as plant under construction, and the Company is capitalizing all Texas jurisdictional costs of owning, operating and maintaining Unit 3. During 1989, the Company plans to request an accounting deferral order from the Texas Commission which will allow the Company to defer the costs of owning, operating and maintaining Unit 3 (excluding an allowance for earnings on shareholders' investment) from the date that Unit 3 meets the Texas in-service criteria until the Company's request for inclusion of Unit 3 in rate base can be filed and ruled upon by the Texas Commission. The Company believes, but cannot predict with certainty, that the Texas Commission will rule favorably on the matter. In the event that an accounting deferral order is not obtained from the Texas Commission, the Company would be required to expense the costs related to Unit 3 beginning in early 1990, which would adversely affect net income. The Company plans to file the Unit 3 case in the second quarter of 1990 and presently anticipates a final order by the end of 1990.

Certain issues relating to the prudence of construction costs specifically incurred with respect to Unit 3, and the prudence of the Company's decisions with respect to its investment in Palo Verde insofar as they affect regulatory treatment of Unit 3, relating to events occurring after the 1978 issuance of a certificate of convenience and necessity for Palo Verde by the Texas Commission, and any possible issues of excess generating capacity relating to Unit 3 are, under the terms of the rate moderation plan, reserved for decision in the Unit 3 case.

Although the timing and method of inclusion of Unit 3 costs in Texas rates cannot be predicted with certainty, management believes the ultimate resolution of the remaining issues of prudence relating to Unit 3 will not result in a material disallowance of the costs incurred. If any excess generating capacity were to be found by the Texas Commission relating to Unit 3, management believes the amount of any resulting exclusion from rate base would likely be temporary and would be restored to rate base in future rate proceedings to permit full recovery of substantially all of the Company's Texas jurisdictional investment in Unit 3. Management believes that inclusion of Unit 3 in Texas rates may require rate moderation, as was the case with Units 1 and 2. The Company's current planning for cash requirements contemplates inclusion of Unit 3, on a phased-in basis, in Texas rates beginning in April 1991. However, any exclusion from rate base by the Texas Commission based on a finding of excess capacity or an increase in rates substantially lower than presently contemplated would have an adverse impact upon the Company's future income and Internally Generated Cash and could substantially increase financing requirements. See Note B of Notes to Consolidated Financial Statements.

Sale and Leaseback Transactions The Company has entered into certain sale and leaseback transactions involving Palo Verde Units 2 and 3. See Note E of Notes to Consolidated Financial Statements. The Texas Commission's March 1988 rate order included in rates the lease payments attributable to Unit 2, to the extent of the book value of the plant sold and leased back, plus all related taxes. As required by statute, the Company filed a report of its Unit 2 sale and leaseback transactions with the Texas Commission. When adopting the rate moderation plan, the Texas Commission included the effect of the Unit 2 transactions in rates because rates recognizing the transactions in such case

would not exceed those under traditional ratemaking methodology. However, the Texas Commission specifically reserved a ruling on the question of whether the transactions were in the public interest and should be reflected in rates in the future in lieu of such traditional methodology. As part of the Company's October 14, 1988 rate filing, the Company requested a ruling from the Texas Commission on whether the transactions were in the public interest. The Texas Commission is also currently evaluating the Company's sale and leaseback transactions involving a portion of Palo Verde Unit 3. A hearing was held on the Unit 3 transaction during December 1988, and a hearing examiner's report is expected during the spring of 1989. Were it to find the Palo Verde sale and leaseback transactions not to be in the public interest, the Texas Commission might choose to disregard the transactions in favor of traditional rate making methodology in setting rates related to the respective generating plants. The Company believes the transactions benefit both ratepayers and shareholders, and, accordingly, the Company believes, but cannot predict with certainty, that the transactions will be found to be in the public interest.

1987 Rate Case Expenses In August 1988, the Company filed to recover approximately $11 million of expenses incurred by the Company in litigating the 1987 rate case. In its March 1988 rate order, the Texas Commission ordered a separate docket to be convened to consider such expenses. Hearings were held in October 1988, and a hearing examiner's report is expected shortly, with a final order during the second quarter of 1989. The Company has requested that it be allowed to recover its expenses by means of a surcharge to its Texas customers. Expenses related to the determination of prudence of the construction of the Palo Verde Station have been requested to be capitalized in rate base and recovered over the life of the Station with a return on the unamortized amount. Management believes, but cannot predict with certainty, that the Company will receive full recovery of these expenses.

Prior Rate Case Appeals The Company's appeals of the orders in its 1984 and 1985 rate cases are in the process of being settled without any consequences to the Company.

New Mexico

In March 1987, the Company entered into a stipulated settlement with certain jurisdictional New Mexico parties which provided for a rate moderation plan for the Company's New Mexico jurisdiction. In May 1987, the New Mexico Commission issued its final order adopting such rate moderation plan. The approved plan provides for (i) continued full inclusion in the Company's rate base of the capital costs of Palo Verde Unit 1 and one-third of Palo Verde Common Plant and inclusion in rate base of certain transmission facilities, (ii) recovery of the New Mexico portion of equity AFUDC attributable to Unit 3 in rates as cost-of-service, amortized over a period ending December 31, 1994, subject to acceleration based upon recoupment of the cost-of-service revenue deferrals described in the following clause, (iii) increases in rates of 3% on a total cents per kilowatt-hour basis in 1987, 3% in base rates no sooner than one year after the 1987 increase and an additional 3% in base rates no sooner than one year after the second 3% increase, with any deficiency in revenue requirements resulting from this rate path being deferred for collection in later years (base rates to be held constant after the third increase until the earlier of December 31, 1994 or the full recoupment of such deferrals and the New Mexico portion of equity AFUDC attributable to Unit 3), (iv) recovery in rates of the lease payments on Unit 2 to the extent of the book value of plant sold and leased back, as well as all related taxes, (v) agreement by the Company that, except for the New Mexico portion of equity AFUDC attributable to Unit 3, neither the capital costs of Palo Verde Unit 3, one-third of Palo Verde Common Plant, a proportionate share of certain Palo Verde transmission facilities nor any Unit 3 operating expenses will at any time be requested for inclusion in the Company's rate base or requested for any cost-of-service treatment insofar as the New Mexico jurisdiction is concerned. Under the New Mexico rate moderation plan, Palo Verde Unit 3 may be used to serve New Mexico load, but such power will be priced as purchased power at the rate of the most economic source of power available at that time. The

New Mexico Commission's adoption of the rate moderation plan resolves any possible issue related to the prudence of the planning, management and construction of Palo Verde and settles any possible issue of excess generating capacity through 1993. Based upon present planning analysis, the Company does not expect to have excess generating capacity insofar as its New Mexico jurisdiction is concerned.

The first of the three scheduled rate increases under the New Mexico rate moderation plan was approved in November 1987 and provided an annual increase in the Company's New Mexico base rates of $9.9 million, or $5.0 million in total revenues, net of fuel savings. Actual revenues to be collected by the Company pursuant to the phase-in of the approved increase aggregated $6.6 million of base revenues, or $1.8 million in total revenues, net of fuel savings. The difference between the approved base revenue increase of $9.9 million and the implemented increase of $6.6 million is, under the terms of the plan, deferred for collection in later years of the plan.

In November 1987, the Company filed for the second increase of approximately $5.5 million under the plan. Under the phase-in provisions of the plan, the increase was limited to 3%, or $1.7 million, with the balance to be deferred. On October 3, 1988, the Commission adopted and approved in its entirety a stipulation on revenue requirements and tariff-schedule-rate design for the case. Under the terms of the stipulation, the Company was authorized to implement its cash increase in base rates under the rate moderation plan of $1.5 million, although the stipulation provided for a zero increase in non-fuel base revenue requirements. The stipulation also allowed for $1.2 million of fuel expense related to Palo Verde Unit 2 to be capitalized as a cost-of-service deferral. New rates in New Mexico became effective on November 4, 1988.

The Company expects to file for the third increase allowed under the plan early in the second quarter of 1989. Hearings are expected to be held in the later half of 1989, with rates to become effective early in the first quarter of 1990.

As stated above, the New Mexico rate moderation plan provides that neither the capital costs of Palo Verde Unit 3, one-third of Common Plant nor a proportionate share of certain Palo Verde transmission facilities (aggregating approximately $54.1 million) nor any Unit 3 operating expenses, including the lease payments attributable to that portion of Unit 3 sold and leased back on December 31, 1987, will at any time be included in the Company's rates or receive any cost-of-service treatment in the New Mexico jurisdiction. The costs related to the New Mexico portion of Unit 3 will need to be recovered through economy, off-system sales of power. Although the current market price for economy, off-system sales of electricity is not sufficient to cover current operating expenses related to Unit 3, including lease payments related to the portion of Unit 3 sold and leased back, the Company believes, based upon current forecasts of plant operating performance, power demand and alternative fuel prices that over the estimated remaining life of the Unit, the Company will recover its costs related to the New Mexico portion of Unit 3.

SFAS No. 92, issued in August 1987 and effective for financial statements for fiscal years beginning after December 15, 1987, establishes specific criteria to be met by a phase-in plan in order for costs deferred for future recovery by the regulator to be capitalized for financial reporting purposes. The rate moderation plan approved in New Mexico does not currently meet such criteria because, under the existing terms of the plan, any portion of cost-of-service deferrals not recouped prior to December 31, 1994 will not be recovered through rates in New Mexico. The Company, however, has filed to amend the plan to meet the criteria of SFAS No. 92 and believes that such amendment will be approved by the New Mexico Commission. Hearings on the Company's application are anticipated to start in the second quarter of 1989. The ability of the Company to continue to report for financial statement purposes amounts equal to the difference between the approved revenue requirements and implemented rates is dependent upon approval of the amendment.

FERC

The Company's sales for wholesale power make up a significant portion of the Company's operating revenues. During 1988 and 1987, approximately 17% of the Company's electric operating revenues resulted from such sales. Although rates to wholesale customers require FERC approval, the Company and its wholesale customers usually establish such rates through negotiations subject to such FERC approval.

In March 1986, the Company filed for increased rates for service to three wholesale customers, IID, TNP and RGEC. The requested increase amounted to approximately $32 million, utilizing a forecasted 1986 test period. In May 1986, the Company was allowed to implement a portion of the increased rates under suspension. The Company subsequently entered into settlement agreements with each of these customers. The FERC approved the settlements with IID and RGEC on March 30, 1987.

The settlement with IID is based upon a long-term firm power sales agreement providing for the sale of 100 megawatts of firm capacity to IID beginning in 1987 and continuing through April 2002. In addition, the agreement calls for contingent capacity of 50 megawatts to be made available to IID beginning in 1992 and continuing through April 2002. The settlement agreement with IID settles any possible issue of the prudence of the construction costs of PVNGS and of excess generating capacity. The Company and IID are currently negotiating the impact that the sale and leaseback of a portion of Unit 3 has on the demand charges during the term of the contract.

The settlement agreement with TNP is based upon a revised firm power sales agreement with TNP. As part of the settlement of the rate increase request, the Company and TNP settled an arbitration with respect to the contractual level of reserve demand under the Company's prior sales agreement with TNP. The revised firm power sales agreement with TNP provides for firm power sales to TNP ranging from 43 megawatts to 79 megawatts, beginning in 1987 and continuing through 2002, with negotiated demand charge rates for such power.

On December 29, 1987, the FERC approved with modifications the settlement with TNP. The FERC refused to bind itself to certain contractual provisions contained in the settlement. TNP and the Company requested a rehearing by the FERC on its order and asked the FERC to allow the Company to place the agreed rates for 1988 in effect. On May 2, 1988, the FERC granted the petition for rehearing. TNP and the Company have subsequently modified the stipulation to address the FERC's concerns, and the FERC approved such stipulation. The Company and TNP have also agreed on the impact of the sale and leaseback of Unit 3 on the demand charges during the term of the contract.

The Company and RGEC have agreed to a 10-year contract based on a flat rate during the life of the contract.

D. Palo Verde Nuclear Generating Station

The Company has expended $1.45 billion (including $417 million of AFUDC net of deferred taxes) through December 31, 1988 for its 15.8% interest in the three 1,270 MW nuclear generating units which comprise the Palo Verde Station, which is located near Phoenix, Arizona. At December 31, 1988, Units 1, 2 and 3 were complete and in commercial operation. See Note C of Notes to Consolidated Financial Statements for information on the Company's treatment of the Texas jurisdictional portion of Palo Verde Unit 3.

A summary of the Company's investment in Palo Verde Station and other jointly owned utility plant, excluding fuel, is as follows:

	Electric Plant in Service	Accumulated Depreciation	Construction Work in Progress
December 31, 1988:			
Palo Verde Station	$632,808,000	$(25,371,000)	$185,865,000
Other	125,423,000	(24,805,000)	19,047,000
December 31, 1987:			
Palo Verde Station	$588,168,000	$ (9,690,000)	$202,792,000
Other	121,589,000	(19,915,000)	10,990,000

The Company's investment, at cost, in the Palo Verde Station in the amount of $818,673,000 at December 31, 1988 excludes amounts which represent the book value of the Company's investment in Palo Verde Station which was sold and leased back during 1986 and 1987 and for which the related leases are accounted for as operating leases. See Note E of Notes to Consolidated Financial Statements for information regarding such transactions and the Company's lease obligations relating thereto. Additionally, the Company's investment, at cost, in the Palo Verde Station is net of a regulatory disallowance write-off in the amount of $38,323,000. See Note C of Notes to Consolidated Financial Statements.

Decommissioning and Spent Nuclear Fuel

The Company is required to plan and fund its share of the estimated costs to decommission Palo Verde, including the portion sold and leased back. The Company has assessed the requirements for the funding of such decommissioning and has determined, based upon an independent study, that the Company will have to fund approximately $97 million (stated in 1986 dollars) for decommissioning of Palo Verde. The Company will fund decommissioning over the estimated service life (approximately 40 years) for the portion of its owned interest in Palo Verde and over the term of the related leases (27 to 29 years) for the sold and leased back portions of Palo Verde. The Company has established funds which, as approved, provide for current deductibility up to 40 years for Federal income tax purposes of some or all of amounts funded. The Company believes that all costs associated with nuclear plant decommissioning will be recoverable through rates.

The Company is currently funding its share of the obligation for spent nuclear fuel costs associated with Palo Verde through payments to the operating agent of Palo Verde of amounts prescribed by the Department of Energy.

Palo Verde Deferred Costs

Palo Verde deferred costs represent operating expenses incurred in connection with, and capitalization of AFUDC on, the Company's investment in Unit 1 and Unit 2 since their respective dates of commercial operation (Unit 1 — February 24, 1986; Unit 2 — September 22, 1986) to April 22, 1988 for Texas and November 6, 1987 for New Mexico. The Company's accounting treatment of such costs and AFUDC is pursuant to rate orders issued by its Texas and New Mexico regulators.

In its final order dated March 30, 1988, the Texas Commission allowed in rate base $74.5 million of Palo Verde deferred costs related to Units 1 and 2. These costs will be amortized over the life of the respective plants (amortization began in May 1988). In addition, the Company is currently earning a rate of return on the remaining deferral balances, approximately $43 million, which will be addressed in the Company's currently pending rate case in order to include actual data through the end of the deferral period. The Company began amortizing its New Mexico jurisdictional portion of Palo Verde

deferred costs over a two-year period in November 1988. A detail of Palo Verde deferred costs reflected in the accompanying consolidated balance sheets at December 31, 1988 and 1987 is as follows:

	1988	1987
	(In thousands)	
Operating expenses deferred:		
Operations and maintenance and taxes	$ 47,419	$ 37,465
Lease payments — Unit 2	42,066	28,852
Other	(6,185)	(7,673)
Total operating expenses	83,300	58,644
AFUDC	44,895	44,018
Accumulated amortization	(1,782)	—
Total	$126,413	$102,662

E. Sale and Leaseback Transactions

In August and December 1986 and December 1987, the Company consummated ten separate sale and leaseback transactions involving all of its 15.8% undivided interest in Palo Verde Unit 2, one-third of its undivided interest in certain Common Plant at Palo Verde and approximately 39.5% of its undivided interest in Unit 3. The Company remains responsible, under the terms of the leases, for all operating and maintenance costs, decommissioning costs, nuclear fuel costs, and other related operating costs of the leased-back facilities.

The aggregate consideration received by the Company in the sale and leaseback transactions was $934.4 million ($684.4 million in 1986 and $250.0 million in 1987). The proceeds from the transactions, which were based upon appraised fair market value, exceeded the cost of the assets sold by $194.0 million, which amount has been deferred and is being amortized into income over the primary terms of the leases. Nine of the ten transactions are accounted for as operating leases; one transaction (sales price of $87.4 million), with an affiliate of a federal savings and loan association is accounted for as a financing transaction. An executive officer of a subsidiary of the Company serves on the board of directors of an affiliate of the savings and loan association and as an advisory director of the parent of the savings and loan association. During 1987, the Company acquired $60 million of newly issued, floating rate exchangeable preferred stock of the savings and loan association. Additionally, an affiliate of the savings and loan association received placement fees aggregating approximately $3.7 million in connection with the ten sale and leaseback transactions and the preferred stock transaction.

Leases related to Unit 2 and Common Plant expire in October 2013, while leases related to Unit 3 expire in January 2017. All of the leases contain certain renewal options and provide for repurchase options, at fair market value, at the termination of the lease. Additionally, all of the leases provide that upon the occurrence of specified events of loss or deemed loss events, as defined, the Company is obligated to pay the related equity investor an amount in cash which, primarily because of certain tax consequences, may exceed the equity investor's unrecovered equity investment. Upon payment of such amount and assumption of the debt portion of the purchase price of the undivided interest, the undivided interest will be transferred to the Company. Approximately 20% of the aggregate purchase price of the undivided interests sold in the sale and leaseback transactions was provided by the equity investors, with the balance being provided through the issuance of non-recourse debt by the lessor/purchasers. Additionally, the Company has agreed to indemnify the lessors in certain circumstances against certain losses, including the loss of certain tax benefits, resulting from specified events.

Contemporaneously with the consummation of the December 1987 sale and leaseback transactions, the Company and the equity investors in the 1986 sale and leaseback transactions agreed to modifications of the documents for those transactions. See Note B of Notes to Consolidated Financial Statements.

The Company believes that it will be able to recover the lease payments, attributable to Units 2 and 3 which are subject to rate regulation, from ratepayers to the extent of the book value of the plant sold and leasedback, plus all related taxes ("book breakeven"). Lease payments attributable to the portion of Unit 3 sold and leasedback which has been deregulated by the New Mexico jurisdiction will have to be recovered through economy off-systems sales of electricity. See Note C of Notes to Consolidated Financial Statements. The balance of the lease payments (approximately $18.6 million per year) are not subject to recovery from ratepayers. Lease expense under the leases accounted for as operating leases amounted to $83,891,000 during 1988, of which $26,315,000 was deferred and capitalized. Future minimum annual rental payments required under such leases are as follows (in thousands):

Year ending December 31,	
1989	$ 82,627
1990	82,627
1991	82,627
1992	82,627
1993	82,627
Thereafter	1,726,212

F. Investments and Other Short-Term Investments

Investments and other short-term investments are generally stated at their lower of cost or market and include, net of current market valuation allowance of $2,060,000 and $6,885,000 in 1988 and 1987, respectively, investments and other short-term investments of $186,319,000 and $322,675,000 at December 31, 1988 and 1987, respectively. Investments and other short-term investments consist primarily of investments in equity securities, dividend capture funds and mortgage-backed securities. Other short-term investments includes an investment in a partnership, which is carried at market value of $53,848,000 and $52,351,000 in 1988 and 1987, respectively.

Gross unrealized gains were $6,082,000 and $1,239,000 and gross unrealized losses were $1,257,000 and $6,844,000 in 1988 and 1987, respectively. Included in non-utility operating revenues were losses on write-downs of subsidiary investments of $3,000,000 and $5,727,000 in 1988 and 1987, respectively.

Net realized losses on investments included in the determination of net income were $4,014,000 and $12,039,000 in 1988 and 1987, respectively. The cost of the securities sold was based on the actual cost of each such security at the time of sale.

G. Common Stock

Employee Stock Purchase Plan

The Company has an employee stock purchase plan under which eligible employees are granted options twice each year to purchase, through payroll deductions, shares of common stock from the Company at a specified discount from the fair market value of the stock; provided, however, if the option price exceeds the fair market value of the stock on the date of exercise of the option, the Company, in lieu of selling the stock at the option price, purchases in the over-the-counter market, for

the accounts of the participants, that number of shares of common stock as the aggregate of the payroll deductions under the plan will purchase.

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company has an automatic dividend reinvestment and stock purchase plan under which holders of record of common stock purchase, on the open market through a purchasing agent, additional shares of common stock by automatic reinvestment of their cash dividends from the Company and/or making optional cash payments of up to $3,000 (but not less than $25) per calendar quarter.

Prior to January 1987, the Company had a dividend reinvestment and stock purchase plan under which holders of record of common stock purchased from the Company, at fair market value, shares of common stock by reinvesting cash dividends and/or making optional cash payments of up to $3,000 per calendar quarter.

Employee Stock Ownership Plan and Trust

The Company has a qualified employee stock ownership plan under which common stock with a fair market value (as defined) equal to the sum of a specified amount of the Company's investment tax credit (based on payroll costs) is contributed by the Company to the plan. No employee cash participation is permitted by the plan. Due to the provisions of the Tax Reform Act of 1986, as of December 31, 1987, the Company will no longer participate or make contributions to the plan.

Customer Stock Purchase Plan

The Company has a customer stock purchase plan under which shares of Company common stock may be purchased from the Company at fair market value by its Texas and New Mexico customers. Customers may purchase shares by making cash payments in amounts of not less than $25 per payment nor more than $3,000 total investment per calendar quarter. Dividends paid on all shares purchased by a participant are automatically reinvested in additional shares, except for those participants who request in writing the stock certificates and cash dividends.

Employee Stock Compensation Plan

The Company has an employee stock compensation plan under which shares of Company common stock are issued from time to time to eligible employees. Under the plan, the Board's Compensation Committee may direct the issuance from time to time of Company common stock to compensate employees for past services rendered to the Company or to pay for various employee benefits with common stock rather than with cash.

Leveraged Employee Stock Ownership Plan and Trust

The Company has a leveraged employee stock ownership plan and trust (LESOP) which has borrowed money that was used to purchase 1,297,051 shares of Company common stock on the open market for allocation to eligible employees. During 1988, 1987 and 1986, the LESOP allocated 194,558, 194,557 and 162,131 shares, respectively.

Employee Stock Option Plan

In December 1987, the Board of Directors approved the adoption of the Company's Employee Stock Option Plan. In May and November 1988, respectively, the Employee Stock Option Plan received shareholder and New Mexico Commission approval. The plan authorizes the issuance of up to

1,000,000 shares of common stock pursuant to options which may be granted at not less than fair market value.

On November 22, 1988, the Board of Directors authorized the allocation of 241,173 shares of common stock options at an option price of $14.625 per share with a ten-year expiration period. Options are allocated to eligible employees on a pro rata basis according to the ratio that the compensation, earned over a ten-year period, of each eligible employee bears to the compensation of all such eligible employees as defined in the plan. As of December 31, 1988, none of the options had been exercised.

Changes in Common Stock

Changes in common stock are as follows:

	Common Stock	
	Shares	Amount (In thousands)
Balance December 31, 1985	34,743,917	$326,033
Issuances of Common Stock:		
1986	766,221	12,767
1987	88,042	1,482
1988	103,129	1,468
Purchase of Common Stock:		
1987	(626,000)	(5,983)
Balance December 31, 1988	35,075,309	$335,767

Shares reserved for issuance under the stock plans described above were 1,740,499 at December 31, 1988.

H. Preferred Stock

Preferred Stock, Redemption Required

Following is a summary of issued and outstanding preferred stock, redemption required:

	December 31,				Optional Redemption Price Per Share at December 31, 1988
	1988		1987		
	Shares	Amount (In thousands)	Shares	Amount (In thousands)	
$10.75 Dividend	64,000	$ 6,400	68,000	$ 6,800	$105.250
$ 8.44 Dividend	109,600	10,960	115,600	11,560	104.220
$ 8.95 Dividend	105,000	10,500	112,500	11,250	106.710
$ 9.50 Dividend	56,000	5,600	60,000	6,000	102.375
$10.125 Dividend	250,000	25,000	250,000	25,000	104.500
$11.375 Dividend	500,000	50,000	500,000	50,000	111.750
	1,084,600	$108,460	1,106,100	$110,610	

Each series of preferred stock, redemption required, is entitled to the benefits of its respective annual sinking fund which requires redemptions of a specified number of shares or a percentage of

outstanding shares. The sinking fund redemption price on all series is $100 per share plus accrued dividends.

Each series, other than the $10.75 series, is redeemable at the option of the Company at various stated redemption prices. Optional redemptions are also generally restricted as to the timing of redemption when such redemptions are part of or in anticipation of any refunding involving the issue of indebtedness or preferred stock having an effective interest cost or effective dividend cost of less than the stated dividend rate of each preferred stock series.

Sinking fund requirements for each of the above series are cumulative and, in the event they are not satisfied at any redemption date, the Company is restricted from paying any dividends on its common stock (other than dividends in common stock or other class of stock ranking junior to the preferred stock as to dividends or assets).

The aggregate amounts of the above preferred stock required to be retired for each of the next five years are as follows (in thousands):

1989	$ 8,750
1990	20,350
1991	16,750
1992	16,750
1993	16,750

Redemptions of preferred stock, redemption required were as follows:

	Shares	Amount (In thousands)
Balance at December 31, 1985	1,306,500	$130,650
Redemption of Preferred Stock, $10.75 Dividend	(4,000)	(400)
Redemption of Preferred Stock, $8.44 Dividend	(10,400)	(1,040)
Redemption of Preferred Stock, $8.95 Dividend	(15,000)	(1,500)
Redemption of Preferred Stock, $9.00 Dividend	(100,000)	(10,000)
Redemption of Preferred Stock, $9.50 Dividend	(20,000)	(2,000)
Balance at December 31, 1986	1,157,100	115,710
Redemption of Preferred Stock, $10.75 Dividend	(4,000)	(400)
Redemption of Preferred Stock, $8.44 Dividend	(12,000)	(1,200)
Redemption of Preferred Stock, $8.95 Dividend	(15,000)	(1,500)
Redemption of Preferred Stock, $9.50 Dividend	(20,000)	(2,000)
Balance at December 31, 1987	1,106,100	110,610
Redemption of Preferred Stock, $10.75 Dividend	(4,000)	(400)
Redemption of Preferred Stock, $8.44 Dividend	(6,000)	(600)
Redemption of Preferred Stock, $8.95 Dividend	(7,500)	(750)
Redemption of Preferred Stock, $9.50 Dividend	(4,000)	(400)
Balance at December 31, 1988	1,084,600	$108,460

Preferred Stock, Redemption not Required

Following is a summary of preferred stock issued and outstanding at December 31, 1988 which is not redeemable except at the option of the Company:

	Shares	Amount (In thousands)	Optional Redemption Price Per Share
$4.50 Dividend	15,000	$ 1,534	$109.00
$4.12 Dividend	15,000	1,506	103.98
$4.72 Dividend	20,000	2,001	104.00
$4.56 Dividend	40,000	4,000	100.00
$8.24 Dividend	52,450	5,157	103.40
	142,450	$14,198	

All preferred stock issues (redemption required and redemption not required) are entitled, in preference to common stock, to $100 per share plus accrued dividends, upon involuntary liquidation. All issues are entitled to an amount per share equal to the applicable optional redemption price plus accrued dividends, upon voluntary liquidation.

I. Long-Term and Financing and Capital Lease Obligations

Outstanding long-term and financing and capital lease obligations are as follows:

	Redemption Price at December 31, 1988(1)	December 31, 1988	1987
		(In thousands)	
Long-Term Obligations:			
First Mortgage Bonds(2):			
4¼% Series, issued 1958, due 1988	— %	$ —	$ 6,100
4⅝% Series, issued 1962, due 1992	100.61	10,385	10,385
6¾% Series, issued 1968, due 1998	102.10	24,800	24,800
7¾% Series, issued 1971, due 2001	103.70	15,838	15,838
9% Series, issued 1974, due 2004	104.40	20,000	20,000
10½% Series, issued 1975, due 2005	106.30	15,000	15,000
8½% Series, issued 1977, due 2007	105.44	25,000	25,000
9.95% Series, issued 1979, due 2004	109.95	20,748	21,811
14½% Series, issued 1984, due 1989	—	25,000	25,000
14% Series, issued 1984, due 1989	—	50,000	50,000
13¼% Series, issued 1984, due 1994	—	29,500	29,500
12¾% Series, issued 1984, due 1989	—	22,000	22,000
Pollution Control Bonds(3):			
Secured by Second Mortgage Bonds(2):			
Variable rate bonds, due 2014, net of $7,936,000 and $11,442,000, respectively, on deposit with trustee(4)		55,564	52,058
Variable rate refunding bonds, due 2014, net of $2,109,000 and $4,998,000, respectively, on deposit with trustee(5)		34,991	32,102
Variable rate refunding bonds, due 2015(6)		59,235	59,235
Balance forward		$408,061	$408,829

	December 31, 1988	December 31, 1987
	(In thousands)	
Balance forward	$408,061	$408,829
Unsecured:		
Variable rate refunding bonds, due 2013, net of $4,574,000 and $5,848,000, respectively, on deposit with trustee(4)	31,231	29,957
Floating rate notes secured by Second Mortgage Bonds(2)(7):		
Due 1988	—	75,000
Due 1991	70,000	70,000
Promissory notes:		
Secured:		
Due 1996 ($616,000 due in 1989)(8)	27,060	58,683
Due 1989 through 2027 ($1,435,000 due in 1989)(9)	28,093	31,688
Unsecured (10):		
Due 1989 to 1997 ($857,000 due in 1989)	46,644	47,103
Mortgage notes payable, interest 9.5% and 12% per annum. Payable in installments through 2007 ($104,000 due in 1989)	5,385	5,479
Total long-term obligations	616,474	726,739
Financing and Capital Lease Obligations:		
Financing obligation, Palo Verde Unit 2 ($494,000 due in 1989)(11)	81,888	82,813
Turbine lease ($719,000 due in 1989)(12)	11,306	11,624
Nuclear fuel ($34,850,000 due in 1989)(13)	67,089	73,772
Capital lease obligations, interest 13% and 15.7% per annum. Payable in installments through 1991 ($39,000 due in 1989)	132	—
Total financing and capital lease obligations	160,415	168,209
Total long-term and financing and capital lease obligations	776,889	894,948
Amounts due within one year:		
Current maturities	(137,177)	(115,782)
Unamortized discount and premium	(1,321)	(1,448)
	$638,391	$777,718

(1) The premiums reflected in the redemption prices continue at reduced amounts in future years, finally resulting in each case in redemption at par in the final year prior to maturity.

(2) Substantially all of the Company's utility plant is subject to a lien under the Indenture of Mortgage securing the Company's First Mortgage Bonds and a lien under the Indenture of Mortgage securing the Company's Second Mortgage Bonds.

The First Mortgage Indenture securing its First Mortgage Bonds provides for sinking and improvement funds. Except as otherwise noted, the Company is required to make annual payments to the trustee equivalent to 1%, $1,115,000 at December 31, 1988, of the greatest aggregate principal amount of such series outstanding prior to a specified date. The Company has generally satisfied the 1% requirements for such series by relinquishing the right to use a net amount of additional property for the issuance of bonds or by purchasing bonds in the open market and expects to continue these practices. With respect to the 9.95% and 13.25% series, commencing in April 1985 and April 1990, respectively, the Company is required to make annual

cash payments to the trustee equivalent to 4.25% and 20%, respectively, of the greatest aggregate principal amount of such series outstanding at any one time prior to a specified date, $1,063,000 in 1988 and 1987; the cash payments must be applied to redeem bonds of the 9.95%, 13.25% series at 100% of the principal amount thereof. With respect to the 12.75%, 14.50% and 14% series bonds, no sinking fund is required.

In accordance with certain provisions of the First Mortgage Indenture, payments of cash dividends on common stock are restricted to an amount equal to retained earnings accumulated after December 31, 1966, plus $4,100,000. Retained earnings in the amount of approximately $186,380,000 are unrestricted as to the payment of cash dividends at December 31, 1988.

The Second Mortgage Bonds have been issued to secure the three variable rate pollution control bond issues due 2014 and 2015, as well as the floating rate note issue due in 1991.

(3) The funds on deposit with a trustee at December 31, 1988 represent a portion of the proceeds from pollution control revenue bonds and accumulated related interest income, which are to be disbursed as needed to pay the cost of acquiring, constructing, reconstructing, improving, maintaining or furnishing the pollution control facilities financed.

(4) The variable rate bonds due 2013 and 2014 are supported by long-term irrevocable letters of credit issued by a bank. These bonds bear interest at such rate, determined annually, as will cause the bonds to have a market value which approximates, as nearly as possible, their par value. During 1988 the interest rate on the variable rate bonds, due 2014, was 4.625% until July 1, 1988 and 5.75% thereafter. With respect to the variable rate refunding bonds, due 2013, the interest rate during 1988 was 6.75% until November 1, 1988 and 6.20% thereafter. The bonds may be required to be repurchased at the holder's option and are subject to mandatory redemption upon the occurrence of certain events and are redeemable at the option of the Company under certain circumstances.

(5) These bonds are supported by a long-term irrevocable letter of credit issued by a bank and bear interest at such rate, determined annually, as will cause the bonds to have a market value which approximates, as nearly as possible, their par value. During 1988, the bonds bore an interest rate of 4.375% until June 16, 1988 and 5.50% thereafter. The bonds may be required to be repurchased at the holder's option and are subject to mandatory redemption upon the occurrence of certain events and are redeemable at the option of the Company under certain circumstances.

(6) These bonds are supported by a long-term irrevocable letter of credit issued by a bank and bear interest at a weekly, daily or term interest rate (5% until July 28, 1988 and 6.20% thereafter). The bonds may be required to be repurchased at the holder's option, are subject to mandatory redemption upon the occurrence of certain events and are redeemable at the option of the Company under certain circumstances.

(7) The interest rate on the note due in 1991 is to be determined using the bank's prime rate, a CD or Eurodollar rate. Pursuant to an interest swap agreement, the interest rate is 9.955%.

(8) Consists of advances to a subsidiary on two promissory notes which provide for aggregate borrowings in the amount of $60,000,000 with interest at 12.75% per annum for the renovation of a building and construction of additional facilities. Principal and interest is payable in quarterly installments of $2,000,000. At January 1, 1996, the estimated unpaid principal balance is due and payable in full. The loan is secured by the properties and other assets to which it relates and a subsidiary's pledge of approximately $11,000,000 of its preferred stock portfolio. The notes are net of participation agreements in the amount of approximately $31,000,000 earning interest of 12.25%. These agreements are held by the Company's subsidiaries.

(9) Consists of notes with interest rates ranging from 5% to 14.125%, principally secured by properties and other assets of subsidiaries and $2,917,000 of letters of credit issued by banks.

(10) Two unsecured notes due in 1989 have interest rates of 14.125% and 14% per annum. Due in 1990 are two notes, one of which has an interest-rate of 13% per annum and the other is fixed (approximately 10.365%) pursuant to the terms of an interest rate exchange agreement with the lending bank. One unsecured note due in 1992 is floating rate, 9.75% at December 31, 1988. One unsecured note due in 1997 has an interest rate of 9.25% per annum.

(11) In December 1986, the Company entered into a financing obligation related to one sale and leaseback transaction involving Palo Verde Unit 2. See Note E of Notes to Consolidated Financial Statements. Semiannual payments, including interest (using an assumed interest rate of 9.01%), which began in July 1987, are $4,181,000, with the last payment being $2,091,000 in July 2013.

(12) In 1980 the Company leased a turbine and certain other related equipment from the trust-lessor for a twenty-year period, with renewal options for up to seven more years. Semiannual lease payments, including interest, which began in January 1982, are $719,000 through January 1991, and $861,000 thereafter to July 2000. The effective annual interest rate implicit in this lease is calculated to 9.6%. A gain to the Company related to the sale of the turbine to the trust in the amount of $2,343,000 is being amortized to income over the term of the lease.

(13) The Company enters into lease arrangements with an independent trust with respect to nuclear fuel loadings into Units 1, 2 and 3 at Palo Verde Station. The Company accounts for the leases as capital leases and, accordingly, has recorded obligations which have balances of $16,776,000 for Unit 1, $20,527,000 for Unit 2 and $29,786,000 for Unit 3 at December 31, 1988 (interest rate of 11% at December 31, 1988). Quarterly lease payments made are based on units of heat production.

Scheduled maturities of long-term and financing and capital lease obligations and sinking fund requirements at December 31, 1988 are as follows (in thousands):

1989	$138,292
1990	55,626
1991	88,055
1992	50,286
1993	13,598

Nuclear fuel is reloaded in the units approximately every three years at which time the related capital lease obligation is recorded. The table above includes scheduled maturities, within that three-year cycle, of obligations existing at December 31, 1988 and does not reflect future fuel loadings and related obligations and maturities.

J. Federal Income Taxes

The provisions (credits) for deferred Federal income taxes which arise from the timing differences between financial and tax reporting are as follows:

	Years Ended December 31,		
	1988	1987	1986
		(In thousands)	
Tax effect of:			
Operating income:			
Depreciation differences	$ 11,834	$ 8,110	$ 15,187
Deferred fuel revenues	1,318	3,901	(4,995)
Provisions for rate refunds	4,733	(777)	(6,125)
Allowance for borrowed funds used during construction	2,595	5,743	12,805
Allowance for borrowed funds on deferred costs	29	3,240	4,794
Taxes capitalized	1,126	3,953	2,916
Nuclear fuel expense differences	(5,324)	(6,477)	(3,301)
Deferred and capitalized Palo Verde operation and maintenance expenses	14,643	25,377	5,967
Sale and leaseback transactions:			
Palo Verde Unit 2 sale and leaseback	—	—	(129,062)
Palo Verde Unit 3 sale and leaseback	—	(55,022)	—
Amortization of gain and other	(459)	127	—
Tax leases	(1,593)	(1,740)	4,140
Deferred revenues	8,480	—	—
Return on deferred costs	1,013	—	—
Net operating loss	(28,337)	—	—
Minimum tax deferred	(3,168)	—	—
Other	(1,639)	(4,557)	634
Other income:			
Regulatory disallowance of plant costs	—	(13,937)	—
Other	5,807	(207)	734
Discontinued operations	(17,115)	1,811	2,210
Change in accounting method	(601)	2,827	—
Total deferred taxes	$ (6,658)	$(27,628)	$ (94,096)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The detail of Federal income taxes by component are as follows:

	Years Ended December 31,		
	1988	1987	1986
		(In thousands)	
Current income taxes:			
Operating	$ 4,931	$ 28,974	$ 45,974
Other income	1,137	(5,074)	5,094
Discontinued operations	(6,068)	(7,259)	(7,882)
Total	—	16,641	43,186
Deferred income taxes:			
Operating	4,650	(18,122)	(97,040)
Other income:			
Disallowance of plant costs	—	(13,937)	—
Other	5,807	(207)	734
Discontinued operations	(17,115)	1,811	2,210
Change in accounting method	—	2,827	—
Total	(6,658)	(27,628)	(94,096)
Charge (benefit) equivalent to investment tax credit:			
Operating	1,351	6,592	80,450
Other income	—	4,784	(138)
Discontinued operations	—	—	3,000
Total	1,351	11,376	83,312
Amortization of investment tax credit:			
Operating	(2,831)	(1,788)	(755)
Other income	—	—	—
Discontinued operations	(111)	(111)	(37)
Total	(2,942)	(1,899)	(792)
Total Federal income tax expense	$ (8,249)	$ (1,510)	$ 31,610

Federal income tax provisions are less than the amounts computed by applying the statutory rate of 34% in 1988, 40% in 1987 and 46% in 1986 to book income before Federal income taxes. Detail is as follows:

	Years Ended December 31,		
	1988	1987	1986
		(In thousands)	
Tax computed at statutory rate	$ 5,481	$17,399	$58,524
(Decreases) increases due to:			
Allowance for equity funds used during construction	(4,442)	(12,776)	(22,814)
Dividends received not subject to Federal income tax	(3,974)	(5,009)	(1,465)
Other	(5,314)	(1,124)	(2,635)
Total Federal income tax expense	$(8,249)	$(1,510)	$31,610
Effective Federal income tax rate	(51.17)%	(3.47)%	24.85%

At December 31, 1988, the Company's accumulated deferred income taxes reflected in the accompanying consolidated balance sheet includes accumulated deferred income tax credits of $249,024,000 and accumulated deferred income tax debits of $213,551,000.

At December 31, 1988, the Company has a consolidated tax net operating loss of $88,000,000. Management has decided to carryforward this loss which expires in the year 2003. For financial statement purposes, net deferred tax credits aggregating approximately $28,337,000 have been eliminated in 1988 based upon their expected amortization during the carryforward period. Upon realization of the tax benefits of the net operating loss carryforward in subsequent periods, the amounts eliminated from deferred tax credits will be reinstated. At December 31, 1988, the Company and its subsidiaries had approximately $1,500,000 of investment tax credit carryforward for Federal income tax purposes. This credit expires in the year 2002.

At December 31, 1988, an indirect subsidiary of the Company has a tax net operating loss carryforward of $26,800,000 and a financial net operating loss carryforward of $22,200,000. Such indirect subsidiary also has investment tax credit carryforwards of approximately $860,000. The tax net operating loss carryforwards expire as follows: $18,000,000 in the year 2000 and $8,800,000 in the year 2001 and the investment tax credit carryforwards expire between 1990 and 2000. The tax net operating losses and investment tax credit carryforwards can only be utilized to offset future taxable income of such indirect subsidiary.

At December 31, 1988, the cumulative net amount of income tax timing differences on which deferred income taxes have not been provided approximated $13,000,000.

K. Commitments and Contingencies

Construction commitments for the Company subsequent to December 31, 1988, total approximately $108,500,000, which includes AFUDC (net of related deferred tax) in the amount of $25,200,000.

The Company has a nuclear fuel purchase commitment with an independent trust which is not reflected in the Company's balance sheets. The amount of such commitment at December 31, 1988 was $24,400,000. The Company has elected and intends to continue to elect to purchase the heat produced from the fuel in the trust as the basis for payment for fuel loadings. The trust has a line of credit of

$125,000,000, of which $101,800,000 was drawn at December 31, 1988. The trust's financing is based upon a letter of credit with a three-year term which is annually extended by one year if notice to the contrary is not given to the trust by the issuing bank. The letter of credit is currently scheduled to expire on January 8, 1992.

First Service Life Litigation

Pending Actions Involving the Company. On September 26, 1988, the Company filed a declaratory judgment action in the 345th Judicial District Court, Travis County, Texas, against First Service Life Insurance Company, a life insurance company organized under the laws of the Cayman Islands ("First Service"), and R. B. Ashworth, as Conservator for the affairs of First Service under the Texas Insurance Code (the "Conservator"), for a determination that (i) the Company has legal, valid, duly perfected and enforceable security interests in certain collateral granted to the Company by First Service to secure annuities purchased by the Company from First Service, the present balance of which is approximately $20 million (the Company's original annuity investment purchased from First Service being $70 million); and (ii) that events of default have occurred under the collateral security documents pertaining to such annuities which entitle the Company to enforce such security interests. In late May 1988, the Company notified First Service that First Service was in default under the annuities and the collateral agreements and that the Company intended to enforce its security interests. The Conservator, who was appointed by the Texas Commissioner of Insurance in early June 1988, notified the Company that First Service might not be in default, expressed doubt as to the validity and enforceability of the security interests held by the Company and demanded that the Company return to the Conservator all of the collateral and desist and refrain from proceeding with enforcement of the security interests and other interference with the conservatorship and the conservatorship proceedings.

On September 29, 1988, the Conservator, in conjunction with his answer and denial of the Company's declaratory judgment action, countersued the Company on behalf of First Service and two affiliated corporations, First Service Life, a Turks and Caicos corporation ("FSL"), and Knickerbocker Life Insurance Company ("Knickerbocker"), for actual damages of at least $50 million, plus punitive damages of at least $300 million. The Conservator's counterclaim seeks (i) a temporary and permanent injunction against the Company's enforcement of its security interests in the collateral, (ii) an accounting from the Company as to all payments and transfers of property to the Company from First Service with respect to the Company's annuities, (iii) a declaratory judgment that the Company's security interests are illegal and unenforceable under the Texas Insurance Code and that the sale and purchase of the annuities was an illegal transaction under the Texas Insurance Code by a company doing insurance business in Texas without authorization and (iv) disgorgement by the Company of all payments received on its annuities and all collateral therefor. The counterclaim alleges several causes of action against the Company including principally fraud, conversion and breach of duty of good faith and fair dealing (based upon an alleged affiliate or "insider" relationship between the Company and First Service).

On December 1, 1988, a receiver (the "Receiver") was appointed for First Service by the 53rd Judicial District Court of Travis County, Texas, and on December 13, 1988, the Receiver in his capacity for First Service was substituted as a party for the Conservator in the above-described litigation. On January 18, 1989, the Receiver was appointed as receiver for FSL as well. The Conservator remains a party to the above-described litigation in its capacity as conservator for Knickerbocker.

Although only preliminary discovery has been conducted, the Company's legal counsel, Small, Craig & Werkenthin, Austin, Texas, has reviewed the basic facts of the case with management and other parties familiar with various aspects of the transactions involved in the litigation, examined

documents and records of the Company and other parties which relate to such transactions and evaluated the allegations against the Company made in the counterclaim. Based upon its preliminary evaluation and investigation of the case to date, and subject to the results of discovery, counsel believes that it is more likely than not that the outcome of the litigation will be favorable to the Company.

The Company believes that the collateral for its annuities is approximately equal in value to the present balance of annuities and that the Company's security interests in the collateral are valid and enforceable, and the Company intends to recover the amounts owed to it on the annuities through enforcement of its rights to the collateral. The Company strongly denies the allegations of the counterclaim, believes the counterclaim is without merit and intends to vigorously defend against it. The Company has made no provision for loss with respect to the annuities or for the effects, if any, of the ultimate outcome of the litigation. Effective April, 1988 the Company discontinued the accrual of interest income on the annuities.

Threatened Litigation. The Company has been notified by other parties who allegedly purchased annuities from First Service (the "Other Annuitants") that the Other Annuitants intend to institute litigation against the Company seeking damages for money allegedly lost by the Other Annuitants on their annuities. The allegations of the Other Annuitants against the Company include allegations that the Company acted in concert with principals and agents of First Service in connection with misrepresentations by such agents of First Service and that the Company exercised control over the affairs of First Service and managed First Service to serve the interest of the Company to the detriment of the interests of policyholders of First Service, including the Other Annuitants. The Other Annuitants further allege that the collateral granted by First Service to the Company for the Company's annuity investment, and the payments received by the Company on its annuities from First Service, constitute fraudulent transfers and preferences and violations of the Texas Insurance Code and the Texas Deceptive Trade Practices Act. The Other Annuitants claim damages totaling approximately \$2.4 million plus interest on their annuities and attorneys' fees. No suit against the Company has been filed by the Other Annuitants.

The Company vigorously denies any liability to the Other Annuitants and believes their claims are without merit. Based upon counsel's limited evaluation and investigation in connection with the Company's suit against the Conservator (and now the Receiver) described above, and subject to the preliminary nature of the claims made by the Other Annuitants, counsel believes that it is more likely than not that, if litigation were instituted by the Other Annuitants on the basis of the claims set forth in their notices to the Company, the ultimate outcome of such litigation would be favorable to the Company.

There are numerous parties who purchased annuities from First Service, not included within the group of the Other Annuitants, who may assert additional claims similar in nature to the claims asserted by the Other Annuitants, against the Company. These claims, if asserted, could result in additional suits against the Company.

Suit Against Directors of First Service. On February 3, 1989, the Receiver filed suit in the 345th Judicial District Court, Travis County, Texas, against certain individuals who were alleged to be directors of First Service and/or FSL, including Billye E. Bostic, President of PasoTex and formerly Executive Vice President and Chief Financial Officer of the Company.

The Receiver alleges that First Service engaged in the sale of annuities in Texas without authorization to do so and that such actions constituted illegal insurance transactions under the Texas Insurance Code. The Receiver further alleges that the alleged illegal sale of annuities by First Service constitutes a breach by the directors of First Service of their fiduciary duty to exercise due care in the

management of the affairs of First Service and/or FSL and resulted in unspecified losses to First Service. The suit seeks actual damages of at least $33 million and, in addition, exemplary damages of at least double the actual damages. Discovery has not commenced.

Mr. Bostic has advised the Company that he denies that he served as a director of First Service or FSL during the period of the alleged activities complained of, denies any liability in respect of the Receiver's suit and intends to vigorously defend against it. Mr. Bostic is represented by counsel separate from the Company's counsel in the First Service litigation. Mr. Bostic is entitled to indemnity with respect to the Receiver's suit to the extent indemnification is afforded by the Company to all of its officers and directors with respect to service on certain outside boards.

Because the Receiver's suit has only been recently filed and no discovery has commenced, counsel for Mr. Bostic is unable to express an opinion as to the ultimate outcome of the suit. No provision for loss, if any, is included in the 1988 consolidated financial statements.

Liability and Insurance Matters.

The Palo Verde participants have insurance for public liability payments resulting from nuclear energy hazards to the full $7.7 billion limit of liability under Federal law, as modified by legislation passed by Congress in August of 1988. 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 restrospective assessment program. The maximum assessment per reactor under the retrospective assessment program for each nuclear incident is approximately $66 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% ownership interest in the three Palo Verde Units, the Company's maximum potential assessment per incident is approximately $31.3 million with an annual payment limitation of $4.74 million. The insureds under this liability insurance include the Palo Verde participants and "any other person or organization with respect to his legal responsibility for damage caused by the nuclear energy hazard."

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $1.725 billion, a substantial portion of which must first be applied to decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchase of power resulting from the accidental outage of any of the three Palo Verde Units if such outage exceeds 21 weeks.

L. Pension Plan

The Company's Retirement Income Plan for Employees of El Paso Electric Company (the plan) covers employees who have completed one year of service with the Company and/or certain subsidiaries. The plan is a noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the plan are used to purchase an annuity contract with an insurance company.

Contributions from the Company and certain subsidiaries are based on the amounts required to be funded under provisions of the plan as actuarially calculated.

The assets of the plan consist primarily of insurance contracts, commercial paper and certificates of deposit, U.S. government and agency obligations, corporate equity securities and corporate obligations.

Net periodic pension cost under SFAS No. 87 — Employers Accounting for Pensions is made up of the components listed below as determined using the projected unit credit actuarial cost method. For

prior years, the Company's net periodic pension cost was determined using the aggregate actuarial cost method.

Net periodic pension cost for 1988 and 1987 (in thousands):

	December 31, 1988	December 31, 1987
Service cost for benefits earned during the period	$ 1,035	$ 1,296
Interest cost on projected benefit obligation	2,812	2,815
Actual return on plan assets	(1,597)	(208)
Net amortization and deferral	(416)	(1,691)
Net periodic pension cost	$ 1,834	$ 2,212

The assumed annual discount rates used in determining the net periodic pension cost were 8.75% for 1988 and 8% for 1987.

The funded status of the plan and amount recognized in the Company's balance sheets at December 31, 1988 and 1987 are presented below (in thousands):

	December 31, 1988	December 31, 1987
Actuarial present value of benefit obligations:		
Vested benefit obligation	$(25,437)	$(27,456)
Accumulated benefit obligation	$(27,184)	$(28,687)
Projected benefit obligation	$(37,653)	$(34,689)
Plan assets at fair value	32,145	28,630
Projected benefit obligation in excess of plan assets	(5,508)	(6,059)
Unrecognized net loss from past experience	51	42
Unrecognized transition obligation	5,415	5,832
Accrued pension liability	$ (42)	$ (185)

The assumed discount rate and rate of increase in compensation levels used in determining the actuarial present value of projected benefit obligation were 8.25% for 1988 and 8.75% for 1987 and 7% for 1988 and 1987, respectively. The expected long-term rate of return on plan assets was 8% for 1988 and 1987.

The pension costs in 1988, 1987 and 1986 were $1,834,000, $2,212,000 and $2,605,000, respectively, which includes amortization of unrecognized transition obligations over a fifteen-year period beginning in 1987.

M. Selected Quarterly Financial Data (Unaudited)

	1988 Quarters				1987 Quarters (1)			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
	(In thousands of dollars except for per share data)							
Operating revenues:								
Utility (2)	$89,539	$92,067	$107,913	$ 92,588	$78,400	$81,756	$95,454	$81,653
Non-utility (6)	61,548	63,312	68,431	63,326	10,617	12,861	33,224	49,017
Net income (loss)	16,997	18,473	21,191	(32,292) (3)	24,610	20,762	5,041 (4)	(5,405) (5)
Net income (loss) applicable to common stock	13,923	15,398	18,117	(35,328)	21,321	17,472	1,814	(8,491)
Net income (loss) per share of common stock	.40	.44	.52	(1.01)	.60	.49	.05	(.23)

(1) The selected quarterly financial data for operating revenues differs from that presented in the Company's quarterly reports on Form 10-Q due to the decision of the Company, beginning in the fourth quarter of 1987, to segregate such item as to utility and non-utility. Prior to the fourth quarter of 1987, such amounts were not material and were condensed into other income (deductions). Net income (loss) for each of the quarters has not been affected by such change.

(2) The selected quarterly financial data for utility operating revenues differs from that presented in the Company's quarterly reports on Form 10-Q due to the reclassification of phase-in plan — accrued revenue from utility operating revenues to operating expenses and other income (deductions) beginning in the fourth quarter of 1988. Net income (loss) for each of the quarters has not been affected by such change.

(3) The decline in net income during the fourth quarter of 1988 as compared to the third quarter of 1988 was primarily due to the Company's decision to discontinue all of the real estate operations of its real estate investment subsidiary. The Company has made provisions for the expected losses on the sale of the real estate investment, including provisions for expected operating losses during the phase-out period of those investments. See Note N of Notes to Consolidated Financial Statements.

(4) The decline in net income during the third quarter of 1987 as compared to the second quarter of 1987 was due primarily to the Company's provision for estimated regulatory disallowance of plant costs. See Note C of Notes to Consolidated Financial Statements.

(5) The decline in net income during the fourth quarter of 1987 as compared to the third quarter of 1987 was due primarily to the realized and unrealized security losses.

(6) The selected quarterly financial data for non-utility operating revenues differs from that presented in the Company's quarterly reports on Form 10-Q due to the reclassification of losses from discontinued real estate operations. Net income (loss) for each of the quarters has not been affected by such change. See Note N of Notes to Consolidated Financial Statements.

N. Segment Information, Discontinued Operations and Significant Customer

Segment Information

The Company's primary business segment is its utility operations. Through its subsidiaries, Franklin Land & Resources, Inc. ("FL&R") and PasoTex Corporation ("PasoTex"), the Company has invested approximately $45.6 million in business activities which have been grouped into the following continuing segments: (1) oil country tubular goods marketing and end finishing, (2) specialty steel

products manufacturing, (3) furniture and accessories manufacturing and (4) other. The Company entered into the oil country tubular goods, specialty steel products and furniture and accessories segments by acquisitions of complete or controlling interests in various companies through PasoTex. These acquisitions occurred during 1987 and were recorded using the purchase method of accounting. The pro forma effects on 1987 operations, as if the acquisitions had taken place at the beginning of 1987, are not material. Prior to 1987, the Company had no material segments other than utility operations.

The Company has also, through PasoTex and FL&R, invested in (i) preferred stocks, including $47.5 million in preferred stock of two savings and loan associations, (ii) a $31 million participation in a note payable, and (iii) partnerships for the leasing of assets to third parties. Additionally, through FL&R, the Company has certain real estate operations, including a hotel and an office and parking building, which it has decided to discontinue.

The financial information pertaining to the Company's continuing business segments for the year ended December 31, 1988 is as follows (in thousands):

		Non-utility				
	Utility	Oil Country Tubular Goods	Specialty Steel Products	Furniture and Accessories	Other	Total
Operating revenues	$ 382,107	$108,266	$94,848	$46,959	$ 6,544	$ 638,724
Operating income (loss) before income taxes	91,082	6,100	4,588	(3,931)	3,528	101,367
Depreciation and amortization	34,254	611	1,548	929	473	37,815
Interest expense	73,654	248	2,284	1,304	3,396	80,886
Capital expenditures	91,102	1,012	3,114	5,777	365	101,370
Identifiable assets:						
Net utility plant	$1,260,843	$ —	$ —	$ —	$ —	$1,260,843
Net non-utility property, plant and equipment	4,552	11,153	17,193	8,422	7,480	48,800
Assets held for sale	—	—	—	—	17,317	17,317
Other	457,783	39,655	35,819	29,677	85,265	648,199
	$1,723,178	$ 50,808	$53,012	$38,099	$110,062	$1,975,159

The financial information pertaining to the Company's business segments for the year ended December 31, 1987 is as follows (in thousands):

		Non-utility				
	Utility	Oil Country Tubular Goods	Specialty Steel Products	Furniture and Accessories	Other	Total
Operating revenues	$ 337,263	$64,623	$29,591	$10,985	$ 520	$ 442,982
Operating income (loss) before income taxes	108,554	3,527	819	625	(2,262)	111,263
Depreciation and amortization	21,162	488	731	232	136	22,749
Interest expense	90,616	145	835	85	2,805	94,486
Capital expenditures	88,627	751	550	1,082	5,916	96,926
Identifiable assets:						
Net utility plant	$1,215,258	$ —	$ —	$ —	$ —	$1,215,258
Net non-utility property, plant and equipment	82	11,777	15,686	6,810	69,998	104,353
Other	749,223	32,494	26,320	23,631	124,294	955,962
	$1,964,563	$44,271	$42,006	$30,441	$194,292	$2,275,573

Discontinued Operations

The Company has adopted a formal plan to discontinue the real estate operations of Franklin Land & Resources, Inc. The estimated loss from the sale of $35,954,000 net of income taxes of $18,522,000, was recorded as of December 31, 1988. This loss included $11,520,000 in estimated operating losses during the phase-out period.

The consolidated balance sheet as of December 31, 1988 includes the following related to the discontinued operations (in thousands):

Assets held for sale	$ 17,317
Notes payable(1)	(27,060)
Allowance for loss on discontinued operations	(11,520)
Accumulated deferred income taxes	6,110
Accumulated deferred investment tax credit	(2,742)
Net Liabilities	$(17,895)

(1) Amounts are net of participation agreements of approximately $31,000,000.

Operating results of discontinued operations have been reclassified from amounts previously reported and have been reported separately in the consolidated income statements. Revenues of discontinued operations were $10,438,000, $9,608,000 and $3,302,000 in 1988, 1987 and 1986, respectively.

Significant Customer

In 1988 and 1987, Imperial Irrigation District, a wholesale customer, accounted for approximately $43,395,000 and $36,227,000, or 11.4% and 10.7%, respectively, of utility operating revenue.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information regarding directors is incorporated herein by reference from the 1989 Proxy Statement. Information regarding executive officers of the Company, under the caption "Executive Officers of the Registrant" in Part I, Item 1 above, is incorporated herein by reference.

Item 11. Executive Compensation

Incorporated herein by reference from the 1989 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Incorporated herein by reference from the 1989 Proxy Statement.

Item 13. Certain Relationships and Related Transactions

Incorporated herein by reference from the 1989 Proxy Statement.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

The information required by this Item has been omitted from this Annual Report to Shareholders.

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1988 — Commission File Number 1-6986

Public Service Company of New Mexico

(Exact name of registrant as specified in its charter)

New Mexico (State or other jurisdiction of incorporation or organization)	85-0019030 (I.R.S. Employer Identification No.)
Alvarado Square Albuquerque, New Mexico (Address of principal executive offices)	87158 (Zip Code)

Registrant's telephone number, including area code: (505) 848-2700

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

Title of each class	Name of each exchange on which registered
Common Stock, $5.00 Par Value	New York Stock Exchange

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

Title of Class

Cumulative Preferred Stock ($100 stated value and without sinking fund) comprised of the following series:

1965 Series, 4.58% — 8.48% Series — 8.80% Series

8.75% Cumulative Preferred Stock ($100 stated value and with a periodic sinking fund)

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 and (2) has been subject to such filing requirements for the past 90 days. YES __X__ NO _____

The total number of shares of the Company's Common Stock outstanding as of March 27, 1989 was 41,774,083. On such date, the aggregate market value of the voting stock held by non-affiliates of the Company, as computed by reference to the New York Stock Exchange composite transaction closing price of $11⅜ per share reported by the Wall Street Journal, was $473,794,394.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following document are incorporated by reference into the indicated part of this report:

Proxy Statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A relating to the annual meeting of stockholders to be held on May 16, 1989—PART III.

TABLE OF CONTENTS

GLOSSARY

AFUDC	Allowance for funds used during construction
APS	Arizona Public Service Company
BTU	British Thermal Unit
decatherm	1,000,000 BTUs
DOE	United States Department of Energy
EIP	Eastern Interconnection Project
El Paso	El Paso Electric Company
EPA	United States Environmental Protection Agency
EPNG	El Paso Natural Gas Company
Exploration Company	Southern Union Exploration Company, a subsidiary of Southern Union
FERC	Federal Energy Regulatory Commission
Gathering Company	Sunterra Gas Gathering Company, a wholly-owned subsidiary of Sunbelt
GCNM	Gas Company of New Mexico, a division of the Company
G.O. No. 49	NMPSC General Order Number 49, Cost Overrun Rule (recodified as NMPSC Rule No. 580)
KWh	Kilowatt hour
Los Alamos	The County of Los Alamos, New Mexico
mcf	Thousand cubic feet
Meadows	Meadows Resources, Inc., a wholly-owned subsidiary of the Company
Meridian	Meridian Oil Company
M-S-R	M-S-R Public Power Agency, a California public power agency
MW	Megawatt
MWh	Megawatt hour
NMEIB	New Mexico Environmental Improvement Board
NMPSC	New Mexico Public Service Commission
NRC	United States Nuclear Regulatory Commission
Paragon	Paragon Resources, Inc., a wholly-owned subsidiary of the Company
Processing Company	Sunterra Gas Processing Company, a wholly-owned subsidiary of Transwestern
PVNGS	Palo Verde Nuclear Generating Station
Salt River Project	Salt River Project Agricultural Improvement and Power District
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SFAS No. 92	Statement of Financial Accounting Standards No. 92, *Regulated Enterprises—Accounting for Phase-in Plans*
SJCC	San Juan Coal Company
SJGS	San Juan Generating Station
Southern Union	Southern Union Company
Southland	Southland Royalty Company
SPS	Southwestern Public Service Company
Sunbelt	Sunbelt Mining Company, Inc., a wholly-owned subsidiary of the Company
throughput	Volumes of gas distributed or transported by GCNM
Transwestern	Transwestern Mining Company, a wholly-owned subsidiary of Sunbelt
Tucson	Tucson Electric Power Company
uncommitted capacity	Capacity in excess of that included (or to be included) in New Mexico jurisdictional rate base or otherwise required to serve firm system load
Unicon	Unicon Producing Company, a partnership consisting of Union Texas Exploration Company, Exploration Finance Company and S.N.P.I., Inc.
Utah	BHP-Utah International, Inc.
Western	Western Coal Co.

PART I

ITEM 1. BUSINESS

THE COMPANY

Public Service Company of New Mexico was incorporated in the State of New Mexico in 1917 and has its principal offices at Alvarado Square, Albuquerque, New Mexico 87158 (telephone number 505-848-2700). The Company is a public utility engaged principally in the generation, transmission, distribution and sale of electricity (see "ELECTRIC OPERATIONS") and in the gathering, transmission, distribution and sale of natural gas (see "NATURAL GAS OPERATIONS") within the State of New Mexico. The Company also owns facilities for the pumping, storage, transmission, distribution and sale of water in Santa Fe, New Mexico. Subsidiaries of the Company have been engaged in a program of diversification into non-utility areas. In 1988, however, the Company decided to discontinue the non-utility operations of its subsidiaries and to dispose of non-utility properties. (See "NON-UTILITY SUBSIDIARY OPERATIONS".)

The total population of the area served by one or more of the Company's utility services is estimated to be approximately one million, of which 52% live in the greater Albuquerque area.

For the fiscal year ended December 31, 1988, the Company derived 72.1% of its utility operating revenues from electric operations, 26.6% from natural gas operations and 1.3% from water operations.

As of December 31, 1988, the Company employed 3,093 persons.

Financial information relating to amounts of revenue and operating income and identifiable assets attributable to the Company's industry segments is contained in note 13 of the notes to consolidated financial statements.

ELECTRIC OPERATIONS

Service Area and Customers

The Company's electric operations serve four principal markets. Sales to retail customers and sales to firm-requirements wholesale customers, sometimes referred to collectively as "system" sales, comprise two of these markets. The third market consists of other contracted sales to utilities for which the Company commits to deliver a specified amount of capacity (measured in MW) or energy (measured in MWh) over a given period of time. The fourth market consists of economy interchange sales made on an hourly basis to utilities at fluctuating, spot-market rates. Sales to the third and fourth markets are sometimes referred to collectively as "off-system" sales. The Company's success in marketing its uncommitted capacity largely depends on its ability to compete, primarily on the basis of cost and deliverability, in the off-system markets.

The Company provides retail electric service to a large area of north central New Mexico, including the cities of Albuquerque, Santa Fe, Rio Rancho, Las Vegas, Belen and Bernalillo. The Company also provides retail electric service to Deming in southwestern New Mexico and to Clayton in northeastern New Mexico. As of December 31, 1988, approximately 282,000 retail electric customers were served by the Company, none of which accounted for more than 4% of the Company's total electric revenues for the year ended December 31, 1988.

The Company holds long-term, non-exclusive franchises of varying durations for electric service in all incorporated communities where it is necessary to do so in order to carry on its electric utility business as it is now being conducted. The Company's electric franchise in Albuquerque expires in early 1992. In addition to discussing a franchise renewal with the Company, the City of Albuquerque is studying other alternatives, including municipalization of the system and alternative suppliers to the franchise area after expiration of the Company's current franchise. The Company will pursue with the City the renewal of the franchise prior to its expiration. The expiration date for the Company's electric franchise in Santa Fe is 1999.

In 1988, the Company furnished firm-requirements wholesale power in New Mexico to the cities of Farmington and Gallup, Texas-New Mexico Power Company and Plains Electric Generation & Transmission Cooperative, Inc. No firm-requirements wholesale customer accounted for more than 3% of the Company's total electric revenues for the year ended December 31, 1988.

Major off-system sales contracts in effect during 1988 were those with SDG&E and SPS, discussed below.

In 1979, the Company and SDG&E executed a power sales agreement providing for sales of capacity and energy to SDG&E at various levels, dependent on the commencement of firm operation of the three PVNGS units. (See "Sources of Power—Nuclear Plant—*The Company's Interest in PVNGS*".) The Company has sold capacity under the agreement at varying levels ranging from zero to 236 MW from May 1982 through April 1988. Energy sales under the agreement accounted for approximately 2.6% of the Company's total MWh sales in 1988. In November 1985, the Company and SDG&E executed an additional agreement providing for SDG&E to purchase 100 MW from the Company for the period May 1988 through April 2001. (See "RATES AND REGULATION—SDG&E Sales Agreement".) Energy sales under this agreement, which commenced in June 1988, accounted for 3.3% of the Company's total MWh sales in 1988.

The Company and SPS entered into an agreement in 1982 to provide for a transmission interconnection between the two utilities, facilitated by EIP. (See ITEM 2—"PROPERTIES".) The interconnection agreement requires the purchase by SPS of energy at a rate of 200 MW per hour from 1985 through 1989. Sales under the SPS agreement accounted for approximately 18.5% of the Company's total MWh sales in 1988. The agreement further requires the Company to purchase from SPS up to 100 MW of interruptible power from 1991 to 1995 and up to 200 MW of interruptible power from 1995 through 2011. The Company may reduce its purchases under the contract by 25 MW annually beginning in 1994 and upon three-years notice.

Power Sales

For the years 1983 through 1988, retail KWh sales have grown at a compound annual rate of 4.6%. In 1988 retail sales grew at an annual rate of 5.3%. However, retail sales have been lower than had been anticipated at the time the Company committed to construct new generating units and sales of firm-requirements wholesale power have declined in recent years. This has increased the importance to the Company of off-system sales. The Company's system and off-system sales and system peak demands in summer and winter are shown in the following tables:

ELECTRIC SALES BY MARKET
(Thousands of dollars)

	1988	1987	1986	1985	1984
Retail	$404,863	$387,542	$363,748	$339,367	$304,316
Firm-requirements wholesale	27,554	32,312	34,431	40,786	92,174
SPS contract	100,006	91,064	72,090	70,550	—
Other contracted sales	62,525	44,351	42,704	35,833	61,766
Economy interchange*	6,903	4,642	6,369	3,922	458

* Economy interchange sales are net of economy purchases and are accounted for as a reduction of fuel and purchased power expense.

ELECTRIC SALES BY MARKET
(Megawatt hours)

	1988	1987	1986	1985	1984
Retail	4,684,588	4,447,798	4,233,296	4,079,842	3,932,803
Firm-requirements wholesale	362,934	396,297	471,676	721,809	1,596,010
SPS contract	1,577,950	1,585,639	1,482,189	1,609,518	—
Other contracted sales	1,567,712	508,990	540,369	1,025,893	1,673,641
Economy interchange*	356,681	226,941	349,689	318,015	146,301

* Net of economy purchases.

SYSTEM PEAK DEMAND*
(Megawatts)

	1988	1987	1986	1985	1984
Summer	956	916	916	861	976
Winter†	862	880	838	814	919

* System peak demand relates to retail and firm-requirements wholesale markets only.

† For the winter season beginning in the year noted.

For discussion of the competitive conditions affecting off-system sales, see Part II, ITEM 7—"MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—CURRENT ISSUES FACING THE COMPANY—The Wholesale Power Market".

Sources of Power

The total net generation capacity of facilities owned or leased by the Company was 1,591 MW as of December 31, 1988, comprised of generation from a nuclear plant, located in Arizona, and from two coal-fired plants and two gas/oil-fired plants, located in New Mexico. (See ITEM 2—"PROPERTIES".) This amount includes capacity committed under sales contracts with other utilities (see "Service Area and Customers"), but does not include capacity purchases, totalling 109 MW, from other participants in SJGS Unit 4. The Company has also entered into an agreement to purchase power from SPS beginning in 1991. (See "Service Area and Customers".) The two gas/oil-fired plants are located in the Company's service area, with one in Las Vegas and one in Albuquerque, and are used for peaking capacity and transmission support requirements. In addition, the Company is interconnected with various utilities making possible economy interchanges and mutual assistance in emergencies.

Coal-fired Plants

SJGS is located in northwestern New Mexico, and consists of four units. Units 1, 2, 3 and 4 at SJGS have net rated capacities of 316 MW, 312 MW, 488 MW and 498 MW, respectively. SJGS Units 1 and 2 are owned on a 50% shared basis with Tucson, Unit 3 is owned on a 50% shared basis with Alamito Company and Unit 4 is owned 55.525% by the Company, 8.475% by the City of Farmington, 28.8% by M-S-R and 7.2% by Los Alamos. The Company's aggregate ownership in SJGS is 835 MW. In connection with the Company's sale to M-S-R in December 1983 of a 28.8% interest in SJGS Unit 4, the Company agreed to purchase under certain conditions 73.53% (105 MW) of M-S-R's capacity through April 30, 1995, an amount which may be reduced by M-S-R under certain conditions. The Company also agreed to market the energy associated with the remaining 26.47% portion of M-S-R's capacity through April 30, 1995 in return for half the profits from such sales. This marketing arrangement may be terminated by M-S-R at any time upon 30 days notice. In connection with the Company's sale to Los Alamos in July 1985 of a 7.2% interest in SJGS Unit 4, the Company agreed to purchase capacity and associated energy of up to 4 MW from January 1, 1988 through December 31, 1990.

The Company also owns 192 MW of net rated capacity derived from its 13% interest in Units 4 and 5 of the Four Corners plant located in northwestern New Mexico on land leased from the Navajo Nation and adjacent to available coal deposits. Units 4 and 5 at the Four Corners plant are jointly owned with SCE, APS, Salt River Project, Tucson and El Paso and are operated by APS.

Since 1972, the Company has pursued studies, environmental assessments and resource acquisitions for a joint project to build a coal-fired generating station in northwestern New Mexico. Originally designated the New Mexico Generating Station, the plant was intended to serve jurisdictional customers, but as the Company saw its emerging surplus capacity, the scope was changed and it was pursued as an independent power producer project, known as the Dineh Power Project, in a joint venture with General Electric, Combustion Engineering, Bechtel and the Navajo Nation. The markets for such a project have not developed as had been anticipated and it can not be determined when or if the proposed station will be constructed. While such construction is still possible, the Company does not consider the recovery of the investment it has made to date to be probable. Accordingly, a provision has been made in the accompanying consolidated statement of earnings (loss) to write off the Company's investment in the proposed generating station.

Nuclear Plant

The Company's Interest in PVNGS. The Company is participating in the three 1,270 MW units of PVNGS, also known as the Arizona Nuclear Power Project, with APS (the operating agent), Salt River Project, El Paso, SCE, Southern California Public Power Authority and The Department of Water and Power of the City of Los Angeles. The Company has a 10.2% interest in PVNGS, with its interest in Units 1 and 2 held under lease. The Company's ownership and leasehold interests in PVNGS amount to 130 MW per unit, or a total of 390 MW. PVNGS Units 1, 2 and 3 were declared in commercial service by the Company in January 1986, September 1986 and January 1988, respectively. Commercial operation of each of the three PVNGS units requires a full power operating license from the NRC. The NRC granted a full power operating license for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987. Tests are performed at the units to maintain the licenses.

In eleven transactions consummated in 1985 and 1986, the Company sold and leased back its entire 10.2% interest in PVNGS Units 1 and 2, together with portions of the Company's undivided interest in certain PVNGS common facilities. In each transaction, the Company sold interests to an owner trustee under an owner trust agreement with an institutional equity investor. The owner trustees, as lessors, leased the interests to the Company under lease agreements having initial terms expiring January 15, 2015 (with respect to the Unit 1 leases) or January 15, 2016 (with respect to the Unit 2 leases). Each lease provides an option to the Company to extend the term of the lease as well as a repurchase option. The aggregate lease payments for the Company's PVNGS leases are approximately $84.6 million per year. Throughout the terms of the leases, the Company continues to have full and exclusive authority and responsibility to exercise and perform all of the rights and duties of a participant in PVNGS under the Arizona Nuclear Power Project Participation Agreement and retains the exclusive right to sell and dispose of its 10.2% share of the power and energy generated by PVNGS Units 1 and 2. The Company also retains responsibility for payment of its share of all taxes, insurance premiums, operating and maintenance costs, costs related to capital improvements and decommissioning and all other similar costs and expenses associated with the leased facilities. The PVNGS leases are operating leases as defined by generally accepted accounting principles.

On several occasions, including during 1988, the NRC has proposed and assessed civil penalties for various violations at PVNGS that have been categorized as problems of Severity Level III or lesser severity (on a scale of I to V in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions"). In addition, the NRC is currently evaluating possible enforcement action relating to alleged violations of NRC regulations in connection with a reactor start-up of PVNGS Unit 1 in May 1988.

PVNGS Units 1 and 3 experienced unscheduled outages on March 5, 1989 and March 3, 1989, respectively. Following these outages, PVNGS Unit 2 was removed from service for testing. The NRC is reviewing the events that took place during the Unit 1 and Unit 3 outages and is requiring APS to complete certain actions and to obtain NRC approval prior to restarting the three units. APS has indicated that the timing of the restart is subject to contingencies beyond its control, but that the actions required for Unit 2 may be completed in April 1989, at which time APS will request NRC approval to restart the unit. Units 1 and 3 are currently refueling.

Decommissioning Funding. The Company has a program for funding its share of decommissioning costs for PVNGS. Under this program, the Company will make a series of annual deposits to an external trust fund over the estimated useful life of each unit, and the trust funds will be invested under a plan which allows the accumulation of funds largely on a tax-deferred basis. The Company began funding its share of decommissioning costs for PVNGS Units 1 and 2 in 1987 and Unit 3 in 1988. The annual trust deposit, currently set at $396,000 per unit, is based upon the Company's 10.2% share of total estimated PVNGS decommissioning costs and projected earnings on the trust funds over time. The annual funding amount is subject to periodic adjustment for changes in decommissioning cost estimates and earnings of the trust fund. The Company's share of Unit 1, Unit 2 and Unit 3 decommissioning costs has been estimated, in 1986 dollars, to be approximately $21 million, $20 million and $22 million, respectively.

PVNGS Liability and Insurance Matters. The PVNGS participants have insurance for public liability payments resulting from nuclear energy hazards to the current $7.7 billion limit of liability under Federal law modified by legislation enacted in August 1988. 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. The maximum assessment per reactor under the retrospective rating program for each nuclear incident is approximately $66 million, subject to an annual limit of $10 million per incident. Based upon the Company's 10.2% ownership interest in the three PVNGS units, the Company's maximum potential assessment per incident is approximately $20 million, with an annual payment limitation of $3 million. The insureds under this liability insurance include the PVNGS participants and "any other person or organization with respect to his legal responsibility for damage caused by the nuclear energy hazard."

The PVNGS participants maintain "all-risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at PVNGS in the aggregate amount of $1.725 billion as of March 1, 1989, a substantial portion of which must first be applied to decontamination. The Company has also secured insurance against a portion of the increased cost of generation or purchased power resulting from the accidental outage of any of the PVNGS units.

Fuel and Water Supply

The percentages of the Company's generation of electricity (on the basis of KWh) fueled by coal, nuclear fuel and gas and oil, and the average costs to the Company of those fuels (in cents per million BTU), during the past five years were as follows:

	Coal		Nuclear		Gas and Oil	
	Percent of Generation	Average Cost	Percent of Generation	Average Cost	Percent of Generation	Average Cost
1984	99.7	108.7	—	—	0.3	342.6
1985	98.4	116.8	—	—	1.6	408.1
1986	85.6	121.3	13.2	76.0	1.2	216.6
1987	79.7	141.1	20.0	73.3	0.3	246.6
1988	70.0	142.5	29.6	75.9	0.4	320.9

Although not included in the above table, start-up and test energy was available from PVNGS in 1985, 1986 and 1987.

The estimated generation mix for 1989 is 75.9% coal, 23.4% nuclear and 0.7% gas and oil. Due to locally available natural gas and oil supplies, the utilization of locally available coal deposits and the generally abundant supply of nuclear fuel, the Company believes that adequate sources of fuel are available for its generating stations.

Coal

The coal requirements for SJGS are being supplied by SJCC, a wholly-owned subsidiary of Utah, from certain Federal, state and private coal leases under a coal sales agreement, pursuant to which SJCC will supply processed coal for operation of SJGS until 2017. Utah has guaranteed the obligations of SJCC under the agreement, which contemplates the delivery of approximately 157 million tons of coal during its remaining term. Such amount would supply the requirements of SJGS through approximately 2017. The primary sources of coal are a mine adjacent to SJGS and a mine located approximately 25 miles northeast of SJGS in the La Plata area of northwestern New Mexico. The average cost of fuel, including ash disposal and land reclamation costs, for SJGS for the years 1986, 1987 and 1988 was 126.0 cents, 151.9 cents and 153.9 cents, respectively, per million BTU ($24.61, $29.48 and $30.04 per ton, respectively).

The Four Corners plant is supplied with coal under a fuel agreement between the owners and Utah, under which Utah has agreed to supply all the coal requirements for the life of the plant. Utah holds a long-term coal mining lease, with options for renewal, from the Navajo Nation and operates a strip mine adjacent to the Four Corners plant with the coal supply expected to be sufficient to supply the units for their estimated useful lives. The fuel agreement provides for certain adjustments in coal prices due to increases or decreases in the cost of electricity, environmental compliance (including mine reclamation), labor, materials, supplies, taxes and royalties. The average cost of fuel for the years 1986, 1987 and 1988 at the Four Corners plant was

99.1 cents, 103.3 cents and 101.4 cents, respectively, per million BTU ($17.50, $18.21 and $17.70 per ton, respectively) including ash disposal and land reclamation costs.

Natural Gas

The natural gas used as fuel for the Company's Albuquerque electric generating plant is delivered by GCNM. (See "NATURAL GAS OPERATIONS".) In addition to rate changes under filed tariffs, the Company's cost of gas increases or decreases according to the average cost of gas supplied by GCNM or other sources.

Nuclear Fuel

The fuel cycle for PVNGS is comprised of the following elements: (1) the mining and milling of uranium ore to produce uranium concentrates; (2) the conversion of uranium concentrates to uranium hexafluoride; (3) the enrichment of uranium hexafluoride; (4) the fabrication of fuel assemblies; (5) the utilization of fuel assemblies in reactors; and (6) the storage of spent fuel and the disposal or (if future circumstances permit) the reprocessing thereof. The participants in PVNGS have obtained quantities of uranium concentrate anticipated to be sufficient, if certain contract options are exercised, to meet operational requirements through 1997. Spot purchases will be made as appropriate in lieu of any uranium which might be obtained pursuant to the contract options. The participants have also contracted for a substantial portion of conversion services required through 1992. A contract has been entered into with DOE for enrichment services required for the operation of the three PVNGS units over a term expiring in November 2014. The validity of the form of the contract used by DOE in its negotiations with utilities had been challenged in the United States District Court for the District of Colorado. However, in February 1989, the court dismissed the case without prejudice. Existing contracts will provide fuel assembly fabrication services for each of the PVNGS units for at least the first ten years of operation and, if options are exercised, for approximately twelve additional years of operation.

PVNGS is designed to permit on-site storage of spent fuel discharged from normal operation of all three PVNGS units through at least the year 2003. In July 1984, APS, on its own behalf and on behalf of the other participants, executed a spent fuel disposal contract with DOE. The Nuclear Waste Policy Act of 1982 imposes the responsibility for the disposal of spent nuclear fuel and other high-level radioactive wastes upon the Federal government and directs the Secretary of the DOE to undertake a program for the development of a permanent waste disposal facility for the receipt and disposal of spent nuclear fuel and to have the first such facility in operation by 1998 under prescribed procedures. In December 1987, Congress passed the Nuclear Waste Policy Amendments Act of 1987, substantially changing the act by, among other things, decreasing to one the number of sites to be initially considered for permanent disposal facilities. In June 1988, DOE reported that such permanent disposal facilities will not be in operation until 2003 and, under DOE's current criteria for shipping allocation rights, PVNGS is scheduled to begin spent fuel shipment to the DOE permanent disposal facilities in 2010. The Company believes that alternative interim spent fuel storage facilities will be available for use by PVNGS until DOE's scheduled shipments from PVNGS begin.

Water

Water for the Four Corners plant and SJGS is obtained from the San Juan River. (See ITEM 3—"LEGAL PROCEEDINGS—SAN JUAN RIVER ADJUDICATION".) Utah holds rights to San Juan River water and has committed a portion of such rights to the Four Corners plant. The Company and Tucson have a contract with the United States Bureau of Reclamation for consumption of 16,200 acre feet of water per year for SJGS, which contract expires in 2005, and in addition have been granted the authority to consume 8,000 acre feet per year of water under a state permit that is held by Utah. The Company is of the opinion that sufficient water has been secured for SJGS until 2005.

Sewage effluent used for cooling purposes in the operation of the PVNGS units has been obtained under contracts with certain municipalities in the area. The contracted quantity of effluent exceeds the amount required for the three PVNGS units. The validity of these effluent contracts is the subject of litigation in state and Federal courts. (See ITEM 3—"LEGAL PROCEEDINGS—PVNGS WATER SUPPLY LITIGATION".) APS has stated that, although the litigation remains subject to further evaluation, it expects that the litigation will not have a materially adverse impact on the operation of PVNGS.

Acquisition of Natural Gas Properties

On January 28, 1985, the Company acquired substantially all of the New Mexico natural gas utility assets of Southern Union (principally a natural gas retail distribution system operated by Southern Union as the Gas Company of New Mexico division and now operated by the Company as GCNM) and Sunbelt acquired all of the stock of Southern Union Gathering Company (subsequently renamed Sunterra Gas Gathering Company), a wholly-owned subsidiary of Southern Union (such assets and stock being hereinafter collectively referred to as the "1985 acquisition properties"), in connection with the settlement of antitrust litigation against Southern Union in which the Company and others were plaintiffs.

In a separate transaction, Transwestern, a wholly-owned subsidiary of Sunbelt, acquired from Southern Union all of the stock of Southern Union Processing Company (subsequently renamed Sunterra Gas Processing Company) on December 31, 1986.

Gas Company of New Mexico Division

The Company distributes natural gas through GCNM to most of the major communities in New Mexico, including Albuquerque and Santa Fe, and served approximately 336,000 customers as of December 31, 1988. GCNM's customers include "sales-service" customers and "transportation-service" customers. Sales-service customers purchase natural gas and receive transportation and delivery services from GCNM for which GCNM receives both cost-of-gas and cost-of-service revenues. Cost-of-gas revenues are a recovery of the cost of purchased gas in accordance with NMPSC rules and regulations and do not contribute to the net earnings of the Company. Transportation-service customers, who procure gas independently but contract with GCNM for transportation and related services, provide GCNM with cost-of-service revenues.

GCNM is organized along geographic lines into three operating regions (central, eastern and western) and one pipeline district. The central region, comprised primarily of Albuquerque, accounts for approximately 54% of GCNM's total customers. The Company holds long-term, non-exclusive franchises with varying expiration dates in all incorporated communities where it is necessary to do so in order to carry on its gas utility business as it is now being conducted. The expiration dates for the Company's franchises in Albuquerque and Santa Fe are 1998 and 1995, respectively.

For the twelve months ended December 31, 1988, GCNM had throughput of approximately 58.2 million decatherms, including sales of 49.1 million decatherms to sales-service customers. No single customer accounted for more than 3% of GCNM's therm sales in 1988. The following table shows GCNM's gas throughput in 1988, 1987 and 1986 by customer class:

GAS THROUGHPUT
(Millions of decatherms)

	1988	1987	1986
Residential	24.7	24.5	22.1
Commercial	11.5	11.4	10.8
Industrial	1.7	2.2	5.9
Public authorities	6.2	6.8	8.3
Irrigation	1.4	1.4	1.9
Resale	2.7	1.2	1.5
Brokerage	0.9	2.8	2.1
Transportation*	9.1	5.1	2.2
	58.2	55.4	54.8

* Customer-owned gas.

GCNM's total operating revenues for the year ended December 31, 1988, were approximately $223.8 million. Cost-of-gas revenues, received from sales-service customers, accounted for approximately 55% of GCNM's total operating revenues. The following table shows by customer class GCNM's revenues in 1988, 1987 and 1986:

GAS REVENUES
(Thousands of dollars)

	1988	1987	1986
Residential	$122,592	$114,164	$117,011
Commercial	45,235	42,120	45,812
Industrial	6,063	8,102	23,139
Public authorities	22,289	22,729	30,213
Irrigation	4,546	3,781	6,142
Resale	6,969	3,819	5,675
Brokerage	1,514	5,213	3,759
Transportation*	4,841	4,315	2,207
Other	9,742	6,391	10,708
	$223,791	$210,634	$244,666

* Customer-owned gas.

Since a major portion of GCNM's load is related to heating, levels of therm sales are affected by the weather. Approximately 48% of GCNM's total therm sales in 1988 occurred in the months of January, February and December.

FERC and NMPSC orders relating to the nondiscriminatory transportation of gas in certain instances, as well as other changes in the natural gas industry, have led to increased competition for sales of natural gas within New Mexico. An order issued by the NMPSC requires New Mexico gas utilities to offer transportation service to all customers on an available capacity basis. Thus, GCNM's customers may choose to purchase natural gas from sources other than GCNM and require transportation by GCNM, subject to the capacity of GCNM's system. Approximately 16% of GCNM's deliveries in 1988 were of gas owned by transportation-service customers. Transportation-service customers pay GCNM according to the services they receive. The Company currently anticipates that customer changes from sales service to transportation service would not materially adversely affect the Company's earnings. However, a reduction in GCNM's sales-service load may increase GCNM's cost of gas and potential take-or-pay exposure.

A significant portion of GCNM's natural gas requirements is provided through Gathering Company. (See "Gathering Company".) GCNM and Gathering Company have entered into long-term contracts for gas supplies generally sufficient to meet GCNM's peak-day demand. However, these long-term contracts, most of which predate the Company's acquisition of GCNM and Gathering Company and contain take-or-pay provisions, obligate GCNM and Gathering Company to take volumes of gas in excess of their annual demand. As a result, GCNM and Gathering Company currently face the challenge of marketing excess gas under unfavorable, off-peak conditions. In addition, GCNM and Gathering Company are disputing claims by certain producers relating to take-or-pay obligations, contract pricing and other matters, some of which are the subject of pending litigation. (See ITEM 3—"LEGAL PROCEEDINGS—NATURAL GAS CONTRACTS LITIGATION" and note 9 of the notes to consolidated financial statements.)

During 1988, GCNM obtained new gas supplies through the negotiation of long-term contracts containing no take-or-pay provisions and through spot market purchases. GCNM purchased approximately 28% of its natural gas requirements for the months of November and December 1988 from these new sources, while the remaining 72% of GCNM's requirements during these months was purchased under pre-existing long-term contracts. This shift in GCNM's gas supply purchase strategy reflects GCNM's efforts to minimize its take-or-pay exposure by reducing its winter purchases under contracts containing take-or-pay provisions based on peak-month purchases and to supplement its supply sources.

GCNM depends on EPNG and Transwestern Pipeline Company for its transportation of gas supplies purchased from sources that are not on GCNM's system. Such transportation is regulated by the FERC. Gas purchased from or transported by these companies is the sole supply for GCNM in certain locations.

Gathering Company

Gathering Company is engaged in the ownership and operation of gas gathering facilities in the San Juan Basin in northwestern New Mexico, the purchase of gas under long-term contracts from sources in the San Juan Basin and the sale of gas to GCNM and other customers. In 1988, Gathering Company sold approximately 20.4 million decatherms to GCNM and 15.3 million decatherms to other customers primarily in the spot market. Effective in January 1988, Gathering Company entered into a new sales contract with GCNM that changed the terms to reflect more appropriately services provided by Gathering Company. Pursuant to a general order, the NMPSC is reviewing the appropriateness of the new contract and, pending a NMPSC decision to allow recovery from customers, GCNM has deferred and not charged its customers $6.1 million (as of December 31, 1988) representing the incremental increase in gas purchase costs resulting from the new contract.

Processing Company

Processing Company processes natural gas purchased or transported by GCNM and Gathering Company. The natural gas is processed at Processing Company plants and delivered to GCNM and Gathering Company under separate contracts. The GCNM contract terminates in August 1998 and the Gathering Company contract is terminable, by either party, upon 30 days written notice. The NMPSC reviewed the contract with GCNM and in October 1988 ordered the Company to impute revenues and expenses from the gas processing plants owned by Processing Company as if GCNM owned Processing Company's gas processing plants. As a result, the order did not allow GCNM to recover from ratepayers through its purchased gas adjustment clause approximately $4.0 million in net processing costs incurred from January 1987 through September 1988. This portion of GCNM's unrecovered costs was charged to expense in 1988.

RATES AND REGULATION

The Company is subject to the jurisdiction of the NMPSC with respect to its retail electric, gas and water rates, service, accounting, issuance of securities, construction of new generation and transmission facilities and other matters. The FERC has jurisdiction over rates and other matters related to wholesale electric sales.

Inventorying Methodology

Inventorying is an electric ratemaking methodology designed to move incremental base load plant into the New Mexico jurisdictional rate base in conjunction with increased New Mexico jurisdictional load. A substantial amount of the Company's capacity has been treated as inventoried capacity under the inventorying methodology. The inventorying methodology has allowed the Company to defer (and to record as non-cash earnings) certain carrying costs associated with inventoried plant, although the Company has remained at risk for significant amounts of depreciation, property taxes and lease costs not recovered through off-system sales. An order issued by the NMPSC on April 5, 1989 provides for the termination of the inventorying methodology. (See "Alternative to the Inventorying Methodology".) As a result of the order, the Company has written off the amounts previously deferred under the inventorying methodology. (See note 12 of the notes to consolidated financial statements.)

Alternative to the Inventorying Methodology

On January 14, 1987, the NMPSC docketed a proceeding to obtain proposals for alternatives to the inventorying methodology and to determine how to implement any final determination in a NMPSC case concerning the reasonableness of costs relating to PVNGS. The proceeding was consolidated with the NMPSC case relating to the Company's proposed reorganization and restructuring, which proposal was withdrawn in September 1988. In September 1988, the Company filed its proposed alternative to the inventorying methodology. The Company proposed a ten-year phase-in of PVNGS Units 1 and 2, the immediate inclusion into rates of the Company's interest in SJGS Unit 4 and the exclusion of PVNGS Unit 3 and certain long-term power contracts. Hearings in the matter concluded in December 1988.

On April 5, 1989, the NMPSC issued an order which, among other things, provides for the inclusion in NMPSC jurisdictional electric rate base of the Company's interests in PVNGS Units 1 and 2, 147 MW of SJGS Unit 4 and the power purchase contract with SPS. However, the order excludes from New Mexico jurisdictional rates the Company's 130 MW interest in PVNGS Unit 3, 130 MW of SJGS Unit 4 and the power purchase contract with M-S-R. (See "Sources of Power" and "Service Area and Customers" under "ELECTRIC OPERATIONS".) The order states that as long as there is excess capacity in the Company's jurisdictional rates, then that excess capacity will share off-system sales equitably with the capacity excluded in the order.

The order does not affect current rates. Rates based on the order will be implemented though a rate case, which the Company expects to file in the near future and the results of which would likely be effective in the first half of 1990. The ultimate implementation of rates based on the inclusion of PVNGS costs will also depend on the outcome of the PVNGS cost investigation. (See "PVNGS Cost Investigation".)

The NMPSC order provides that 147 MW of SJGS Unit 4 will be immediately included in rates effective the date the NMPSC issues its final order in the rate case. The NMPSC order also provides that the rate case will consider (i) whether recovery of the Company's investment of PVNGS Units 1 and 2 should start immediately or whether such recovery should be phased in over a period of time, (ii) whether there should be a full and immediate return on PVNGS Units 1 and 2 or whether all or a portion of the return on such investment should be disallowed for some period of time and (iii) any other appropriate rate treatment of these units.

PVNGS Cost Investigation

In December 1986, the NMPSC issued G.O. No. 49, requiring the evaluation of certain cost overruns associated with the construction of electric generating plant prior to the inclusion of such plant in a company's rate base. In January 1987, the NMPSC docketed an investigation of PVNGS costs and indicated that the proceeding will determine the prudence of such costs incurred by the Company and quantify the costs resulting from imprudence. The hearing examiner has ruled that the Company has the burden of proving that PVNGS construction costs were reasonable and that its decisions to invest in and continue

participation in PVNGS were prudent. In November 1988, the NMPSC staff and the Company entered into an agreement in principle providing for the possible settlement of construction cost issues between them on the basis of a PVNGS construction audit being performed by Ernst & Whinney for the Arizona Corporation Commission. In December 1988, upon the joint motion of the staff and the Company, the hearing examiner stayed the portion of the proceedings related to construction cost issues pending completion of the Arizona construction audit.

On March 24, 1989, the report on the Arizona construction audit was released. The report concluded that certain PVNGS construction costs, AFUDC and ad valorem taxes were unreasonable. The Company's share of such costs is approximately $9.9 million. The report also identified certain areas that were found to exceed the standard of reasonableness and to have had a positive impact on the project, including built-in separation of electrical equipment, design replication of the three units at PVNGS, certain aspects of the regulatory (licensing) management function and certain labor and contract arrangements. The report estimated the potential direct cost savings of the identified areas in which performance exceeded the standard of reasonableness as between $278.5 million and $306.9 million (excluding AFUDC and ad valorem taxes) for the entire project. The above-referenced agreement in principle between the NMPSC staff and the Company provides, as a basis for possible settlement of construction cost issues, for the disallowance of the Company's share of costs found unreasonable in the audit report with no consideration for savings resulting from areas exceeding the standard of reasonableness.

On April 5, 1989, the NMPSC ordered parties to the case to file, by April 19, 1989, statements of position concerning the use of the results of the Arizona construction audit as a basis to resolve the construction cost issues in this case. The NMPSC also ordered the parties to the case to file, by May 8, 1989, statements of position on whether the inquiry into system planning issues should be terminated or continued, given the NMPSC order issued in the inventorying alternatives case, which provides for, among other things, the exclusion of the Company's interest in PVNGS Unit 3 from New Mexico jurisdictional rates. (See "Alternative to the Inventorying Methodology".) A hearing in the case is scheduled to commence in July 1989.

Coal Costs

On April 18, 1983, the NMPSC issued an order initiating an investigation relating to a retained economic interest formerly held by Western, a jointly-owned subsidiary of the Company and Tucson which was liquidated in 1981, under a sublease from Western to Utah covering certain leases at the coal mine adjacent to SJGS. (See "ELECTRIC OPERATIONS—Fuel and Water Supply—Coal".) In 1981, in completion of its liquidation, Western assigned all of its interest under the sublease to the trustee of the San Juan Coal Trust, of which the Company and Tucson were initially the sole beneficiaries. The Company ultimately sold its interest in the San Juan Coal Trust to institutional investors for approximately $69 million. In its order, the NMPSC indicated that the ultimate issues to be determined in the investigation were whether the retained economic interest payments incurred as part of the cost of coal for SJGS for the period 1981 through 1982 constituted a legitimate cost at a reasonable level to be passed on to the Company's New Mexico jurisdictional ratepayers and whether the ratepayers or the shareholders were entitled to the gain resulting from the sale of the retained economic interest in the San Juan Coal Trust. On January 17, 1989, the NMPSC adopted a hearing examiner's recommended decision which concluded that the economic interest payments incurred as part of the cost of coal for SJGS constitute a legitimate charge at a reasonable level to be paid by the Company's New Mexico jurisdictional ratepayers and that the shareholders are entitled to the proceeds resulting from the sale of the retained economic interest in the San Juan Coal Trust.

On March 7, 1988, the Attorney General filed a complaint with the NMPSC seeking examination of such coal costs since 1982. However, the NMPSC dismissed the complaint on March 20, 1989.

SDG&E Sales Agreement

In November 1985, the Company and SDG&E entered into an agreement providing for SDG&E to purchase 100 MW of capacity from the Company for the period May 1988 through April 2001. (See "ELECTRIC OPERATIONS—Service Area and Customers".) In March 1988, the Company submitted the agreement to the FERC for approval. Subsequently, SDG&E filed an intervention and protest challenging

the Company's filing at the FERC, and requesting that, due to allegedly inadequate information justifying the Company's request for approval, the FERC either reject the filing or suspend it and set it aside for hearings. SDG&E further requested that the FERC modify the agreement to reflect changes in southwestern utility fuel costs and in the purchase power market since the execution of the agreement. On June 13, 1988, the FERC accepted the agreement and ordered service under the agreement to be effective as of that date. Sales to SDG&E began on June 14, 1988. On July 13, 1988, the Company filed a request for rehearing seeking an effective date of May 1, 1988, as provided in the agreement itself. SDG&E also filed a request for rehearing of the FERC order. On October 6, 1988, the FERC denied both the Company's and SDG&E's requests for rehearing. Both the Company and SDG&E have filed requests with the United States Court of Appeals for the District of Columbia Circuit for review of the FERC orders.

Other Electric Matters

The Company has electric fuel adjustment clauses covering all retail and firm-requirements wholesale KWh sales. There is an approximate 60-day time lag in implementation of the fuel adjustment clause for billing purposes, except for firm-requirements wholesale customers for which there is an approximate 30-day time lag.

Natural Gas Operations

In August 1988, the NMPSC granted GCNM a $9.9 million increase in cost-of-service rates. Also approved in the order were unbundled transportation rates and discount pricing for transportation services, and other aspects of rate design needed by GCNM to compete in the industry. The unbundled transportation rates allow for separate and individual pricing of gathering, processing, transmission, distribution, storage and standby services. The order also directs GCNM to file on or before December 31, 1989 a rate case which will, at a minimum, address rate design issues based upon the actual experience of the rates that resulted from the August 1988 decision.

GCNM has considered various alternatives to mitigate imbalances in its gas supply and demand (see "NATURAL GAS OPERATIONS—Gas Company of New Mexico Division") and has initiated a proceeding with the NMPSC to examine these alternatives. In this proceeding, GCNM has requested that the NMPSC (1) review GCNM's transitional gas-supply strategy and examine potential future alternatives, (2) review and approve Gathering Company's role in GCNM's gas-supply strategy, including a new contract between GCNM and Gathering Company (see "NATURAL GAS OPERATIONS—Gathering Company"), (3) review and approve GCNM's historical gas procurement practices, (4) review GCNM's exposure under gas supply contracts and approve specific mechanisms to deal with take-or-pay and certain other contract costs and obligations, including those at issue in pending litigation (see ITEM 3—"LEGAL PROCEEDINGS —NATURAL GAS CONTRACT LITIGATION" and note 9 of the notes to consolidated financial statements), and (5) review regulatory options for planning GCNM's future gas supply. This proceeding is set for hearing in July 1989.

GCNM's retail gas rate schedules contain purchased gas adjustment clauses which provide for timely recovery of the cost of gas purchased by GCNM for resale to its customers. In August 1988, GCNM applied for continued use of its purchased gas adjustment clause as required biannually pursuant to NMPSC rules. A hearing in this case was held in March 1989. The Company expects the NMPSC will issue its decision later in 1989.

NAVAJO TAX ASSESSMENT

In March 1988, the Company received notice from the Navajo Nation that the Navajo Nation's Tax Commission intends to impose the Navajo Nation's business activity, possessory interest and severance taxes (including past taxes, interest and penalties) on property and business activity in an area of northwestern New Mexico known as the Eastern Navajo Agency. It is possible that the amount of taxes that might ultimately be assessed against or paid by the Company and its subsidiaries would be significant. However, due to questions of law concerning the Navajo Nation's authority to impose the tax in the area, considerations of regulatory treatment and obligations of prior owners with respect to certain past taxes asserted by the Navajo Nation (see ITEM 3—"LEGAL PROCEEDINGS—OTHER PROCEEDINGS"), the Company believes it is unlikely that the impact of the tax on its earnings would be material.

ENVIRONMENTAL FACTORS

The Company, in common with other electric and gas utilities, is subject to stringent regulations for protection of the environment by both state and Federal authorities. PVNGS is subject to the jurisdiction of the NRC, which has authority to issue permits and licenses and to regulate nuclear facilities in order to protect the health and safety of the public from radioactive hazards and to conduct environmental reviews pursuant to the National Environmental Policy Act. (See "ELECTRIC OPERATIONS—Sources of Power—*Nuclear Plant*".) The Company does not currently expect that material expenditures for additional pollution control equipment for its existing facilities will be required under current environmental laws.

The New Mexico regulation for nitrogen oxides is extremely stringent. Four Corners Units 4 and 5, which cannot meet this regulation with existing pollution control equipment, have operated for several years under variances from this regulation. In December 1987, the NMEIB granted a variance which extends through September 30, 1989 and September 30, 1991, for Units 4 and 5, respectively. This variance was granted by the NMEIB to provide time to install certain additional equipment intended to achieve compliance with existing emissions limitations without adverse operational impacts. The Company anticipates that its share of the costs related to such installation will be immaterial.

Revisions to environmental laws and regulations continue to be proposed and adopted at Federal and state levels. Pursuant to the Federal Clean Air Act Amendments of 1977, the EPA has adopted regulations, applicable to certain Federally-protected areas, that address visibility impairment which can be reasonably attributed to specific sources. The EPA may also adopt regulations to deal with visibility impairment resulting from regional haze. In addition, amendments to the Clean Air Act have been proposed which are intended to address problems of "acid rain", toxic air pollutants and the nonattainment of national ambient air quality standards. The Company cannot currently predict the financial and operational impacts of such laws, regulations and proposals.

NON-UTILITY SUBSIDIARY OPERATIONS

In 1988, the Company made the decision to discontinue the non-utility operations of its subsidiaries and to dispose of non-utility properties. (See note 11 of the notes to consolidated financial statements.) Such operations have consisted primarily of fiberboard manufacturing, real estate, coal mining, telecommunications manufacturing and financial services and have been carried out by Meadows, Sunbelt or their subsidiaries. During 1988 the Company's subsidiaries ceased all coal mining operations.

Meadows is in default as to interest and principal on a substantial portion of its notes payable and is in the process of liquidating its assets. The Company does not anticipate recovery of any of its investment in Meadows and has made a provision for potential claims.

Sunbelt is in technical default under existing bank credit arrangements for failure to meet certain covenants as a result of write-downs taken in 1988 in conjunction with discontinued mining operations. Sunbelt is current on all payments under these arrangements.

ITEM 2. PROPERTIES

Substantially all of the Company's utility plant is mortgaged to secure its first mortgage bonds.

As of December 31, 1988, the total net generation capacity of facilities owned or leased by the Company was 1,591 MW. The Company's electric generating stations in commercial service as of December 31, 1988, were as follows:

Type	Name	Location	Net MW Generation Capacity
Nuclear	PVNGS (a)	Wintersburg, Arizona	390
Coal	SJGS (b)	Waterflow, New Mexico	835
Coal	Four Corners (c)	Fruitland, New Mexico	192
Gas/Oil	Reeves	Albuquerque, New Mexico	154
Gas/Oil	Las Vegas	Las Vegas, New Mexico	20
			1,591

(a) The Company is entitled to 10.2% of the capacity and the energy generated by PVNGS Units 1 and 2 under leasehold interests. The Company has a 10.2% ownership interest in PVNGS Unit 3. (See ITEM 1—"BUSINESS—ELECTRIC OPERATIONS—Sources of Power—*Nuclear Plant*".)

(b) SJGS Units 1, 2 and 3 are 50% owned by the Company; SJGS Unit 4 is 55.525% owned by the Company.

(c) Four Corners Units 4 and 5 are 13% owned by the Company.

The Four Corners plant and a portion of the facilities adjacent to SJGS are located on land held under easements from the United States and also under leases from the Navajo Nation, the enforcement of which leases might require Congressional consent. The risk with respect to the enforcement of these easements and leases is not deemed by the Company to be material. However, the Company is dependent in some measure upon the willingness and ability of the Navajo Nation to protect these properties.

As of December 31, 1988, the Company's electric transmission system, including jointly-owned lines, consisted of: 246 circuit miles of 46,000 volt lines; five circuit miles of 69,000 volt lines; 637 circuit miles of 115,000 volt lines; 180 circuit miles of 230,000 volt lines; 1,551 circuit miles of 345,000 volt lines (including EIP, a 216 circuit mile transmission line which has been sold and leased back by the Company) and 165 circuit miles of 500,000 volt lines. The distribution systems consisted of 4,707 miles of overhead lines and 2,328 cable miles of underground lines (excluding street lighting). The Company owned 211 substations having an aggregate transformer capacity of 8,989 megavolt amps, 23% of which is step-up transformer capacity at generating stations.

The property owned by GCNM, as of December 31, 1988, consisted primarily of natural gas gathering, storage, transmission and distribution systems. The gathering systems consisted of approximately 1,200 miles (approximately 360 miles of which are leased to Gathering Company) of pipe with compression and treatment facilities. Provisions for storage made by GCNM include ownership and operation of an underground storage facility located near Albuquerque and an agreement with owners of a unitized oil field located near Artesia, New Mexico in which GCNM has injection and redelivery rights. The transmission systems consisted of approximately 1,250 miles of pipe with appurtenant compression facilities. The distribution systems consisted of approximately 8,600 miles of pipe.

GCNM leases approximately 130 miles of transmission pipe from the DOE for transportation of natural gas to Los Alamos and to certain other communities in northern New Mexico. The lease can be terminated by either party on thirty days written notice, although the Company would have the right to use the facility for two years thereafter.

The property of Gathering Company includes approximately 550 miles of gathering pipe with appurtenant compression facilities.

Processing Company owns facilities located in northwestern New Mexico having an aggregate design capacity for processing of natural gas of approximately 300,000 mcf per day.

The electric and gas transmission lines are generally located within easements and rights-of-way on public, private or Indian lands.

The Company also owns service and office facilities in Albuquerque and in other operating divisions throughout its service territory.

The Company's water property consists of wells, pumping and treatment plants, storage reservoirs and transmission and distribution mains.

The Company leases interests in PVNGS Units 1 and 2 and related property (see ITEM 1—"BUSINESS —ELECTRIC OPERATIONS—Sources of Power—*Nuclear Plant*"), EIP and associated equipment, data processing, communication, office and other equipment, office space, utility poles (joint use), vehicles and real estate. Certain leases, primarily for data processing equipment, are capital leases. All other leases are operating leases.

As of December 31, 1988, the principal mineral interests of Sunbelt and its subsidiaries (including whole and partial interests) included the following: approximately 57,600 acres of coal properties in New Mexico, consisting of state, Federal and private coal leases and Federal preference right coal lease applications, located principally in the northwestern portion of the state; approximately 960 leased acres of other mineral properties in New Mexico, consisting of a private lease of a Federal mineral claim; and approximately 10,400 acres of private coal leases and approximately 700 acres owned in fee located principally in Rogers, Craig and Nowata Counties, Oklahoma. (See note 11 of the notes to consolidated financial statements.)

Paragon has maintained land and water rights for future power plants by operating or by leasing and managing farms and ranches. However, the Company has decided to dispose of certain of these properties.

Additional information required by this item is included in ITEM 1—"BUSINESS".

ITEM 3. LEGAL PROCEEDINGS

PVNGS WATER SUPPLY LITIGATION

The validity of the primary effluent contract under which water necessary for the operation of the PVNGS units is obtained was challenged in a suit filed in January 1982 by the Salt River Pima-Maricopa Indian Community (the "community") against the Department of the Interior, the Federal agency alleged to have jurisdiction over the use of such effluent. The PVNGS participants, including the Company, were named as additional defendants in the proceeding, which is before the United States District Court for the District of Arizona. The portion of the action challenging the effluent contract has been stayed until the community litigates certain claims in the same action against the Department of the Interior and other defendants. On October 21, 1988, Federal legislation was enacted conforming to the requirements of a proposed settlement that would terminate this case without affecting the validity of the primary effluent contract. Congress, however, has not yet appropriated the Federal money necessary to effectuate the settlement. Moreover, the Arizona state legislature is required to appropriate approximately $3 million before the settlement will become final. Finally, the settlement must be approved by the court in the Lower Gila River Watershed litigation referred to below.

In November 1982, certain operators of farms located in the vicinity of the PVNGS site filed a lawsuit in Maricopa County Superior Court against the Company and others claiming prior rights to effluent to be delivered to PVNGS under the primary and secondary effluent contracts. In January 1984, APS joined with Salt River Project in bringing an action in an Arizona state court against the plaintiffs in the foregoing lawsuit and an owner of the land in the river basin from which the effluent to be received under the primary contract is alleged to be derived, seeking a declaratory judgment as to rights to effluent under Arizona law. Such declaratory judgment action was consolidated in the Arizona state court with the lawsuit filed in November 1982. In October 1985, the state court ruled in the PVNGS participants' favor in these consolidated lawsuits, holding that the effluent contracts are neither void, unenforceable nor enjoinable for the reasons raised in the

consolidated lawsuits by the parties adverse to the PVNGS participants (the "adverse parties"). The adverse parties appealed that decision to the Arizona Court of Appeals. The Company and certain other parties cross-appealed and on December 17, 1986, the consolidated appeals and cross-appeals were transferred to the Arizona Supreme Court, where oral argument was heard on February 20, 1987. Subsequently, three of the five Supreme Court justices removed themselves from the case, and a rehearing of oral argument occurred on February 16, 1988. A decision by the Arizona Supreme Court is still pending.

The Company understands that a summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed of Arizona to assert any claims to water by January 20, 1987 in an action pending in the Maricopa County Superior Court. PVNGS is located within the geographic area subject to the summons and the rights of the PVNGS participants to the use of groundwater and effluent at PVNGS is potentially at issue in this action. APS, as the PVNGS project manager, filed claims that dispute the court's jurisdiction over the PVNGS participants' groundwater rights and their contractual rights to effluent and, alternatively, seek confirmation of such rights. No trial date has been set in this matter.

SAN JUAN RIVER ADJUDICATION

In 1975, the State of New Mexico filed an action entitled State of New Mexico v. United States, et al., in the District Court of San Juan County, New Mexico, to adjudicate all water rights in the "San Juan River Stream System". The Company was made a defendant in the litigation in 1976. The action is expected to adjudicate water rights used at the Four Corners plant, at SJGS and at Santa Fe. (See ITEM 1—"BUSINESS—ELECTRIC OPERATIONS—Fuel and Water Supply".) The Company cannot at this time anticipate the effect, if any, of any water rights adjudication on the present arrangements for water at SJGS and the Four Corners plant, nor can it determine what effect the action will have on water for Santa Fe. It is the Company's understanding that final resolution of the case cannot be expected for several years.

NATURAL GAS CONTRACTS LITIGATION

Antitrust-Related Litigation

GCNM and Gathering Company are experiencing gas purchase contract disputes and litigation relating largely to the previous antitrust litigation that resulted in the Company's acquisition of GCNM from Southern Union in January 1985. (See ITEM 1—"BUSINESS—NATURAL GAS OPERATIONS—Acquisition of Natural Gas Properties".) Consistent with the Company's legal position in such previous antitrust litigation, and based upon the advice of counsel, GCNM and Gathering Company, under Company ownership, have refused to pay producers prices under certain 1976 pricing amendments to natural gas purchase contracts, which amendments the Company believes were the result of a price-fixing conspiracy. GCNM and Gathering Company have paid what they believe to be the reasonable value of the gas at the time of delivery.

On December 31, 1986, Exploration Company filed a lawsuit against the Company and GCNM, which is pending in the United States District Court for the Northern District of Texas, seeking damages alleged to result from GCNM's failure since 1985 to pay the prices under the 1976 pricing amendments to natural gas purchase contracts with Exploration Company. The lawsuit seeks damages for an estimated $100 million. The lawsuit also alleges damages resulting from GCNM's alleged failure to take the minimum quantity of gas required by the gas purchase contracts. The Company has filed an answer and counterclaim contending that the 1976 pricing amendments were the result of the price-fixing conspiracy. Also, in response to the efforts of Exploration Company to enforce the 1976 pricing amendments, the Company filed suit on January 29, 1987, against Exploration Company in the United States District Court for the District of New Mexico seeking antitrust injunctive relief. The complaint alleges that the continued efforts by Exploration Company to enforce the 1976 pricing amendments constitute new antitrust violations and seeks an injunction against the continued enforcement of those amendments.

On May 4, 1988, the Company and Gathering Company filed a lawsuit in the United States District Court for the District of New Mexico against Meridian, EPNG and Southland (wholly-owned by Meridian)

seeking a declaration that the 1976 pricing amendments in contracts with EPNG and Southland are unlawful and unenforceable by reason of the price-fixing conspiracy and that the defendants be enjoined against attempting to enforce the amendments. On June 24, 1988, Southland filed a lawsuit in the District Court of Harris County, Texas against the Company and Gathering Company seeking damages for their alleged failure to perform under the Southland contracts. Southland's complaint alleges damages in excess of $40 million, claimed to be still accruing, related to payments for gas purchased by GCNM and Gathering Company and additional damages "of at least several million dollars" related to minimum-take provisions and seeks an injunction for specific performance of the Southland contracts. In addition, Southland and Meridian filed a counterclaim in the action before the United States District Court for the District of New Mexico for substantially the same relief sought in the Texas proceeding. The Company is contesting Southland's claims.

Other Gas Supply Litigation

Unicon is asserting claims against Gathering Company and the Company relating to gas-contract provisions and to an alleged obligation to construct certain facility improvements. These claims relate to events and agreements both predating and following the acquisition of GCNM and Gathering Company from Southern Union in January 1985.

On February 21, 1986, the Company and Gathering Company filed an action against Unicon and Southern Union in the District Court of Bernalillo County, New Mexico seeking a declaration of the rights and obligations of the respective parties. Unicon has counterclaimed, asserting (i) take-or-pay and ratable-take claims for each year since 1982, (ii) claims for an alleged breach of contractual obligations to make facility improvements for the benefit of Unicon and (iii) claims for alleged economic coercion with respect to certain price amendments in the years 1985 through 1987. Unicon's counterclaim seeks injunctive relief and compensation for "damages in an as yet undetermined amount that will be proven at trial." The counterclaim also seeks trebled damages under the New Mexico Unfair Practices Act, punitive damages and attorney fees.

The Company and Gathering Company have received claims, totalling over $70 million, relating to alleged take-or-pay and ratable-take obligations through 1987 and to the alleged economic coercion, and anticipate significant additional take-or-pay and ratable-take claims for 1988. It is also anticipated that the facility-improvement claim, not yet quantified by Unicon, will be significant. The Company believes that substantial portions of Unicon's claims are duplicative. The matter is currently set for trial in July 1989.

OTHER PROCEEDINGS

See ITEM 1—"BUSINESS—RATES AND REGULATION" for a discussion of other proceedings and disputes.

In the 1984 agreement under which the Company purchased the 1985 acquisition properties, Southern Union agreed to indemnify and hold the Company harmless from any and all occurrences and legal actions (except assumed operational liabilities) arising prior to the closing date, January 28, 1985, in connection with such properties. Pursuant to the agreement, the Company notified Southern Union of claims for indemnification. On September 23, 1988, Southern Union filed suit against the Company and Gathering Company in the District Court of Dallas County, Texas seeking a declaratory judgment that Southern Union has no liability to the Company or Gathering Company for various claims made by the Company and Gathering Company for indemnification. On November 8, 1988, the Company, Sunbelt and Gathering Company filed suit against Southern Union in the District Court of Bernalillo County, New Mexico seeking damages for breach of the agreement by Southern Union for failing to indemnify for various claims. The Company anticipates that all of Southern Union's allegations in the Texas proceeding will be implicitly at issue in the New Mexico litigation. Although the Company is unable to predict the ultimate outcome of the litigation, the Company believes that the indemnification claims made against Southern Union are valid.

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

None.

SUPPLEMENTAL ITEM. EXECUTIVE OFFICERS OF THE COMPANY

Executive officers, their ages, offices held and initial effective dates thereof, are as follows:

Name	Age	Office	Initial Effective Date
J. D. Geist	54	Chairman of the Board and President	November 23, 1982
W. M. Eglinton	41	Executive Vice President and Chief Operating Officer, Electric and Water Operations	June 1, 1988
J. T. Ackerman	47	President and Chief Operating Officer, Gas Operations	February 1, 1985
J. F. Jennings, Jr.	55	President and Chief Executive Officer, Meadows Resources, Inc.	May 29, 1986
J. B. Mulcock, Jr.	49	Senior Vice President, Corporate Affairs and Secretary	April 23, 1985
M. H. Maerki	49	Senior Vice President and Chief Financial Officer	June 1, 1988

All executive officers are elected annually by the board of directors of the Company, with the exception of Mr. Jennings who is elected by Meadows' board of directors.

All of the above executive officers have been employed by the Company and/or its subsidiaries for more than five years in executive or management positions.

PART II

ITEM 5. MARKET FOR THE COMPANY'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's common stock is traded on the New York Stock Exchange. Ranges of sales prices of the Company's common stock, reported as composite transactions (symbol: PNM), and dividends paid on common stock for 1988 and 1987, by quarters, are as follows:

Quarter Ended	Range of Sales Prices High	Range of Sales Prices Low	Dividends Per Share
1988:			
December 31	15¼	11⅛	$0.38
September 30	14¾	12⅛	0.38
June 30	17⅝	14¾	0.38
March 31	22⅜	16¾	0.73
Fiscal Year	22⅜	11⅛	$1.87
1987:			
December 31	24⅞	17⅜	$0.73
September 30	33⅛	24	0.73
June 30	36⅝	30⅝	0.73
March 31	39¼	33⅛	0.73
Fiscal Year	39¼	17⅜	$2.92

On March 27, 1989, there were 53,987 holders of record of the Company's common stock.

On January 24, 1989, the board of directors of the Company declared a dividend of $.38 per share of common stock payable February 24, 1989 to shareholders of record February 3, 1989. For a discussion of the suspension of dividends on the Company's common stock, see note 2 of the notes to consolidated financial statements and ITEM 7—"MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS."

Cumulative Preferred Stock

While isolated sales of the Company's cumulative preferred stock have occurred in the past, the Company is not aware of any active trading market for its cumulative preferred stock. Quarterly cash dividends were paid on each series of the Company's cumulative preferred stock at their stated rates during 1988 and 1987.

ITEM 6. SELECTED FINANCIAL DATA

	1988	1987	1986	1985	1984
	(In thousands except per share amounts and ratios)				
Total Operating Revenues*	$ 841,924	$ 785,224	$ 775,807	$ 776,730	$ 468,255
Earnings (Loss) from Continuing Operations	$ (9,942)†	$ 117,121	$ 159,324	$ 148,169	$ 117,640
Net Earnings (Loss)	$ (230,137)	$ 95,389	$ 151,005	$ 146,310	$ 132,840
Earnings (Loss) per Common Share from Continuing Operations	$ (.50)†	$ 2.52	$ 3.49	$ 3.35	$ 2.67
Net Earnings (Loss) per Common Share	$ (5.78)	$ 2.00	$ 3.29	$ 3.30	$ 3.11
Total Assets	$2,392,749	$2,717,141	$2,667,639	$2,968,344	$2,543,373
Preferred Stock with Mandatory Redemption Requirements	$ 55,242	$ 60,513	$ 66,147	$ 119,080	$ 121,080
Long-Term Debt, less Current Maturities	$ 980,767	$ 862,962	$ 862,796	$1,112,381	$ 996,988
Common Stock Data:					
Dividends paid per common share	$ 1.87	$ 2.92	$ 2.92	$ 2.89	$ 2.85
Dividend pay-out ratio	N/M	146.0%	88.8%	87.6%	91.7%
Market price per common share at year end	$ 12.50	$ 18.75	$ 33.00	$ 29.50	$ 24.375
Book value per common share at year end	$ 18.03	$ 25.68	$ 26.51	$ 25.73	$ 25.28
Average number of common shares outstanding	41,761	41,647	40,401	37,059	35,011
Return on Average Common Equity	(23.9)%	7.7%	12.8%	13.2%	12.5%
Capitalization:					
Common stock equity	40.7%	52.2%	52.6%	42.2%	42.7%
Preferred stock:					
Without mandatory redemption requirements	3.2	2.9	2.8	4.6	5.0
With mandatory redemption requirements	3.0	2.9	3.2	5.1	5.7
Long-term debt, less current maturities	53.1	42.0	41.4	48.1	46.6
	100.0%	100.0%	100.0%	100.0%	100.0%

Due to the discontinuance of non-utility operations (see note 11 of the notes to the consolidated financial statements), certain prior year amounts have been reclassified.

* Includes gas operating revenues since January 28, 1985, the acquisition date of the gas operations.

† Includes charges for the write-off of deferred carrying costs on uncommitted electric generating capacity, the write-off of a proposed generating station and other non-recurring charges aggregating $120.3 million ($2.88 per share).

N/M—Not meaningful

The selected financial data should be read in conjunction with the consolidated financial statements, the notes to consolidated financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations contained elsewhere in this report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of the Company's financial condition and the significant factors which influence the results of operations. This discussion should be read in conjunction with the Company's consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

The commercial operation of the third and final unit of PVNGS in January 1988 concluded the Company's major generating plant construction program which was begun in the late 1960s. Utility construction expenditures have declined significantly and will continue in the foreseeable future to be substantially lower than the levels experienced during the late 1970s and early 1980s, and are expected for the years 1989-1993 to consist primarily of the cost of upgrading and expanding the electric transmission system and utility distribution systems.

Over the next five years (1989-1993), the Company expects to incur $398 million of construction expenditures. This amount includes $12 million in AFUDC, a non-cash item that reflects the Company's costs of debt and equity capital used to finance utility construction, and $74 million for the purchase of nuclear fuel. The Company currently has no material capital commitments beyond 1993 which would significantly differ from the levels reflected in the five year construction projections.

Actual construction expenditures for 1988 and the Company's projections for 1989-1993 (in millions of dollars) are shown below:

	1988	1989	1990	1991	1992	1993
Cash	$90	$87	$81	$73	$70	$75
AFUDC	7	3	3	2	2	2
Total	$97	$90	$84	$75	$72	$77

The Company conducts a continuing review of its construction program. This program and the above estimates are subject to periodic revisions based upon changes in assumptions as to system load growth, rates of inflation, the availability and timing of environmental and other regulatory approvals, the availability and costs of outside sources of capital and changes in project construction schedules.

The Company's other major cash requirements include payments of long-term debt maturities and mandatory redemptions of preferred stock (together, $35.8 million for 1989 and $185.0 million for 1990-1993) and annual lease payments of $84.6 million for the Company's leasehold interests in PVNGS Units 1 and 2. Such cash requirements exclude the debt obligations of Meadows.

The Company's ability to generate cash internally has been under pressure due to investments in and operating costs associated with substantial generation plant not in New Mexico retail ratebase, a soft market for wholesale electric power sales, increased competition from alternative sources and suppliers of energy and other factors. However, the Company believes its internal cash generation will be adequate to meet the financing requirements of its continuing operations for the years 1989-1993.

Efforts to boost the Company's internal cash generation have included continuing cost control programs and increased efforts to market electricity at both the retail and wholesale levels. In August 1988, the Company implemented a cost reduction program which included the elimination of approximately 800 positions, the termination of certain employee benefits and the reduction of other costs. Also in August 1988, the NMPSC issued an order in a GCNM rate case allowing GCNM to implement rate increases that provide for approximately $9.9 million of additional annualized cost-of-service revenues. The rate increases were effective beginning in August 1988.

Although the Company currently expects to meet its 1989 utility financing requirements primarily through internally generated funds, certain external sources of funds are available to the Company. Such sources include bank borrowings and commercial paper. As of December 31, 1988, the Company had credit commitments from various banks totaling approximately $328.0 million. As of such date, $10.3 million of these commitments had been used for bank borrowings, $144.4 million supported outstanding commercial paper and $173.3 million were available either to support the issuance of additional commercial paper or to be used for additional bank borrowings.

The Company may also raise external capital, upon NMPSC approval, by issuing common stock and, provided certain tests specified in the Company's mortgage indenture and Restated Articles of Incorporation are met, first mortgage bonds and preferred stock. The Company, however, currently has no plans to issue additional first mortgage bonds, preferred stock or common stock. Due to earnings tests in the Company's Restated Articles of Incorporation and the losses incurred in 1988, the issuance of preferred stock would require the consent of the holders of a majority of the shares of preferred stock then outstanding until such time as the tests are met. The ability of the Company to issue first mortgage bonds is also dependent upon earnings. In addition, the Company's ability to raise external capital and the cost of such funds depend upon earnings, credit ratings and financial market conditions, among other factors.

The Company had $165.0 million in cash and investments in marketable securities at the end of 1988.

The Company's capital structure at December 31, 1988 consisted of 53.1% long-term debt, 3.0% preferred stock with mandatory redemption requirements, 3.2% preferred stock without mandatory redemption requirements and 40.7% common stock equity.

RESULTS OF OPERATIONS

Net earnings (loss) available for common stock for the last three years were:

1988	1987	1986
$(241) million or $(5.78) per share	$83 million or $2.00 per share	$133 million or $3.29 per share

The loss experienced in 1988 was due primarily to a provision for the estimated loss from the discontinuance of the Company's non-utility operations, a provision for an extraordinary loss on discontinuation of application of regulatory accounting principles regarding certain assets, the write-off of the Company's investment in a proposed coal-fired generating station, the write-off of deferred carrying costs on uncommitted electric generating capacity and one-time costs related to a work force reduction. Net earnings available for common stock declined $1.29 per share or $50 million in 1987, primarily as a result of certain tax benefits recognized in 1986 and the commercial operation of PVNGS Unit 2 for a full year in 1987. The commercial operation of the PVNGS units has several adverse effects on the results of operations, as discussed below. The following discussion highlights significant items which affected the amount of reported earnings in 1988 and 1987 and certain items which may continue to affect earnings in the years beyond.

Continuing Operations

Earnings (loss) from continuing operations for the last three years were:

1988	1987	1986
$(10) million or $(.50) per share	$117 million or $2.52 per share	$159 million or $3.49 per share

Electric operating revenues increased $43.7 million in 1988 primarily as a result of an 18.1% increase in total KWh sales. A long-term sales contract, which contributed $18.4 million in revenues in 1988 and $39.8 million in revenues in 1987, expired in April 1988. That expiration was partially offset by sales to the same customer beginning in June 1988 under a new long-term contract, which contributed $21.1 million in revenues in 1988. The Company also had revenues of $17.7 million in 1988 from sales for resale under short-term contracts, some of which expired in 1988. In addition, $100.0 million and $5.2 million in revenues were contributed by long-term sales contracts that expire at the end of 1989 and 1990, respectively. The $42.7 million increase in 1987 electric operating revenues was caused largely by a 7.0% increase in energy sales to residential and commercial customers.

Gas operating revenues increased $13.2 million in 1988 primarily as a result of the implementation of new gas rates in August 1988 and increased therm sales to wholesale customers. Gas operating revenues decreased $34.0 million in 1987 due primarily to lower gas purchase costs, which are recovered from customers through a purchased gas adjustment clause.

Fuel and purchased power expense increased $10.3 million in 1988 and $13.6 million in 1987. Such increases were due primarily to an increase in nuclear fuel expenses resulting from the commercial operation of PVNGS Units 1 and 2 in 1986 and PVNGS Unit 3 in 1988 and as a result of higher energy sales in both years. (See note 1 of the notes to consolidated financial statements.)

Other operation expenses increased $17.2 million in 1988 due primarily to non-recurring early retirement, severance and other costs related to a work force reduction and due to the commercial operation of PVNGS Unit 3. Other operation expenses increased $52.9 million in 1987 due primarily to a full year of lease payments for PVNGS Unit 2. Other operation expenses should decline in 1989, reflecting a cost reduction program, including the work force reduction, implemented by the Company in August 1988.

Operating income taxes increased $21.7 million in 1987. The increase was due primarily to the effects of certain tax benefits in 1986 associated with start-up activities at PVNGS, losses on hedging transactions and premiums incurred in the retirement of certain first mortgage bonds, which tax benefits did not recur in 1987 at the same levels. These tax benefits increased net earnings by $12.3 million in 1987.

AFUDC (equity and borrowed funds), a non-cash item, decreased $27.3 million in 1988 and $14.5 million in 1987. Both decreases are a result of lower average construction work in progress balances resulting largely from the commercial operation of PVNGS Units 1 and 2 in 1986 and PVNGS Unit 3 in 1988. This low level of AFUDC will continue into the 1990s, reflecting the planned reduction in utility construction spending.

As a result of the NMPSC's April 5, 1989 order in the inventorying alternatives case, the Company has discontinued the deferral of carrying costs on uncommitted electric generating capacity and, in 1988, wrote off amounts previously deferred. (See note 12 of the notes to consolidated financial statements.)

The Company has determined that recovery of its investment in a proposed coal-fired generating station is not probable. Accordingly, project development costs of $38.1 million (net of income tax benefits) was written off in 1988.

Other, under other income and deductions, net of taxes, decreased $28.8 million in 1988. This decrease resulted primarily from a write-off relating to the Company's share of costs identified as unreasonable in a PVNGS construction cost audit performed for the Arizona Corporation Commission, decreases in investment income, the write-off of deferred gas processing costs and a provision for other losses. The $7.2 million increase in 1987 was due primarily to the earnings of $6.1 million from Processing Company and Gathering Company.

Interest charges increased $7.3 million in 1988 as a result of increased borrowings through commercial paper. In 1987, interest charges decreased $16.3 million due largely to the retirement of first mortgage bonds in 1986.

Discontinuance of Non-Utility Operations

In 1988, the Company made the decision to discontinue the non-utility operations of its subsidiaries and to dispose of non-utility properties. (See note 11 of the notes to consolidated financial statements.) As a

result, the Company has made a provision for an estimated after-tax loss of $137.8 million on the disposal of non-utility assets, including a provision for after-tax operating losses of $29.5 million for the operations of such properties prior to their expected disposition in 1989. Estimated losses from the disposal of these assets are due primarily to the decrease in value of southwestern real estate holdings and the loss the Company expects to incur on the sale of a fiberboard manufacturing facility.

Losses from operations of discontinued non-utility operations were $35.8 million for 1988 and $21.7 million for 1987. The increased losses were due primarily to poor real estate sales, a provision for coal mining reclamation costs and the write-off of certain coal property investments in 1988.

Extraordinary Item

In 1988, the Company wrote off $46.6 million (net of income tax benefits) of costs which it no longer expects to recover through the regulatory process.

CURRENT ISSUES FACING THE COMPANY

The Company's future financial condition and results of operations may be affected by the factors discussed below.

NMPSC Proceedings Relating to PVNGS and SJGS Unit 4

On April 5, 1989, the NMPSC issued an order which, among other things, provides for the inclusion in NMPSC jurisdictional electric rate base of the Company's interests in PVNGS Units 1 and 2, 147 MW of SJGS Unit 4 and the power purchase contract with SPS. However, the order excludes from rates the Company's 130 MW interest in PVNGS Unit 3, 130 MW of SJGS Unit 4 and the power purchase contract with M-S-R. (See "Sources of Power" and "Service Area and Customers" under "ELECTRIC OPERATIONS".) The order states that as long as there is excess capacity in the Company's jurisdictional rates, then that excess capacity will share off-system sales equitably with the capacity excluded in the order.

The order does not affect current rates. Rates based on the order will be implemented through a rate case, which the Company expects to file in the near future and the results of which would likely be effective in the first half of 1990. The ultimate implementation of rates based on the inclusion of PVNGS costs will also depend on the outcome of the PVNGS cost investigation. (See note 10 of the notes to consolidated financial statements.)

The NMPSC order provides that 147 MW of SJGS Unit 4 will be immediately included in rates effective the date the NMPSC issues its final order in the rate case. The NMPSC order also provides that the rate case will consider (i) whether recovery of the Company's investment in PVNGS Units 1 and 2 should start immediately or whether such recovery should be phased in over a period of time, (ii) whether there should be a full and immediate return on PVNGS Units 1 and 2 or whether all or a portion of the return on such investment should be disallowed for some period of time and (iii) any other appropriate rate treatment of these units.

The Company has made a provision for losses it deems appropriate at this point in the NMPSC proceedings. However, the NMPSC has not issued final orders in the PVNGS cost investigation and the upcoming rate case. In addition, the Company is dependent on the wholesale market for the ultimate recovery of its remaining investment in capacity excluded from New Mexico jurisdictional rates.

The Wholesale Power Market

The Company's ability to market its uncommitted capacity is under extreme pressure. This ability is constrained by existing transmission availability and by levels of competition in the off-system market. Price competition in this market will continue to be intense due to the availability of surplus capacity from other utilities, projected low prices for oil and natural gas and the emergence of cogeneration, independent power producers and self-generation as competing energy sources. The Company's market assessments conclude that other southwestern and western utilities will have increasing requirements for capacity and energy in the

1990s. However, the Company projects that the current soft wholesale power market will continue into the mid 1990s and that, as a result, there will continue to be downward pressure on prices for wholesale sales.

The Retail Electric Market

The Company's electric service franchise with the City of Albuquerque, covering an area which contributes 38.6% of the Company's 1988 electric revenues, expires in early 1992. In addition to discussing a franchise renewal with the Company, the City of Albuquerque is studying other alternatives, including municipalization of the system and alternative suppliers to the franchise area after expiration of the Company's current franchise. The Company will pursue with the City the renewal of the franchise prior to its expiration. Kirtland Air Force Base, the Company's largest retail customer, representing 3.3% of 1988 electric revenues, continues to receive service without a contract.

Natural Gas Issues

GCNM and Gathering Company have entered into long-term contracts for gas supplies generally sufficient to meet GCNM's peak-day demand. However, these long-term contracts, most of which predate the Company's acquisition of GCNM and Gathering Company and contain take-or-pay provisions, obligate GCNM and Gathering Company to take volumes of gas in excess of their annual demand. As a result, GCNM and Gathering Company are currently facing take-or-pay claims and the challenge of marketing excess gas under unfavorable, off-peak conditions. GCNM is seeking to minimize its take-or-pay exposure by reducing its winter purchases under contracts containing take-or-pay provisions based on peak-month purchases.

GCNM has considered various alternatives to mitigate imbalances in its gas supply and demand and has initiated a proceeding with the NMPSC to examine these alternatives. GCNM has requested that the NMPSC review, among other things, GCNM's exposure from take-or-pay claims and other contract disputes with natural gas producers and that the NMPSC approve specific mechanisms for recovery of costs arising from these claims. This proceeding, set for hearing in July 1989, will address the allocation of significant costs between the Company and its customers.

Dividend on the Company's Common Stock

The payment of cash dividends on the common stock of the Company is subject to certain restrictions, including those contained in the Company's mortgage indenture, which effectively prevent the payment of the common dividend unless the Company has retained earnings. As a result of the deficit in retained earnings, the Company's board of directors has announced the suspension of dividend payments on the Company's common stock. The Board anticipates that no dividend on common stock will be declared through the fourth quarter of 1989. The board of directors has directed the Company's management to investigate and pursue the implementation of a quasi-reorganization. A quasi-reorganization, if implemented, would result in the transfer from additional paid-in capital to retained earnings of an amount sufficient to eliminate the deficit balance in retained earnings. Thereafter, retained earnings would be measured from the effective date of the quasi-reorganization. The payment of future dividends will also depend on earnings, the financial condition of the Company, market requirements and other factors.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Management's Responsibility for Financial Statements

The management of Public Service Company of New Mexico is responsible for the preparation and presentation of the accompanying consolidated financial statements. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles and include amounts that are based on informed estimates and judgements of management.

Management maintains a system of internal accounting controls which it believes is adequate to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with management authorization and the financial records are reliable for preparing the consolidated financial statements. The system of internal accounting controls is supported by written policies and procedures, by a staff of internal auditors who conduct comprehensive internal audits and by the selection and training of qualified personnel.

The board of directors of the Company, through its audit committee comprised entirely of outside directors, meets periodically with management, internal auditors and the Company's independent auditors to discuss auditing, internal control and financial reporting matters. To ensure their independence, both the internal auditors and independent auditors have full and free access to the audit committee.

The independent auditors, Peat Marwick Main & Co., are engaged to audit the Company's consolidated financial statements in accordance with generally accepted auditing standards.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Public Service Company of New Mexico:

We have audited the consolidated financial statements of Public Service Company of New Mexico and subsidiaries as listed in the accompanying index. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedules as listed in the accompanying index. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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 presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Public Service Company of New Mexico and subsidiaries at December 31, 1988 and 1987 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1988, in conformity with generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

PEAT MARWICK MAIN & CO.

Albuquerque, New Mexico
April 14, 1989

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EARNINGS (LOSS)

	Year Ended December 31, 1988	1987	1986
	(In thousands except per share amounts)		
Operating Revenues:			
Electric (note 1)	$ 607,317	$563,617	$520,896
Gas	223,791	210,634	244,666
Water	10,816	10,973	10,245
Total operating revenues	841,924	785,224	775,807
Operating Expenses:			
Fuel and purchased power (note 1)	152,017	141,766	128,130
Gas purchased for resale	122,575	116,202	149,685
Other operation expenses	261,687	244,467	191,604
Maintenance and repairs	46,568	43,501	41,879
Depreciation and amortization	66,920	60,264	60,249
Taxes, other than income taxes	34,823	31,683	30,511
Income taxes (note 4)	17,268	14,990	(6,727)
Total operating expenses	701,858	652,873	595,331
Operating income	140,066	132,351	180,476
Other Income and Deductions, net of taxes (note 4):			
Allowance for equity funds used during construction	4,658	26,690	34,926
Deferred carrying costs on uncommitted electric generating capacity (note 12)	(20,234)	13,069	16,191
Write-off of proposed generating station (note 6)	(38,104)	—	—
Other	(10,634)	18,175	10,945
Net other income and deductions	(64,314)	57,934	62,062
Income before interest charges	75,752	190,285	242,538
Interest Charges:			
Interest on long-term debt	81,775	67,573	87,961
Other interest charges	6,329	13,222	9,147
Allowance for borrowed funds used during construction	(2,410)	(7,631)	(13,894)
Net interest charges	85,694	73,164	83,214
Earnings (Loss) from Continuing Operations	(9,942)	117,121	159,324
Discontinued Operations, net of tax (note 11):			
Loss from operations of non-utility operations	(35,826)	(21,732)	(8,319)
Estimated loss on disposal of non-utility operations, including provision for operating losses during the phase-out period	(137,773)	—	—
Earnings (Loss) before Extraordinary Item	(183,541)	95,389	151,005
Extraordinary Item—loss on discontinuation of application of regulatory accounting principles for certain assets, net of tax (note 12)	(46,596)	—	—
Net Earnings (Loss)	(230,137)	95,389	151,005
Preferred Stock Dividend Requirements	11,117	11,935	18,187
Net Earnings (Loss) Available for Common Stock	$(241,254)	$ 83,454	$132,818
Average Number of Common Shares Outstanding	41,761	41,647	40,401
Earnings (Loss) per Share of Common Stock:			
Earnings (loss) from continuing operations	$ (.50)	$ 2.52	$ 3.49
Loss from discontinued operations	(.86)	(.52)	(.20)
Estimated loss on disposal of non-utility operations	(3.30)	—	—
Earnings (loss) before extraordinary item	(4.66)	2.00	3.29
Extraordinary item	(1.12)	—	—
Net Earnings (Loss)	$ (5.78)	$ 2.00	$ 3.29
Dividends Paid per Share of Common Stock	$ 1.87	$ 2.92	$ 2.92

See accompanying notes to consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (DEFICIT)

	Year Ended December 31, 1988	1987	1986
		(In thousands)	
Balance at Beginning of Year	$ 175,337	$ 213,416	$ 198,703
Net Earnings (Loss)	(230,137)	95,389	151,005
Dividends:			
Cumulative preferred stock	(11,117)	(11,935)	(18,187)
Common stock	(78,087)	(121,533)	(118,105)
Balance at End of Year (note 2)	$(144,004)	$ 175,337	$ 213,416

See accompanying notes to consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

ASSETS

	December 31, 1988	1987
	(In thousands)	
Utility Plant, at Original Cost (notes 2, 6, 10 and 12):		
Electric plant in service	$1,864,136	$1,518,610
Gas plant in service	358,531	338,842
Water plant in service	43,686	41,945
Common plant in service	41,528	42,226
Plant held for future use	21,975	33,103
	2,329,856	1,974,726
Less accumulated depreciation and amortization	568,661	510,002
	1,761,195	1,464,724
Construction work in progress	72,401	369,092
Nuclear fuel, net of accumulated amortization	51,347	58,738
Net utility plant	1,884,943	1,892,554
Other Property and Investments:		
Non-utility property, at cost, net of accumulated depreciation, partially pledged	62,997	123,559
Other investments (note 1)	7,709	203,660
Total other property and investments	70,706	327,219
Current Assets:		
Cash	1,379	2,262
Temporary investments (note 1)	163,648	7,367
Receivables, net	119,308	101,529
Fuel, materials and supplies, at average cost	62,689	52,219
Gas in underground storage, at weighted average cost	11,590	11,496
Prepaid expenses	13,905	13,709
Net assets of discontinued operations (note 11)	—	180,069
Total current assets	372,519	368,651
Deferred charges	64,581	128,717
	$2,392,749	$2,717,141

CAPITALIZATION AND LIABILITIES

	1988	1987
Capitalization (note 2):		
Common stock equity:		
Common stock outstanding—41,774,083 shares in 1988 and 41,733,504 shares in 1987	$ 208,870	$ 208,668
Additional paid-in capital	688,392	687,899
Retained earnings (deficit)	(144,004)	175,337
Total common stock equity	753,258	1,071,904
Cumulative preferred stock without mandatory redemption requirements	59,000	59,000
Cumulative preferred stock with mandatory redemption requirements	55,242	60,513
Long-term debt, less current maturities	980,767	862,962
Total capitalization	1,848,267	2,054,379
Current Liabilities:		
Short-term debt (note 3)	—	152,000
Accounts payable	136,553	105,256
Current maturities of long-term debt (note 2)	33,517	18,741
Accrued interest and taxes	11,612	4,708
Other current liabilities	54,192	26,830
Total current liabilities	235,874	307,535
Deferred Credits:		
Accumulated deferred investment tax credits (note 4)	130,033	150,175
Accumulated deferred income taxes (note 4)	70,836	125,133
Other deferred credits	107,739	79,919
Total deferred credits	308,608	355,227
Commitments and Contingencies (notes 6 through 12)		
	$2,392,749	$2,717,141

See accompanying notes to consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

	1988	1987	1986
	Year Ended December 31, (In thousands)		
Cash Flows From Operating Activities:			
Net earnings (loss)	$(230,137)	$ 95,389	$ 151,005
Adjustments to reconcile net earnings (loss) to net cash flows from operating activities:			
Depreciation and amortization	91,087	71,859	73,458
Allowance for equity funds used during construction	(4,658)	(26,690)	(34,926)
Deferred carrying costs on uncommitted electric generating capacity	20,234	(13,069)	(16,191)
Accumulated deferred investment tax credit	(20,142)	(34,713)	38,432
Accumulated deferred income tax	(67,963)	8,675	(6,136)
Write-off of proposed generating station	50,970	—	—
Loss on sale of other property and investments	5,904	—	—
Loss from extraordinary item	53,504	—	—
Provision for other losses	38,452	—	—
Changes in certain assets and liabilities:			
Receivables	(17,779)	5,000	(2,494)
Fuel, materials and supplies	(10,760)	(15,137)	(4,842)
Net assets of discontinued operations	180,069	(3,691)	2,462
Accounts payable	31,464	25,877	(12,846)
Accrued interest	229	(3,233)	(13,534)
Accrued taxes payable	6,675	(23,136)	(38,498)
Other current liabilities	16,315	(8,800)	6,441
Other, net	11,064	(4,919)	13,518
Net cash flows from operating activities	154,528	73,412	155,849
Cash Flows From Investing Activities:			
Utility plant additions	(86,549)	(93,411)	(163,489)
Proceeds from sale of utility plant, net	—	—	429,611
Other property additions	(7,701)	(3,015)	(34,867)
Other property sales	9,729	4,951	—
Loss on hedging transactions	—	—	(17,597)
Temporary investments, net	42,482	30,914	117,657
Net cash flows from investing activities	(42,039)	(60,561)	331,315
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	682	14,619	103,676
Proceeds from pollution control revenue bonds	5,548	13,063	2,719
Redemptions and repurchases of preferred stock	(5,257)	(5,606)	(99,600)
Reacquisition of first mortgage bonds	—	(3,827)	(212,247)
Bond and preferred stock reacquisition premiums	—	(395)	(44,780)
Proceeds from other long-term debt	44,647	43,239	96,978
Repayments of other long-term debt	(66,468)	(79,099)	(170,696)
Net increase (decrease) in short-term debt	(3,000)	135,500	(27,100)
Dividends paid	(89,524)	(132,698)	(139,338)
Net cash flows from financing activities	(113,372)	(15,204)	(490,388)
Increase (Decrease) in Cash	(883)	(2,353)	(3,224)
Cash at Beginning of Year	2,262	4,615	7,839
Cash at End of Year	$ 1,379	$ 2,262	$ 4,615
Supplemental Cash Flow Disclosures:			
Interest paid	$ 101,179	$ 89,963	$ 114,553
Income taxes paid (refunded)	$ (9,842)	$ 48,604	$ 132,250

See accompanying notes to consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CAPITALIZATION

				December 31, 1988	December 31, 1987
				(In thousands)	
Common Stock Equity (note 2):					
Common stock, par value $5 per share				$ 208,870	$ 208,668
Additional paid-in capital				688,392	687,899
Retained earnings (deficit)				(144,004)	175,337
Total common stock equity				753,258	1,071,904
	Stated Value	Shares Outstanding at December 31, 1988	Current Redemption Price		
Cumulative Preferred Stock (note 2):					
Without mandatory redemption requirements:					
1965 Series, 4.58%	$100	130,000	$102.00	13,000	13,000
8.48% Series	100	200,000	103.00	20,000	20,000
8.80% Series	100	260,000	103.10	26,000	26,000
		590,000		59,000	59,000
With mandatory redemption requirements:					
8.75% Series	100	312,409	105.80	31,241	32,179
12.52% Series	50	526,680	—	26,334	30,667
		839,089		57,575	62,846
Redeemable within one year		(46,660)		(2,333)	(2,333)
		792,429		55,242	60,513
Long-Term Debt (note 2):					
Issue and Final Maturity		Interest Rates			
First mortgage bonds:					
1988 through 1993		4⅜% to 4⅞%		8,655	16,465
1994 through 1998		5⅞% to 13⅛%		46,552	46,615
1999 through 2003		7¼% to 8⅛%		47,273	47,857
2004 through 2008		8⅛% to 10⅛%		155,642	156,743
2009 through 2013		12⅞%		2,366	3,016
1993 through 2013—pollution control series, securing pollution control revenue bonds		5.9% to 10¾%		437,045	437,045
Funds held by trustee				—	(5,548)
Total first mortgage bonds				697,533	702,193
Pollution control revenue bonds:					
2003 through 2013		10% to 10¼%		100,000	100,000
2009		variable rate		37,300	37,300
Short-term debt expected to be refinanced (note 3)				144,678	—
Other, including unamortized premium and discount				34,773	42,210
Total long-term debt				1,014,284	881,703
Current maturities				(33,517)	(18,741)
Long-term debt, less current maturities				980,767	862,962
Total Capitalization				$1,848,267	$2,054,379

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1988, 1987 and 1986

(1) Summary of Significant Accounting Policies

System of Accounts

The Company maintains its accounts for utility operations primarily in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners ("NARUC"), and adopted by the New Mexico Public Service Commission ("NMPSC"). As a result of the ratemaking process, the application of generally accepted accounting principles by the Company differs in certain respects from the application by non-regulated businesses. Such differences generally regard the time at which certain items enter into the determination of net earnings in order to follow the principle of matching costs and revenues.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and subsidiaries in which it owns a majority voting interest. To the extent the operations of the Company's subsidiaries have been discontinued (see note 11), all current and prior year amounts have been segregated in the accompanying financial statements as discontinued operations. All significant intercompany transactions and balances have been eliminated.

Utility Plant

Utility plant is stated at original cost, which includes payroll-related costs such as taxes, pension and other fringe benefits, administrative costs and an allowance for funds used during construction. Utility plant includes certain electric assets not subject to NMPSC regulation. The operations of such electric assets are included in operating income. (See note 12.)

It is Company policy to charge repairs and minor replacements of property to maintenance expense and to charge major replacements to utility plant. Gains or losses resulting from retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

Depreciation and Amortization

Provision for depreciation of utility plant is made at annual straight-line rates approved by the NMPSC. The average depreciation rates used were as follows:

	1988	1987	1986
Electric plant	3.06%	3.14%	3.23%
Gas plant	2.97%	3.11%	3.15%
Water plant	2.25%	2.14%	2.03%
Common plant	8.62%	9.10%	9.46%

The provision for depreciation of certain equipment, including amortization applicable to capital leases, is charged to clearing accounts and subsequently allocated to operating expenses or construction projects based on the use of the equipment.

Depreciation of non-utility property is computed on the straight-line method. Amortization of nuclear fuel is computed based on the units of production method.

Allowance for Funds Used During Construction ("AFUDC")

As provided by the uniform systems of accounts, AFUDC, a non-cash item, is charged to utility plant. AFUDC represents the cost of borrowed funds (allowance for borrowed funds used during construction) and

a return on other funds (allowance for equity funds used during construction). The Company capitalizes AFUDC on construction work in progress and nuclear fuel in the process of enrichment to the extent allowed by regulatory agencies.

AFUDC is computed using the maximum rate, net of taxes, permitted by the FERC. The rates used were 8.37%, 9.06% and 8.97% for 1988, 1987 and 1986, respectively, compounded semi-annually.

Deferred Carrying Costs on Uncommitted Electric Generating Capacity

A substantial portion of the Company's generating capacity has been treated as inventoried capacity under the inventorying methodology. Inventorying is an electric ratemaking methodology designed to move incremental base load plant into New Mexico jurisdictional rate base in conjunction with increased New Mexico jurisdictional load. The inventorying methodology has allowed the Company to defer (and to record as non-cash earnings) certain carrying charges associated with inventoried plant, although the Company has remained at risk for significant amounts of depreciation, property taxes and lease costs not recovered through off-system sales.

In 1987, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 92, *Regulated Enterprises—Accounting for Phase-in Plans,* as an amendment to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* SFAS No. 92 required the Company to obtain NMPSC approval of modifications or alternatives to the Company's inventorying methodology to allow the full recovery of deferred carrying costs within ten years from the date of such NMPSC approval. The NMPSC order, issued April 5, 1989, in the inventorying alternatives case did not provide for the recovery of deferred carrying costs pursuant to SFAS No. 92. Accordingly, the Company has discontinued the inventorying methodology and has written off amounts previously deferred. (See note 12.)

Fuel, Purchased Power and Gas Purchase Costs

Economy sales and other near-term energy delivery transactions by the electric utility are shown as a reduction of fuel and purchased power expenses. (See *Revenues* below.) The Company uses the deferral method of accounting for the portion of fuel, net purchased power and gas purchase costs which are reflected in subsequent periods under fuel and purchased power clauses and gas adjustment clauses. Future recovery of these costs is based on orders issued by the regulatory commissions.

Amortization of Debt Discount, Premium and Expense

Discount, premium and expense related to the issuance and retirement of long-term debt are amortized over the lives of the respective issues.

Income Taxes

Certain revenue and expense items in the consolidated statement of earnings (loss) are recorded for financial reporting purposes in a year different from the year in which they are recorded for income tax purposes. Deferred income taxes are provided on these timing differences to the extent allowed for ratemaking purposes through tax normalization. (See note 4.) Certain other timing differences result in reductions of income tax expense in the current year as required by the NMPSC. This flow-through method is used primarily for certain capitalized start-up and pre-operational costs at Palo Verde Nuclear Generating Station ("PVNGS"), premiums on retirement of first mortgage bonds, losses on hedging transactions, accelerated amortization of pollution control facilities and for minor differences between book and tax depreciation.

Rates subject to FERC jurisdiction allow recovery of amounts necessary to provide additional tax normalization of the timing differences described above which are accounted for under the flow-through method for other customers. Provision has been made for additional deferred income taxes attributable to amounts collected under these rates.

Deferred taxes are provided on all non-permanent differences between book and taxable income attributable to non-utility operations. These differences consist primarily of interest and other expenses which are capitalized for book purposes and income which is taxable in periods other than when recognized for financial reporting purposes.

The Company defers investment tax credits related to utility assets and amortizes them over the estimated useful lives of the related assets. Investment tax credits generated by non-utility properties are recognized as reductions of current income tax expense.

In December 1987, the FASB issued SFAS No. 96, *Accounting for Income Taxes,* which prescribes a new accounting standard for income taxes. SFAS No. 96 retains the requirement that deferred income taxes be recorded to reflect tax normalization. Additionally, it requires that such deferrals be recorded using the liability method. Under this method, deferred tax liabilities are computed using the enacted tax rates scheduled to be in effect when the temporary differences reverse. For regulated operations, any changes in tax rates applied to accumulated deferred income taxes may not be immediately recognized because of ratemaking and tax accounting provisions contained in the Tax Reform Act of 1986.

The FASB delayed the effective date for SFAS No. 96 to fiscal years beginning after December 15, 1989 with earlier adoption permitted. The Company has not determined when it will adopt SFAS No. 96, but it is anticipated that such adoption will not have a material effect upon the Company's financial statements and operating results, regardless of when it occurs.

Revenues

Revenues are recognized based on cycle billings rendered to customers monthly. The Company does not accrue revenues for service provided but not billed at the end of a fiscal period.

Prior to 1988, certain off-system energy sales to utilities had been accounted for as a reduction of fuel and purchased power expense. Such energy sales are now classified as operating revenues and prior years' amounts have been reclassified accordingly.

Statement of Cash Flows

The Company has adopted SFAS No. 95, *Statement of Cash Flows,* which sets forth standards for cash flow reporting and requires the presentation of a statement of cash flows in place of the statement of changes in financial position. For purposes of the cash flow statement, the Company considers currency on hand and demand deposits to be cash. The previous years' information has been recast to reflect the implementation of SFAS No. 95.

Marketable Securities

Marketable equity securities are stated at the lower of aggregate cost or market. Other long-term investments are stated at cost.

Due to a change in the Company's management strategy for its investment policy as a result of the Company's withdrawal of its proposed corporate reorganization and restructuring, investments in marketable securities, classified as non-current in 1987, are now classified as current assets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(2) Capitalization

Changes in common stock, additional paid-in capital and cumulative preferred stock are as follows:

	Common Stock			Cumulative Preferred Stock — Without Mandatory Redemption Requirements		Cumulative Preferred Stock — With Mandatory Redemption Requirements	
	Number of Shares	Aggregate Par Value	Additional Paid-In Capital	Number of Shares	Aggregate Stated Value	Number of Shares	Aggregate Stated Value
			(Dollars in thousands)				
Balance at December 31, 1985	37,965,868	$189,829	$588,415	1,660,000	$106,000	1,540,800	$119,080
Public issuance of stock	1,800,000	9,000	44,256	—	—	—	—
Stock Plans	1,547,490	7,738	42,682	—	—	—	—
Redemption of stock	—	—	—	(1,070,000)	(47,000)	(448,250)	(44,825)
Redeemable within one year	—	—	—	—	—	(104,410)	(8,108)
Balance at December 31, 1986	41,313,358	206,567	675,353	590,000	59,000	988,140	66,147
Stock Plans	420,146	2,101	12,518	—	—	—	—
Redemption of stock	—	—	28	—	—	(53,008)	(3,301)
Redeemable within one year	—	—	—	—	—	(46,660)	(2,333)
Balance at December 31, 1987	41,733,504	208,668	687,899	590,000	59,000	888,472	60,513
Stock Plans	40,579	202	436	—	—	—	—
Redemption of stock	—	—	57	—	—	(49,383)	(2,938)
Redeemable within one year	—	—	—	—	—	(46,660)	(2,333)
Balance at December 31, 1988	41,774,083	$208,870	$688,392	590,000	$ 59,000	792,429	$ 55,242

Common Stock

The number of authorized shares of common stock with par value of $5 per share is 80 million shares. The board of directors of the Company has periodically reserved common stock for the Shareholder's Dividend Reinvestment Plan, the Employee Stock Purchase Plan, the Master Employee Savings Plans and the Consumer Stock Plan ("Stock Plans"). After April 1987, all shares required by the Stock Plans (with the exception of the Consumer Stock Plan) were obtained from the open market. In May 1988, the Master Employee Savings Plans ceased offering Company shares as an investment option. The board of directors of the Company has terminated the Shareholder's Dividend Reinvestment Plan, the Employee Stock Purchase Plan and the Consumer Stock Plan as of September 1, 1988.

The payment of cash dividends on the common stock of the Company is subject to certain restrictions, including those contained in the Company's mortgage indenture, which effectively prevent the payment of the common dividend unless the Company has retained earnings. As a result of the deficit in retained earnings, the Company's board of directors has announced the suspension of dividend payments on the Company's common stock. The board anticipates that no dividend on common stock will be declared through the fourth quarter of 1989. The board of directors has directed the Company's management to investigate and pursue the implementation of a quasi-reorganization. A quasi-reorganization, if implemented, would result in the transfer from additional paid-in capital to retained earnings of an amount sufficient to eliminate the deficit balance in retained earnings. Thereafter, retained earnings would be measured from the effective date of the quasi-reorganization. The payment of future dividends will also depend on earnings, the financial condition of the Company, market requirements and other factors.

Cumulative Preferred Stock

The number of authorized shares of cumulative preferred stock is 10 million shares.

The Company, upon 30 days notice, may redeem the cumulative preferred stock at stated redemption prices plus accrued and unpaid dividends. Redemption prices are at reduced premiums in future years. No

redemptions for the 12.52% Series may be made prior to October 15, 1991, except for the use of sinking fund and optional redemptions.

Mandatory redemption requirements for 1989 through 1993 are $2.3 million, $2.7 million, $3.6 million, $3.6 million and $3.6 million, respectively.

In 1988, 1987 and 1986, the Company redeemed or purchased approximately $5.3 million, $11.4 million and $93.8 million, respectively, of the Company's cumulative preferred stock.

Long-Term Debt

Substantially all utility plant is pledged to secure the Company's first mortgage bonds. A portion of certain series of long-term debt will be redeemed serially prior to their due dates. The aggregate amounts (in thousands) of maturities through 1993 on long-term debt outstanding at December 31, 1988, are as follows:

1989	$ 33,517
1990	$ 2,957
1991	$155,323
1992	$ 1,988
1993	$ 11,243

Long-term debt includes approximately $144.7 million of issues which, although current by their terms, can be refinanced by existing long-term credit arrangements. (See note 3.) The above table includes indebtedness supported by certain long-term credit commitments which are scheduled to terminate in 1991 and, accordingly, amounts then outstanding and supported by these credit commitments will be due at such time unless the credit commitments are renewed. The Company believes that these credit commitments will be extended to years beyond 1991.

Included in current maturities for 1989 is $30.4 million of a subsidiary's long-term debt which is classified as current due to its technical default under existing bank credit arrangements for failure to meet certain covenants as a result of write-downs taken in 1988 in conjunction with discontinued mining operations. The subsidiary is current on all payments under these arrangements.

(3) Short-Term Debt

The Company's interim financing requirements are met through the issuance of commercial paper and notes payable to banks. At December 31, 1988, the Company had credit commitments from various banks totaling approximately $173.3 million available either to support the issuance of commercial paper or to provide for additional bank borrowings. The Company generally pays commitment fees or maintains cash balances on deposit with banks to assure availability of its credit commitments. These commitments consist of both lines of credit and revolving credit agreements ranging in duration from one to three years.

Effective February 1, 1988, certain bank loans and commercial paper were classified as long-term debt consistent with underlying credit agreements and the Company's intention to maintain this debt for more than 12 months. At December 31, 1988, $144.4 million of commercial paper and $.3 million of notes payable to banks were classified as long-term. At December 31, 1987, commercial paper of $149.0 million and notes payable to banks of $3.0 million were classified as short-term.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(4) Income Taxes

Income taxes included in earnings (loss) from continuing operations consist of the following components:

	1988	1987	1986
		(In thousands)	
Current Federal income tax	$ 7,432	$26,683	$ 65,290
Current State income tax	1,521	1,777	23,798
Deferred Federal income tax	(8,983)	2,959	(4,831)
Deferred State income tax	(916)	1,540	(481)
Investment tax credit utilized and deferred	(333)	(3,329)	42,992
Amortization of accumulated investment tax credits	(6,383)	(5,367)	(5,176)
Total income taxes	$ (7,662)	$24,263	$121,592
Charged (credited) to operating expenses	$ 17,268	$14,990	$(6,727)
Charged (credited) to other income and deductions	(24,930)	9,273	128,319
Total income taxes	$ (7,662)	$24,263	$121,592

The Company's provision for income taxes from continuing operations, exclusive of extraordinary items, was less than the Federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	1988	1987	1986
Federal income tax at statutory rate of 34%, 40% and 46% for 1988, 1987 and 1986, respectively	$ (5,986)	$ 56,554	$129,221
Allowance for funds used during construction	(2,403)	(13,728)	(22,457)
Deferred carrying costs on uncommitted electric generating capacity	6,879	(5,228)	(7,448)
Investment tax credits	(6,383)	(5,367)	(5,176)
PVNGS start-up and pre-operational costs	(3,836)	(7,582)	(16,061)
Capital gains rate net of minimum tax	—	—	(16,101)
Depreciation of flow-through items	2,971	1,631	724
Reversal of flow-through items resulting from sale of PVNGS	—	—	55,146
Gains on the sale of PVNGS, deferred for financial reporting purposes	(907)	(1,193)	17,162
Premiums on retirement of first mortgage bonds	644	466	(14,666)
Losses on hedging transactions	188	217	(7,276)
Amortization of pollution control facilities	(1,528)	(1,766)	(2,041)
Reversal of permanent differences resulting from write-off of proposed generating station	6,234	—	—
State income tax	(215)	2,410	12,537
Other	(3,320)	(2,151)	(1,972)
Total income taxes	$ (7,662)	$ 24,263	$121,592

Deferred income taxes result from certain timing differences between the recognition of income and expense for tax and financial reporting purposes, as described in note 1.

The major sources of these differences for which deferred taxes have been provided and the tax effects of each are as follows:

	1988	1987	1986
		(In thousands)	
Deferred fuel costs	$ 8,160	$ 2,968	$ (3,074)
Depreciation and cost recovery timing differences	16,985	9,299	18,628
Pension cost timing differences	(1,067)	2,636	(4,043)
Contributions in aid of construction	(4,113)	(4,903)	—
Receipt of advance lease payments	744	828	(19,928)
Unbilled revenues	(2,486)	(2,689)	—
Alternative minimum tax in excess of regular tax	(5,132)	(6,709)	—
Write-off of proposed generating station	(12,865)	—	—
Other	(10,125)	3,069	3,105
Total deferred taxes	$ (9,899)	$ 4,499	$ (5,312)

The cumulative net amount of income tax timing differences upon which deferred income taxes have not been provided is estimated to be approximately $80.6 million and $96.7 million as of December 31, 1988 and 1987, respectively. Such amounts exclude AFUDC and deferred carrying costs on uncommitted electric generating capacity which are recorded on a net of tax basis.

See notes 11 and 12 for income taxes applicable to discontinued operations and extraordinary item.

At December 31, 1988, the Company had a net operating loss carryforward for Federal income tax purposes of $35.0 million which expires in 2003. For financial reporting purposes, the Company has utilized losses to offset existing deferred tax credits in the amount of $91.3 million. To the extent loss carryforwards are utilized for income tax purposes in the future, the deferred tax credits will be reinstated.

(5) Pension Plan and Other Post-Employment Benefits

Pension Plan

The Company and its subsidiaries have a pension plan covering substantially all of their employees, including officers. The plan is non-contributory and provides for benefits to be paid to eligible employees at retirement based primarily upon years of service with the Company and their compensation rates near retirement. The Company's policy is to fund actuarially-determined contributions. Contributions to the plan reflect benefits attributed to employees' years of service to date and also for services expected to be provided in the future. Plan assets primarily consist of common and preferred stocks, fixed income securities (primarily United States government obligations) and real estate.

In 1988 and 1986, the Company reduced its work force by 799 positions and 367 positions, respectively, in programs that included early retirements, voluntary and involuntary separation packages and layoffs. The effect of these reductions on pension costs is reflected in the table below.

The components of pension cost (in thousands) are as follows:

	1988	1987	1986
Service cost	$ 4,338	$ 6,598	$ 4,878
Interest cost	10,634	10,965	8,668
Actual return on plan assets	(14,088)	(10,432)	(12,163)
Other	172	(1,356)	872
Net periodic pension cost	1,056	5,775	2,255
Termination loss	9,036	—	10,640
Curtailment gain	(1,819)	—	(2,868)
Total pension cost	$ 8,273	$ 5,775	$ 10,027

The following sets forth the plan's funded status and amounts (in thousands) at December 31, 1988 and 1987:

	1988	1987
Vested benefits	$ 81,570	$ 68,656
Non-vested benefits	5,147	6,174
Accumulated benefit obligation	86,717	74,830
Effect of future compensation levels	32,377	33,250
Projected benefit obligation	119,094	108,080
Fair value of plan assets	141,487	126,714
Assets in excess of projected benefit obligations	$ 22,393	$ 18,634

The components of assets in excess of projected benefit obligations (in thousands) are as follows:

	1988	1987
Net unrecognized gain from past experience different from assumed	$15,106	$ 8,597
Unamortized asset at transition, being amortized through the year 2002	15,126	16,290
Accrued pension liability	(7,839)	(6,253)
	$22,393	$18,634

For both years, the weighted average discount rates used to measure the projected benefit obligation was 10.0%, the rate of increase in future compensation levels based on age-related scales was 6.5% and the expected long-term rate of return on plan assets was 10.0%.

Other Post-Employment Benefits

The Company also provides medical and dental benefits to eligible retirees who retire either at normal retirement date or early retirement. Currently, retirees under age 65 are offered the same benefits as active employees. Retirees age 65 and above are offered the same benefits as active employees after reflecting Medicare coordination. The cost of providing these benefits for retirees was $671,000, $820,000 and $799,000 for 1988, 1987 and 1986, respectively.

(6) Construction Program and Jointly-Owned Plants

The Company operates and jointly owns San Juan Generating Station ("SJGS"). At December 31, 1988, the Company owned an undivided 50% interest in the first three units of SJGS and 55.5% of Unit 4.

The Company participated with several other utilities in the construction of three generating units at PVNGS. Commercial operation commenced in 1986 for Unit 1 and Unit 2 and 1988 for Unit 3. In 1985 and 1986, the Company completed sale and leaseback transactions for its undivided interests in Units 1 and 2 and certain related common facilities.

It is estimated that the Company's construction expenditures for 1989 will approximate $90 million, including expenditures on the jointly-owned projects. In connection therewith, substantial commitments have been made.

At December 31, 1988, the Company's ownership interest and investments in jointly-owned generating facilities are:

Station (Fuel Type)	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Composite Ownership Interest
		(In thousands)		
San Juan Generating Station (Coal)	$811,488	$212,593	$ 2,220	51.6%
Palo Verde Nuclear Generating Station Unit 3 (Nuclear)*	$315,984	$ 9,074	$11,500	10.2%
Four Corners Generating Station Units 4 and 5 (Coal)	$ 97,814	$ 20,050	$11,645	13.0%

* Includes the Company's remaining interest in common facilities for all PVNGS units.

Since 1972 the Company has participated in a joint project, known as the Dineh Power Project, for the construction of a coal-fired generating station. The markets for such a project have not developed as had been anticipated and it can not be determined when or if the proposed station will be constructed. While such construction is still possible, the Company does not consider the recovery of the investment it has made to date to be probable. Accordingly, a provision has been made in the amount of $38.1 million (net of income taxes) to write off the Company's investment in the proposed generating station.

(7) Long-Term Power Contracts

The Company has entered into contracts for the purchase of electric power. Under a contract with M-S-R Public Power Agency, which contract expires in 1995, the Company is obligated to pay certain minimum amounts and a variable component representing the expenses associated with the energy purchased and debt service costs associated with capital improvements. Total payments under this contract amounted to $41.1 million, $41.0 million and $38.9 million for 1988, 1987 and 1986, respectively. The minimum payment for each of the next five years under this contract is $28.1 million annually.

The Company has a long-term contract with Southwestern Public Service Company ("SPS") requiring the Company to purchase capacity beginning in 1991. Minimum payments under the contract for 1991, 1992 and 1993 will be $4.9 million, $8.6 million and $8.8 million, respectively. The amount of minimum payments after 1993 will depend on whether the Company exercises certain options to reduce its purchase obligations.

The contract with SPS also requires SPS to purchase power from the Company through the end of 1989. Revenues from such sales accounted for approximately 11.9% of total 1988 revenues and 11.5% of total 1987 revenues. No customer accounted for more than 10% of total revenues in 1986.

(8) Lease Commitments

The Company classifies its leases in accordance with generally accepted accounting principles. The Company leases Units 1 and 2 of PVNGS, transmission facilities, office buildings and other equipment under operating leases. The aggregate annual lease payments for the PVNGS leases are $84.6 million over base lease terms expiring in 2015 and 2016. Each PVNGS lease contains renewal and fair market value purchase options at the end of the base lease term. Total net leased property under capital leases at December 31, 1988 and 1987 was approximately $2.2 million and $3.9 million, respectively.

Future minimum lease payments at December 31, 1988 are:

	Capital Leases	Operating Leases
	(In thousands)	
1989	$3,061	$ 98,194
1990	1,153	96,473
1991	20	95,690
1992	14	95,405
1993	13	94,987
Later years	—	2,033,463
Total minimum lease payments	4,261	$2,514,212
Less amount representing interest and executory costs	502	
Present value of net minimum lease payments	$3,759	

Operating lease expense was approximately $101.4 million in 1988, $102.6 million in 1987 and $59.1 million in 1986. As of December 31, 1988, the aggregate minimum payments to be received in future periods under noncancelable subleases are approximately $2.5 million.

(9) Natural Gas Contract Disputes

Gas Company of New Mexico ("GCNM"), a division of the Company, and Sunterra Gas Gathering Company ("Gathering Company"), a subsidiary of the Company, are currently disputing claims by certain producers relating to contract pricing, take-or-pay obligations and other matters. Some of these claims are the subject of pending litigation against GCNM and Gathering Company. In addition, other claims and litigation may arise. GCNM and Gathering Company are vigorously defending against these claims. The Company also intends to continue active pursuit of negotiations to resolve these matters. The Company is seeking to recover from its customers, through rate mechanisms subject to NMPSC regulation, amounts which may be paid to producers. In addition, the Company is asserting claims against third parties who, the Company believes, have contributed to the Company's potential liabilities. The Company has evaluated, and will continue to evaluate, the impact of these matters on the Company.

(10) Palo Verde Nuclear Generating Station

As stated in note 6, the Company participates with six other utilities in the three units of PVNGS. In 1985 and 1986, the Company sold and leased back its entire undivided interest in PVNGS Units 1 and 2 and certain common facilities. PVNGS Units 1 and 2 were declared in commercial service in 1986 and Unit 3 was declared in commercial service in 1988.

On January 14, 1987, the NMPSC issued an order docketing a case to investigate the prudence of the Company's investment in PVNGS. The Company has the burden of proving, and the Company believes, that PVNGS construction costs were reasonable and that its decisions to invest in and continue participation in

PVNGS were prudent. In November 1988, the NMPSC staff and the Company entered into an agreement in principle providing for the possible settlement of construction cost issues between them on the basis of a PVNGS construction audit being performed for the Arizona Corporation Commission.

On March 24, 1989, the report on the Arizona construction audit was released. The report concluded that certain PVNGS construction costs, AFUDC and ad valorem taxes were unreasonable. The Company's share of such costs is approximately $7.8 million (after income taxes), which has been charged to expense as of December 31, 1988.

On April 5, 1989, the NMPSC ordered parties to the case to file, by April 19, 1989, statements of position concerning the use of the results of the Arizona construction audit as a basis to resolve the construction cost issues in this case. The NMPSC also ordered the parties to the case to file, by May 8, 1989, statements of position on whether the inquiry into system planning issues should be terminated or continued, given the NMPSC order issued in the inventorying alternatives case which provides for, among other things, the exclusion of the Company's interest in PVNGS Unit 3 from New Mexico jurisdictional rates. (See note 12.) The hearing in the case is to commence on July 10, 1989. Should the NMPSC order a prudency disallowance, the Company would be required to charge any disallowed costs to expense at the time such disallowances are determined to be probable. While the Company cannot predict the ultimate outcome of these NMPSC proceedings, management believes that PVNGS was managed and constructed in a prudent manner.

The PVNGS participants have insurance for public liability payments resulting from nuclear energy hazards to the full $7.7 billion limit of liability under Federal law modified by legislation enacted in August 1988. 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. The maximum assessment per reactor under the retrospective rating program for each nuclear incident is approximately $66 million, subject to an annual limit of $10 million per incident. Based upon the Company's 10.2% ownership interest in the three PVNGS units, the Company's maximum potential assessment per incident is approximately $20 million, with an annual payment limitation of $3 million.

The PVNGS participants maintain "all-risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at PVNGS in the aggregate amount of $1.725 billion, a substantial portion of which must first be applied to decontamination. The Company has also secured insurance against a portion of the increased cost of generation or purchased power resulting from the accidental outage of any of the three PVNGS units.

The Company's share of PVNGS decommissioning costs is presently estimated, in 1986 dollars, at approximately $63 million. The Company has a program for funding its share of the costs of decommissioning PVNGS. The program calls for annual deposits to an external decommissioning trust in the current amount of $396,000 per unit, subject to adjustment for changes in estimated decommissioning costs and trust fund earnings. The trust funds are invested under a plan which allows the Company to accumulate funds for decommissioning largely on a tax-deferred basis. The Company began funding its share of decommissioning costs for PVNGS Units 1 and 2 in 1987 and PVNGS Unit 3 in 1988.

(11) Discontinuance of Non-Utility Operations

In 1988, the Company made the decision to discontinue the non-utility operations of its subsidiaries and to sell such non-utility properties. Such operations consist primarily of fiberboard manufacturing, real estate, coal mining, telecommunications manufacturing and financial services and were carried out by or through the Company's wholly-owned subsidiaries. Estimated losses on disposal of non-utility operations of $137.8 million (net of income tax benefits of $64.1 million) primarily reflect the decrease in the value of southwestern real estate holdings and the loss the Company expects to incur on the sale of a fiberboard

manufacturing facility. Such losses also include a provision of $29.5 million for expected operating losses prior to the expected disposal of non-utility operations in 1989. Approximately $13.8 million of the expected operating loss was incurred in 1988.

Operating results of the discontinued operations prior to the date of discontinuation are shown separately in the accompanying consolidated statement of earnings (loss). Such amounts include income tax benefits related to the losses from discontinued operations of $13.6 million in 1988, $15.7 million in 1987 and $14.5 million in 1986. Total sales from the discontinued operations were $128.0 million, $111.9 million and $54.2 million in 1988, 1987 and 1986, respectively. Prior to the decision to discontinue non-utility operations, such total sales and income tax benefits were included in other income and deductions in the consolidated statement of earnings (loss).

Net assets of the discontinued operations to be disposed of consisted of the following at December 31, 1988 and 1987:

	1988	1987
	(In thousands)	
Assets and liabilities of discontinued operations (before adjustments for loss on disposal):		
Current assets	$ 50,337	$ 46,428
Plant, property and equipment, net	19,353	98,150
Investments in unconsolidated affiliates	169,505	130,267
Other assets	46,909	8,574
Total assets	286,104	283,419
Notes payable	138,265	62,771
Other liabilities	54,497	40,579
Total liabilities	192,762	103,350
	$ 93,342	$180,069
Carrying value of net assets of discontinued operations (after adjustment for estimated loss on disposal)	$ —	$ 180,069

A subsidiary of the Company is in default as to interest and principal on a substantial portion of its notes payable shown above and is in the process of liquidating its assets. The Company does not anticipate recovery of any of its investment in the discontinued operations and has made a provision for potential claims.

(12) NMPSC Proceedings Relating to PVNGS and SJGS Unit 4

The Company's investment in PVNGS has been the subject of regulatory inquiry in recent years. The Company had previously filed a corporate reorganization and restructuring proposal which was the Company's response to its excess generating capacity problem. On January 14, 1987, the NMPSC docketed a proceeding to obtain proposals for alternatives to the inventorying methodology and to determine how to implement any final determination in a NMPSC case concerning the reasonableness of costs relating to PVNGS. The proceeding was consolidated with the NMPSC case relating to the Company's proposed reorganization and restructuring, which proposal was withdrawn in September 1988. In September 1988, the Company filed its proposed alternative to the inventorying methodology. The Company proposed a ten-year phase-in of PVNGS Units 1 and 2, the immediate inclusion into rates of the Company's interest in SJGS Unit 4 and the exclusion of PVNGS Unit 3 and certain long-term power contracts. Hearings in the matter concluded in December 1988.

On April 5, 1989, the NMPSC issued an order which, among other things, provides for the inclusion in NMPSC jurisdictional electric rate base of the Company's interests in PVNGS Units 1 and 2, 147 MW of SJGS Unit 4 and the power purchase contract with SPS. (See note 7.) However, the order excludes from New Mexico jurisdictional rates the Company's 130 MW interest in PVNGS Unit 3, 130 MW of SJGS Unit 4 and the power purchase contract with M-S-R. (See note 7.) The order states that as long as there is excess capacity in the Company's jurisdictional rates, then that excess capacity will share off-system sales equitably with the capacity excluded in the order.

The order does not affect current rates. Rates based on the order will be implemented though a rate case, which the Company expects to file in the near future and the results of which would likely be effective in the first half of 1990. The ultimate implementation of rates based on the inclusion of PVNGS costs will also depend on the outcome of the PVNGS cost investigation. (See note 10.)

The NMPSC order provides that 147 MW of SJGS Unit 4 will be immediately included in rates effective the date the NMPSC issues its final order in the rate case. The NMPSC order also provides that the rate case will consider (i) whether recovery of the Company's investment of PVNGS Units 1 and 2 should start immediately or whether such recovery should be phased in over a period of time, (ii) whether there should be a full and immediate return on PVNGS Units 1 and 2 or whether all or a portion of the return on such investment should be disallowed for some period of time and (iii) any other appropriate rate treatment of these units.

Since the order did not provide for the recovery of deferred carrying costs on uncommitted electric generating capacity pursuant to SFAS No. 92, the Company has discontinued the inventorying methodology and has written off $70.1 million of such costs previously deferred. Of such amount, $52.7 million, related to generating capacity to be included in New Mexico jurisdictional rates, was charged to other income and deductions and $17.4 million, related to excluded generating capacity, was reported as an extraordinary item.

The Company has discontinued the use of regulatory accounting principles for the resources excluded from regulation. Such discontinuance requires the Company to adjust the carrying value of excluded resources by those items, excluding AFUDC, which were recorded solely based on regulatory accounting principles. The Company has recognized a loss, which is treated as an extraordinary item, of $46.6 million (including an income tax expense of $6.8 million) primarily as a result of these proceedings. Such loss includes the write-off of $17.4 million of deferred carrying costs on uncommitted electric generating capacity.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(13) Segment Information

The financial information pertaining to the Company's electric, gas and other operations for the years ended December 31, 1988, 1987 and 1986 are as follows:

	Electric	Gas	Other	Total
		(In thousands)		
1988:				
Operating revenues	$ 607,317	$223,791	$ 10,816	$ 841,924
Operating expenses excluding income taxes	470,162	208,540	5,888	684,590
Pre-tax operating income	137,155	15,251	4,928	157,334
Operating income tax	15,624	448	1,196	17,268
Operating income	$ 121,531	$ 14,803	$ 3,732	$ 140,066
Depreciation and amortization expense	$ 56,450	$ 9,548	$ 922	$ 66,920
Construction expenditures	$ 68,230	$ 19,524	$ 9,427	$ 97,181
Identifiable assets:				
Net utility plant	$1,601,556	$243,123	$ 40,264	$ 1,884,943
Other	323,006	93,616	91,184	507,806
Total assets	$1,924,562	$336,739	$131,448	$ 2,392,749
1987:				
Operating revenues	$ 563,617	$210,634	$ 10,973	$ 785,224
Operating expenses excluding income taxes	437,203	195,329	5,351	637,883
Pre-tax operating income	126,414	15,305	5,622	147,341
Operating income tax	12,703	463	1,824	14,990
Operating income	$ 113,711	$ 14,842	$ 3,798	$ 132,351
Depreciation and amortization expense	$ 49,982	$ 9,313	$ 969	$ 60,264
Construction expenditures	$ 102,548	$ 17,125	$ 5,050	$ 124,723
Identifiable assets:				
Net utility plant	$1,623,751	$233,331	$ 35,472	$ 1,892,554
Net assets of discontinued operations	—	—	180,069	180,069
Other	475,416	90,301	78,801	644,518
Total assets	$2,099,167	$323,632	$294,342	$ 2,717,141
1986:				
Operating revenues	$ 520,896	$244,666	$ 10,245	$ 775,807
Operating expenses excluding income taxes	373,611	223,205	5,242	602,058
Pre-tax operating income	147,285	21,461	5,003	173,749
Operating income tax	(8,224)	(606)	2,103	(6,727)
Operating income	$ 155,509	$ 22,067	$ 2,900	$ 180,476
Depreciation and amortization expense	$ 50,567	$ 8,916	$ 766	$ 60,249
Construction expenditures	$ 178,230	$ 19,689	$ 36,588	$ 234,507
Identifiable assets:				
Net utility plant	$1,643,227	$226,430	$ 33,322	$ 1,902,979
Net assets of discontinued operations	—	—	176,378	176,378
Other	427,598	78,260	82,424	588,282
Total assets	$2,070,825	$304,690	$292,124	$ 2,667,639

(14) Supplemental Income Statement Information

Taxes, other than income taxes, charged to operating expenses were as follows:

	1988	1987	1986
		(In thousands)	
Ad valorem	$14,950	$12,712	$11,099
City franchise	8,890	8,996	8,279
Payroll	7,112	6,606	7,083
Other	3,871	3,369	4,050
Total	$34,823	$31,683	$30,511

Amortization of intangibles, royalties, and advertising costs were less than 1% of revenues in each of the above periods.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT

Years Ended December 31, 1988, 1987 and 1986

Classification December 31, 1988	Balance at Beginning of Year	Additions at Cost	Retirements	Other Changes Add	Other Changes Deduct	Balance at End of Year
			(In thousands)			
Utility plant:						
Electric plant in service:						
Intangible	$ 3,181	$ 8,988	$ —	$ —	$ —	$ 12,169
Production	905,110	311,538	1,171	859	1,970	1,214,366
Transmission	208,296	2,956	222	—	46	210,984
Distribution	340,067	25,713	3,338	14	684	361,772
General	61,956	4,774	2,366	1,227	746	64,845
	1,518,610	353,969	7,097	2,100	3,446	1,864,136
Gas plant in service:						
Intangible	2,376	269	—	181	—	2,826
Production	57,816	1,428	969	—	326	57,949
Natural gas storage and processing	4,885	—	—	—	—	4,885
Transmission	62,507	1,105	195	1,731	156	64,992
Distribution	182,200	14,837	1,690	—	6	195,341
General	29,058	4,098	1,130	512	—	32,538
	338,842	21,737	3,984	2,424	488	358,531
Water plant in service:						
Intangible	259	—	—	—	—	259
Source of supply plant	4,964	—	—	—	—	4,964
Pumping plant	2,052	71	13	—	—	2,110
Water treatment plant	3,968	—	—	—	—	3,968
Transmission and distribution	28,537	1,738	73	19	57	30,164
General	2,165	345	188	—	101	2,221
	41,945	2,154	274	19	158	43,686
Common plant in service:						
Intangible	13,613	776	—	—	—	14,389
General	28,613	1,138	2,552	83	143	27,139
	42,226	1,914	2,552	83	143	41,528
Construction work in progress	369,092	(296,867)	—	176	—	72,401
Electric plant held for future use	33,103	277	—	—	11,405	21,975
Nuclear fuel	76,826	9,808	8,663	—	—	77,971
Total utility plant	2,420,644	92,992	22,570	4,802	15,640	2,480,228
Non-utility property*	139,884	4,189	12,931	1,200	50,136	82,206
Total property, plant and equipment	$2,560,528	$ 97,181	$35,501	$6,002	$65,776	$2,562,434

Description of other changes

	Add	Deduct
Transfers between accounts	$2,530	$ 2,530
Transfer of expired contract deposits to plant in service	—	449
Write-off of electric plant held for future use	—	11,405
Write-off of non-utility property	—	48,451
Original cost of property acquired	1,742	156
Miscellaneous corrections and adjustments	1,730	2,785
	$6,002	$65,776

* Excludes properties of discontinued operations.

(Continued)

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT—(Continued)

Years Ended December 31, 1988, 1987 and 1986

Classification December 31, 1987	Balance at Beginning of Year	Additions at Cost	Retirements	Other Changes Add	Other Changes Deduct	Balance at End of Year
			(In thousands)			
Utility plant:						
Electric plant in service:						
Intangible	$ 3,750	$ —	$ 1,266	$ 1,091	$ 394	$ 3,181
Production	914,057	9,036	469	600	18,114	905,110
Transmission	207,227	1,691	116	—	506	208,296
Distribution	316,802	28,293	3,306	657	2,379	340,067
General	57,712	6,274	1,564	96	562	61,956
	1,499,548	45,294	6,721	2,444	21,955	1,518,610
Gas plant in service:						
Intangible	2,212	186	20	—	2	2,376
Production	57,692	549	360	—	65	57,816
Natural gas storage and processing	4,874	11	—	—	—	4,885
Transmission	62,216	627	337	1	—	62,507
Distribution	173,182	10,593	1,564	—	11	182,200
General	27,012	3,041	954	—	41	29,058
	327,188	15,007	3,235	1	119	338,842
Water plant in service:						
Intangible	259	—	—	—	—	259
Source of supply plant	4,949	15	—	—	—	4,964
Pumping plant	2,058	—	6	—	—	2,052
Water treatment plant	3,968	—	—	—	—	3,968
Transmission and distribution	25,494	2,444	64	674	11	28,537
General	2,106	139	100	20	—	2,165
	38,834	2,598	170	694	11	41,945
Common plant in service:						
Intangible	15,900	1,778	4,459	394	—	13,613
General	28,920	917	640	376	960	28,613
	44,820	2,695	5,099	770	960	42,226
Construction work in progress	321,164	47,598	—	330	—	369,092
Electric plant held for future use	74,132	2,168	7	15,218	58,408	33,103
Nuclear fuel	70,223	6,603	—	—	—	76,826
Total utility plant	2,375,909	121,963	15,232	19,457	81,453	2,420,644
Non-utility property*	79,367	2,760	2,354	61,243	1,132	139,884
Total property, plant and equipment	$2,455,276	$124,723	$17,586	$80,700	$82,585	$2,560,528

Description of other changes

	Add	Deduct
Transfers between accounts	$77,053	$77,053
Transfer of expired contract deposits to plant in service	—	636
Miscellaneous corrections and adjustments	3,647	4,896
	$80,700	$82,585

* Excludes properties of discontinued operations

(Continued)

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE V—PROPERTY, PLANT AND EQUIPMENT—(Continued)

Years Ended December 31, 1988, 1987 and 1986

Classification December 31, 1986	Balance at Beginning of Year	Additions at Cost	Retirements	Other Changes Add	Other Changes Deduct	Balance at End of Year
			(In thousands)			
Utility plant:						
Electric plant in service:						
Intangible	$ 6,021	$ —	$ —	$ —	$2,271	$ 3,750
Production	902,151	109,357	97,407	—	44	914,057
Transmission	204,944	4,025	1,562	8	188	207,227
Distribution	282,106	37,198	2,032	8	478	316,802
General	47,310	12,846	2,311	59	192	57,712
	1,442,532	163,426	103,312	75	3,173	1,499,548
Gas plant in service:						
Intangible	542	565	2	1,107	—	2,212
Production	57,575	1,244	1,049	—	78	57,692
Natural gas storage and processing	4,872	2	—	—	—	4,874
Transmission	58,505	3,868	261	104	—	62,216
Distribution	163,155	12,341	2,383	69	—	173,182
General	26,400	2,776	1,060	—	1,104	27,012
	311,049	20,796	4,755	1,280	1,182	327,188
Water plant in service:						
Intangible	225	34	—	—	—	259
Source of supply plant	4,954	4	—	—	9	4,949
Pumping plant	1,955	103	—	—	—	2,058
Water treatment plant	3,968	—	—	—	—	3,968
Transmission and distribution	23,008	2,551	57	—	8	25,494
General	2,045	148	87	—	—	2,106
	36,155	2,840	144	—	17	38,834
Common plant in service:						
Intangible	14,161	939	—	2,271	1,471	15,900
General	27,461	2,972	1,471	1	43	28,920
	41,622	3,911	1,471	2,272	1,514	44,820
Construction work in progress	630,761	(11,746)	298,921	1,070	—	321,164
Electric plant held for future use	68,095	6,344	314	7	—	74,132
Nuclear fuel	55,763	14,460	—	—	—	70,223
Total utility plant	2,585,977	200,031	408,917	4,704	5,886	2,375,909
Non-utility property*	46,452	34,476	3,103	1,615	73	79,367
Total property, plant and equipment	$2,632,429	$234,507	$412,020	$6,319	$5,959	$2,455,276

Description of other changes

	Add	Deduct
Transfers between accounts	$5,038	$5,038
Transfer of expired contract deposits to plant in service	—	412
Transfer of contract termination charges	—	130
Miscellaneous corrections and adjustments	1,281	379
	$6,319	$5,959

* Excludes properties of discontinued operations.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

Years Ended December 31, 1988, 1987 and 1986

Description December 31, 1988	Balance at Beginning of Year	Additions: Charged to Operating Expenses	Additions: Charged to Other Accounts	Retirements	Other Changes: Add	Other Changes: Deduct	Balance at End of Year
				(In thousands)			
Utility plant:							
Accumulated provision for depreciation of utility plant:							
Electric plant in service	$373,936	$52,627	$ 876	$ 7,482	$1,037	$1,167	$419,827
Gas plant in service	110,201	8,876	842	4,925	1,695	—	116,689
Water plant in service	7,846	882	46	279	—	5	8,490
Common plant in service	8,741	873	1,552	765	99	105	10,395
	500,724	63,258	3,316	13,451	2,831	1,277	555,401
Accumulated provision for amortization of intangible assets—franchises and computer software	10,190	3,626	226	—	—	58	13,984
Accumulated provision for amortization of nuclear fuel	18,088	—	19,106	8,663	—	1,907	26,624
Retirement work in progress.	(912)	—	—	(188)	—	—	(724)
Total utility plant	528,090	66,884	22,648	21,926	2,831	3,242	595,285
Non-utility property*	16,326	—	2,988	277	179	7	19,209
	$544,416	66,884	$25,636	$22,203	$3,010	$3,249	$614,494
Other amortization		36					
		$66,920					

Description of other additions and changes	Charged to Other Accounts	Other Changes: Add	Other Changes: Deduct
Depreciation and amortization of equipment charged to clearing accounts for distribution in accordance with use	$ 3,542	$ —	$ —
Amortization of nuclear fuel charged to fuel and purchased power	19,106	—	—
Depreciation of non-utility property charged to other income and deductions	2,988	—	—
Transfers between accounts	—	548	548
Accumulated depreciation on property acquired	—	1,397	—
Miscellaneous corrections and adjustments	—	1,065	2,701
	$25,636	$3,010	$3,249

* Excludes accumulated depreciation and amortization on properties of discontinued operations.

(Continued)

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT—(Continued)

Years Ended December 31, 1988, 1987 and 1986

Description December 31, 1987	Balance at Beginning of Year	Additions: Charged to Operating Expenses	Additions: Charged to Other Accounts	Retirements	Other Changes: Add	Other Changes: Deduct	Balance at End of Year
			(In thousands)				
Utility plant:							
Accumulated provision for depreciation of utility plant:							
Electric plant in service	$333,334	$46,772	$ 1,471	$ 4,912	$1,719	$4,448	$373,936
Gas plant in service	103,751	8,814	824	3,164	—	24	110,201
Water plant in service	7,195	742	55	168	22	—	7,846
Common plant in service	7,061	798	1,861	474	769	1,274	8,741
	451,341	57,126	4,211	8,718	2,510	5,746	500,724
Accumulated provision for amortization of intangible assets—franchises and computer software	12,637	2,654	648	5,748	45	46	10,190
Accumulated provision for amortization of nuclear fuel	9,460	—	8,628	—	—	—	18,088
Retirement work in progress	(508)	—	—	404	—	—	(912)
Total utility plant	472,930	59,780	13,487	14,870	2,555	5,792	528,090
Non-utility property*	11,647	—	2,876	7	1,810	—	16,326
	$484,577	59,780	$16,363	$14,877	$4,365	$5,792	$544,416
Other amortization		484					
		$60,264					

Description of other additions and changes

	Charged to Other Accounts	Add	Deduct
Depreciation and amortization of equipment charged to clearing accounts for distribution in accordance with use	$ 4,859	$ —	$ —
Amortization of nuclear fuel charged to fuel and purchased power	8,628	—	—
Depreciation of non-utility property charged to other income and deductions	2,876	—	—
Transfers between accounts	—	1,810	1,810
Miscellaneous corrections and adjustments	—	2,555	3,982
	$16,363	$4,365	$5,792

* Excludes accumulated depreciation and amortization on properties of discontinued operations.

(Continued)

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE VI—ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT—(Continued)

Years Ended December 31, 1988, 1987 and 1986

Description December 31, 1986	Balance at Beginning of Year	Additions: Charged to Operating Expenses	Additions: Charged to Other Accounts	Retirements	Other Changes: Add	Other Changes: Deduct	Balance at End of Year
				(In thousands)			
Utility plant:							
Accumulated provision for depreciation of utility plant:							
Electric plant in service	$292,231	$47,014	$ 1,162	$ 6,925	$2,132	$2,280	$333,334
Gas plant in service	99,225	8,794	656	4,548	—	376	103,751
Water plant in service	6,634	686	43	169	72	71	7,195
Common plant in service	5,393	778	1,916	1,119	181	88	7,061
	403,483	57,272	3,777	12,761	2,385	2,815	451,341
Accumulated provision for amortization of intangible assets—franchises and computer software	9,454	2,953	576	713	367	—	12,637
Accumulated provision for amortization of nuclear fuel	1,154	—	8,306	—	—	—	9,460
Retirement work in progress	429	—	—	937	—	—	(508)
Total utility plant	414,520	60,225	12,659	14,411	2,752	2,815	472,930
Non-utility property*	9,835	—	1,957	141	—	4	11,647
	$424,355	60,225	$14,616	$14,552	$2,752	$2,819	$484,577
Other amortization		24					
		$60,249					

Description of other additions and changes	Charged to Other Accounts	Other Changes: Add	Other Changes: Deduct
Depreciation and amortization of equipment charged to clearing accounts for distribution in accordance with use	$ 4,353	$ —	$ —
Amortization of nuclear fuel charged to fuel and purchased power	8,306	—	—
Depreciation of non-utility property charged to other income and deductions	1,957	—	—
Transfers between accounts	—	2,627	2,627
Miscellaneous corrections and adjustments	—	125	192
	$14,616	$2,752	$2,819

* Excludes accumulated depreciation and amortization on properties of discontinued operations.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE VIII—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended December 31, 1988, 1987 and 1986

	Balance at Beginning of Year	Additions: Charged to Operating Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Year
			(In thousands)		
December 31, 1987:					
Allowance for doubtful receivables ...	$ 205	$ 28	$ 4(a)	$ 237(b)	$ —
December 31, 1986:					
Allowance for doubtful receivables ...	$1,263	$1,259	$480(a)	$2,797(b)	$205

(a) Recoveries of amounts previously written off.

(b) Uncollectible receivables written off.

Beginning in 1987, the Company discontinued using an allowance for doubtful receivables and began using the direct write-off method for doubtful receivables as ordered for rate making purposes.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

SCHEDULE IX—SHORT-TERM BORROWINGS

Years Ended December 31, 1988, 1987 and 1986

Category of Aggregate Short-Term Borrowings	Balance at End of Year	Weighted Average Interest Rate at End of Year	Maximum Amount Outstanding During Year	Average Amount Outstanding During the Year	Average Interest Rate During the Year
			(Dollars in thousands)		
December 31, 1988*:					
Notes payable to banks	$ —	—%	$ 8,528	$ 2,910	8.35%
Commercial paper	$ —	—%	$160,550	$ 12,898	7.06%
December 31, 1987:					
Notes payable to banks	$ 3,000	8.35%	$ 27,841	$ 11,866	8.99%
Commercial paper	$149,000	8.58%	$163,600	$103,547	6.92%
December 31, 1986:					
Notes payable to banks	$ 5,000	7.90%	$ 50,500	$ 12,207	5.79%
Commercial paper	$ 10,500	5.35%	$142,620	$ 48,755	6.62%

* Effective February 1, 1988 certain bank loans and commercial paper were classified as long-term debt consistent with underlying credit agreements and management's intention to maintain this debt for more than twelve months.

The average amount outstanding during the year is calculated using month-end balances. The average interest rate during the year is calculated by dividing interest expense by the average amount outstanding during the year.

The above table excludes short-term borrowings of discontinued operations.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

QUARTERLY OPERATING RESULTS

The unaudited operating results by quarters for 1988 and 1987 are as follows:

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
1988:				
Operating Revenues(2)	$237,736	$195,743	$ 201,778	$ 206,667
Operating Income	$ 38,783	$ 31,604	$ 34,296	$ 35,383
Earnings (Loss) before Extraordinary Item(1)	$ 20,736	$ 12,344	$ (55,476)	$(161,145)
Net Earnings (Loss)(3)	$ 20,736	$ 12,344	$ (82,101)	$(181,116)
Earnings (Loss) before Extraordinary Item per Share(1)	$ .43	$ .23	$ (1.39)	$ (3.92)
Net Earnings (Loss) per Share(3)	$ .43	$ .23	$ (2.03)	$ (4.40)
1987:				
Operating Revenues(2)	$230,264	$189,825	$ 183,897	$ 181,238
Operating Income	$ 39,577	$ 30,973	$ 35,216	$ 26,585
Net Earnings	$ 29,151	$ 21,472	$ 26,219	$ 18,547
Net Earnings per Share	$ .63	$ .44	$ .56	$ .37

In the opinion of management of the Company, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of the results of operations for such periods have been included.

(1) During the third quarter of 1988, the Company's board of directors decided to discontinue the Company's non-utility subsidiary operations. As a result, estimated losses of $53.0 million for the third quarter and $84.8 million for the fourth quarter were recognized. (See note 11 of the notes to consolidated financial statements.) In addition, during the fourth quarter of 1988, the Company recorded a write-off of deferred carrying costs on uncommitted electric generating capacity, a write-off of a proposed generating station and other non-recurring charges, aggregating $105.5 million (net of taxes).

(2) Certain off-system energy sales to utilities had been accounted for as a reduction of fuel and purchased power expense. Such sales have been reclassified as revenues.

(3) In 1988, the Company discontinued the use of regulatory accounting principles for the resources excluded from regulation. Such discontinuance requires the Company to adjust the carrying value of excluded resources by those items, excluding AFUDC, which were recorded solely based on regulatory accounting principles. As a result, the Company recorded $26.6 million in the third quarter of 1988 and $20.0 million in the fourth quarter of 1988 as an extraordinary item. (See note 12 of the notes to consolidated financial statements.)

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

COMPARATIVE OPERATING STATISTICS

	1988	1987	1986	1985	1984
Electric Service					
Energy Sales—KWh (in thousands):					
Residential	1,493,009	1,448,989	1,353,933	1,319,529	1,279,917
Commercial	2,097,277	2,003,735	1,872,902	1,765,077	1,706,044
Industrial	899,508	787,901	797,927	788,880	762,117
Other ultimate customers	194,794	207,173	208,534	206,356	184,725
Total sales to ultimate customers	4,684,588	4,447,798	4,233,296	4,079,842	3,932,803
Sales for resale*	3,508,596	2,490,926	2,494,234	3,357,220	3,269,651
Total KWh sales	8,193,184	6,938,724	6,727,530	7,437,062	7,202,454
Electric Revenues (in thousands):					
Residential	$ 140,731	$ 136,194	$ 126,053	$ 119,026	$ 107,395
Commercial	187,800	179,653	166,424	152,921	134,532
Industrial	62,401	56,534	56,649	53,127	50,439
Other ultimate customers	13,931	15,161	14,622	14,293	11,950
Total revenues from ultimate customers	404,863	387,542	363,748	339,367	304,316
Sales for resale*	190,085	167,727	149,225	147,169	153,940
Total revenues from energy sales	594,948	555,269	512,973	486,536	458,256
Miscellaneous electric revenues	12,369	8,348	7,923	8,313	3,645
Total electric revenues	$ 607,317	$ 563,617	$ 520,896	$ 494,849	$ 461,901
Customers at Year End:					
Residential	250,076	244,427	237,759	227,420	217,614
Commercial	31,024	29,882	28,736	27,053	25,614
Industrial	390	399	414	428	436
Other ultimate customers	376	332	213	216	194
Total ultimate customers	281,866	275,040	267,122	255,117	243,858
Sales for resale*	11	8	7	8	8
Total customers	281,877	275,048	267,129	255,125	243,866
Reliable Net Capability—KW	1,591,000	1,461,000	1,566,000	1,305,000	1,337,000
Coincidental Peak Demand—KW	956,000	916,000	916,000	861,000	976,000
Average Fuel Cost per Million BTU	$1.2460	$1.2894	$1.1710	$1.2233	$1.0970
BTU per KWh of Net Generation	11,146	11,526	11,608	11,214	11,023
Water Service					
Water Sales—Gallons (in thousands)	2,726,666	2,683,961	2,535,656	2,387,468	2,392,085
Revenues (in thousands)	$ 10,816	$ 10,973	$ 10,245	$ 8,144	$ 6,354
Customers at Year End	19,713	19,448	18,820	18,240	17,717

* Prior to 1988, certain off-system energy sales to utilities were accounted for as a reduction of fuel and purchased power expense. Such sales for 1984-1987 have been reclassified to be consistent with 1988.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES

COMPARATIVE OPERATING STATISTICS

	1988	1987	1986	1985*
Gas Service				
Gas Throughput—Decatherms (in thousands):				
Residential	24,692	24,510	22,076	19,232
Commercial	11,460	11,359	10,745	9,642
Industrial	1,726	2,196	5,909	13,806
Public authorities	6,206	6,811	8,323	9,073
Brokerage	879	2,796	2,079	13
Irrigation	1,440	1,402	1,853	1,693
Sales for resale	2,667	1,211	1,535	1,702
Total gas sales	49,070	50,285	52,520	55,161
Transportation throughput	9,133	5,149	2,245	147
Total gas throughput	58,203	55,434	54,765	55,308
Gas Revenues (in thousands):				
Residential	$122,592	$114,164	$117,011	$111,427
Commercial	45,235	42,120	45,812	45,519
Industrial	6,063	8,102	23,139	48,933
Public authorities	22,289	22,729	30,213	38,181
Brokerage	1,514	5,213	3,759	31
Irrigation	4,546	3,781	6,142	6,507
Sales for resale	6,969	3,819	5,675	6,638
Total revenues from gas sales	209,208	199,928	231,751	257,236
Transportation	4,841	4,315	2,207	83
Miscellaneous gas revenues	9,742	6,391	10,708	16,418
Total gas revenues	$223,791	$210,634	$244,666	$273,737
Customers at Year End:				
Residential	303,173	297,204	290,175	283,530
Commercial	28,858	28,661	28,218	27,435
Industrial	105	118	145	170
Public authorities	2,469	2,425	2,444	2,427
Brokerage	2	2	14	1
Irrigation	1,261	1,257	1,328	1,432
Sales for resale	6	5	11	10
Transportation	20	16	16	4
Total customers	335,894	329,688	322,351	315,009

* Effective from acquisition date, January 28, 1985. Certain amounts have been reclassified for comparability.

ITEM 9. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

Reference is hereby made to "Election of Directors" in the Company's Proxy Statement relating to the annual meeting of stockholders to be held on May 16, 1989 (the "1989 Proxy Statement") and to PART I, SUPPLEMENTAL ITEM—"EXECUTIVE OFFICERS OF THE COMPANY".

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Executive Compensation" in the 1989 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Reference is hereby made to "Voting Information" and "Election of Directors" in the 1989 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Reference is hereby made to the 1989 Proxy Statement for such disclosure, if any, as may be required by this item.

PART IV

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

(a)—1. See Index to Financial Statements under Item 8.

(a)—2. The following consolidated financial information for the years 1988, 1987 and 1986 is submitted under Item 8.

Schedule V —Property, plant and equipment.
Schedule VI —Accumulated depreciation and amortization of property, plant and equipment.
Schedule VIII —Valuation and qualifying accounts and reserves.
Schedule IX —Short-term borrowings.

All other schedules are omitted for the reason that they are not applicable, not required or the information is otherwise supplied.

(a)—3-A. Exhibits Filed:

Exhibit Number	Description
3.2	—Bylaws of the Company, as amended through March 31, 1989.
10.59	—Alliance Telecommunications Corporation Director Initial Stock Option Plan dated February 4, 1988.
10.60	—Alliance Telecommunications Corporation Director Fee Waiver Option Plan dated February 4, 1988.
10.60.1	—Alliance Telecommunications Corporation Director Fee Waiver Option Agreement dated May 3, 1988.
10.61	—Form of Executive Retention Plan, CMC Group and January 24, 1989 Resolution Authorizing Plan.
10.62	—Public Service Company of New Mexico and Paragon Resources, Inc. Deferred Compensation Trust Agreement dated December 30, 1988.

(a)—3-B. Exhibits Incorporated By Reference:

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation 201.24 by reference to the filings set forth below:

Exhibit No.	Description	Filed as Exhibit:	File No.
Articles of Incorporation and By-laws			
3.1	Restated Articles of Incorporation of the Company, as amended through May 10, 1985.	4-(b) to Registration Statement No. 2-99990 of the Company.	2-99990
Instruments Defining the Rights of Security Holders, Including Indentures			
4.1	Indenture of Mortgage and Deed of Trust dated as of June 1, 1947, between the Company and Irving Trust Company, as Trustee, together with the Ninth Supplemental Indenture dated as of January 1, 1967, the Twelfth Supplemental Indenture dated as of September 15, 1971, the Fourteenth Supplemental Indenture dated as of December 1, 1974 and the Twenty-second Supplemental Indenture dated as of October 1, 1979 thereto relating to First Mortgage Bonds of the Company.	4-(d) to Registration Statement No. 2-99990 of the Company.	2-99990
4.2	Portions of sixteen supplemental indentures to the Indenture of Mortgage and Deed of Trust dated as of June 1, 1947, between the Company and Irving Trust Company, as Trustee, relevant to the declaration or payment of dividends or the making of other distributions on or the purchase by the Company of shares of the Company's Common Stock.	4-(e) to Registration Statement No. 2-99990 of the Company.	2-99990
4.3	Agreement of the Company pursuant to Item 601(b)(4)(iii) of Regulation S-K.	4-C to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1983.	1-6986
Material Contracts			
10.1	Supplemental Indenture of Lease dated as of July 19, 1966 between the Company and other participants in the Four Corners Project and the Navajo Indian Tribal Council.	4-D to Registration Statement No. 2-26116 of the Company.	2-26116

Exhibit No.	Description	Filed as Exhibit:	File No.
10.1.1	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease dated April 25, 1985 between the Navajo Tribe of Indians and Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, and Tucson Electric Power Company.	10.1.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.2	Fuel Agreement, as supplemented, dated as of September 1, 1966 between Utah Construction & Mining Co. and the participants in the Four Corners Project including the Company.	4-H to Registration Statement No. 2-35042 of the Company.	2-35042
10.3	Fourth Supplement to Four Corners Fuel Agreement No. 2 effective as of January 1, 1981, between Utah International Inc. and the participants in the Four Corners Project including the Company.	(10)-BB to Annual Report of the Registrant on Form 10-K for the fiscal year ending December 31, 1980.	1-6986
10.4	Contract between the United States and the Company dated April 11, 1968, for furnishing water.	5-L to Registration Statement No. 2-41010 of the Company.	2-41010
10.4.1	Amendatory Contract between the United States and the Company dated September 29, 1977 for furnishing water.	5-R to Registration Statement No. 2-60021 of the Company.	2-60021
10.5	Co-Tenancy Agreement between the Company and Tucson Gas & Electric Company dated February 15, 1972 pertaining to the San Juan generating plant.	5-O to Registration Statement No. 2-44425 of the Company.	2-44425
10.5.1	Modification No. 4 to Co-Tenancy Agreement between the Company and Tucson Electric Power Company dated October 25, 1984.	10.5.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.5.2	Modification No. 5 to Co-Tenancy Agreement between the Company and Tucson Electric Power Company dated July 1, 1985.	10.5.2 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.6	San Juan Project Construction Agreement between the Company and Tucson Gas & Electric Company, executed December 21, 1973.	5-R to Registration Statement No. 2-50338 of the Company.	2-50338
10.6.1	Modification No. 4 to San Juan Project Construction Agreement between the Company and Tucson Electric Power Company dated October 25, 1984.	10.6.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No:
10.6.2	Modification No. 5 to San Juan Project Construction Agreement between the Company and Tucson Electric Power Company dated July 1, 1985.	10.6.2 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.7	San Juan Project Operating Agreement between the Company and Tucson Gas & Electric Company, executed December 21, 1973.	5-S to Registration Statement No. 2-50338 of the Company.	2-50338
10.7.1	Modification No. 4 to San Juan Project Operating Agreement between the Company and Tucson Electric Power Company dated October 25, 1984.	10.7.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.7.2	Modification No. 5 to San Juan Project Operating Agreement between the Company and Tucson Electric Power Company dated July 1, 1985.	10.7.2 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.8	Arizona Nuclear Power Project Participation Agreement among the Company and Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, Tucson Gas & Electric Company and El Paso Electric Company, dated August 23, 1973.	5-T to Registration Statement No. 2-50338 of the Company.	2-50338
10.8.1	Amendments One through Four to Arizona Nuclear Power Project Participation Agreement.	(c) to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1979.	1-6986
10.8.2	Amendment No. 5 to the Arizona Nuclear Power Project Participation Agreement dated as of December 5, 1979.	10-Z to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.8.3	Amendment No. 6 to the Arizona Nuclear Power Project Participation Agreement effective October 16, 1981.	10-AA to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.8.4	Amendment No. 7, effective April 1, 1982, to the Arizona Nuclear Power Project Participation Agreement.	10-BB to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1982.	1-6986
10.8.5	Amendment No. 8, effective September 12, 1983, to the Arizona Nuclear Power Project Participation Agreement.	10-JJ to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1983.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.8.6	Amendment No. 9 to Arizona Nuclear Power Project Participation Agreement dated as of June 12, 1984.	10-JJ to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986
10.8.7	Amendment No. 10 to Arizona Nuclear Power Project Participation Agreement dated as of November 21, 1985.	10.8.7 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.8.8	Amendment No. 11 to Arizona Nuclear Power Project Participation Agreement dated June 13, 1986 and effective January 10, 1987.	10.8.8 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.9	Coal Sales Agreement executed August 18, 1980 between San Juan Coal Company, the Company and Tucson Electric Power Company.	(10)-EE to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1980.	1-6986
10.9.1	Amendment Number 1 to Coal Sales Agreement dated September 30, 1981 among San Juan Coal Company, the Company and Tucson Electric Power Company.	10-V to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.9.2	Amendment No. Three to Coal Sales Agreement dated April 30, 1984 among San Juan Coal Company, the Company and Tucson Electric Power Company (confidentiality treatment has been requested and exhibit is not filed herewith).	10-NN to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986
10.10	Modifications No. 1 to San Juan Project Agreements.	A part of 10-T to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.11	San Juan Unit 4 Early Purchase and Participation Agreement dated as of September 26, 1983, between the Company and M-S-R Public Power Agency, and Modifications No. 2 to the San Juan Project Agreements dated December 31, 1983.	10-KK to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1983.	1-6986
10.11.1	Amendment No. 1 to the Early Purchase and Participation Agreement between Public Service Company of New Mexico and M-S-R Public Power Agency, executed as of December 16, 1987, for San Juan Unit 4.	10.11.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.12	Amended and Restated San Juan Unit 4 Purchase and Participation Agreement dated as of December 28, 1984 between the Company and the Incorporated County of Los Alamos.	10-OO to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.13	Modifications No. 3 to San Juan Project Agreements dated July 17, 1984.	10-KK to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986
10.14	Participation Agreement among the Company, Tucson Electric Power Company and certain financial institutions relating to the San Juan Coal Trust dated as of December 31, 1981.	10-W to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.15	Participation Agreement dated as of June 30, 1983 among Security Trust Company, as Trustee, the Company, Tucson Electric Power Company and certain financial institutions relating to San Juan Coal Trust.	10-II to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31. 1983.	1-6986
10.16	Participation Agreement between the Company, the Owner Trustee and the Equity Participants with respect to the leveraged preferred stock of the Company dated as of December 1, 1981.	10-CC to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1981.	1-6986
10.17	Interconnection Agreement dated November 24, 1982, between the Company and Southwestern Public Service Company.	10-II to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1982.	1-6986
10.18*	Lease dated February 5, 1985 between The First National Bank of Boston, Lessor, and the Company, Lessee.	10.28 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.18.1*	Supplement No. 1 dated September 30, 1985, to Lease dated February 5, 1985 between The First National Bank of Boston, Lessor, and the Company, Lessee.	10.28.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.19	New Mexico Public Service Commission Order dated December 12, 1984, and Exhibit A thereto, in NMPSC Case No. 1804, regarding inventoried capacity.	10-PP to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986
10.20	New Mexico Public Service Commission Order dated August 12, 1986, and Attachment A thereto, in NMPSC Case No. 2011, regarding the application of the inventorying methodology to certain sale and leaseback transactions.	10.20 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.21*	Facility Lease dated as of December 16, 1985, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico.	28(a) to the Company's Current Report on Form 8-K dated December 31, 1985.	1-6986
10.21.1*	Amendment No. 1 dated as of July 15, 1986, to Facility Lease dated as of December 16, 1985.	28.1 to the Company's Current Report on Form 8-K dated July 17, 1986.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.21.2*	Amendment No. 2 dated as of November 18, 1986, to Facility Lease dated as of December 16, 1985.	28.1 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
10.21.3	Amendment No. 3 dated as of March 30, 1987, to Facility Lease dated as of December 16, 1985.	10.21.3 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.22	Facility Lease dated as of July 31, 1986, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico.	28.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1986.	1-6986
10.22.1	Amendment No. 1 dated as of November 18, 1986, to Facility Lease dated as of July 31, 1986.	28.5 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
10.22.2	Amendment No. 2 dated as of December 11, 1986, to Facility Lease dated as of July 31, 1986.	10.22.2 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.22.3	Amendment No. 3 dated as of April 8, 1987, to Facility Lease dated as of July 31, 1986.	10.22.3 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.23*	Facility Lease dated as of August 12, 1986, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico.	28.1 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
10.23.1*	Amendment No. 1 dated as of November 18, 1986, to Facility Lease dated as of August 12, 1986.	28.9 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
10.23.2	Amendment No. 2 dated as of November 25, 1986, to Facility Lease dated as of August 12, 1986.	10.23.2 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.24	Facility Lease dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico (Unit 1 Transaction).	28.1 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
10.24.1	Amendment No. 1 dated as of April 8, 1987, to Facility Lease dated as of December 15, 1986.	10.24.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.25	Facility Lease dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico (Unit 2 Transaction).	28.9 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
10.25.1	Amendment No. 1 dated as of April 8, 1987, to Facility Lease dated as of December 15, 1986.	10.25.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.26	Restated and Amended Public Service Company of New Mexico Accelerated Management Performance Plan (1988). (August 16, 1988.)	19.5 to the Company's Report on Form 10-Q for the quarter ended September 30, 1988.	1-6986
10.26.1	First Amendment to Restated and Amended Public Service Company of New Mexico Accelerated Management Performance Plan (1988). (August 30, 1988.)	19.6 to the Company's Report on Form 10-Q for the quarter ended September 30, 1988.	1-6986
10.27	Public Service Company of New Mexico Service Bonus Plan, October 23, 1984.	19.4 to the Company's Report on Form 10-Q for the quarter ended September 30, 1988.	1-6986
10.27.1	First Amendment to Public Service Company of New Mexico Service Bonus Plan dated November 20, 1985.	10.11.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.29	Corporate Long-Term Executive Incentive Compensation Plan (May 1984) of the Company. (Terminated.)	10.30 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.30	Corporate Long-Term Executive Incentive Compensation Plan (1986-1989) of the Company.	10.31 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.31	Management Life Insurance Plan (July 1985) of the Company.	10.39 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.32	Supplemental Executive Retirement Plan of the Company dated July 23, 1985.	10.41 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.33	Compensatory Agreement with Mr. James F. Jennings, Jr.	10-MM to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.34	Bellamah Community Development Executive Deferred Compensation Plan. (Terminated.)	10-II to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1984.	1-6986
10.35	Bellamah Community Development Executive Deferred Compensation Plan (1986). (Terminated.)	10.31 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1985.	1-6986
10.36	Bellamah Community Development Executive Deferred Compensation Plan (1987). (Terminated.)	19.1 to the Company's Quarterly Report on Form 10-Q for Quarter ended March 31, 1987.	1-6986
10.37	Sunbelt Mining Company, Inc. Annual Executive Compensation Incentive Plan (1987).	10.42 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
10.38	Meadows Resources, Inc. Executive Deferred Compensation Plan, Plexsys Investment. (November 23, 1987.)	19.2 to the Company's Quarterly Report on Form 10-Q for Quarter ended September 30, 1988.	1-6986
10.39	Ontario Partners Bonus Plan.	19.3 to the Company's Quarterly Report on Form 10-Q for Quarter ended March 31, 1987.	1-6986
10.40	Meadows Resources, Inc. Short Term Incentive Plan (1987). (Terminated.)	19.4 to the Company's Quarterly Report on Form 10-Q for Quarter ended March 31, 1987.	1-6986
10.41	Public Service Company of New Mexico Exec-U-Care Group Medical Reimbursement Insurance Trust Participation Agreement.	19.5 to the Company's Quarterly Report on Form 10-Q for Quarter ended March 31, 1987.	1-6986
10.42	Amended and Restated Medical Reimbursement Plan of Public Service Company of New Mexico.	19.6 to the Company's Quarterly Report on Form 10-Q for Quarter ended March 31, 1987.	1-6986
10.44	Republic Holding Company Series M Preferred Stock Program.	19.4 to the Company's Quarterly Report on Form 10-Q for Quarter ended June 30, 1987.	1-6986
10.45	Sunbelt Mining Company, Inc. Short Term Incentive Compensation Plan dated May 1987.	19.5 to the Company's Quarterly Report on Form 10-Q for Quarter ended June 30, 1987.	1-6986
10.46	Meadows Resources, Inc. Executive Deferred Compensation Venture Capital Program and Incentive Plan. (March 5, 1987.)	10.46 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.47	Meadows Resources, Inc., Second Restated and Amended Executive Deferred Compensation Plan, Alliance Telecommunications Investment. (August 24, 1988.)	19.3 to the Company's Quarterly Report on Form 10-Q for Quarter ended September 30, 1988.	1-6986
10.48	Santa Fe County Ranch Resort Plan. (1987-1988.) (Terminated.)	10.48 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.49	Public Service Company of New Mexico Electric Utility Long-Term Executive Incentive Compensation Plan. (June 1984.) (Terminated.)	10.49 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.49.1	Public Service Company of New Mexico ESBU Long-Term Executive Incentive Compensation Plan. (Second Cycle: 1986 through 1989.)	10.49.1 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.50	Public Service Company of New Mexico ESBU Management Incentive Plan. (Terminated.)	10.50 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.51	Public Service Company of New Mexico Gas Company of New Mexico Long-Term Executive Incentive Compensation Plan. (First Cycle: 1986 through 1989.)	10.51 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.52	Public Service Company of New Mexico Gas Company of New Mexico Management Incentive Plan. (April 1985.) (Terminated.)	10.52 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.53	Amendment No.2 dated as of April 10, 1987, to the Facility Lease dated as of August 12, 1986, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico. (Unit 2 Transaction.) (This is an amendment to a Facility Lease which is substantially similar to the Facility Lease filed as Exhibit 28.1 to the Company's Current Report on Form 8-K dated August 18, 1986.)	10.53 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.54	Amendment No. 3 dated as of March 30, 1987, to the Facility Lease dated as of December 16, 1985, between The First National Bank of Boston, as Owner Trustee, and Public Service Company of New Mexico. (Unit 1 Transaction.) (This is an amendment to a Facility Lease which is substantially similar to the Facility Lease filed as Exhibit 28(a) to the Company's Current Report on Form 8-K dated December 31, 1985.)	10.54 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
10.55	Decommissioning Trust Agreement between Public Service Company of New Mexico and First Interstate Bank of Albuquerque dated as of July 31, 1987.	10.55 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.56	New Mexico Public Service Commission Order dated July 30, 1987, and Exhibit 1 thereto, in NMPSC Case No. 2004, regarding the PVNGS decommissioning trust fund.	10.56 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.57	MCB/RSB Management Incentive Programs. (December 1, 1985.)	10.57 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
10.58	MdF Long-Term Bonus Plan for management. (1987.) (Terminated.)	10.58 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1987.	1-6986
Subsidiaries of the Registrant			
22	Certain Subsidiaries of the Registrant	22 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986
Additional Exhibits			
28.1	Collateral Trust Indenture dated as of December 16, 1985, among First PV Funding Corporation, Public Service Company of New Mexico and Chemical Bank, as Trustee.	28(i) to the Company's Current Report on Form 8-K dated December 31, 1985.	1-6986
28.1.1	Series 1986A Bond Supplemental Indenture dated as of July 15, 1986, to Collateral Trust Indenture dated as of December 16, 1985.	28.4 to the Company's Current Report on Form 8-K dated July 17, 1986.	1-6986
28.1.2	Series 1986B Bond Supplemental Indenture dated as of November 18, 1986, to Collateral Trust Indenture dated as of December 16, 1985.	28.12 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.1.3	Unit 1 Supplemental Indenture of Pledge (Lease Obligation Bonds, Series 1986B) dated as of December 15, 1986, to the Collateral Trust Indenture dated as of December 16, 1985.	28.8 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.1.4	Unit 2 Supplemental Indenture of Pledge (Lease Obligation Bonds, Series 1986B) dated as of December 15, 1986, to the Collateral Trust Indenture dated as of December 16, 1985.	28.16 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
28.2°	Participation Agreement dated as of December 16, 1985, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 16, 1985 with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 16, 1985 with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions.	2 to the Company's Current Report on Form 8-K dated December 31, 1985.	1-6986
28.2.1°	Amendment No. 1 dated as of July 15, 1986, to Participation Agreement dated as of December 16, 1985.	2.1 to the Company's Current Report on Form 8-K dated July 17, 1986.	1-6986
28.2.2°	Amendment No. 2 dated as of November 18, 1986, to Participation Agreement dated as of December 16, 1985.	2.1 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.3°	Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 16, 1985, between The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee.	28(b) to the Company's Current Report on Form 8-K dated December 31, 1985.	1-6986
28.3.1°	Supplemental Indenture No. 1 dated as of July 15, 1986, to the Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 16, 1985.	28.2 to the Company's Current Report on Form 8-K dated July 17, 1986.	1-6986
28.3.2°	Supplemental Indenture No. 2 dated as of November 18, 1986, to the Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 16, 1985.	28.2 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.4°	Assignment, Assumption and Further Agreement dated as of December 16, 1985, between Public Service Company of New Mexico and The First National Bank of Boston, as Owner Trustee.	28(e) to the Company's Current Report on Form 8-K dated December 31, 1985.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
28.5	Participation Agreement dated as of July 31, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of July 31, 1986, with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of July 31, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions.	2.1 to the Company's Quarterly Report on Form 10-Q for Quarter ended June 30, 1986.	1-6896
28.5.1	Amendment No. 1 dated as of November 18, 1986, to Participation Agreement dated as of July 31, 1986.	28.4 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.6	Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of July 31, 1986, between The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee.	28.2 to the Company's Quarterly Report on Form 10-Q for Quarter ended June 30, 1986.	1-6986
28.6.1	Supplemental Indenture No. 1 dated as of November 18, 1986, to the Trust Indenture, Mortgage, Security Agreement and Assignments of Rents dated as of July 31, 1986.	28.6 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.7	Assignment, Assumption, and Further Agreement dated as of July 31, 1986, between Public Service Company of New Mexico and The First National Bank of Boston, as Owner Trustee.	28.3 to the Company's Quarterly Report on Form 10-Q for quarter ended June 30, 1986.	1-6986
28.8*	Participation Agreement dated as of August 12, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of August 12, 1986 with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of August 12, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions.	2.1 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
28.8.1*	Amendment No. 1 dated as of November 18, 1986, to Participation Agreement dated as of August 12, 1986.	28.8 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
28.9*	Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of August 12, 1986, between The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee.	28.2 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
28.9.1*	Supplemental Indenture No. 1 dated as of November 18, 1986, to the Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of August 12, 1986.	28.10 to the Company's Current Report on Form 8-K dated November 25, 1986.	1-6986
28.10*	Assignment, Assumption, and Further Agreement dated as of August 12, 1986, between Public Service Company of New Mexico and The First National Bank of Boston, as Owner Trustee.	28.3 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
28.11	Participation Agreement dated as of December 15, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 15, 1986, with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions (Unit 1 Transaction).	2.1 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.12	Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee (Unit 1 Transaction).	28.2 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.13	Assignment, Assumption and Further Agreement dated as of December 15, 1986, between Public Service Company of New Mexico and The First National Bank of Boston, as Owner Trustee (Unit 1 Transaction).	28.3 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
28.14	Participation Agreement dated as of December 15, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 15, 1986 with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986 with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions (Unit 2 Transaction).	2.2 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.15	Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee (Unit 2 Transaction).	28.10 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.16	Assignment, Assumption, and Further Agreement dated as of December 15, 1986, between Public Service Company of New Mexico and The First National Bank of Boston, as Owner Trustee (Unit 2 Transaction).	28.11 to the Company's Current Report on Form 8-K dated December 17, 1986.	1-6986
28.17°	Waiver letter with respect to "Deemed Loss Event" dated as of August 18, 1986, between the Owner Participant named therein, and Public Service Company of New Mexico.	28.12 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
28.18°	Waiver letter with respect to "Deemed Loss Event" dated as of August 18, 1986, between the Owner Participant named therein, and Public Service Company of New Mexico.	28.13 to the Company's Current Report on Form 8-K dated August 18, 1986.	1-6986
28.19	Agreement No. 13904 (Option and Purchase of Effluent), dated April 23, 1973, among Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, the Cities of Phoenix, Glendale, Mesa, Scottsdale, and Tempe, and the Town of Youngtown.	28.19 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986

Exhibit No.	Description	Filed as Exhibit:	File No.
28.20	Agreement for the Sale and Purchase of Wastewater Effluent, dated June 12, 1981, among Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District and the City of Tolleson, as amended.	28.20 to Annual Report of the Registrant on Form 10-K for fiscal year ending December 31, 1986.	1-6986

°One or more additional documents, substantially identical in all material respects to this exhibit, have been entered into, relating to one or more additional sale and leaseback transactions. Although such additional documents may differ in other respects (such as dollar amounts and percentages), there are no material details in which such additional documents differ from this exhibit.

(b) Reports on Form 8-K:

The Company filed no reports on Form 8-K during the quarter ended December 31, 1988 and during the period beginning January 1, 1989 and ending April 14, 1989.

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.

PUBLIC SERVICE COMPANY OF NEW MEXICO
(Registrant)

Date: April 14, 1989

By /s/ J. D. GEIST
J. D. Geist
Chairman of the Board and President

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	Capacity	Date
/s/ J. D. GEIST J. D. Geist *Chairman of the Board and President*	Principal Executive Officer and Director	April 14, 1989
/s/ M. H. MAERKI M.H. Maerki *Senior Vice President and Chief Financial Officer*	Principal Financial Officer	April 14, 1989
/s/ B. D. LACKEY B. D. Lackey *Vice President and Corporate Controller*	Principal Accounting Officer	April 14, 1989
/s/ J. P. BUNDRANT J. P. Bundrant	Director	April 14, 1989
/s/ A. B. COLLINS, JR. A. B. Collins, Jr.	Director	April 14, 1989
/s/ C. E. LEYENDECKER C. E. Leyendecker	Director	April 14, 1989
/s/ A. G. ORTEGA A. G. Ortega	Director	April 14, 1989
/s/ R. R. REHDER R. R. Rehder	Director	April 14, 1989
/s/ R. B. ROUNTREE R. B. Rountree	Director	April 14, 1989
/s/ R. H. STEPHENS R. H. Stephens	Director	April 14, 1989
/s/ E. R. WOOD E. R. Wood	Director	April 14, 1989

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