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AUTH.NAME AUTHOR AFFILIATION
CONWAY,W.F. Arizona Public Service Co. (formerly Arizona Nuclear Power
RECIP.NAME RECIPIENT AFFILIATION
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SUBJECT: Forwards cash flow projections for 1991 & "Annual Rept 1990 Southern California Public Power Authority" as evidence of payment of deferred premiums per 10CFR140.21(e).

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WILLIAM F. CONWAY
EXECUTIVE VICE PRESIDENT
NUCLEAR

161-03984-WFC/JRP

May 30, 1991

Docket Nos. STN 50-528/529/530

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-37
Washington, D.C. 20555

Dear Sir:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1,2 and 3
Licensee Guarantee of Payment of Deferred Premium
File: 91-003-240

Pursuant to the requirements of 10 CFR 140.21(e), Arizona Public Service Company, for itself and on behalf of the participants in Palo Verde Nuclear Generating Station, herewith submits the projected 1991 cash flow statements.

Should you have any questions, please call Michael E. Powell at (602) 340-4891.

Sincerely,

William F. Conway

William F. Conway

WFC/JRP/sad

Attachment

cc: J. B. Martin
D. H. Coe
A. C. Gehr
A. H. Gutterman

M004
1/1

NCF91 CJD-H4

ARIZONA PUBLIC SERVICE COMPANY

1991 Net Cash Flow Projection
for Palo Verde Nuclear Generating Station
(000'S)

		1990 Actual	1991 Projected
Participant: ARIZONA PUBLIC SERVICE COMPANY			
1.	Net Income After Taxes	$180,012	$184,042
	Less:		
2.	Dividends Paid on Preferred Stock	32,088	30,174
3.	Dividends Paid on Common Stock	190,472	170,000
4.	Retained Earnings	(42,548)	(16,132)
	Adjustments:		
5.	Depreciation and Amortization (1)	256,466	269,713
6.	Deferred Income Taxes	82,008	87,655
7.	ITC Net Deferred	(7,012)	(7,427)
8.	Allowance for Funds Used During Construction (Equity & Borrowed)	(12,747)	(14,965)
9.	Gross Cost Deferrals	(135,783)	(134,783)
10.	Decommissioning	(5,685)	(8,123)
11.	Other (2)	(1,687)	(1,688)
12.	Total Adjustments	175,560	190,382
13.	Internal Cash Flow (Line 4 + Line 12)	133,012	174,250
14.	Average Quarterly Cash Flow (Line 13/4)	33,253	43,563

Percentage Ownership in All Nuclear Units:

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

Maximum Total Contingent Liability for PVNGS is $30 million ($10 million per Unit)

(1) Includes Nuclear Fuel Amortization.
(2) Includes Amortization of Tax Benefits Sold in 1981.
(3) Includes Portion of Palo Verde Unit 2 Leased.

30-Apr-91 (NRC_REQ)

INTERNAL CASH FLOW PROJECTION
FOR
PALO VERDE NUCLEAR GENERATING STATION
FOR FISCAL YEARS ENDED APRIL 30, 1990 and 1991
($000)

	1990 ACTUAL	1991 PROJECTED
Net Income after taxes	(13,192)	8,854
Less dividends paid:		
Preferred dividend requirements		
Dividends on common stock		
Retained Earnings	(13,192)	8,854
Adjustments:		
Depreciation and amortization	152,044	158,667
Deferred Income Taxes and Investment Tax Credits		
Allowance for Funds Used During Construction	(5,026)	(5,545)
Total Adjustments	147,018	153,122
Internal Cash Flow	133,826	161,976
Average Quarterly Cash Flow	33,457	40,494
Percentage Ownership in all nuclear units		
Unit 1	17.49%	17.49%
Unit 2	17.49%	17.49%
Unit 3	17.49%	17.49%

I, Mark Bonsall, Corporate Treasurer of the Salt River Project certify that the above 1990 figures are based upon our Accounting Records, and agree, as approppriate with our audited financial statements. The 1991 projections are based upon May 1990 through March 1991 actual amounts, plus budgeted figures for the month of April.

Mark Bonsall

SOUTHERN CALIFORNIA EDISON COMPANY

1991 Internal Cash Flow Projection
(Dollars in Thousands)

	1990 Actual	1991 Projected
Net Income After Taxes	$736,800	*
Dividends Paid	612,300	*
Retained Earnings	$124,500	*
Adjustments:		
Depreciation	711,200	765,700
Net Deferred Taxes & ITC	45,100	122,000
Allowance for Funds Used During Construction	(22,900)	(25,000)
Total Adjustments	$733,400	$862,700
Internal Cash Flow	$857,900	*
Average Quarterly Cash Flow	$214,475	*

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 1991 is expected to be comparable to the Actual Cash Flow for 1990.

1991 Internal Cash Flow Projection of Los Angeles Department of Water and Power for Palo Verde Nuclear Power Station

(Thousands of Dollars)

	1989–90 Actual Total	1990–91 Projected Total *
Net Income	$156,466	$134,850
Less Transfer to City	(85,818)	(92,500)
Retained Earnings	70,648	42,350
Adjustments		
Depreciation and Amortization	139,031	147,900
Allowance for funds used during construction	(2,757)	(8,890)
Total Adjustments	136,274	139,010
Internal Cash Flow	$206,922	$181,360
Average Quarterly Cash Flow	$51,731	$45,340

* Preliminary

1991 PRO FORMA CASH FLOW STATEMENT
FOR PUBLIC SERVICE COMPANY OF NEW MEXICO
(Excluding Non-utility Subsidiaries)

	1990 Actual	1991 Projected
Net Income After Taxes	442	24,104
Less Dividends Paid	10,002	9,021
Retained Earnings	(9,560)	15,083
Adjustments:		
Depreciation and Amortization	73,204	74,519
Deferred Income Taxes and Investment Tax Credits	(12,607)	1,899
Allowance for Equity Funds Used During Construction	0	0
Other, Non-Cash	34,374	17,242
TOTAL ADJUSTMENTS	94,971	93,660
INTERNAL CASH FLOW	85,411	108,743
Average Quarterly Cash Flow	21,353	27,186

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: Tom Sategna
Tom Sategna
Controller, Electric and Water

1990-91 INTERNAL CASH FLOW PROJECTION
EL PASO ELECTRIC COMPANY
(THOUSANDS OF DOLLARS)

	1990	1991
Net Income (Loss) After Taxes	$ (21,864)	$ 7,011
Less Dividends Paid	11,881	8,244
Increase (decrease) in Retained Earnings	(33,745)	(1,233)
Adjustments:		
Depreciation and Amortization (1)	47,068	(14,349)
Deferred Income Taxes and ITC	(15,144)	1,388
AFUDC (2)	(29,417)	(23,006)
Total Adjustments	2,507	(35,967)
Internal Cash Flow	$ (31,238)	$ (37,200)
Average Quarterly Cash Flow	$ (7,810)	$ (9,300)

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

Maximum Total Contingent Liability $ 0 (3)

(1) Includes depreciation and amortization, regulatory disallowance, Palo Verde deferred costs, amortization of Palo Verde deferred gain and phase-in plan deferrals
(2) Includes AEFUDC, ABFUDC and carrying charges on Palo Verde deferred costs
(3) Not provided by Financial Planning

9106100031

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended June 30, 1990	Year Ended June 30, 1989
Cash flows from operating activities:		
Billings to participants in excess of costs recoverable	$ 628	$ 909
Adjustments to arrive at net cash provided by operating activities:		
Amortization of debt costs	54	54
Changes in assets and liabilities:		
Interest receivable	42	(28)
Accounts payable and accrued expenses	10	7
Net cash provided by operating activities	734	942
Cash flows from investing activities:		
Advances for capacity and energy, net	(1,945)	(4,209)
Purchases of investments	(15,816)	(10,248)
Proceeds from sale of investments	19,447	12,085
Net cash provided by (used for) investing activities	1,686	(2,372)
Cash flows from financing activities:		
Payment for bond issue costs	(61)	-
Net cash used for financing activities	(61)	-
Net increase (decrease) in cash and cash equivalents	2,359	(1,430)
Cash and cash equivalents at beginning of year	5,640	7,070
Cash and cash equivalents at end of year	$ 7,999	$ 5,640
Supplemental disclosure of cash flow information:		
Cash paid during year for interest (net of amount capitalized)	$ 2,757	$ 2,757

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS
IN FUNDS REQUIRED BY THE BOND INDENTURE
YEAR ENDED JUNE 30, 1990
(In thousands)

	Advance Payments Fund	Interim Advance Payments Fund	Revenue Fund	Operating Working Capital Fund	Debt Service Account	Debt Service Reserve Account	Total
Balance at June 30, 1989	$20,009	$ 327	$ 7	$400	$ 710	$3,624	$25,077
Additions							
Investment earnings	1,768	210	6	28	36	294	2,342
Distribution of investment earnings	573	(210)	(6)	(28)	(36)	(293)	
Revenue from power sales			2,760				2,760
Distribution of revenues			(2,767)		2,767		
Transfer of investments	1,495	(322)			(1,173)		
Miscellaneous transfers	(7,209)	5,976		60	1,173		
Total	(3,373)	5,654	(7)	60	2,767	1	5,102
Deductions							
Advances for capacity and energy		3,140					3,140
Administrative expenditures	203						203
Interest paid					2,757		2,757
Interest paid on investment purchases	10			2			12
Premium paid on investment purchases	661					1	662
Total	874	3,140	-	2	2,757	1	6,774
Balance at June 30, 1990	$15,762	$2,841	$ -	$458	$ 720	$3,624	$23,405

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 $250 and $292 at June 30, 1990 and 1989, nor do they include total amortized net investment premiums of $290 and $690 at June 30, 1990 and 1989.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MEAD-PHOENIX PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1990	June 30, 1989
ASSETS		
Utility plant		
Construction work in progress	$14,078	$12,999
Special funds		
Investments	132	1,089
Cash and cash equivalents	22	65
	154	1,154
	$14,232	$14,153
LIABILITIES		
Long-term debt	$ 100	$ 100
Current liabilities		
Accrued interest	1	1
Accounts payable and accrued expenses	83	4
	84	5
Advances from participants	14,048	14,048
Commitments and contingencies		
	$14,232	$14,153

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MEAD-PHOENIX PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended June 30, 1990	1989
Cash flows from operating activities:	$ -	$ -
Cash flows from investing activities:		
Payments for feasibility study	(1,000)	(703)
Purchases of investments	(1,015)	(4,818)
Proceeds from sale of investments	1,972	5,572
Net cash (used for) provided by investing activities	(43)	51
Cash flows from financing activities:		
Payment of long-term debt		(14,048)
Proceeds from advances from participants		14,048
Net cash provided by financing activities	-	-
Net (decrease) increase in cash and cash equivalents	(43)	51
Cash and cash equivalents at beginning of year	65	14
Cash and cash equivalents at end of year	$ 22	$ 65

Supplemental disclosure of cash flow information:

Cash paid during the year for interest (net of amount capitalized)	$ -	$ -

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MULTIPLE PROJECT FUND

SUPPLEMENTAL BALANCE SHEET
JUNE 30, 1990
(In thousands)

ASSETS

Special funds	
Investments	$603,796
Interest receivable	21,943
	$625,739

LIABILITIES

Long-term debt	$600,372
Arbitrage rebate payable	1,287
Current liabilities:	
Accrued interest	24,080
Commitments and contingencies	
	$625,739

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MULTIPLE PROJECT FUND

SUPPLEMENTAL STATEMENT OF CASH FLOWS
YEAR ENDED JUNE 30, 1990
(In thousands)

Cash flows from operating activities:	$ -
Cash flows from investing activities:	
Purchases of investments	(603,796)
Net cash used for investing activities	(603,796)
Cash flows from financing activities:	
Proceeds from sale of bonds and accrued interest	603,796
Net cash provided by financing activities	603,796
Net increase in cash and cash equivalents	-
Cash and cash equivalents at beginning of year	-
Cash and cash equivalents at end of year	$ -
Supplemental disclosure of cash flow information:	
Cash paid during the year for interest (net of amount capitalized)	$ -

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

MULTIPLE PROJECT FUND

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS
IN FUNDS REQUIRED BY THE BOND INDENTURE
YEAR ENDED JUNE 30, 1990
(In thousands)

	Proceeds Account	Debt Service Account	Total
Balance at June 30, 1989	$ -	$ -	$ -
Additions			
Bond proceeds	600,012		600,012
Interest received		3,784	3,784
Balance at June 30, 1990	$600,012	$3,784	$603,796

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 $21,943 at June 30, 1990.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SUPPLEMENTAL FINANCIAL INFORMATION

INDEX

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED SCHEDULE OF LONG-TERM DEBT
AT JUNE 30, 1990
(In thousands)

Project	Series	Date of Sale	Effective Interest Rate	Maturity on July 1	Total
Principal -					
Palo Verde Project Revenue and Refunding Bonds	1982A	08/13/82	10.9%	1990 to 2017	$ 12,025
	1982B	11/12/82	7.7%	1990 to 2017	36,065
	1983A	04/08/83	8.8%	1990 to 2017	14,350
	1984A	07/18/84	10.3%	1990 to 2004	12,315
	1985A	05/22/85	8.7%	1990 to 2014	9,790
	1985B	07/02/85	9.1%	1990 to 2017	35,050
	1986A	03/13/86	8.2%	1990 to 2015	78,130
	1986B	12/16/86	7.2%	1990 to 2017	352,675
	1987A	02/11/87	6.9%	1990 to 2017	345,125
	1989A	02/15/89	7.2%	1990 to 2015	294,505
					1,190,030
Southern Transmission System Project Revenue and Refunding Bonds	1984A	02/09/84	9.3%	1990 to 2004	29,790
	1984B	10/17/84	10.2%	1990 to 2000	11,610
	1985A	08/15/85	8.9%	1990 to 2021	15,535
	1986A	03/18/86	8.0%	1990 to 2021	370,985
	1986B	04/29/86	7.5%	1990 to 2023	476,105
	1988A	11/22/88	7.2%	1990 to 2015	237,280
					1,141,305
Multiple Project Revenue Bonds	1989	01/04/90	6.9%	1999 to 2020	647,750
Hoover Uprating Project Revenue Bonds	1986A	08/13/86	8.1%	1993 to 2017	34,435
Mead-Phoenix Bank Loan					100
Total principal amount					3,013,620
Unamortized bond discount -					
Palo Verde Project					(143,575)
Southern Transmission System Project					(124,256)
Multiple Project Fund					(47,378)
Hoover Uprating Project					(138)
Total unamortized bond discount					(315,347)
					2,698,273
Long-term debt due within one year					(25,145)
Total long-term debt, net					$2,673,128

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, 1990	June 30, 1989
ASSETS		
Utility plant		
Production	$ 594,323	$ 600,778
Transmission	14,172	6,008
General	2,289	186
	610,784	606,972
Less - Accumulated depreciation	77,421	56,180
	533,363	550,792
Construction work in progress	4,119	3,569
Nuclear fuel, at amortized cost	25,931	26,428
Net utility plant	563,413	580,789
Special funds		
Investments	136,567	110,678
Interest receivable	3,129	1,630
Cash and cash equivalents	83,844	107,672
	223,540	219,980
Accounts receivable	4,272	3,635
Materials and supplies	8,968	6,859
Costs recoverable from future billings to participants	69,004	58,587
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $33,660 and $24,106	218,597	228,150
Other deferred costs	466	864
	219,063	229,014
	$1,088,260	$1,098,864
LIABILITIES		
Long-term debt	$1,031,200	$1,043,540
Current liabilities		
Long-term debt within one year	15,255	14,370
Accrued interest	36,180	36,219
Accounts payable and accrued expenses	5,625	4,735
	57,060	55,324
Commitments and contingencies		
	$1,088,260	$1,098,864

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year Ended June 30, 1990	1989
Operating revenue		
Sales of electric energy	$120,782	$110,164
Operating expenses		
Nuclear fuel	4,176	10,628
Other operation	28,145	19,635
Maintenance	8,660	5,518
Depreciation	17,980	17,427
Decommissioning	5,699	5,699
Total operating expenses	64,660	58,907
Operating income	56,122	51,257
Investment income	18,290	18,239
Income before debt expenses	74,412	69,496
Debt expense		
Interest on debt	84,829	85,116
Costs recoverable from future billings to participants	($ 10,417)	($ 15,620)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS

(In thousands)

	Year Ended June 30, 1990	1989
Cash flows from operating activities:		
Costs recoverable from future billings to participants	($ 10,417)	($ 15,620)
Adjustments to arrive at net cash provided by operating activities:		
Depreciation	17,980	17,427
Decommissioning	5,699	5,699
Amortization of nuclear fuel	3,676	9,528
Amortization of debt costs	12,899	12,017
Changes in assets and liabilities:		
Interest receivable	(1,499)	574
Accounts receivable	(637)	(2,799)
Materials and supplies	(2,109)	(331)
Other assets	(32)	15
Accrued interest	(39)	(1,354)
Accounts payable and accrued expenses	890	(7,582)
Net cash provided by operating activities	26,411	17,574
Cash flows from investing activities:		
Payments for construction of facility	(9,980)	(7,781)
Purchases of investments	(189,032)	(101,134)
Proceeds from sale of investments	163,143	130,015
Net cash (used for) provided by investing activities	(35,869)	21,100
Cash flows from financing activities:		
Payment for principal of long-term debt	(14,370)	(13,095)
Proceeds from sale of refunding bonds		185,200
Payment for bond issue costs		(4,325)
Payment for defeasance of revenue bonds		(180,827)
Net cash used for financing activities	(14,370)	(13,047)
Net (decrease) increase in cash and cash equivalents	(23,828)	25,627
Cash and cash equivalents at beginning of year	107,672	82,045
Cash and cash equivalents at end of year	$ 83,844	$107,672
Supplemental disclosure of cash flow information:		
Cash paid during the year for interest (net of amount capitalized)	$ 72,399	$ 73,871

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, 1990
(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, 1989	$48,828	$154,423	$29	$ 349	$ 5,636	$10,573		$219,838
Additions								
Investment earnings	4,332	12,102	2	168	467	1,054		18,125
Distribution of investment earnings		(11,090)	(2)	12,704	(455)	(1,030)		127
Revenue from power sales				119,979				119,979
Distribution of revenues		74,485		(132,758)	47,753	9,171	$3,471	2,122
Other income	3				121			124
Transfer for interest payment		114,686						114,686
Miscellaneous transfers	591	85	—	(442)	746	358	(3,471)	(2,133)
Total	4,926	190,268	-	(349)	48,632	9,553	-	253,030
Deductions								
Construction expenditures	2,428					4,342		6,770
Operating expenditures					33,734			33,734
Fuel costs	971				3,124			4,095
Payment of principal		14,370						14,370
Interest paid		187,086						187,086
Property tax					3,382			3,382
Interest paid on investment purchases	267	686				196		1,149
Premium paid on investment purchases	8	765	—	—	—	18	—	791
Total	3,674	202,907	-	-	40,240	4,556	-	251,377
Balance at June 30, 1990	$50,080	$141,784	$29	$ -	$14,028	$15,570	$ -	$221,491

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 $3,129 and $1,630 at June 30, 1990 and 1989, nor do they include total amortized net investment premiums of $1,080 and $1,488 at June 30, 1990 and 1989.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1990	June 30, 1989
ASSETS		
Utility plant		
Transmission	$ 662,727	$ 661,255
General	18,893	18,857
	681,620	680,112
Less - Accumulated depreciation	76,477	57,272
	605,143	622,840
Construction work in progress	7,320	4,287
Net utility plant	612,463	627,127
Special funds		
Investments	95,595	95,927
Advance to Intermountain Power Agency	19,550	20,161
Interest receivable	2,632	1,174
Cash and cash equivalents	69,002	63,295
	186,779	180,557
Accounts receivable	611	547
Costs recoverable from future billings to participants	93,708	80,807
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $28,933 and $21,539	166,840	174,258
	$1,060,401	$1,063,296
LIABILITIES		
Long-term debt	$1,007,159	$1,014,443
Current liabilities		
Long-term debt due within one year	9,890	5,825
Accrued interest	37,090	37,259
Accounts payable and accrued expenses	6,262	5,769
	53,242	48,853
Commitments and contingencies		
	$1,060,401	$1,063,296

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year Ended June 30, 1990	1989
Operating revenue		
Sales of transmission services	$93,508	$94,769
Operating expenses		
Other operation	10,501	8,137
Maintenance	4,134	3,205
Depreciation	19,205	19,207
Total operating expenses	33,840	30,549
Operating income	59,668	64,220
Investment income	11,611	10,784
Income before debt expense	71,279	75,004
Debt expense		
Interest on debt	84,180	84,035
Costs recoverable from future billings to participants	($12,901)	($ 9,031)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION SYSTEM PROJECT

SUPPLEMENTAL STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended June 30, 1990	1989
Cash flows from operating activities:		
Costs recoverable from future billings to participants	($12,901)	($ 9,031)
Adjustments to arrive at net cash provided by operating activities:		
Depreciation	19,205	19,207
Amortization of debt costs	10,000	9,125
Changes in assets and liabilities:		
Interest receivable	(1,457)	(319)
Accounts receivable	(63)	(547)
Other assets	24	
Accrued interest	(168)	(1,352)
Accounts payable and accrued expenses	493	1,767
Net cash provided by operating activities	15,133	18,850
Cash flows from investing activities:		
Payments for construction of facility	(4,544)	(7,990)
Purchases of investments	(124,280)	(61,515)
Proceeds from sale of investments	124,612	63,748
Refund from Intermountain Power Agency	611	
Net cash used for investing activities	(3,601)	(5,757)
Cash flows from financing activities:		
Payment for principal of long-term debt	(5,825)	(2,260)
Proceeds from sale of refunding bonds		156,050
Payment for bond issue costs		(2,457)
Payment for defeasance of revenue bonds		(153,739)
Net cash used for financing activities	(5,825)	(2,406)
Net increase in cash and cash equivalents	5,707	10,687
Cash and cash equivalents at beginning of year	63,295	52,608
Cash and cash equivalents at end of year	$69,002	$ 63,295

Supplemental disclosure of cash flow information:

Cash paid during the year for interest (net of amount capitalized)	$74,349	$ 72,906

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, 1990
(In thousands)

	Construction Fund-Initial Facilities Account	Debt Service Fund	Revenue Fund	Operating Fund	General Reserve Fund	Total
Balance at June 30, 1989	$ 5,302	$131,477		$ 6,740	$15,631	$159,150
Additions						
Investment earnings	235	8,376	$ 281	638	1,567	11,097
Distribution of investment earnings		(7,678)	9,652	(632)	(1,342)	
Revenue from transmission sales			93,042			93,042
Distribution of revenue		84,070	(102,975)	12,764	6,141	
Transfer for interest payment		97,316				97,316
Total	235	182,084	-	12,770	6,366	201,455
Deductions						
Payments-in-aid of construction	5,275					5,275
Operating expenditures				12,372		12,372
Payment of principal		5,825				5,825
Interest paid		171,666				171,666
Interest paid on investment purchases		941			221	1,162
Premium paid on investment purchases		68				68
Total	5,275	178,500	-	12,372	221	196,368
Balance at June 30, 1990	$ 262	$135,061	$ -	$ 7,138	$21,776	$164,237

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 $2,632 and $1,174 at June 30, 1990 and 1989, nor do they include total amortized net investment discounts of $359 and $72 at June 30, 1990 and 1989.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1990	June 30, 1989
ASSETS		
Special funds		
Investments	$15,116	$18,747
Advances for capacity and energy, net	12,163	10,218
Interest receivable	250	292
Cash and cash equivalents	7,999	5,640
	35,528	34,897
Billings to participants in excess of costs recoverable	(1,632)	(1,004)
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $208 and $155	1,115	1,107
	$35,011	$35,000
LIABILITIES		
Long-term debt	$34,297	$34,296
Current liabilities		
Accrued interest	689	689
Accounts payable and accrued expenses	25	15
	714	704
Commitments and contingencies	—	—
	$35,011	$35,000

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

HOOVER UPRATING PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year Ended June 30, 1990	1989
Operating revenue		
Sales of electric energy	$2,760	$2,760
Operating expenses		
Capacity charges	608	391
Energy charges	586	596
Other operation	152	140
Total operating expenses	1,346	1,127
Operating income	1,414	1,633
Investment income	2,025	2,033
Income before debt expense	3,439	3,666
Debt expense		
Interest on debt	2,811	2,757
Billings to participants in excess of costs recoverable	$ 628	$ 909

NOTE 4: (Continued)

$15,255,000 in 1991, $16,325,000 in 1992, $17,530,000 in 1993, $18,860,000 in 1994 and $20,355,000 in 1995. The average interest rate on outstanding debt during fiscal years 1990 and 1989 was 6.9% and 7.0%, 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, 1990 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 5) 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.

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 installments 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, 2002 for the 1986 Series B Bonds, and 2007 for the 1988 Series A Bonds. Scheduled principal maturities for STS during the five fiscal years following June 30, 1990 are $9,890,000 in 1991, $10,545,000 in 1992, $11,295,000 in 1993, $12,100,000 in 1994 and $13,000,000 in 1995. The average interest rate on outstanding debt during fiscal years 1990 and 1989 was 7.3% and 7.4%, respectively.

Multiple Project Fund

To finance costs of construction and acquisition of ownership interests or capacity rights in one or more projects expected to be undertaken within the next five years, the Authority issued Multiple Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of August 1, 1989 (Bond Indenture), as amended and supplemented. Reference is made to the Combined Schedule of Long-Term Debt at June 30, 1990 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) with respect to each authorized project, the revenues of such authorized project, and (3) all funds established by the Bond Indenture.

Of the outstanding Multiple Project Revenue Bonds, $153,500,000 are not subject to redemption prior to maturity. The balance of the outstanding bonds, at the option of the Authority, are subject to redemption prior to maturity.

NOTE 4: (Continued)

The Bond Indenture requires mandatory sinking fund installments to be made beginning in fiscal year 2006 for the 1989 Series Bonds. The first scheduled principal maturity for the Multiple Project is $13,500,000 in 1999. The average interest rate on outstanding debt during fiscal year 1990 was 6.9%.

The Bond Indenture required that, at the time of issuance of the Bonds, sufficient funds were available to pay costs related to issuance of the bonds, and that such funds come from a source other than proceeds of the bonds. The Department of Water and Power of the City of Los Angeles (LADWP) advanced $7,219,000 to the Authority for the payment of the costs.

The advance plus 7.09% interest becomes immediately payable to the LADWP after the first transfer of bond proceeds by the Authority from the Multiple Project Fund to a separate authorized project account to finance the costs of construction and acquisition of ownership interest of the project.

The Authority has no obligation to repay the advance or interest to the LADWP if bond proceeds are not transferred from the Multiple Project Fund to a separate project account; except that on retirement of the bonds the amount of any remaining funds in the Multiple Project Fund shall be payable to the LADWP without interest.

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, 1990 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 5), (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).

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 mandatory sinking fund installments to be made beginning in fiscal year 2002 for the 1986 Series A Bonds. The next scheduled principal maturities for the Hoover Uprating Project is $490,000 in 1993 and $525,000 in 1994. The average interest rate on outstanding debt during fiscal years 1990 and 1989 was 8.0%.

NOTE 4: (Continued)

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

Mead-Phoenix Project

Prior to fiscal year 1989, the Authority borrowed $14,148,000 to finance the feasibility study and development costs of the Mead Phoenix Project. During fiscal year 1989, the Authority received from the participants $14,048,000 retiring all the notes but $100,000. These receipts are shown as Advances from Participants. Authority management anticipates repaying these advances during fiscal 1991 or later.

Refunding Bonds

During fiscal year 1989, the proceeds from the sale of $295,005,000 of Palo Verde Power Project Refunding Bonds were used to advance refund $187,635,000 of previously issued bonds and the proceeds from the sale of $239,320,000 of Southern Transmission Project Revenue Bonds were issued to refund $147,995,000 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, 1990 the aggregate amount of debt considered to be extinguished was $2,210,680,000.

NOTE 5 - 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 1). 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 the Southern Transmission System Project (see Note 1). Under the terms of the contracts, the participants are entitled to transmission service utilizing the Southern Transmission System

NOTE 5: (Continued)

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 on Transmission Project Revenue Bonds and other debt, whether or not the Southern Transmission System Project or any part thereof has been completed, is operating or 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 1). 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 6 - 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 (GAAP), which are not included as "costs" are deferred to such periods as they are intended to be recovered through billings for the repayment of principal on related debt.

NOTE 6: (Continued)

Costs recoverable from future billings to participants are comprised of the following:

	June 30, 1989	Fiscal 1990 Activity	June 30, 1990
GAAP items not included in billings to participants:			
Depreciation of plant	$100,155	$37,186	$137,341
Amortization of bond discount, debt issue costs, and cost of refunding	53,796	22,523	76,319
Nuclear fuel amortization and decommissioning expense	18,137	4,838	22,975
Interest expense	6,211	(3)	6,208
Bond requirements included in billings to participants:			
Operations and maintenance net of investment income	(30,267)	(7,383)	(37,650)
Costs of acquisition of capacity - STS	(11,750)	(6,600)	(18,350)
Reduction in debt service due to transfer of excess construction funds	40,999		40,999
Principal repayments	(35,550)	(25,145)	(60,695)
Other	(3,341)	(2,726)	(6,067)
	$138,390	$22,690	$161,080

NOTE 7 - 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

REPORT WITH FINANCIAL STATEMENTS
AND SUPPLEMENTAL
FINANCIAL INFORMATION

JUNE 30, 1990 AND 1989

400 South Hope Street
Los Angeles, CA 90071-2889

Telephone 213 236 3000

Price Waterhouse

REPORT OF INDEPENDENT ACCOUNTANTS

August 24, 1990

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 cash flows present fairly, in all material respects, the financial position of the Southern California Public Power Authority (Authority) at June 30, 1990 and 1989, and the results of its operations and its cash flows for the years then ended, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audits 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.

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, Mead-Phoenix Project and Multiple Project Fund and the separate statements of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project present fairly, in all material respects, the financial position of each of the Projects at June 30, 1990 and 1989, and their cash flows and the results of operations of the Palo Verde Project, Southern Transmission System Project and Hoover Uprating Project for the years then ended, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which

require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. We believe that our audits provide a reasonable basis for the opinion expressed above.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial information, as listed on 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 audits 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)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead Phoenix Project	Multiple Project Fund	Total	June 30, 1989 Total
	June 30, 1990						
ASSETS							
Utility plant							
Production	$ 594,323					$ 594,323	$ 600,788
Transmission	14,172	$ 662,727				676,899	667,263
General	2,289	18,893				21,182	19,043
	610,784	681,620				1,292,404	1,287,084
Less - Accumulated depreciation	77,421	76,477				153,898	113,452
	533,363	605,143				1,138,506	1,173,632
Construction work in progress	4,119	7,320		$14,078		25,517	20,855
Nuclear fuel, at amortized cost	25,931					25,931	26,428
Net utility plant	563,413	612,463		14,078		1,189,954	1,220,915
Special funds							
Investments	136,567	95,595	$15,116	132	$603,796	851,206	226,441
Advance to Intermountain Power Agency		19,550				19,550	20,161
Advances for capacity and energy, net			12,163			12,163	10,218
Interest receivable	3,129	2,632	250		21,943	27,954	3,096
Cash and cash equivalents	83,844	69,002	7,999	22		160,867	176,672
	223,540	186,779	35,528	154	625,739	1,071,740	436,588
Accounts receivable	4,272	611				4,883	4,182
aterials and supplies	8,968					8,968	6,859
osts recoverable from future billings to participants	69,004	93,708	(1,632)			161,080	138,390
Deferred costs							
Unamortized debt expenses, less accumulated amortization of $62,801 and $46,363	218,597	166,840	1,115			386,552	403,515
Other deferred costs	466					466	864
	219,063	166,840	1,115			387,018	404,379
	$1,088,260	$1,060,401	$35,011	$14,232	$625,739	$2,823,643	$2,211,313
LIABILITIES							
Long-term debt	$1,031,200	$1,007,159	$34,297	$ 100	$600,372	$2,673,128	$2,092,379
Arbitrage rebate payable					1,287	1,287	
Current liabilities							
Long-term debt due within one year	15,255	9,890				25,145	20,195
Accrued interest	36,180	37,090	689	1	24,080	98,040	74,168
Accounts payable and accrued expenses	5,625	6,262	25	83		11,995	10,523
	57,060	53,242	714	84	24,080	135,180	104,886
Advances from participants				14,048		14,048	14,048
Commitments and contingencies							
	$1,088,260	$1,060,401	$35,011	$14,232	$625,739	$2,823,643	$2,211,313

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, 1990				
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Total	Year Ended June 30, 1989
Operating revenues					
Sales of electric energy	$120,782		$2,760	$123,542	$112,924
Sales of transmission services	___	$93,508	___	93,508	94,769
Total operating revenues	120,782	93,508	2,760	217,050	207,693
Operating expenses					
Nuclear fuel expenses	4,176			4,176	10,628
Other operation	28,145	10,501	1,346	39,992	28,899
Maintenance	8,660	4,134		12,794	8,723
Depreciation	17,980	19,205		37,185	36,634
Decommissioning	5,699	___	___	5,699	5,699
Total operating expenses	64,660	33,840	1,346	99,846	90,583
Operating income	56,122	59,668	1,414	117,204	117,110
Investment Income	18,290	11,611	2,025	31,926	31,056
Income before debt expenses	74,412	71,279	3,439	149,130	148,166
Debt expense					
Interest on debt	84,829	84,180	2,811	171,820	171,908
Costs recoverable from future billings to participants	($ 10,417)	($12,901)	$ 628	($ 22,690)	($ 23,742)

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, 1990						
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Multiple Project Fund	Total	Year Ended June 30, 1989
Cash flows from operating activities:							
Costs recoverable from future billings to participants	($10,417)	($ 12,901)	$ 628			($ 22,690)	($ 23,742)
Adjustments to arrive at net cash provided by operating activities:							
Depreciation	17,980	19,205				37,185	36,634
Decommissioning	5,699					5,699	5,699
Amortization of nuclear fuel	3,676					3,676	9,528
Amortization of debt costs	12,899	10,000	54			22,953	21,196
Changes in assets and liabilities:							
Interest receivable	(1,499)	(1,457)	42			(2,914)	227
Accounts receivable	(637)	(63)				(700)	(3,346)
Materials and supplies	(2,109)					(2,109)	(331)
Other assets	(32)	24				(8)	15
Accrued interest	(39)	(168)				(207)	(2,706)
Accounts payable and accrued expenses	890	493	10			1,393	(5,808)
Net cash provided by operating activities	26,411	15,133	734			42,278	37,366
Cash flows from investing activities:							
Payments for construction of facility	(9,980)	(4,544)				(14,524)	(15,771)
Advances for capacity of energy, net			(1,945)			(1,945)	(4,209)
Payments for feasibility study				($1,000)		(1,000)	(703)
Purchase of investments	(189,032)	(124,280)	(15,816)	(1,015)	($603,796)	(933,939)	(177,715)
Proceeds from sale of investments	163,143	124,612	19,447	1,972		309,174	211,420
Refund from Intermountain Power Agency		611				611	
Net cash (used for) provided by investing activities	(35,869)	(3,601)	1,686	(43)	(603,796)	(641,623)	13,022
Cash flows from financing activities:							
Proceeds from sale of bonds					603,796	603,796	
Proceeds from sale of refunding bonds							341,250
Payment for defeasance of revenue bonds							(334,566)
Payment for principal of long-term debt	(14,370)	(5,825)				(20,195)	(29,403)
Payment for bond issue costs			(61)			(61)	(6,782)
Proceeds from advances from participants							14,048
Net cash (used for) provided by financing activities	(14,370)	(5,825)	(61)		603,796	583,540	(15,453)
Net (decrease) increase in cash and cash equivalents	(23,828)	5,707	2,359	(43)		(15,805)	34,935
Cash and cash equivalents at beginning of year	107,672	63,295	5,640	65		176,672	141,737
Cash and cash equivalents at end of year	$ 83,844	$ 69,002	$ 7,999	$ 22	$ -	$160,867	$176,672
Supplemental disclosure of cash flow information:							
Cash paid during the year for interest (net of amount capitalized)	$ 72,399	$ 74,349	$ 2,757	$ -	$ -	$149,505	$149,534

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

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

NOTES TO FINANCIAL STATEMENTS

NOTE 1 - 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:

Participants	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%

The members do not currently participate in the Multiple Project Fund.

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

NOTE 1: (Continued)

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. During fiscal year 1989, all three units were "on-line" the majority of the year. During fiscal year 1990, Unit 1 was down the entire year and Units 2 and 3 were down approximately one-half the year for repairs.

Southern Transmission System Project

The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has made payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), which provides for the transmission of energy from the Intermountain 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 to 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 during June 1987.

Mead-Phoenix Project

The Authority has 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 complete and the project is in contract negotiations with its participants.

NOTE 1: (Continued)

Multiple Project Fund

During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more projects for the generation or transmission of electric energy which are expected to be undertaken within the next five years. Currently, the Authority has not authorized specific projects to be financed with the proceeds of the Bonds.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

The financial statements of the Authority 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. The Authority is not subject to regulations of 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.

NOTE 2: (Continued)

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 has been established. 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 reported 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, which in general is not in excess of market. As discussed in Note 3, all of the investments are restricted as to their use.

Cash and Cash Equivalents

Cash and cash equivalents include cash and all investments with maturities less than ninety days.

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 6).

Debt Expenses

Debt expenses include interest on debt, and the amortization of bond discounts, debt issue and refunding costs.

Arbitrage Rebate

A rebate payable to the Internal Revenue Service (IRS) results from the investment of the proceeds from the Multiple Project Revenue Bond Offering in a taxable financial instrument that yields a higher rate of interest income than the cost of the associated funds. The excess of interest income over costs is payable to the IRS within the next five years.

NOTE 3 - SPECIAL FUNDS:

The Bond Indentures for three of the four projects and the Multiple Project Fund 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
Proceeds Account	Trustee	To initially receive the proceeds of the sale of the Multiple Project Revenue Bonds
Earnings Account	Trustee	To receive investment earnings on the Multiple Project Revenue Bonds

NOTE 3: (Continued)

Special funds, in thousands, were as follows:

	June 30, 1990 Carrying Value	1990 Market	1989 Carrying Value	1989 Market
Palo Verde Project	$ 223,540	$ 227,000	$219,980	$225,200
Southern Transmission System Project	186,779	186,300	180,557	180,400
Hoover Uprating Project	35,528	35,400	34,897	34,800
Mead-Phoenix Project	154	200	1,154	1,200
Multiple Project Fund	625,616	625,600		
	$1,071,617	$1,074,500	$436,588	$441,600

Palo Verde Project

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

	June 30, 1990	1989
Construction Fund-Initial Facilities Account	$ 50,871	$ 49,415
Debt Service Fund -		
Debt Service Account	51,871	63,733
Debt Service Reserve Account	91,001	90,217
Bond Anticipation Note Fund	30	30
Revenue Fund	2	353
Operating Fund	14,038	5,644
Reserve and Contingency Fund	15,727	10,588
	$223,540	$219,980

NOTE 3: (Continued)

Southern Transmission System Project

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

	June 30, 1990	June 30, 1989
Construction Fund - Initial Facilities Account	$ 263	$ 5,309
Debt Service Fund -		
Debt Service Account	47,720	43,548
Debt Service Reserve Account	89,952	88,948
Revenue Fund	2	
Operating Fund	7,168	6,814
General Reserve Fund	22,124	15,777
Total	$167,229	$160,396

At June 30, 1990 and 1989 the Authority had non-interest bearing advances outstanding to IPA of $19,550,000 and $20,161,000, respectively.

Hoover Uprating Project

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

	June 30, 1990	June 30, 1989
Advance Payments Fund	$18,559	$19,947
Revenue Fund		7
Operating Working Capital Fund	471	400
Debt Service Fund -		
Debt Service Account	723	710
Debt Service Reserve Account	3,612	3,615
Total Special Funds	$23,365	$24,679

At June 30, 1990 and 1989 the Authority had non-interest bearing advances to USBR of $12,163,000 and $10,218,000, respectively.

NOTE 3: (Continued)Multiple Project Fund

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

	June 30, 1990
Multiple Project Fund -	
Multiple Project Proceeds Account	$600,012
Multiple Project Debt Service Account	3,784
Multiple Project Earnings Account	21,943
	$625,739

Mead-Phoenix Project

At June 30, 1990 and 1989, the balances in the Development Fund were $154,000 and $1,154,000, respectively, substantially all of which were invested in securities of the United States Government.

NOTE 4 - 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, 1990 for details related to outstanding bonds.

The Bond Indenture provides that the Revenue Bond 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 5) 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 Decommissioning Account in the Reserve and Contingency Fund).

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 installments 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, 2003 for the 1986 Series A Bonds, the 1986 Series B Bonds and the 1987 Series A Bonds and 2005 for the 1985 Series B Bonds and 1989 Series A Bonds. Scheduled principal maturities for the Palo Verde Project during the five fiscal years following June 30, 1990 are

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*

Principal Amount	Initial Amount	Maturity	Yield	Price (per $100)
$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

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Bill D. Carnahan (Riverside)
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Gale A. Drews (Colton)
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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.

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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

APPENDIX A

R.W. BECK
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February 2, 1989

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

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%

r 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.

n-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	June 30 1987	June 30 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

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.

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

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 City of 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]52
Commercial	227	249	265	279	[illegible]98
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, $6,05[illegible]nd $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	[illegible]
Other	595	625	636	655	[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 [illegible] the City of Pasadena for inclusion of this Official Statement. This information does not purport to cover all asp[illegible] of the Power Department's business, operations and financial position. During the initial offering period for th[illegible] securities offered by this Official Statement, a copy of the most recent Pasadena Water and Power Department 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[illegible]
Industrial	675	705	720	745	771
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	$ 4,58[illegible]

* Unaudited data.

City 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	[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 th

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 o

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, a

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

TOM BRADLEY
Mayor

Commission
RICK J. CARUSO, *President*
JACK W. LEENEY, *Vice President*
ANGEL M. ECHEVARRIA
CAROL WHEELER
WALTER A. ZELMAN
JUDITH K. DAVISON, *Secretary*

PAUL H. LANE, *General Manager and Chief Engineer*
NORMAN E. NICHOLS, *Assistant General Manager - Power*
DUANE L. GEORGESON, *Assistant General Manager - Water*
DANIEL W. WATERS, *Assistant General Manager - External Affairs*
NORMAN J. POWERS, *Chief Financial Officer*

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 Yor 004

Issuer:

Policy Number:

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 cases where the Bonds are issuable only in a form whereby interest is payable to registered Bondholders or their assigns, the 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.

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

Secretary

Effective Date:

Authorized Representative

UNITED STATES TRUST COMPANY OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Authorized Officer

Form # 66-0003 (11/87)