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Arizona Public Service Company
P.O. BOX 53999 • PHOENIX, ARIZONA 85072-3999

WILLIAM L. STEWART
EXECUTIVE VICE PRESIDENT
NUCLEAR

102-02977-WLS/JRP
June 1, 1994

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Washington, DC 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Licensee Guarantee of Payment of Deferred Premium
File: 94-003-240

Pursuant to the requirements of 10 CFR 140.21(e), Arizona Public Service Company, for itself and on behalf of the PVNGS participants, herewith submits the projected 1994 cash flow statements.

Should you have any questions, please contact Richard A. Bernier of my staff at (602) 393-5882.

Sincerely,

WL Stewart

WLS/JRP/dld

Enclosure

cc: K. E. Perkins
L. J. Callan
B. E. Holian
K. E. Johnston

210007

M004 /1

ARIZONA PUBLIC SERVICE COMPANY
1994 Net Cash Flow Projection
for Palo Verde Nuclear Generating Station
(000's)

Participant: ARIZONA PUBLIC SERVICE COMPANY

		1993 Actual	1994 Projected
1.	Net Income After Taxes	$250,386	$227,575
	Less:		
2.	Dividends Paid on Preferred Stock	30,945	29,536
3.	Dividends Paid on Common Stock	170,000	170,000
4.	Retained Earnings	49,441	28,039
	Adjustments:		
5.	Palo Verde Accretion Income (Pretax) (1)	(74,881)	(33,596)
6.	In-Lieu Refund/Obligation Revenues (Pretax) (1)	(21,375)	(9,308)
7.	Depreciation and Amortization (2)	254,634	268,172
8.	Deferred Income Taxes	102,697	70,799
9.	Deferred ITC (Net)	(6,948)	(6,855)
10.	Allowance for Funds Used During Construction (Equity & Borrowed)	(6,479)	(8,560)
11.	Decommissioning	(7,072)	(11,647)
12.	Total Adjustments	240,576	269,005
13.	Internal Cash Flow (Line 4 + Line 12)	290,017	297,044
14.	Average Quaterly Cash Flow (Line 13/4)	72,504	74,261

Percentage Owner ship 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) Related to 12/91 ACC settlement agreement.
(2) Includes Nuclear Fuel Amortization.
(3) Includes Portion of Palo Verde Unit 2 Leased.

NCF94 Surveys

APS STATISTICS - PG. 5 (Dollars in Thousands)	DECEMBER 1992	JANUARY 1993	FEBRUARY 1993	MARCH 1993	APRIL 1993	MAY 1993	JUNE 1993	JULY 1993	AUGUST 1993	SEPTEMBER 1993	OCTOBER 1993	NOVEMBER 1993	DECEMBER 1993
NON-CASH INCOME:													
133. AFUDC Debt	4,492	4,380	4,388	4,151	3,931	3,821	4,022	3,990	3,937	3,675	3,920	3,955	4,153
134. AFUDC Equity	3,103	3,045	3,058	3,049	3,062	3,148	2,961	2,933	2,884	2,776	2,546	2,337	2,326
135. Net Deferral Ex Equity (17+26-27)	0	0	0	0	0	0	0	0	0	0	0	0	0
136. Restoration - After tax	40,753	41,111	41,472	41,836	42,204	42,575	42,949	43,327	43,708	44,091	44,478	44,868	45,262
137. "In-Lieu" Revenue - After tax	12,919	12,920	12,920	12,919	12,920	12,919	12,920	12,920	12,920	12,919	12,920	12,920	12,920
138. TOTAL NON-CASH INCOME - NET	61,267	61,456	61,838	61,955	62,117	62,463	62,852	63,170	63,449	63,461	63,864	64,080	64,661
139. Earnings Ex. Reg. Write-off (7+43)	214,353	223,149	228,198	231,043	232,301	230,559	230,079	229,304	223,633	225,648	215,809	216,104	219,546
140. NON-CASH INC. % EARNINGS(138/139)	28.58%	27.54%	27.10%	26.82%	26.74%	27.09%	27.32%	27.55%	28.37%	28.12%	29.59%	29.65%	29.45%
NET CASH FLOW:													
141. Net Income	246,805	255,463	260,377	263,060	264,155	262,220	261,651	260,506	254,598	256,404	248,822	247,049 -	250,386 ✓
----- Add -----													
142. Depreciation & Amortization	219,118	219,453	219,738	220,265	220,659	221,115	221,308	221,562	221,694	221,952	222,046	222,154	222,610 ✓
143. Nuclear Fuel Amortization	36,605	37,816	38,205	39,349	39,367	39,561	38,287	36,716	34,886	34,411	34,228	33,557	32,024
144. Deferred Income Taxes	84,097	85,071	85,990	86,163	88,937	89,330	90,000	84,087	85,585	86,355	104,492	103,928	102,697
145. Tax Impacts of Cholla 4 Gain	0	0	0	0	0	0	0	0	0	0	0	0	0
146. Deferred ITC	(6,804)	(6,856)	(6,905)	(6,887)	(6,950)	(6,927)	(6,921)	(6,893)	(6,796)	(6,722)	(6,664)	(6,646)	(6,948) ✓
147. Regulatory Write-off - Pretax	0	0	0	0	0	0	0	0	0	0	0	0	0
---- Subtract ----													
148. AFUDC (133+134)	7,595	7,425	7,446	7,200	6,993	6,969	6,983	6,923	6,821	6,451	6,466	6,292	6,479 ✓
149. Gross Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0 ✓
150. Common & Preferred Dividends	202,574	202,574	202,574	202,173	202,173	202,116	201,683	201,683	201,683	202,274	200,966	201,694	200,945 ✓
151. Amortized TBT	0	0	0	0	0	0	0	0	0	0	0	0	0
152. Remove Recognition of TBT Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
153. Deferred Tax on Deferred Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0
154. Decommissioning (Sept 1988 on)	6,512	6,512	6,512	6,512	6,512	6,512	6,512	6,512	6,512	6,792	6,792	6,792	7,072
155. Restoration - Pretax	67,421	68,013	68,610	69,212	69,821	70,435	71,054	71,679	72,310	72,943	73,584	74,229	74,881 ✓
156. "In-Lieu" Revenue - Pretax	21,374	21,375	21,375	21,374	21,374	21,374	21,375	21,375	21,374	21,374	21,374	21,375	21,375 ✓
157. NET CASH FLOW EX. NON-CASH	274,345	285,048	290,888	295,479	299,295	297,893	296,698	287,806	281,267	282,566	291,742	289,660	290,017 ✓
TME CAPITAL EXPENDITURE LESS AFU													
158. Capital Expenditures	224,419	219,387	228,297	221,106	220,429	225,078	226,214	224,044	237,821	229,258	231,453	228,625	234,944
159. Stagg Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
160. AFUDC (133+134)	(7,595)	(7,425)	(7,446)	(7,200)	(6,993)	(6,969)	(6,983)	(6,923)	(6,821)	(6,451)	(6,466)	(6,292)	(6,479)
161. AFUDC Debt-Tax on Transitional	0	0	0	0	0	0	0	0	0	0	0	0	0
162. CAPITAL EXPENDITURE LESS AFUDC	216,824	211,962	220,851	213,906	213,436	218,109	219,231	217,121	231,000	222,807	224,987	222,333	228,465
163. NCF % CAPITAL EXPEND. (157/162)	126.53%	134.48%	131.71%	138.13%	140.23%	136.58%	135.34%	132.56%	121.76%	126.82%	129.67%	130.28%	126.94%
164. NCF % CAPITALIZATION (157/50)	6.51%	6.87%	7.07%	7.13%	7.30%	7.28%	7.26%	7.01%	6.84%	6.70%	6.92%	7.08%	6.92%
FUNDS FROM OPERATIONS:													
165. Net Cash Flow (157)	274,345	285,048	290,888	295,479	299,295	297,893	296,698	287,806	281,267	282,566	291,742	289,660	290,017
166. Plus Common & Preferred Dividends	202,574	202,574	202,574	202,173	202,173	202,116	201,683	201,683	201,683	202,274	200,966	201,694	200,945
167. FUNDS FROM OPERATIONS	476,919	487,622	493,462	497,652	501,468	500,009	498,381	489,489	482,950	484,840	492,708	491,354	490,962
168. Fixed Charges (119)	246,246	243,149	239,798	237,454	234,543	231,391	228,667	227,661	226,145	225,929	224,710	222,789	220,590
169. FFO INCLUDING FIXED CHARGES	723,165	730,771	733,260	735,106	736,011	731,400	727,048	717,150	709,095	710,769	717,418	714,143	711,552
170. FFO INTEREST COVERAGE (169/168)	2.93	3.00	3.05	3.09	3.13	3.16	3.17	3.15	3.13	3.14	3.19	3.20	3.22
171. FFO % AVG DEBT ADJ. FOR S/L (167/72)	16.56%	17.01%	17.41%	17.67%	17.89%	17.95%	17.92%	17.68%	17.48%	17.54%	17.82%	17.82%	17.80%
172. BOOK VALUE PER SHARE $ (5/31)	$20.72	$20.36	$20.54	$20.67	$20.17	$20.44	$20.23	$20.75	$21.25	$21.58	$21.13	$21.20	$21.37

ARIZONA PUBLIC SERVICE
CONSOLIDATED FINANCIAL MODEL
(DOLLARS IN THOUSANDS)

	JAN 1994	FEB 1994	MAR 1994	APR 1994	MAY 1994	JUN 1994	JUL 1994	AUG 1994	SEP 1994	OCT 1994	NOV 1994	DEC 1994	YRT 1994
ET CASH FLOW													
ET INCOME	233770	231369	230198	227583	230700	223857	224567	226062	228865	228052	229094	227575	227575
EPR & AMORT	258259	257740	257550	258100	258812	260603	262260	263208	264427	265345	267111	268173	268173 -1 ROUNDING
EFER TAXES	97035	96792	97585	97572	99064	95927	93350	84366	80866	77086	75014	70799	70799
EF ITC NET	-6815	-6788	-6864	-6854	-7033	-6951	-6974	-7000	-6953	-6873	-6979	-6855	-6855
EG W/O	0	0	0	0	0	0	0	0	0	0	0	0	0
THER	0	0	0	0	0	0	0	0	0	0	0	0	0
ESS:													
AFC TOTAL	6508	6798	6930	7067	7069	7167	7180	7296	8126	8222	8319	8560	8560
DEFERRALS	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMON DIVID	170000	170000	170000	170000	170000	170000	170000	170000	170000	170000	170000	170000	170000
PREF DIVID	30998	31013	38562	30655	31214	30766	30766	31475	30605	30243	30228	29536	29536
AMORTIZED TBT	0	0	0	0	0	0	0	0	0	0	0	0	0
DECOMM TOTAL	7525	7952	8379	8806	9233	9661	9992	10323	10654	10985	11316	11647	11647
GR INLIEU REV	21374	21374	21374	21375	21375	19995	18214	16433	14652	12871	11089	9308	9308
GR ACCRET REV	75540	76202	76872	77547	78229	72018	65753	59433	53059	46628	40141	33596	33596
ET CASH FLOW	270305	265774	256352	260951	264422	263829	271298	271676	280109	284661	293147	297044	297044
APITAL EXPENDITURES EXCLUDING AFC:													
CNST EXPEND	265080	274300	280925	286524	290940	292450	287634	291272	288785	277756	278161	279285	279285
CAP P TAX	2591	2645	2689	2724	2739	2744	2756	2760	2757	2756	2759	2771	2771
INV IN.SUBS	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0	0	0	0	0	0	0
AP EXPEND	267671	276945	283614	289248	293679	295194	290390	294032	291542	280512	280920	282056	282056
L-T REPAY	637056	600056	660320	573620	556835	566940	566940	616940	493489	319059	177442	177552	177552
AP REQUIR	904726	877001	943934	862868	850514	862134	857330	910972	785031	599571	458361	459608	459608
CF/CNST EXP	101.97	96.89	91.25	91.07	90.89	90.21	94.32	93.27	97.00	102.49	105.39	106.36	106.36
CF/CAP EXP	100.98	95.97	90.39	90.22	90.04	89.37	93.43	92.40	96.08	101.48	104.35	105.31	105.31
CF/CAP REQ	29.88	30.30	27.16	30.24	31.09	30.60	31.64	29.82	35.68	47.48	63.96	64.63	64.63
CF/COM DIV	2.59	2.56	2.51	2.54	2.56	2.55	2.60	2.60	2.65	2.67	2.72	2.75	2.75
CF/CAPITAL	6.54	6.43	6.17	6.36	6.35	6.21	6.48	6.53	6.68	6.96	7.12	7.04	7.04
OVENANT COVERAGE:													
FMB >= 2.0X	4.57	4.25	4.43	4.40	4.44	4.39	4.40	4.39	4.44	4.43	4.44	4.42	4.42
CASH >= 2.0X	3.83	3.80	3.79	3.78	3.80	3.75	3.81	3.84	3.91	3.95	3.99	4.02	4.02
PREF >= 1.5X	2.05	1.93	1.99	1.97	1.93	1.93	1.96	1.97	2.02	2.02	1.98	1.98	1.98
ON_CASH O&M:													
TRANSP DEPR	427	422	419	415	413	413	413	412	412	409	406	403	4966
PENSION	721	721	722	721	721	722	721	721	722	722	722	722	8658
UNCOLLECTIBLE	412	378	437	489	214	267	341	266	258	233	224	366	3885
OTAL	1560	1521	1578	1625	1348	1402	1475	1399	1392	1364	1352	1491	17509

SOUTHERN CALIFORNIA EDISON COMPANY
1994 Internal Cash Flow Projection
(Dollars in Thousands)

	1993 Actual	1994 Projected
Net Income After Taxes	$678,045	*
Dividends Paid	$672,830	*
Retained Earnings	$5,215	*
Adjustments:		
Depreciation & Decommissioning	$892,502	$908,000
Net Deferred Taxes & ITC	$106,216	$33,000
Allowance for Funds Used During Construction	($36,429)	($35,000)
Total Adjustments	$962,289	$906,000
Internal Cash Flow	$967,504	*
Average Quarterly Cash Flow	$241,876	*

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 2 & 3	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 1994 is expected to be comparable to the Actual Cash Flow for 1993.

2:01 PM 5/5/94

INTERNAL CASH FLOW PROJECTION OF SALT RIVER PROJECT
(JOINT OWNER OF PALO VERDE NUCLEAR GENERATING STATION)
FOR FISCAL YEARS ENDED APRIL 30, 1993 and 1994
($000)

	1993 ACTUAL	1994 PROJECTED
Net Income after taxes	54,962	70,675
Less dividends paid:		
Preferred dividend requirements		
Dividends on common stock		
Retained Earnings	54,962	70,675
Adjustments:		
Depreciation and amortization	169,718	174,462
Deferred Income Taxes and Investment Tax Credits		
Allowance for Funds Used During Construction	(7,364)	(8,163)
Total Adjustments	162,354	166,299
Internal Cash Flow	217,316	236,974
Average Quarterly Cash Flow	54,329	59,244
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, Dean Yee, Corporate Treasurer of the Salt River Project Agricultural Improvement and Power District certify that the above 1993 figures are based upon our Accounting Records, and agree, as appropriate with our audited financial statements. The 1994 projections are based upon May 1993 through March 1994 actual amounts, plus budgeted figures for the month of April. The 1994 projections do not reflect expected actual figures, as budget is not revised to reflect changing conditions.

Dean K Yee

Dean Yee

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1994 PRO FORMA CASH FLOW STATEMENT
FOR PUBLIC SERVICE COMPANY OF NEW MEXICO
(EXCLUDING NON-UTILITY SUBSIDIARIES)

	1993 Actual	1994 Projected
Net Income After Taxes	(61,486)	74,206
Less Dividends Paid	6,829	7,173
Retained Earnings	(68,315)	67,033
Adjustments:		
Depreciation & Amortization	95,415	103,766
Deferred Income Taxes & Investment Tax Credits	(71,714)	6,960
Allowance for Equity Funds Used During Construction	0	(1,505)
Other, Non-Cash	223,450	(15,727)
TOTAL ADJUSTMENTS	247,151	93,494
INTERNAL CASH FLOW	178,836	160,527
Average Quarterly Cash Flow	44,709	40,132

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

PUBLIC SERVICE COMPANY OF NEW MEXICO
CAPITIAL REQUIREMENTS & INTERNAL CASH GENERATION
Stipulation Case

($ MILLONS)	1994	1995	1996	1997	1998
CAPITAL REQUIREMENTS:					
Construction Expenditures	$122,427	$134,171	$110,216	$93,123	$103,885
Construction AFUDC	(1,505)	(869)	(827)	(532)	(453)
Other Cash Requirements	21,470	16,857	16,860	29,633	6,756
TOTAL CAPITAL REQUIREMENTS	$142,392	$150,159	$126,249	$122,224	$110,188
INTERNAL CASH GENERATION:					
Net Income (Including One Time Items)	$74,206	$61,240	$73,693	$71,893	$73,340
Depreciation and Amortization	91,574	90,515	93,134	95,245	97,418
Nuclear Fuel Amortization	12,192	11,831	11,514	11,686	11,926
Deferred Income Tax	12,168	5,225	8,388	6,527	4,919
ITC--Net	(5,208)	(5,177)	(5,180)	(5,180)	(5,180)
Other Non-Cash Items	4,372	4,481	4,598	4,698	4,803
Construction AFUDC	(1,505)	(869)	(827)	(532)	(453)
Previous Years Taxes	0	0	0	0	0
Deferred Fuel	0	0	0	0	0
Other Sources & Timing Differences	(20,099)	(2,916)	(5,300)	(400)	(400)
FUNDS FROM OPERATIONS	$167,700	$164,329	$180,020	$183,936	$186,373
Preferred Dividends	7,173	7,060	6,946	6,833	6,719
TOTAL INTERNAL CASH GENERATION (FROM OPERATIONS)	$160,527	$157,269	$173,074	$177,103	$179,654
NET CASH FROM ASSETS SALES	$137,697	$0	$4,900	$0	$0
LESS: CASH FOR BOND RETIREMENT	($142,000)	$0	$0	$0	$0
TOTAL INTERNAL CASH GENERATION	$156,224	$157,269	$177,974	$177,103	$179,654

CAPREQ1.WK4

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EL PASO ELECTRIC COMPANY

Cash Balance Analysis
1994

(Dollars in Millions)

	Actual			Projected									
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Beginning Cash Balance	$184	$193	$198	$183	$180	$169	$149	$160	$168	$163	$166	$162	$184
Operating Receipts	49	45	45	40	41	45	49	51	50	48	43	42	548
Operating Disbursements	(32)	(31)	(33)	(30)	(39)	(37)	(26)	(29)	(27)	(26)	(35)	(26)	(371)
Capital Expenditures	(3)	(4)	(7)	(8)	(7)	(7)	(6)	(9)	(7)	(14)	(6)	(6)	(84)
Operating Cash Flow	14	10	5	2	(5)	1	17	13	16	8	2	10	93
Cash Available for Interest	198	203	203	185	175	170	166	173	184	171	168	172	277
Interest Paid													
Secured	5	5	5	5	6	5	6	5	5	5	6	5	63
Unsecured and Other	0	0	15	0	0	16	0	0	16	0	0	16	63
Total	5	5	20	5	6	21	6	5	21	5	6	21	126
Ending Cash Balance	**$193**	**$198**	**$183**	**$180**	**$169**	**$149**	**$160**	**$168**	**$163**	**$166**	**$162**	**$151**	**$151**
Cumulative Cash Escrow Bonded Rates	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1**	**$3**	**$6**	**$8**	**$10**	**$12**	

1994 INTERNAL CASH FLOW PROJECTION OF
LOS ANGELES DEPARTMENT OF WATER AND POWER
FOR PALO VERDE NUCLEAR POWER STATION

THOUSANDS OF DOLLARS

	1992–93 ACTUAL	1993–94 PROJECTION
NET INCOME	$176,137	$87,120
LESS: TRANSFER TO THE CITY	($74,160)	($101,880)
RETAINED EARNINGS	$101,977	($14,760)
ADJUSTMENTS		
DEPRECIATION AND AMORTIZATION	$171,369	$184,920
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	($15,152)	($3,340)
TOTAL ADJUSTMENTS	$156,217	$181,580
INTERNAL CASH FLOW	$258,194	$166,820

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 1993

Commission File Number 1-9936

SCEcorp

(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	95-4137452 (I.R.S. Employer Identification No.)

2244 Walnut Grove Avenue Rosemead, California (Address of principal executive offices)	91770 (Zip Code)	(818) 302-2222 (Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock	New York and Pacific (also listed on London Exchange)

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

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

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

The aggregate market value of registrant's voting stock held by non-affiliates was approximately $8,118,598,988 on or about March 1, 1994, based upon prices reported on the New York Stock Exchange. As of March 1, 1994, there were 447,799,172 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents listed below have been incorporated by reference into the parts of this report so indicated.

(1) Designated portions of the Annual Report to Shareholders for the year ended December 31, 1993	Parts I, II and IV
(2) Designated portions of the Joint Proxy Statement relating to registrant's 1994 Annual Meeting of Shareholders	Part III

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PART I

Item 1. Business

Business of SCEcorp

SCEcorp was incorporated on April 20, 1987, under the laws of the State of California for the purpose of becoming the parent holding company of Southern California Edison Company ("Edison"), a California public utility corporation. SCEcorp owns all of the issued and outstanding common stock of Edison and, in addition, owns all of the issued and outstanding capital stock of The Mission Group ("Mission Group"), which in turn owns the stock of subsidiaries engaged in nonutility businesses. These subsidiaries are currently engaged in developing cogeneration and other energy projects ("Mission Energy"), making financial investments in electric generating facilities and other assets ("Mission First Financial") and developing, managing, and selling existing real estate projects ("Mission Land").

SCEcorp is engaged solely in the business of holding for investment the stock of its subsidiaries and is not presently conducting any independent business activities. For the year ended December 31, 1993, Edison and Mission Group accounted for 99.3% and 0.7%, respectively, of the net income of SCEcorp. At December 31, 1993, Edison had 16,487 full-time employees and Mission Group and its subsidiaries had 706 full-time employees. Currently, SCEcorp has no employees of its own.

The principal executive offices of SCEcorp are located at 2244 Walnut Grove Avenue, Rosemead, California 91770, and its telephone number is (818) 302-2222.

Regulation of SCEcorp

SCEcorp and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935 ("Holding Company Act") on the basis that SCEcorp and Edison are incorporated in the same state and their business is predominately intrastate in character and carried on substantially in the state of incorporation. It is necessary for SCEcorp to file an annual exemption statement with the Securities and Exchange Commission ("SEC"), and the exemption may be revoked by the SEC upon a finding that the exemption may be detrimental to the public interest or the interest of investors or consumers. SCEcorp has no intention of becoming a registered holding company under the Holding Company Act.

SCEcorp is not a public utility under the laws of the State of California and is not subject to regulation as such by the California Public Utilities Commission ("CPUC"). See "Business of Southern California Edison Company--Regulation of Edison" below for a description of the regulation of Edison by the CPUC. However, the CPUC decision authorizing Edison to reorganize into a holding company structure contains certain conditions, which, among other things, ensure the CPUC access to books and records of SCEcorp and its affiliates which relate to transactions with Edison; require SCEcorp and its subsidiaries to employ accounting and other procedures and controls to ensure full review by the CPUC and to protect against subsidization of nonutility activities by Edison's customers; require that all transfers of market, technological or similar data from Edison to SCEcorp or its affiliates be made at market value; preclude Edison from guaranteeing any obligations of SCEcorp without prior written consent from the CPUC; provide for royalty payments to be paid by SCEcorp or its subsidiaries in connection with the transfer of product rights, patents, copyrights or similar legal rights from

Edison; and prevent SCEcorp and its subsidiaries from providing certain facilities and equipment to Edison except through competitive bidding. In addition, the decision provides that Edison shall maintain a balanced capital structure in accordance with prior CPUC decisions, that Edison's dividend policy shall continue to be established by Edison's Board of Directors as though Edison were a comparable stand-alone utility company, and that the capital requirements of Edison, as determined to be necessary to meet Edison's service obligations, shall be given first priority by the Boards of Directors of SCEcorp and Edison.

Environmental Matters

Legislative and regulatory activities in the areas of air and water pollution, waste management, hazardous chemical use, noise abatement, land use, aesthetics and nuclear control continue to result in the imposition of numerous restrictions on SCEcorp's subsidiaries with respect to the operation of existing facilities, on the timing, cost, location, design, construction and operation of new facilities required to meet future load requirements, and on the cost of mitigating the effect of past operations on the environment. These activities substantially affect future planning and will continue to require modifications of existing facilities and operating procedures. SCEcorp is unable to predict the extent to which additional regulations may affect the operations and capital expenditure requirements of its subsidiaries.

The Clean Air Act provides the statutory framework to implement a program for achieving national ambient air quality standards and provides for maintenance of air quality in areas exceeding such standards. The Clean Air Act was amended in 1990, giving the South Coast Air Quality Management District ("SCAQMD") 20 years to achieve all the federal air quality standards. The SCAQMD's Air Quality Management Plan ("AQMP"), adopted in 1991, demonstrates a commitment to attain federal air quality standards within 20 years. Consistent with the requirements of the AQMP and the Clean Air Act Amendments of 1990 ("CAAA"), the SCAQMD adopted rules to reduce emissions of oxides of nitrogen ("NOx") from combustion turbines, internal combustion engines, industrial coolers and utility boilers. On October 15, 1993, the SCAQMD adopted the Regional Clean Air Incentives Market ("RECLAIM") which replaces most of the previous rule requirements with a market mechanism for NOx emission trading (trading credits). RECLAIM will, however, still require Edison to reduce NOx emissions through retrofit or purchase of trading credits on all basin generation by over 86% by 2003. In Ventura County, a NOx rule was adopted requiring more than an 88% NOx reduction by June 1996 at all utility boilers. Edison's expected total cost to meet these requirements is approximately $330,000,000 of capital expenditures.

The CAAA do not require any significant additional emissions control expenditures that are identifiable at this time. The amendments call for a five-year study of the sources and causes of regional haze in the southwestern U.S. The extent to which this study may require sulfur dioxide emissions reductions at Edison's Mohave Generating Station ("Mohave") is not known. The acid rain provisions of the amended Clean Air Act also put an annual limit on sulfur dioxide emissions allowed from power plants. Edison will receive more sulfur dioxide allowances than it requires for its projected operations. The CAAA also require the Environmental Protection Agency ("EPA") to carry out a three-year study of risk to public health from emissions of toxic air contaminants from power plants, and to regulate such emissions only if required. As a result of a petition by Mohave County in the State of Arizona, the Nevada Department of Environmental Protection ("NDEP") studied the impact of the plume from Edison's Mohave plant on the Mohave area air quality. The

regulatory outcome requires Edison to meet a new lower opacity limit in early 1994. The NDEP will review the opacity limit again in 1995 in conjunction with an ongoing tracer study being conducted by the EPA and evaluate potential impacts on visibility in the Grand Canyon from sulfur dioxide emissions. Until more definitive information on tracer study results are available, Edison expects to meet all the present regulations through improved operations at the plant.

Regulations under the Clean Water Act require permits for the discharge of certain pollutants into waters of the United States. Under this act, the EPA issues effluent limitation guidelines, pretreatment standards and new source performance standards for the control of certain pollutants. Individual states may impose even more stringent limitations. In order to comply with guidelines and standards applicable to steam electric power plants, Edison incurs additional expenses and capital expenditures. Edison presently has discharge permits for all applicable facilities.

The Safe Drinking Water and Toxic Enforcement Act prohibits the exposure to individuals of chemicals known to the State of California to cause cancer or reproductive harm and the discharge of such listed chemicals into potential sources of drinking water. Additional chemicals are continuously being put on the state's list, requiring constant monitoring by Edison.

The State of California has adopted a policy discouraging the use of fresh water for plant cooling purposes at inland locations. Such a policy, when taken in conjunction with existing federal and state water quality regulations and coastal zone land use restrictions, could substantially increase the difficulty of siting new generating plants anywhere in California.

SCEcorp has identified 46 sites for which any of its subsidiaries, are or may be, responsible for remediation under environmental laws. SCEcorp's subsidiaries are participating in investigations and cleanups at a number of these sites and SCEcorp has recorded a $60,000,000 liability for the estimated minimum costs to clean up several sites. Additional costs may be incurred as progress is made in determining the magnitude of required remedial actions, as the share of these costs attributable to SCEcorp's subsidiaries in proportion to other responsible parties is determined and as additional investigations and cleanups are performed.

The CPUC currently allows Edison rate recovery of environmental-cleanup costs, subject to reasonableness reviews. Edison filed for a reasonableness review of costs incurred through 1991 at two hazardous substance sites. Hearings have been delayed due to a 1992 CPUC decision involving another California utility, which concluded that the current procedure may not be appropriate for these costs and requested interested parties to recommend alternatives. In November 1993, the major California utilities, the DRA and others filed a collaborative report recommending an incentive mechanism, which would require shareholders to fund 10% of cleanup costs. Shareholders would have the opportunity to recover these costs through insurance. Accordingly, Edison has recorded a regulatory asset which represents 90% of the estimated cleanup costs for sites covered by this proposed mechanism. The remaining sites' cleanup costs are expected to be immaterial and would be recovered through base rates. If approved by the CPUC, Edison would be allowed to recover 90% of cleanup costs incurred to date under the reasonableness review procedure ($11,000,000). A March 10, 1994 proposed decision issued by a CPUC ALJ accepted the collaborative report's recommendation. A final CPUC decision is expected in early 1994.

Twenty of the 46 sites identified are Edison's former manufactured gas plant sites. Edison's cleanup responsibility for these sites is based on Edison's, or a predecessor company's, ownership or operation of the plants. These gas plants were operated for the production of gas prior to the widespread availability of natural gas. The EPA and the California Department of Toxic Substances Control have determined that specified constituents of the gas plant by-products are hazardous substances or hazardous wastes, and may require removal or other remedial action.

The Resource Conservation and Recovery Act ("RCRA") provides the statutory authority for the EPA to implement a regulatory program for the safe treatment, recycling, storage and disposal of solid and hazardous wastes. There is an unresolved issue regarding the degree to which coal wastes should be regulated under RCRA. Increased regulation may result in an increase in expenses related to the operation of Mohave.

The Toxic Substance Control Act and accompanying regulations govern the manufacturing, processing, distribution in commerce, use and disposal of polychlorinated biphenyls, a toxic substance used in certain electrical equipment ("PCB waste"). Current costs for deposal of PCB waste are immaterial.

Edison's capitalized expenditures for environmental protection for the years 1969 through 1993 and its currently estimated capital expenditures for such purpose for the years 1994 through 1998 are as follows:

				(In thousands)				
Years	Total	Air Pollution Control	Water Pollution Control	Solid Waste Disposal	Noise Abatement	Aesthetics	Additional Plant Capacity	Miscellaneous
1969-1993	$3,823,749	$770,911	$285,648	$60,320	$15,323	$2,454,146	$16,531	$220,870
1994 . . .	277,198	68,104	17,531	11,108	260	176,339	--	3,856
1995 . . .	285,484	42,649	26,979	25,376	231	186,306	--	3,943
1996 . . .	286,080	41,698	26,912	14,435	148	202,273	--	614
1997 . . .	254,861	11,534	14,389	11,900	199	216,583	--	256
1998 . . .	227,631	11,374	9,471	3,577	1,103	201,217	--	889

These estimates include budgeted and forecasted plant expenditures responsive to currently effective legislation. Projected capital expenditures for environmental protection are subject to continuous review and periodic revisions because of escalation in engineering and construction costs, additions and deletions of planned facilities, changes in technology, evolving environmental regulatory requirements and other factors beyond Edison's control. Edison believes that costs incurred for these environmental purposes will be recognized by the CPUC and the FERC as reasonable and necessary costs of service for rate recovery purposes.

Business of Southern California Edison Company

Edison was incorporated under California law in 1909. Edison is a public utility primarily engaged in the business of supplying electric energy to a 50,000 square-mile area of central and southern California, excluding the City of Los Angeles and certain other cities. This area includes some 800 cities and communities and a population of nearly 11 million people. As of December 31, 1993, Edison had 16,487 full-time employees. During 1993, 37% of Edison's total operating revenue was derived from commercial customers, 36% from residential customers, 13% from industrial customers, 8% from public authorities, 4% from agricultural and other customers and 2% from resale customers. Edison comprises the major portion of the assets and revenues of SCEcorp, its parent holding company.

Regulation of Edison

Edison's retail operations are subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, issuances of securities and accounting and depreciation practices. Edison's resale operations are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). The FERC has the authority to regulate resale rates as well as other matters, including transmission service pricing, accounting and depreciation practices and licensing of hydroelectric projects.

Edison is subject to the jurisdiction of the Nuclear Regulatory Commission ("NRC") with respect to its nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject those power plants to continuing review and regulation.

The construction, planning and siting of Edison's power plants within California are subject to the jurisdiction of the California Energy Commission and the CPUC. Edison is subject to rules and regulations promulgated by the California Air Resources Board and local air pollution control districts with respect to the emission of pollutants into the atmosphere, the regulatory requirements of the California State Water Resources Control Board and regional boards with respect to the discharge of pollutants into waters of the state and the requirements of the California Department of Toxic Substances Control with respect to handling and disposal of hazardous materials and wastes. Edison is also subject to regulation by the EPA, which administers certain federal statutes relating to environmental matters. Other federal, state and local laws and regulations relating to environmental protection, land use and water rights also impact Edison. (See previous discussion of Environmental Matters under the Business of SCEcorp, above.)

The California Coastal Commission has continuing jurisdiction over the coastal permit for San Onofre Nuclear Generating Station ("San Onofre") Units 2 and 3. Although the units are operating, the permit remains open. This jurisdiction may continue for several years because it involves oversight on mitigation measures arising from the permit.

The Department of Energy ("DOE") has regulatory authority over certain aspects of Edison's operations and business relating to energy conservation, solar energy development, power plant fuel use and disposal, coal conversion, public utility regulatory policy and natural gas pricing.

Rate Matters

CPUC Retail Ratemaking

The rates for electricity provided by Edison to its retail customers comprise several major components established by the CPUC to compensate Edison for basic business and operational costs, fuel and purchased power costs, and the costs of adding major new facilities.

Basic business and operational costs are recovered through base rates, which are determined in general rate case proceedings held before the CPUC every three years. During a general rate case, the CPUC critically reviews Edison's operations and general costs to provide service (excluding energy costs and, in certain instances, major plant additions). The CPUC then determines the revenue requirement to cover those costs, including items such as depreciation, taxes, cost of capital, operation, maintenance, and administrative and general expenses. The revenue

requirement is forecasted on the basis of a specified test year. Following the revenue requirement phase of a general rate case, Edison and the CPUC proceed to a rate design phase which allocates revenue requirements and establishes rate levels for customers.

Base rates may be adjusted in the years between general rate case years through an attrition year allowance. The attrition year allowance is intended to allow Edison to recover, without lengthy hearings, specific uncontrollable cost changes in its base rate revenue requirement and thereby preserve Edison's opportunity to earn its authorized rate of return in the years that are not general rate case test years.

In December 1993, Edison filed an application with the CPUC in which it proposed a performance-based ratemaking procedure for recovery of operation and maintenance ("O&M") expenses and capital-related costs. Such costs have traditionally been recovered through general rate cases, attrition proceedings, and cost of capital proceedings.

Edison proposed that the CPUC authorize a base rate revenue indexing formula which would combine O&M and capital-related cost recovery. In addition, Edison proposed that the period between general rate cases be lengthened from three to six years. Cost of capital proceedings would occur only after significant changes in utility capital markets.

Edison's fuel, purchased power and energy-related costs of providing electrical service are recovered through a balancing account mechanism called the Energy Cost Adjustment Clause ("ECAC"). Under the ECAC balancing account procedure, fuel, purchased power and energy-related revenues and costs are compared and the difference is recorded as either an undercollection or overcollection. The amount recorded in the balancing account is periodically amortized through rate changes which return overcollections to customers by reducing rates or collect undercollections from customers by increasing rates. The costs recorded in the ECAC balancing account are subject to review by the CPUC and allowed for rate recovery only to the extent they are found to be reasonable. Certain incentive provisions are included in the ECAC that can affect the amount of fuel and energy-related costs actually recovered. Edison is required to make an ECAC filing for each calendar year, and must also make a second filing for a mid-year adjustment if such filing would result in an ECAC rate change exceeding 5% of total annual revenue.

For Edison's interest in the three units of the Palo Verde Nuclear Generating Station ("Palo Verde"), the CPUC authorized a 10-year rate phase-in plan which deferred $200,000,000 of investment-related revenue during the first four years of operations for each of the three units, commencing on their respective commercial operation dates. Revenue deferred for each unit under the plan for years one through four was $80,000,000, $60,000,000, $40,000,000 and $20,000,000, respectively. The deferrals and related interest are being recovered over the final six years of each unit's phase-in plan.

The CPUC has also adopted a nuclear unit incentive procedure which provides for a sharing of additional energy costs or savings between Edison and its ratepayers when operation of any of the units of San Onofre or Palo Verde is outside a specified target capacity factor ("TCF") range. For San Onofre Units 2 and 3, and Palo Verde Units 1, 2 and 3 the TCF range is 55% to 80% of their rated capacity.

The Electric Revenue Adjustment Mechanism ("ERAM") reflects the difference between the recorded level of base rate revenue and the authorized level of base rate revenue. This mechanism has been adopted by the CPUC primarily to minimize the effect on earnings of fluctuations in retail kilowatt-hour sales.

General Rate Case ("GRC")

In December 1991, the CPUC issued a decision on the revenue requirement phase of Edison's 1992 test year GRC application. The CPUC authorized a $72,000,000 or 1% increase in Edison's base rate revenues, effective January 20, 1992. The decision did not adopt Edison's request to capitalize, rather than expense, computer software development and research, development and demonstration ("RD&D") expenditures, but did allow Edison to file additional information regarding such capitalization.

In April 1992, Edison filed supplemental testimony supporting its request to capitalize application software development costs, and proposed to decrease its authorized level of base rate revenues ("ALBRR") by $53,000,000 in 1993 and 1994. Edison and the CPUC's Division of Ratepayer Advocates ("DRA") entered into a settlement agreement to allow rate recovery of capitalized software expenditures in which Edison agreed to an additional $32,000,000 base rate revenue decrease. The CPUC approved the settlement agreement in November 1992, and authorized a $48,900,000 decrease to Edison's ALBRR effective January 1, 1993. The related base rate revenue decrease was included in Edison's January 15, 1993, consolidated revenue change. The CPUC also authorized a $12,900,000 increase to Edison's ALBRR effective January 1, 1994. The related base rate revenue increase was included in Edison's January 24, 1994, consolidated revenue change.

In September 1992, Edison filed supplemental testimony supporting its request to capitalize RD&D expenditures. In the additional filing, Edison proposed to capitalize approximately $9,000,000 in RD&D project expenditures. The DRA's supplemental testimony alleged that Edison did not comply with a CPUC order regarding joint remote meter reading and recommended a $10,000,000 penalty for non-compliance. Additionally, the DRA proposed to disallow approximately $4,500,000 of capital costs associated with Edison's research on off-grid generation technology. The CPUC's decision is expected by the end of 1994.

In December 1992, the CPUC approved an ALBRR increase of $110,000,000, effective January 1, 1993, for the 1993 attrition year allowance. The related base rate revenue increase was included in Edison's January 15, 1993 consolidated revenue change. In April 1993, the CPUC modified its decision (pursuant to a petition by Edison), and approved an ALBRR increase of $10,400,000 effective April 28, 1993. The related base rate revenue increase was included in Edison's January 24, 1994, consolidated revenue change.

In December 1993, the CPUC approved an ALBRR increase of $97,200,000 effective January 1, 1994, for: (1) the 1994 attrition year allowance; (2) increased federal income taxes pursuant to the Revenue Reconciliation Act of 1993; and, (3) reduction in Edison's California property tax liability resulting from a settlement agreement with the California State Board of Equalization.

Each year, the CPUC reviews the components of the cost of capital for all the California energy utilities in a generic cost of capital proceeding. On December 3, 1993, the CPUC issued a final decision resulting in a $108,000,000 reduction to Edison's ALBRR effective January 1, 1994. The decision also resulted in a reduction of Edison's overall rate of return from 9.94% to 9.17%, a reduction in return on common equity from 11.80% to 11.00%, and an increase to Edison's common equity capital ratio from 46.00% to 47.25% effective January 1, 1994. The related base rate revenue decrease was included in Edison's January 24, 1994, consolidated revenue change.

In December 1993, Edison filed with the CPUC its 1995 GRC application. In its application, Edison requested an increase to the ALBRR of $117,000,000 above the expected year-end 1994 ALBRR level to become effective January 1, 1995. On March 14, 1994, the DRA issued a report which, based on Edison's preliminary review, recommended a $269,000,000 reduction to Edison's expected year-end 1994 authorized level of base rate revenue. Evidentiary hearings are expected to commence in April 1994, with a final CPUC decision anticipated in December 1994.

In January 1994, the CPUC approved an ALBRR increase of $8,800,000 effective January 24, 1994, for base rate recovery of the permanent component of Edison's fuel oil inventory. The related base rate revenue increase was included in Edison's January 24, 1994, consolidated revenue change.

In November 1993, the CPUC approved an ALBRR increase of: (1) $64,400,000 effective December 31, 1993; and (2) $63,100,000 effective January 1, 1994, to reflect cost recovery of employee post-retirement benefits other than pensions ("PBOP"). In addition, the CPUC approved an ALBRR reduction of $39,500,000 effective December 30, 1993, to reflect the removal of costs associated with Edison's 1992 PBOP contributions. The related base rate revenue reduction associated with the PBOP ALBRR changes was included in Edison's January 24, 1994, consolidated revenue change, less $16,000,000 of rate recovery deferred until 1995.

Energy Cost Adjustment Clause

In January 1992, the DRA issued a report on the reasonableness of Edison's non-standard, non-affiliate qualifying facilities ("QF") power purchase contracts included in Edison's 1989 and 1990 annual ECAC applications. With respect to both ECAC periods, the DRA asserted that Edison had incorrectly calculated firm capacity payments and bonus capacity payments to QFs by including certain energy deliveries which the DRA contended should be excluded or "truncated" from the calculation. The DRA recommended disallowances of $2,500,000 for the 1989 record period and $4,800,000 for the 1990 record period. On April 26, 1993, the DRA withdrew its January 1992 testimony pursuant to an Edison-DRA agreement to jointly petition the CPUC for clarification of the CPUC's intent regarding truncation and two other QF contract administration issues. Edison and the DRA filed their joint petition on April 23, 1993. On November 2, 1993, the CPUC voted to dismiss the joint petition on the basis that the issues presented were complex and could be developed more appropriately in an ECAC proceeding or through direct negotiations among the affected parties. Pursuant to the Edison-DRA agreement, a dismissal on this basis permits the DRA to renew its challenge to Edison's truncation practice beginning with the 1991 ECAC record period and thereafter in each subsequent ECAC record period. To date, the DRA has not recommended further disallowances attributable to the truncation issue.

In March 1992, Edison and the DRA settled disputes relating to Edison's power purchases from the 13 non-utility generation facilities partially owned by Mission Energy. Pursuant to the settlements, Edison agreed not to enter into new power purchase-contracts with Mission Energy and to a one-time disallowance. On March 10, 1993, the CPUC issued a decision approving the settlement and authorizing a ratepayer refund of $250,000,000 over a two-year period beginning January 1, 1994. The decision also ordered an immediate adjustment to Edison's ECAC balancing account with interest accruing until the rate reduction takes effect. The

$250,000,000 disallowance is fully reflected in Edison's financial statements.

In October 1993, the DRA issued its report on QF reasonableness issues for the ECAC record period April 1990 through March 1991. In its report, the DRA recommended that the CPUC disallow $1,574,000 in power purchase expenses incurred as a result of purchases during the record period under a QF contract with Mojave Cogeneration Company, a nonutility generator. In its report, the DRA also alleged that in 1990 and 1991 Edison imprudently renegotiated Mojave Cogeneration Company's contract with Edison, resulting in higher ratepayer costs. The DRA further alleged that ratepayers may be harmed in the amount of $31,600,000 (present value) over the contract's twenty-year life. The DRA found the execution of five other QF contracts to be reasonable. Hearings will likely be held no earlier than the second half of 1994.

The DRA issued four reports addressing Edison's non-QF reasonableness showing for the April 1, 1991 through March 31, 1992 period. The DRA recommended: 1) a disallowance of $2,205,000 of replacement power costs associated with extended outage duration or reduced power production at Edison's nuclear units, which was allegedly caused by human error; and 2) a reduction of $1,203,000 to Edison's proposed TCF reward for San Onofre Unit 3, based on excluding generation above the unit capacity rating. A January 25, 1994 ALJ proposed decision found three nuclear plant outages unreasonable, resulting in a potential $1,600,000 disallowance, but rejected the DRA's recommendations for reducing Edison's TCF reward. Edison filed comments on the proposed decision on February 14, 1994. The final CPUC decision is expected in March 1994.

On May 28, 1993, Edison requested a $152,000,000 annual rate increase for service beginning January 1, 1994, for changes to the Energy Cost Adjustment Billing Factor, Electric Revenue Adjustment Balancing Accounts ("ERABF"), Low Income Surcharge and base rate levels. Edison also made a rate stabilization proposal which defers recovery of approximately $200,000,000 of 1994 fuel and purchased-power expenses until 1995. In July 1993, Edison updated its ECAC request to a $181,000,000 increase. The DRA proposed a $105,000,000 increase. In October 1993, Edison and the DRA stipulated to a proposed $164,688,000 ECAC revenue increase subject to adjustment for incorporating Edison's forecast December 31, 1993 balance in the ECAC, Low Income Ratepayer Assistance, and ERABF to reflect more recent recorded data. On January 19, 1994, the CPUC issued its decision which adopted a revenue increase of $274,600,000. When this revenue change is combined with other revenue changes which occurred on or before January 1, 1994, the total combined revenue change is $232,101,000.

On May 28, 1993, Edison filed the non-QF portion of its Reasonableness of Operations Report, which included power purchases and exchanges and the operation of its hydro, coal, gas and nuclear resources for the period April 1, 1992 through March 31, 1993. In February 1994, the DRA recommended: (1) a $7,200,000 disallowance relating to fuel oil inventory management; and (2) a $5,000,000 disallowance for transmission loss revenues. Hearings on this matter are scheduled for October 1994.

Edison filed its QF Reasonableness of Operations Report on September 1, 1993. It is presently unknown when the DRA will file testimony in the QF reasonableness phase.

Palo Verde Outage Review

In March 1989, Palo Verde Units 1 and 3 experienced automatic shutdowns. Since the resultant outages overlapped previously scheduled refueling outages, normal refueling, maintenance, inspection, surveillance, modification and testing activities were conducted at the units, as well as modifications to the plants required by the NRC. Unit 3 was restored to service on December 30, 1989, and Unit 1 was restored to service on July 5, 1990.

In December 1989, the CPUC instituted an investigation into the outages pursuant to the California Public Utilities Code ("Code"). The Code requires the CPUC to institute an investigation when any portion of a utility's generating facilities has been out of service for nine consecutive months. The CPUC order required that the subsequent collection of rates associated with Palo Verde Units 1 and 3 be subject to refund pending review of the outages. In November 1991, the DRA issued a report recommending disallowances totaling more than $160,000,000 including a $63,000,000 disallowance for revenue collected during the outages (including interest).

In September 1993, Edison and the DRA agreed to settle these disputes for $38,000,000 (including $29,000,000 for replacement power costs, $2,000,000 for capital projects and approximately $7,000,000 for interest), subject to CPUC approval. The settlement resolves all issues related to the 1989-1990 outages at Palo Verde. The effect of the settlement has been fully reflected in the financial statements. Edison expects a CPUC decision regarding the settlement in mid 1994.

Mohave Order Instituting Investigation ("OII")

In April 1986, the CPUC began investigating the 1985 rupture of a high pressure steam pipe at Mohave. Edison is the plant operator and 56% owner. The CPUC's OII reviewed Edison's share of repair costs and replacement fuel and energy related costs associated with the outage. Edison incurred costs of approximately $90,000,000 (including interest) to repair damage from the accident and provide replacement power during the six-month outage. This total is net of Edison's recovery of expenses from the settlement of lawsuits with contractors and insurance.

In May 1991, the DRA and its consultant issued reports alleging that Edison imprudently operated the Mohave plant and therefore contributed to the accident. As a result, the DRA recommended that all expenses incurred because of the accident be disallowed in rates. The DRA did not quantify its proposed disallowance. Edison believes that metallurgical and physical characteristics of a weld reduced the otherwise expected pipe life to the point of failure after 15 years of service. Edison filed testimony contesting the allegations in May 1992, in December 1992, and on March 1, 1993. In March 1994, the CPUC issued a decision finding that Edison acted unreasonably in failing to implement an inspection program. The CPUC decision ordered a second phase of this proceeding to quantify the disallowance.

High Voltage Direct Current Expansion Project ("HVDCEP")

The HVDCEP began operation in 1989. In October 1989, Edison filed a report with the CPUC requesting recovery of $72,600,000 in project costs. Subsequently, Edison and the DRA agreed on an accounting adjustment of $150,000, and a settlement agreement was filed. A February 3, 1993 CPUC decision upheld the settlement agreement allowing Edison recovery in rates of approximately $72,450,000. In its 1995 GRC, Edison is requesting rate recovery of an additional $7,000,000 associated with completion items and

other HVDCEP-related expenditures. The total amount of rate recovery for the HVDCEP that Edison will be allowed remains subject to further adjustment pending a final determination of the cost-effectiveness of the project in comparison with the power exchange agreement between Edison and the Los Angeles Department of Water and Power.

FERC Resale Ratemaking

Edison sells electricity to public power utilities (the cities of Anaheim, Azusa, Banning, Colton, Riverside and Vernon), Southern California Water Company and Arizona Public Service Company ("APS") under rates subject to FERC jurisdiction. In accordance with FERC procedures resale rates are subject to refund with interest if subsequently disallowed. Edison believes any refunds from pending rate proceedings, would not materially affect its results of operations or financial position.

Fuel Supply

Fuel and purchased-power costs amounted to approximately $3.29 billion in 1993, a 7% increase over 1992. Sources of energy and unit costs of fuel for 1989 through 1993 were as follows:

	Sources of Energy					Average Cost Per Million BTU's(1)				
	Year ended December 31,					Year ended December 31,				
	1989	1990	1991	1992	1993	1989	1990	1991	1992	1993
Oil	4%	2%	*	*	*	$3.03	$4.39	$4.07	$5.75	$6.08
Natural Gas	24	17	18%	24%	23%	3.24	3.02	2.81	2.78	2.89
Nuclear	17	20	21	22	18	1.04	0.94	0.87	0.66	0.51
Coal	13	13	14	14	13	1.14	1.21	1.15	1.15	1.19
All Fuels	58	52	53	60	54	2.15	1.90	1.64	1.65	1.77
Hydroelectric(2)	4	3	4	3	7					
Purchased Power (2):										
Firm	6	3	3	3	2					
Economy	7	13	8	2	3					
Other power producers:										
Biomass	1	2	2	2	3					
Cogeneration	17	19	20	20	20					
Geothermal	5	6	7	7	8					
Solar	1	1	1	1	1					
Wind	1	1	2	2	2					
Total	100%	100%	100%	100%	100%					

(1) British Thermal Unit ("BTU") is the standard unit of measure for the heat content of fuels. One BTU is the amount of heat required to raise the temperature of one pound of water, at 39.1 degrees Fahrenheit, by one degree Fahrenheit.
(2) There are no fuel costs associated with these categories.

* Indicates a source of less than 1%.

Average fuel costs, expressed in cents per kilowatt-hour, for the year ended December 31, 1993, were: oil, 7.996¢; natural gas, 2.930¢; nuclear, 0.537¢; and coal, 1.226¢.

Natural Gas Supply

Twelve of Edison's major steam electric generating units are designed to burn oil or natural gas as a primary boiler fuel. In 1990, Edison adopted an all-gas strategy to comply with air quality goals by eliminating burning oil in all but very extreme conditions. In August 1991, the CPUC adopted regulations which made Edison fully responsible for all gas procurement activities previously performed by local distribution companies for natural gas.

To implement its all-gas strategy, Edison acquired a balanced portfolio of gas supply and transportation arrangements. Traditionally, natural gas needs in southern California were met from gas production in the southwest region of the country. To diversify its gas supply, Edison entered into four 15-year natural gas supply agreements with major producers in western Canada. These contracts, totaling 200,000,000 cubic feet per day, have market-sensitive pricing arrangements. This represents about 40% of Edison's current average annual supply needs. The rest of Edison's gas supply is acquired under short-term contracts from West Texas, New Mexico, and the Rocky Mountain region.

Firm transportation arrangements provide the necessary long-term reliability for supply deliverability. To transport Canadian supplies, Edison contracted for 200,000,000 cubic feet per day of firm transportation arrangements on the Pacific Gas Transmission and Pacific Gas & Electric Expansion Project connecting southern California to the low-cost gas producing regions of western Canada. Edison has a 30-year commitment to this project, construction of which was completed in late 1993. In addition, Edison has a 15-year commitment to 200,000,000 cubic feet per day of firm transportation rights on El Paso Natural Gas' pipeline to transport Southwest U.S. gas supplies.

Nuclear Fuel Supply

Edison has contractual arrangements covering 100% of the projected nuclear fuel cycle requirements for San Onofre through the years indicated below:

	Units 2 & 3
Uranium concentrates(1)	1995
Conversion	1995
Enrichment	1998
Fabrication	2000
Spent fuel storage(2)	2005/2004

(1) Assumes the San Onofre participants meet their supply obligations in a timely manner.

(2) Assumes full utilization of expanded on-site storage capacity and normal operation of the units, including interpool transfers and maintaining full-core reserve. To supplement existing spent fuel storage, a contingency plan is being developed to construct additional on-site storage capacity with initial operation scheduled for no later than 2002. The Nuclear Waste Policy Act of 1982 requires that the DOE provide for the disposal of utility spent nuclear fuel beginning in 1998. The DOE has stated that it is unlikely that it will be able to start accepting spent nuclear fuel at its permanent repository before 2010.

Participants in Palo Verde have purchased uranium concentrates sufficient to meet projected requirements through 1997. Independent of arrangements made by other participants, Edison will furnish its share of uranium concentrates requirements through at least 1995 from existing contracts. Contracts to provide conversion services cover requirements through 1994. Enrichment and fabrication contracts will meet Palo Verde requirements through 1995 and 1997, respectively.

Palo Verde on-site expanded spent fuel storage capacity will accommodate needs through 2005 for Units 1 and 2 and 2006 for Unit 3, while maintaining full-core reserve.

Business of The Mission Group and its Subsidiaries

Mission Group was incorporated in 1987 to own the stock and coordinate the activities of several companies engaged in nonutility businesses. The principal subsidiaries of Mission Group are Mission Energy, Mission First Financial and Mission Land. A fourth subsidiary, Mission Power Engineering Company, discontinued operations in 1990. The businesses of these companies are described below. For SCEcorp's business segment information for each of the three years ended December 31, 1993, 1992 and 1991, see Note 12 of "Notes to Consolidated Financial Statements" contained in the 1993 Annual Report to Shareholders incorporated by reference in this report.

On December 31, 1993, Mission Group had consolidated assets of $3.3 billion and, for the year then ended, had consolidated operating revenue of $424,500,000 and consolidated net income of $3,000,000.

Mission Group's principal executive offices are located at 18101 Von Karman Avenue, #1700, Irvine, California 92715.

Mission Energy. Mission Energy, primarily through its subsidiary corporations, is engaged in the business of developing, owning, and operating cogeneration, small power, geothermal, and other principally energy-related projects. At December 31, 1993, Mission Energy subsidiaries held interests in 33 operating power production facilities with an aggregate power production capability of 4,105 MW, of which 1,862 MW are attributable to Mission Energy's interests. These operating facilities are located in California, Nevada, New Jersey, Pennsylvania, Virginia, Washington, Australia, Spain, and the United Kingdom. In addition, facilities aggregating more than 1,746 MW, of which one 500 MW facility is located in Australia, are in construction or advanced permitting stages. Mission Energy owns interests in oil and gas producing operations and related facilities in Canada and U.S. locations in Texas, Alabama, New Mexico, California and offshore Louisiana. In February 1994, Mission Energy -- as lead developer -- and its partners, General Electric Capital Corporation, Mitsui & Co., Ltd. and P.T. Batu Hitam Perkasa, signed a 30-year power-purchase agreement with the Indonesian government for the 1,230-MW Paiton project.

At December 31, 1993, Mission Energy had total consolidated assets of $1.8 billion and for the year then ended, had consolidated operating revenue of $272,800,000 and consolidated net income of $2,300,000.

Currently, most of Mission Energy's operating power production facilities have QF status under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the regulations promulgated thereunder. QF status exempts the projects from the application of the Holding Company Act, many provisions of the Federal Power Act, and state laws and regulations respecting rates and financial or organizational regulation of electric

utilities. Mission Energy, through wholly-owned subsidiaries, also has ownership interests in two operating power projects that have received exempt wholesale generator status as defined in the Holding Company Act. In addition, some Mission Energy subsidiaries have made fuel-related investments and a limited number of non-energy related investments.

While QF status entitles projects to the benefits of PURPA, each project must still comply with other federal, state and local laws, including those regarding siting, construction, operation, licensing and pollution abatement.

Mission First Financial. Mission First Financial participates in investment opportunities involving leveraged leasing, project financing, affordable housing and cash management. Its investments include interests in nuclear power, cogeneration, waste-to-energy, hydroelectric, electric transportation and affordable housing facilities. Since its inception in 1987, Mission First Financial has invested in 71 projects. In 1993, Mission First Financial invested $20,000,000 in a sale/leaseback of electric locomotive equipment with the Dutch rail authority. In addition, Mission First Financial invested $62,000,000 in 23 completed affordable housing projects and signed commitments to invest in 19 additional projects.

At December 31, 1993, Mission First Financial had total consolidated assets of $972,000,000 and, for the year then ended, had consolidated operating revenue of $31,500,000 (including interest income) and consolidated net income of $29,200,000.

Mission Land. Mission Land is engaged, directly and through its subsidiaries, in the business of developing, owning and managing industrial parks and other real property investments. Mission Land owns and manages commercial and industrial buildings in industrial parks located in Brea, Chino, Garden Grove, Ontario, Oceanside and Rancho Cucamonga, California. Mission Land and its subsidiaries also have interests in industrial, residential and commercial real estate in California; Tolleson, Arizona; Munster, Indiana; Chicago, Illinois and in other locations. SCEcorp has decided no longer to pursue real estate development as one of its core businesses and plans to exit this business in an orderly fashion over time.

At December 31, 1993, Mission Land had total consolidated assets of $516,300,000 and for the year then ended, had consolidated operating revenue of $112,500,000 and a consolidated net loss of $15,300,000. Mission Land has reduced assets by one-third since 1991 primarily through asset sales, reduced debt significantly, improved operating income through higher occupancy rates, and has increased reserves. As a result, Mission Land believes it has improved its ability to systematically exit the real estate business in a self-sustaining way. However, Mission Land may experience additional losses if the real estate market remains weak.

Item 2. Properties

Existing Utility Generating Facilities

Edison owns and operates 12 oil- and gas-fueled electric generating plants, one diesel-fueled generating plant, 38 hydroelectric plants and an undivided 75.05% interest (1,614 MW net) in Units 2 and 3 at San Onofre. These plants are located in central and southern California. Palo Verde (15.8% Edison-owned, 579 MW net) is located near Phoenix, Arizona. Palo Verde Units 1, 2 and 3 started commercial operation on February 1, 1986, September 19, 1986, and January 20, 1988, respectively. Edison owns a 48% undivided interest (754 MW) in Units 4 and 5 at the Four

Corners Generating Station ("Four Corners Project"), a coal-fueled steam electric generating plant in New Mexico. Palo Verde and the Four Corners Project are operated by other utilities. Edison operates and owns a 56% undivided interest (885 MW) in Mohave, which consists of two coal-fueled steam electric generating units in Clark County, Nevada. Edison receives an entitlement of 277 MW from the DOE's Hoover Dam Hydroelectric Project. At year-end 1993, the existing Edison-owned generating capacity (summer effective rating) was comprised of approximately 67% gas, 14% nuclear, 11% coal and 8% hydroelectric.

San Onofre, the Four Corners Project, certain of Edison's substations and portions of its transmission, distribution and communication systems are located on lands of the United States or others under (with minor exceptions) licenses, permits, easements or leases or on public streets or highways pursuant to franchises. Certain of such documents obligate Edison, under specified circumstances and at its expense, to relocate transmission, distribution and communication facilities located on lands owned or controlled by federal, state or local governments.

With certain exceptions, major and certain minor hydroelectric projects with related reservoirs, currently having an effective operating capacity of 1,154 MW and located in whole or in part on lands of the United States, are owned and operated by Edison under governmental licenses which expire at various times between 1994 and 2022. Such licenses impose numerous restrictions and obligations on Edison, including the right of the United States to acquire the project upon payment of specified compensation. When existing licenses expire, FERC has the authority to issue new licenses to third parties, but only if their license application is superior to Edison's and then only upon payment of specified compensation to Edison. Any new licenses issued to Edison are expected to be issued under terms and conditions less favorable than those of the expired licenses. Edison's applications for the relicensing of certain hydroelectric projects referred to above with an aggregate effective operating capacity of 89.0 MW are pending. Annual licenses issued for all Edison projects, whose licenses have expired and are undergoing relicensing, will be renewed until the new licenses are issued.

In 1993, Edison's peak demand was 16,475 MW, set on September 9, 1993. The 1993 peak was 1,938 MW less than Edison's record peak demand of 18,413 MW that occurred on August 17, 1992. Total area system operating capacity of 20,606 MW was available to Edison at the time of the 1993 record peak.

Substantially all of Edison's properties are subject to the lien of a trust indenture securing First and Refunding Mortgage Bonds ("Trust Indenture"), of which approximately $3.5 billion principal amount was outstanding at December 31, 1993. Such lien and Edison's title to its properties are subject to the terms of franchises, licenses, easements, leases, permits, contracts and other instruments under which properties are held or operated, certain statutes and governmental regulations, liens for taxes and assessments, and liens of the trustees under the Trust Indenture. In addition, such lien and Edison's title to its properties are subject to certain other liens, prior rights and other encumbrances, none of which, with minor or unsubstantial exceptions, affects Edison's right to use such properties in its business, unless the matters with respect to Edison's interest in the Four Corners Project and the related easement and lease referred to below may be so considered.

Edison's rights in the Four Corners Project, which is located on land of The Navajo Tribe of Indians under an easement from the United States and a lease from The Navajo Tribe, may be subject to possible defects. These defects include possible conflicting grants or encumbrances not

ascertainable because of the absence of, or inadequacies in, the applicable recording law and the record systems of the Bureau of Indian Affairs and The Navajo Tribe, the possible inability of Edison to resort to legal process to enforce its rights against The Navajo Tribe without Congressional consent, possible impairment or termination under certain circumstances of the easement and lease by The Navajo Tribe, Congress or the Secretary of the Interior and the possible invalidity of the Trust Indenture lien against Edison's interest in the easement, lease and improvements on the Four Corners Project.

El Paso Electric Company ("El Paso") Bankruptcy

El Paso owns and leases a combined 15.8% interest in Palo Verde and owns a 7% interest in Units 4 and 5 of the Four Corners Project. In January 1992, El Paso filed a voluntary petition to reorganize under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Western District of Texas. Pursuant to an agreement among the Palo Verde participants and an agreement among the participants in Four Corners Units 4 and 5, each participant is required to fund its proportionate share of operation and maintenance, capital and fuel costs of Palo Verde and Four Corners Units 4 and 5, respectively. The participation agreements provide that if a participant fails to meet its payment obligation, each non-defaulting participant must pay its proportionate share of the payments owed by the defaulting participant. In February 1992, the bankruptcy court approved a stipulation between El Paso and APS, as the operating agent of Palo Verde, pursuant to which El Paso agreed to pay its proportionate share of all Palo Verde invoices delivered to El Paso after February 6, 1992. El Paso agreed to make these payments until such time, if ever, the bankruptcy court orders El Paso's rejection of the participation agreement governing the relations among the Palo Verde participants. The stipulation also specifies that approximately $9,200,000 of El Paso's Palo Verde payment obligations invoiced prior to February 7, 1992, are to be considered "pre-petition" general unsecured claims of the other Palo Verde participants.

On August 27, 1993, El Paso filed with the bankruptcy court an Amended Plan of Reorganization and Disclosure Statement ("Amended Plan"). The Amended Plan, which is subject to numerous conditions, proposes a reorganization pursuant to which El Paso will become a wholly-owned subsidiary of Central and South West Corporation. The Amended Plan also proposes, among other things, (i) rejection of the El Paso leases and reacquisition by El Paso of the Palo Verde interests represented by the leases, and (ii) El Paso's assumption of the Four Corners Operating Agreement and the Arizona Nuclear Power Project Participation Agreement. On November 19, 1993, the bankruptcy court approved a Cure and Assumption Agreement among El Paso and the Palo Verde Participants, in which El Paso shall (i) assume the Participation Agreement on the date the Amended Plan becomes effective, and (ii) cure its pre-petition default on the date the court approves the Order Confirming El Paso's Amended Plan. On December 8, 1993, the bankruptcy court confirmed El Paso's Amended Plan. Effectiveness of the Amended Plan is still subject to approval by numerous state and federal agencies. El Paso estimates that it will take about 18 months to obtain all necessary regulatory approvals.

Construction Program and Capital Expenditures

In April 1992, the CPUC decided how Edison and other California utilities will meet their resource needs through 2002. The CPUC ruled that Edison must obtain 624 MW of new generation through competitive bidding. The decision required that 175 MW be reserved for renewables, such as wind, hydro and geothermal. The competitive bid solicitation was issued in August 1993 and suspended in December 1993 due to the discovery

of a bidding anomaly that raised prices above those allowed by the rules of the solicitation. After the suspension, Edison requested the solicitation be cancelled because current forecasts show that Edison has no need for additional generating capacity until at least 2005.

From the solicitation results, Edison has estimated that the cost of these resources would be approximately $530,000,000 (present value in 1997 dollars). However, two events have occurred that should reduce Edison's cost exposure resulting from power purchases under this CPUC mandated process. First, on March 15, 1994, Edison and Kenetech Corporation, a potential winning bidder in Edison's solicitation, signed a memorandum of understanding for a wind resource power purchase. Contingent upon CPUC approval, Kenetech, under this proposed agreement, will provide lower cost resources than those potentially awarded through Edison's solicitation. Second, on March 16, 1994, the CPUC issued an interim decision that reduces Edison's solicitation by 25% and gives Edison authority to eliminate the added costs from the bidding anomaly by imposing a payment cap. Although Edison will likely continue to request cancellation of the competitive solicitation, these two events reduce Edison's exposure. The exact amount of this reduction cannot be estimated until the methodology the CPUC intends for implementation of these changes is known.

Cash required by SCEcorp for its capital expenditures totaled $1.26 billion in 1993, $1.24 billion in 1992, and $1.03 billion in 1991. Construction expenditures for the 1994-1998 period are estimated as follows:

	1994	1995	1996	1997	1998	Total
			(In millions)			
Electric generating plant	$ 378	$ 353	$ 283	$ 264	$ 491	$1,769
Electric transmission lines and substations	131	121	153	173	252	830
Electric distribution lines and substations	486	559	529	560	556	2,690
Other expenditures	184	194	145	139	92	754
Nonutility expenditures	164	147	88	1	1	401
Total	1,343	1,374	1,198	1,137	1,392	6,444
Less: allowance for funds used during construction	38	44	43	43	43	211
Cash required for construction expenditures	$1,305	$1,330	$1,155	$1,094	$1,349	$6,233

Edison's construction program and related expenditures are continuously reviewed and periodically revised because of changes in estimated system load growth, rates of inflation, receipt of adequate and timely rate relief, the availability and timing of environmental, siting and other regulatory approvals, the scope of modifications required by regulatory agencies, the availability and costs of external sources of capital, the development of new technology and other factors beyond Edison's control.

Since the completion of San Onofre Units 2 and 3 and Palo Verde Units 1, 2 and 3, construction work in progress has been significantly reduced. The reduction in construction work in progress caused allowance for funds used during construction ("AFUDC"), which does not represent current cash income, to decline accordingly. Pre-tax AFUDC represented 5.7% of earnings for 1993.

In addition to cash required for construction expenditures for the next five years as discussed above, $1.3 billion is needed to meet requirements for long-term debt maturities, and sinking fund redemption

requirements. The majority of these capital requirements are expected to be met by internally generated sources.

Edison's estimates of cash available for operations for the five years through 1998 assume, among other things, the receipt of adequate and timely rate relief and the realization of its assumptions regarding cost increases, including the cost of capital. Edison's estimates and underlying assumptions are subject to continuous review and periodic revision.

The timing, type and amount of all additional long-term financing are also influenced by market conditions, rate relief and other factors, including limitations imposed by Edison's Articles of Incorporation and Trust Indenture.

Nuclear Power Matters

Although higher energy costs will be incurred for replacement generation during any periods the San Onofre and Palo Verde Units are not in operation, substantially all such costs will be included in future ECAC filings. Edison cannot predict what other effects, if any, legislative or regulatory actions may have upon it or upon the future operation of the San Onofre or Palo Verde Units or the extent of any additional costs it may incur as a result thereof, except for those that follow.

San Onofre Unit 1

On November 30, 1992, Edison discontinued operation of San Onofre Unit 1. The CPUC approved an agreement between Edison and the DRA which allows Edison recovery of its investment of approximately $350,000,000 (after deferred taxes), including an 8.98% rate of return, by August 1996.

The agreement does not affect Unit 1's decommissioning, scheduled to start in 2013. The estimated current-dollar decommissioning costs for Unit 1 have been recorded as a liability.

San Onofre Units 2 and 3

In 1974, the California Coastal Commission, as a condition of the San Onofre Units 2 and 3 coastal permit, established a three-member Marine Review Committee ("MRC") to assess the marine environmental effects caused by the Units. In August 1989, the MRC issued its final report which alleged, in part, that San Onofre Units 2 and 3 caused adverse effects to several species of marine life and to the environment.

Based on the MRC findings, the Coastal Commission in 1991 revised the coastal permit for Units 2 and 3 and required Edison to restore 150 acres of degraded wetlands, construct a 300-acre artificial kelp reef, and install fish behavioral barriers inside the Units' cooling water intake structure. Edison is currently in the process of planning and designing these projects, all of which must receive the approval of the Coastal Commission and state and federal resource and regulatory agencies. Current estimates place Edison's share of these capital costs at about $83,000,000 which is expected to be spent over the next 10 to 12 years.

Palo Verde Nuclear Generating Station

On March 14, 1993, APS, as operating agent, manually shut down Palo Verde Unit 2 as a result of a steam generator tube leak. Unit 2 remained shut down and began its scheduled refueling outage on March 19, 1993.

An extensive inspection of the Palo Verde Unit 2 steam generators was performed prior to the unit's return to service on September 1, 1993. APS

determined that intergranular attack/intergranular stress corrosion cracking was a major contributor to the tube leak. APS is continuing its evaluation of the effects of possible steam generator tube degradation in all three units (six steam generators) and has instituted several avenues of study and corrective action.

Palo Verde Units 1, 2, and 3 will be operated at reduced power (85%) until the investigation and other associated activities are completed. APS expects to be able to return the units to full power after implementing corrective action.

Nuclear Facility Decommissioning

Edison's share of costs to decommission nuclear generation facilities is estimated to be $225,500,000 for San Onofre Unit 1; $280,900,000 for San Onofre Unit 2; $365,400,000 for San Onofre Unit 3; $50,200,000 for Palo Verde Unit 1; $49,800,000 for Palo Verde Unit 2; and $55,400,000 for Palo Verde Unit 3. These costs are all in 1993 dollars.

Edison is currently collecting $104,255,000 annually in rates for its share of decommissioning costs for San Onofre Units 1, 2 and 3 and Palo Verde Units 1, 2 and 3. As of December 31, 1993, Edison's decommissioning trust funds totaled approximately $853,000,000 (market value).

In accordance with the Energy Policy Act of 1992, Edison's recorded liability at December 31, 1993, of $72,300,000 represents its share of the estimated costs to decommission three federal nuclear enrichment facilities. This cost is based on San Onofre's and Palo Verde's past purchases of enrichment services and will be paid over 15 years. These costs are expected to be recovered through the ECAC procedure and from participants.

Nuclear Facility Depreciation

To reduce Edison nuclear facilities' capital cost effect on future customer rates, Edison has filed for a $75,000,000 per year accelerated recovery of its nuclear investments. To offset the increased cost recovery, Edison proposes to lengthen its recovery period for transmission and distribution assets. This proposal would have no significant effect on customer rates. The CPUC held hearings in October 1993 and Edison expects a decision in mid-1994.

Nuclear Insurance

Edison carries the maximum insurance coverage reasonably available to protect against losses from damage to its nuclear units and to provide some of its replacement energy costs in the unlikely event of an accident at any of its nuclear units. A description of this insurance is included in Note 10 of "Notes to Consolidated Financial Statements" incorporated herein. Although Edison believes an accident at its nuclear units is extremely unlikely, in the event of an accident, regardless of fault, Edison's insurance coverage might be inadequate to cover the losses to Edison. In addition, such an accident could result in NRC action to suspend operation of the damaged unit. Further, the NRC could suspend operation at Edison's undamaged nuclear units and the CPUC and FERC could deny rate recovery of related costs. Such an accident, therefore, could materially and adversely affect the operations and earnings of Edison.

Nuclear Waste Policy Act

Under the Nuclear Waste Policy Act of 1982, Edison, acting as agent for the San Onofre participants, has entered into a contract with the DOE for disposal of spent nuclear fuel for San Onofre Units 1, 2 and 3. Under

the terms of the contract, Edison is required to pay a quarterly fee of one mill per kilowatt hour to the DOE for net nuclear power generated and sold on and after April 7, 1983. During 1992, DOE implemented a refund process for overpayments to the Nuclear Waste Fund through credits against future quarterly payments.

For generation prior to April 7, 1983, the contract required payment of a one-time fee equivalent to one mill per kilowatt hour, plus accrued interest. The obligation for this one-time fee was being discharged by equal quarterly payments. In October 1992 and 1993, DOE credits arising from overpayments to the Nuclear Waste Fund were also applied to this obligation. In October 1993, this obligation was paid in full. Expenses associated with the disposal of spent nuclear fuel are recovered through the ECAC procedure and from participants.

Competitive Environment

Under various acts of Congress, federal power projects have been constructed in California and neighboring states. Municipally owned utilities, cooperative utilities and other public bodies have certain preferences over investor-owned utilities in the purchase of electric power provided by federally funded power projects and, in addition, have certain preferences over investor-owned utilities in connection with the acquisition of licenses to build and/or operate hydroelectric power plants. Any energy which is or may be generated at these projects and transmitted for the account of such other utilities and public bodies over present or future government or utility-owned lines into the territory or markets served by Edison would result in a loss of sales by Edison.

Under the laws of California, utility districts may include incorporated as well as unincorporated territory. Such districts, as well as municipalities, have the right to construct, purchase or condemn and operate electric facilities. In addition, when a city owning an electric system annexes adjacent unincorporated territory which Edison has previously served, Edison may experience a loss of customers.

Edison's construction permits for San Onofre Units 2 and 3 contain certain conditions which require Edison (i) on timely notice, to permit privately or publicly owned utilities, including Edison's resale customers within or adjacent to Edison's service area, to participate on mutually agreeable terms in future nuclear units initiated by Edison, and (ii) to interconnect and coordinate reserves with, furnish emergency service to, sell bulk power to and purchase bulk power from, and provide certain transmission services for such utilities. Edison has also entered into agreements with certain of its resale customers which contemplate their possible participation in jointly owned generating projects initiated by Edison, and the integration of power sources acquired by each such customer, including the dispatching, reserve sharing, partial power-supply requirements and transmission service required in connection with such integrated operations. Pursuant to these agreements, two resale customers exercised an option to participate in Edison's ownership entitlement in San Onofre Units 2 and 3. Effective November 1977, Edison sold an undivided 3.45% interest in San Onofre Units 2 and 3 to these two resale customers for approximately $90,000,000. Effective September 1981, a further 1.5% interest in Units 2 and 3 was sold to one of these resale customers for approximately $50,000,000. In addition, since 1986, six of Edison's resale customers have acquired ownership interests in other generating sources and made purchases from other utilities in such amounts as to decrease Edison's revenues from resale cities from 4.4% to 1.6% of sales. This revenue loss has not had a substantial effect on Edison's business and opportunities.

PURPA has fostered the entry of nonutility companies into the electric generation business. Under PURPA, nonutility power producers are allowed to construct QFs for the production of electricity from certain alternative or renewable energy resources, and utilities are required to purchase the electrical output of these QFs at prices set pursuant to state regulations and, in the future, pursuant to a CPUC-approved competitive bidding process.

Edison is required by contracts and state regulation to continue to buy power generated by QFs, under long-term contracts negotiated earlier at prices that are most often higher than the power Edison can produce or purchase from other sources. Edison is presently managing contracts with QF developers to reduce ratepayer impacts and to more closely match Edison's needs with proposed development. Further, certain operators of QFs sell power they produce to large industrial and commercial customers of Edison from projects located on-site. Further loss of sales from such customers may be aggravated in the future as a result of attempts by these producers to gain access to a utility's transmission lines to sell power directly to retail customers now being served by that utility--an activity called "retail wheeling." Edison opposes any attempt to impose mandatory wheeling to Edison's retail customers.

In late 1992, Congress passed the Energy Policy Act of 1992. This Act creates a new class of Exempt Wholesale Generators ("EWGs") who are exempt from the restrictions otherwise imposed on utilities under the Public Utility Holding Company Act. The effect of this exemption is to facilitate the development of more independent third-party generators potentially available to satisfy utilities' needs for increased power supplies. However, unlike purchases from QFs, utilities have no statutory obligation to purchase power from EWGs. Furthermore, EWGs are precluded from making direct sales to retail electricity customers.

The Energy Policy Act also broadens the authority of the FERC to require a utility to transmit power produced by a wholesale producer to another utility. Municipal utilities are eligible applicants for such transmission service. However, the FERC is precluded from ordering a utility to transmit power from another entity directly to a retail customer. The authority of states to order such retail wheeling is unclear; but, to the extent such authority exists, it is explicitly preserved by the Energy Policy Act.

Item 3. Legal Proceedings

Antitrust Matters

In 1983, a public power utility, the City of Vernon, filed a complaint against Edison in the United States District Court for the Central District of California, alleging violation of certain antitrust laws. The complaint alleged that Edison engaged in anticompetitive behavior by restricting access to Edison transmission facilities and foreclosing Vernon from purchasing bulk power supplies from other sources. Vernon also alleged that Edison unlawfully designed its resale rates and claimed damages of approximately $60,000,000 before trebling. Edison filed three motions for Summary Judgment and the District Court entered final judgment in favor of Edison in August 1990. In October 1990, Vernon appealed the District Court decision to the Ninth Circuit Court of Appeals. In February 1992, the Court of Appeals affirmed the District Court's rulings on all issues but one, involving injunctive relief only, and remanded that issue back to the District Court for consideration. In July 1992, Vernon filed a writ of certiorari to the U.S. Supreme Court which was denied. On July 13, 1993, Edison and Vernon settled the remaining issue regarding injunctive relief. The settlement is part of a broader settlement of regulatory issues that was approved by the FERC on October 27, 1993.

On January 31, 1991, California Energy Company ("CEC") filed a lawsuit in United States District Court for the Northern District of California against SCEcorp, Edison, several nonutility subsidiaries, selected individuals, and Kidder, Peabody & Co. CEC alleged antitrust violations of the Sherman Act, conspiracy to interfere with contractual relations and common law unfair competition. CEC asked for treble damages (as proved at trial) for antitrust violations and compensatory and punitive damages for the pendent claims. Furthermore, CEC requested that SCEcorp divest itself of Mission Energy. On April 30, 1993, Edison and CEC reached a settlement. In June 1993, a nonutility affiliate and CEC settled a related lawsuit concerning construction of CEC's power plants. Pursuant to the settlements, the case was dismissed.

Further terms of the CEC settlement relate to litigation involving Mission Power Engineering Company in connection with a construction contract. In June 1990, Mission Power filed suit to foreclose on mechanics liens against CEC, Coso Finance Partners, Coso Energy Developers, Coso Power Developers ("Coso Entities") and Credit Suisse in California Superior Court in Inyo County. Mission Power claimed damages in excess of $79,000,000 and alleged breach of contract, fraud and negligent misrepresentation. In December 1990, the Coso Entities filed a cross-complaint against Mission Power and The Mission Group alleging $97,000,000 plus punitive damages for breach of contract, negligence, and misrepresentations. On June 10, 1993, the parties announced they had reached a settlement of all outstanding disputes regarding construction of the Coso Geothermal Project. Under the settlement, Coso Partnerships made a net payment of $20,000,000 to Mission Power. This was less than the amount of revenue Mission Power had previously recorded, resulting in a one-time charge of $11,000,000 after tax for the second quarter.

Transphase Systems, Inc. filed a lawsuit on May 3, 1993, in the United States District Court for the Central District of California against Edison and San Diego Gas & Electric Company ("SDG&E"). The complaint alleged that Transphase was competitively disadvantaged because it could not directly access the demand side management funds Edison collects from its ratepayers to fund conservation and demand side management activities and that the utilities willfully acquired and maintain monopoly power in the energy conservation industry. The complaint sought $50,000,000 in damages before trebling. Edison filed a motion to dismiss the complaint on the grounds that it was without merit. The court granted Edison's motion on October 7, 1993, and denied plaintiffs the opportunity to replead the case. Plaintiffs have appealed to the Ninth Circuit Court of Appeals.

Environmental Litigation

On November 8, 1990, an environmental organization and two individuals filed a lawsuit against Edison in United States Federal District Court for the Southern District of California. The lawsuit alleges Edison's operation of San Onofre Units 2 and 3 is in violation of its National Pollutant Discharge Elimination System permits. The basis for the allegations was a report prepared for the California Coastal Commission on the marine environmental effects of the generating station. The plaintiffs requested that the Court enjoin operation of Units 2 and 3, impose civil penalties, and order Edison to repair the alleged damage to the marine environment. After mediation by the court, the parties agreed on a settlement that includes: (i) $2,000,000 in wetlands research which will be undertaken by the Pacific Estuarine Research Laboratory at San Diego State University; (ii) $7,500,000 in additional wetland restoration within the San Dieguito River Valley; (iii) a $5,500,000, 10 year, Marine Education Program which will be based at Edison's Redondo Generating Station; and (iv) $1,400,000 in attorney's fees. The court approved the settlement on June 15, 1993.

On September 23, 1993, the California Department of Toxic Substances Control ("DTSC") issued a Report of Violation to Edison, alleging various hazardous waste violations of the California Health & Safety Code at several Edison facilities. Edison is currently in settlement negotiations with DTSC regarding these alleged violations and tentatively has reached an agreement in principle for settlement in the amount of $1,900,000.

San Onofre Personal Injury Litigation

In 1993, a former NRC inspector who was assigned to San Onofre in 1985 and 1986 filed a lawsuit against Edison, SDG&E and a fuel rod manufacturer in Los Angeles County Superior Court, Central District. The case was subsequently transferred to the Federal District Court for the Southern District of California. The inspector claimed that exposure to radioactive materials at the plant caused her leukemia. Plant records showed that the inspector's exposure to radiation was well below NRC regulatory levels. Plaintiff nevertheless alleged that she was exposed to radioactive fuel particles, that this caused a radiation exposure above the NRC levels and that this exposure was a legal cause for her illness. Plaintiff sought compensatory and punitive damages. The defendants denied having liability for plaintiff's illness.

A jury trial began on January 4, 1994. In closing arguments at the end of the trial, plaintiff's counsel requested damages between $4,000,000 and $4,500,000 for medical costs and economic losses and asked for three to five times that amount for pain and suffering compensatory damages. After deliberations, the jury reported that it was "hung" and could not reach a unanimous verdict on the threshold question of whether plaintiff was exposed to radiation levels above the NRC-defined levels. (A 7-2 majority of the jury had concluded that plaintiffs exposure did exceed these levels). Finding itself hung on the exposure question, the jury did not decide the other questions regarding causation, the amount of compensatory damages and whether Edison's conduct warranted punitive damages. If the jury had found that punitive damages should be assessed, the trial would have resumed to decide the amount of such damages.

On February 8, 1994, the trial judge declared a mistrial because of the hung jury. The second trial was scheduled to begin on March 15, 1994. On March 14, 1994, the case was settled. The amount of the settlement payment will not have a material adverse effect on Edison's net income.

Item 4. Submission of Matters to a Vote of Security Holders

Inapplicable.

Pursuant to Form 10-K's General Instruction ("General Instruction") G(3), the following information is included as an additional item in Part I:

Executive Officers of the Registrant (1)(2)

SCEcorp

Executive Officer	Age at December 31, 1993	Company Position	Effective Date
John E. Bryson	50	Chairman of the Board, Chief Executive Officer and Director	October 1, 1990
Bryant C. Danner	56	Senior Vice President and General Counsel	July 1, 1992
Alan J. Fohrer	43	Senior Vice President, Treasurer and Chief Financial Officer	January 21, 1993
Richard K. Bushey	53	Vice President and Controller	July 21, 1988
Kenneth S. Stewart	42	Assistant General Counsel and Corporate Secretary	November 19, 1992

(1) The Executive Officers of SCEcorp include the Chairman of the Board and Chief Executive Officer, the elected Vice Presidents and the Secretary of SCEcorp and Edison as well as the Chief Executive Officers and Presidents, Executive Vice Presidents and Senior Vice Presidents of Mission Energy, Mission Financial, and Mission Land (collectively "The Mission Companies") all of whom may be deemed policy makers of SCEcorp.

(2) Effective March 1, 1993, Michael R. Peevey retired from his position as President of SCEcorp.

None of SCEcorp's elected executive officers are related to each other by blood or marriage. As set forth in Article IV of SCEcorp's Bylaws, the elected officers of SCEcorp are chosen annually by and serve at the pleasure of SCEcorp's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. Each of the elected executive officers of SCEcorp holds an identical position with Edison except for Alan J. Fohrer, who does not hold the Treasurer position at Edison and has been actively engaged in the business of Edison for more than five years except for Bryant C. Danner. Those officers who have not held their present position with SCEcorp and/or Edison for the past five years had the following business experience during that period:

John E. Bryson	Executive Vice President and Chief Financial Officer of SCEcorp	May 1988 to September 1990
	Executive Vice President and Chief Financial Officer of Edison	January 1985 to September 1990
Bryant C. Danner	Partner with law firm of Latham & Watkins(1)(2)	January 1970 to June 1992
Alan J. Fohrer	Vice President, Treasurer and Chief Financial Officer of SCEcorp and Edison	April 1991 to January 1993
	Assistant Treasurer of SCEcorp	July 1988 to March 1991
	Assistant Treasurer and Manager of Cost Control of Edison	September 1987 to March 1991

Kenneth S. Stewart	Assistant General Counsel of Edison and SCEcorp	March 1992 to October 1992
	Senior Counsel of Edison	March 1989 to February 1992
	Attorney of Edison	June 1987 to February 1989

(1) Prior to leaving the law firm of Latham & Watkins, Bryant C. Danner was in the firm's environmental department.

(2) This entity is not a parent, subsidiary or other affiliate of Edison.

Edison

Executive Officer	Age at December 31, 1993	Company Position(1)(2)	Effective Date
John E. Bryson	50	Chairman of the Board, Chief Executive Officer and Director	October 1, 1990
Bryant C. Danner	56	Senior Vice President and General Counsel	July 1, 1992
Alan J. Fohrer	43	Senior Vice President and Chief Financial Officer	June 17, 1993
Charles B. McCarthy, Jr.	53	Senior Vice President	June 1, 1990
Harold B. Ray	53	Senior Vice President (Power Systems)	June 1, 1990
R. H. Bridenbecker	50	Vice President (Customer Solutions)	June 1, 1990
Vikram S. Budhraja	46	Vice President (Planning and Technology)	February 1, 1992
Richard K. Bushey	53	Vice President and Controller	January 1, 1984
Ronald Daniels	54	Vice President (Regulatory Projects)	August 10, 1992
John R. Fielder	48	Vice President (Regulatory Policy and Affairs)	February 1, 1992
Robert G. Foster	46	Vice President (Public Affairs)	November 18, 1993
L. D. Hamlin	49	Vice President (Power Production)	February 1, 1992
Margaret H. Jordan	50	Vice President (Health Care and and Employee Services)	December 7, 1992
Russell W. Krieger	45	Vice President (Nuclear Generation)	June 17, 1993
J. Michael Mendez	52	Vice President (Regional Leadership)	February 8, 1993
Georgia R. Nelson	43	Vice President (Performance Support)	March 18, 1993
Lewis M. Phelps	50	Vice President (Corporate Communications)	May 1, 1989
Richard M. Rosenblum	43	Vice President (Engineering and Technical Services)	June 17, 1993
C. Alex Miller	36	Treasurer	June 17, 1993
Kenneth S. Stewart	42	Assistant General Counsel and Corporate Secretary	November 19, 1992

(1) Effective March 1, 1993, Michael R. Peevey retired from his position as President of Edison, and Harry E. Morgan, Jr. retired from his position as Vice President of Edison and Site Manager of San Onofre. At December 31, 1993, Charles B. McCarthy, Jr. was Senior Vice President of Edison; however, effective January 1, 1994, Mr. McCarthy retired from this position.

(2) John E. Bryson, Bryant C. Danner, Richard K. Bushey and Kenneth S. Stewart also hold the same positions with SCEcorp. Alan J. Fohrer holds the office of Senior Vice President, Treasurer and Chief Financial Officer of SCEcorp. SCEcorp is the parent holding company of Edison.

None of Edison's executive officers are related to each other by blood or marriage. As set forth in Article IV of Edison's Bylaws, the officers of Edison are chosen annually by and serve at the pleasure of Edison's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the executive officers have been actively engaged in the business of Edison for more than five years except for Bryant C. Danner and Margaret H. Jordan. Those officers who have not held their present position for the past five years had the following business experience during that period:

John E. Bryson	Executive Vice President and Chief Financial Officer	January 1985 to September 1990
Bryant C. Danner	Partner with Law Firm of Latham & Watkins(1)(3)	January 1970 to June 1992
Harold B. Ray	Vice President -- Nuclear Engineering Safety and Licensing	August 1989 to May 1990
	Vice President -- Fuel Supply, Procurement and Material Management	January 1988 to July 1989
R. H. Bridenbecker	Vice President and Site Manager -- San Onofre Nuclear Generating Station	September 1989 to May 1990
	Vice President (Customer Service)	January 1988 to August 1989
Vikram S. Budhraja	Vice President -- System Planning and Fuel Supply	April 1991 to January 1992
	Manager -- Electric System Planning	September 1986 to March 1991
Ronald Daniels	Vice President -- Revenue Requirements	August 1989 to July 1992
	Manager -- Revenue Requirements	September 1975 to July 1989
John R. Fielder	Vice President -- Information Services	January 1989 to January 1992
Alan J. Fohrer	Vice President, Treasurer and Chief Financial Officer	April 1991 to January 1993
	Assistant Treasurer and Manager -- Cost Control	September 1987 to March 1991
L. D. Hamlin	Manager -- Steam Generation	April 1990 to January 1992
	Manager -- Research, System Planning and Research Department	September 1986 to April 1990
Robert G. Foster	Regional Vice President (Sacramento Office)	January 1988 to October 1993
Margaret H. Jordan	Vice President -- Kaiser Foundation Health Plan of Texas(2)(3)	March 1986 to December 1992
Russell W. Krieger	Station Manager (San Onofre)	August 1990 to May 1993
	Station Operation Manager (San Onofre)	August 1985 to July 1990

J. Michael Mendez	Vice President -- Human Resources	August 1991 to February 1993
	Division Vice President -- Customer Service	January 1991 to July 1991
	Division Manager -- Customer Service	September 1989 to January 1991
	Manager -- Personnel and Employee Relations	September 1985 to September 1989
Georgia R. Nelson	Special Assistant to the Chairman	February 1992 to March 1993
	Manager -- Procurement and Material Management	September 1989 to January 1992
	Manager -- Telecommunications	November 1987 to August 1989
Lewis M. Phelps	Manager -- Corporate Communications	July 1985 to April 1989
Richard M. Rosenblum	Manager of Nuclear Regulatory Affairs	June 1989 to May 1993
	Manager of Nuclear Oversight	September 1986 to May 1989
C. Alex Miller	Assistant Treasurer	April 1991 to May 1993
	Manager of Financial Planning and Regulatory Finance	September 1987 to March 1991
Kenneth S. Stewart	Assistant General Counsel	March 1992 to November 1992
	Senior Counsel	March 1989 to February 1992
	Attorney	June 1987 to February 1989

(1) Prior to leaving the law firm of Latham & Watkins, Bryant C. Danner was in the firm's environmental department.

(2) As Vice President of the Kaiser Foundation Health Plan of Texas, Margaret H. Jordan was responsible for serving over 124,000 members in 10 multispecialty medical offices in the Dallas/Fort Worth area.

(3) This entity is not a parent, subsidiary or other affiliate of Edison.

The Mission Companies

Executive Officer	Age at December 31, 1993	Company Position[1]	Effective Date
Edward R. Muller	41	President and Chief Executive Officer -- Mission Energy	August 23, 1993
Robert M. Edgell	46	Executive Vice President -- Mission Energy	April 1, 1988
Robert Dietch	55	Senior Vice President, Project Management/Operations -- Mission Energy	February 1, 1992
Alan M. Fenning	43	Senior Vice President and General Counsel -- Mission Energy	April 1, 1988

James V. Iaco, Jr.	49	Senior Vice President and Chief Financial Officer -- Mission Energy	January 24, 1994
S. Daniel Melita	42	Senior Vice President -- Mission Energy	November 1, 1993
Thomas R. McDaniel	44	President and Chief Executive Officer -- Mission First Financial and Mission Land	January 1, 1988
Lawrence W. Yu	40	Executive Vice President -- Mission First Financial	October 15, 1993
Michael L. Noel	52	Executive Vice President -- Mission Land	January 17, 1994
Charles W. Johnson	47	Executive Vice President -- Mission Land	August 7, 1992

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(1) Effective August 1, 1993, James S. Pignatelli resigned from his position as President and Chief Executive Officer of Mission Energy. Alan J. Fohrer served as interim Vice Chairman and interim Chief Executive Officer of Mission Energy prior to Edward R. Muller's appointment as President and Chief Executive Officer. John A. Moriarty served as Senior Vice President of Mission Land until April 15, 1993; Mr. Moriarty currently serves as Vice President of Mission Land.

None of The Mission Companies' executive officers are related to each other by blood or marriage. As set forth in Article IV of their respective Bylaws, the officers of The Mission Companies are chosen annually by and serve at the pleasure of the respective Boards of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the executive officers have been actively engaged in the business of the respective Mission Companies and/or SCEcorp and Edison for more than five years except for Edward R. Muller, James V. Iaco, Jr., S. Daniel Melita and Charles W. Johnson. Those officers who have not held their present position for the past five years had the following business experience during that period:

Edward R. Muller	Vice President, Chief Financial Officer, General Counsel and Secretary, Whittaker Corporation(1)(13)	October 1992 to July 1993
	Vice President, Chief Administrative Officer, General Counsel and Secretary, Whittaker Corporation(2)(13)	March 1988 to September 1992
James V. Iaco, Jr.	President, James V. Iaco & Associates(3)(4)(13)	October 1993 to January 1994
	Independent Business Consultant(5)(13)	October 1992 to September 1993
	Independent Business Consultant(6)(13)	November 1991 to September 1992
	Senior Vice President, Chief Financial Officer, Intermark, Inc.(7)(13)	January 1990 to October 1991
	Senior Vice President, Chief Financial Officer and Treasurer, MAXXAM Inc.(8)(13)	September 1981 to October 1990
Robert Dietch	Vice President, Engineering, Planning and Research of Edison	January 1987 to January 1992

S. Daniel Melita	Vice President, Mission Energy[9][13]	September 1992 to October 1993
	Vice President, International Operations of EBASCO Constructors, Inc., EBASCO Overseas Corporation[10][13]	October 1989 to August 1992
Michael L. Noel	Senior Vice President and Chief Financial Officer of Mission Energy	February 1992 to December 1993
	Senior Vice President of Edison	April 1991 to January 1992
	Vice President, Treasurer and Chief Financial Officer of SCEcorp and Edison	October 1990 to March 1991
	Vice President and Treasurer of SCEcorp	July 1988 to September 1990
	Vice President and Treasurer of Edison	July 1980 to September 1990
Lawrence W. Yu	Senior Vice President of Mission First Financial	July 1991 to September 1993
	Vice President of Mission First Financial	September 1987 to June 1991
Charles W. Johnson	President, Glenfed Development Corp.[11][13]	September 1990 to June 1992
	Executive Vice President/Deputy Subsidiary Group Administrator, Glenfed Service Corporation[12][13]	August 1987 to August 1990

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(1) Edward R. Muller served as Chief Financial Officer and General Counsel (the second most senior officer) of Whittaker Corporation, a company during the period from 1992 to 1993 engaged in various aerospace businesses.

(2) Edward R. Muller served as Chief Administrative Officer and General Counsel (the third most senior officer) of Whittaker Corporation, a company during the period from 1988 to 1992 engaged in various aerospace, chemical and biotechnology businesses and which underwent significant restructurings, including a leveraged recapitalization and a tax-free spin off.

(3) James V. Iaco, Jr. was elected Senior Vice President and Chief Financial Officer of Mission Energy Company effective January 24, 1994.

(4) As President of James V. Iaco & Associates, James V. Iaco, Jr. provided consultant services specializing in mergers and acquisitions, restructurings, financing crisis management and other management services.

(5) As an independent business consultant, James V. Iaco, Jr. completed the disposition of subsidiaries of Phoenix Distributors, Inc. ("Phoenix"). Phoenix was one of the largest independent industrial gas and welding supply distributor in the United States. Mr. Iaco acted as the Company's chief financial officer, completing the refinancing and restructuring of the remaining operation of the Company.

(6) James V. Iaco, Jr. served as an independent business consultant primarily engaged as the chief operating officer of a major developer of time-share resort properties at the request of the shareholders.

(7) As Senior Vice President, Chief Financial Officer, James V. Iaco, Jr. developed debt reduction and restructuring plans.

(8) James V. Iaco, Jr. served as Senior Vice President, Chief Financial Officer and Treasurer at MAXXAM, Inc., a Fortune 200 company engaged in aluminum production, forest products operations and real estate development.

(9) As Director International Business Development, S. Daniel Melita planned and implemented international marketing and sales strategies for all business units and was responsible for selecting team partners and establishing joint venture companies.

(10) As Vice President, International Operations of EBASCO Constructors, Inc./EBASCO Overseas Corporation, S. Daniel Melita was responsible for all overseas activities including operations and business development, consulting construction management and lump sum turn key construction.

(11) As President, Charles W. Johnson directed all real estate operations and business combinations which included direct development, joint ventures and syndications.

(12) As Executive Vice President, Charles W. Johnson directed all real estate operations where Glenfed had made a direct equity investment. This included August Financial Corporation, Glenfed Development Corporation and Glenfed Properties.

(13) This entity is not a parent, subsidiary or other affiliate of SCEcorp.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Information responding to Item 5 is included in SCEcorp's Annual Report to Shareholders for the year ended December 31, 1993, ("Annual Report") under "Quarterly Financial Data" on page 38 and under "Shareholder Information" on page 41, and is incorporated by reference pursuant to General Instruction G(2). The number of Common Stock shareholders of record was 140,600 on March 4, 1994. Additional information concerning the market for SCEcorp's Common Stock is set forth on the cover page hereof.

Item 6. Selected Financial Data

Information responding to Item 6 is included in the Annual Report under "Selected Financial and Operating Data: 1989-1993" on page 40, and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

Information responding to Item 7 is included in the Annual Report under "Management's Discussion and Analysis" on pages 21 through 29 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 8. Financial Statements and Supplementary Data

Certain information responding to Item 8 is set forth after Item 14 in Part IV. Other information responding to Item 8 is included in the Annual Report on pages 23 through 40 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information concerning executive officers of SCEcorp is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K. Other information responding to Item 10 is included in the Joint Proxy Statement ("Proxy Statement") filed with the Commission in connection with SCEcorp's Annual Meeting to be held on April 21, 1994, under the heading, "Election of Directors of SCEcorp and Edison," and is incorporated herein by reference pursuant to General Instruction G(3).

Item 11. Executive Compensation

Information responding to Item 11 is included in the Proxy Statement under the heading "Election of Directors of SCEcorp and Edison," and is incorporated herein by reference pursuant to General Instruction G(3).

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information responding to Item 12 is included in the Proxy Statement under the headings "Election of Directors of SCEcorp and Edison," and "Stock Ownership of Certain Shareholders" and is incorporated herein by reference pursuant to General Instruction G(3).

Item 13. Certain Relationships and Related Transactions

Information responding to Item 13 is included in the Proxy Statement under the heading "Election of Directors of SCEcorp and Edison," and is incorporated herein by reference pursuant to General Instruction G(3).

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)(1) Financial Statements

The following items contained in the 1993 Annual Report to Shareholders are incorporated by reference in this report.

Management's Discussion and Analysis of Results of Operations and Financial Condition
Responsibility for Financial Reporting
Report of Independent Public Accountants
Consolidated Statements of Income -- Years Ended December 31, 1993, 1992 and 1991
Consolidated Balance Sheets -- December 31, 1993, and 1992
Consolidated Statements of Cash Flows -- Years Ended December 31, 1993, 1992 and 1991
Consolidated Statements of Retained Earnings -- Years Ended December 31, 1993, 1992 and 1991
Notes to Consolidated Financial Statements

(2) Report of Independent Public Accountants and Schedules Supplementing Financial Statements

The following documents may be found in this report at the indicated page numbers.

	Page
Report of Independent Public Accountants on Supplemental Schedules	33
Schedule III--Condensed Financial Information of Parent	34
Schedule V--Property, Plant and Equipment for the Years Ended December 31, 1993, 1992 and 1991	36
Schedule VI--Accumulated Depreciation and Amortization of Property, Plant, and Equipment for the Years Ended December 31, 1993, 1992 and 1991	39
Schedule VII--Guarantees of Securities of Other Issuers for the Year Ended December 31, 1993	42
Schedule VIII--Valuation and Qualifying Accounts for the Years Ended December 31, 1993, 1992 and 1991	43
Schedule IX--Short-Term Borrowings For Each of the Three Years in the Period Ended December 31, 1993	46
Schedule X--Supplementary Income Statement Information For for Each of the Three Years in the Period Ended December 31, 1993	47
Schedule XIII--Other Investments, December 31, 1993	48

Schedules I through XIII, inclusive, except those referred to above, are omitted as not required or not applicable.

(3) Exhibits

See Exhibit Index on page 50 of this report.

(b) Reports on Form 8-K

October 12, 1993
Item 5: Other Events: Termination of Mission Energy Company Project in Mexico

October 27, 1993

Item 5: Other Events: Earnings Report

Item 7: Financial Statements: Pro Forma Financial Information and Exhibits

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SUPPLEMENTAL SCHEDULES

To SCEcorp:

We have audited, in accordance with generally accepted auditing standards, the consolidated financial statements included in the 1993 Annual Report to Shareholders of SCEcorp, incorporated by reference in this Form 10-K, and have issued our report thereon dated February 4, 1994. Our audits of the consolidated financial statements were made for the purpose of forming an opinion on those basic consolidated financial statements taken as a whole. The supplemental schedules listed in Part IV of this Form 10-K which are the responsibility of SCEcorp's management are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations, and are not part of the basic consolidated financial statements. These supplemental schedules have been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

ARTHUR ANDERSEN & CO.
ARTHUR ANDERSEN & CO.

Los Angeles, California
February 4, 1994

SCEcorp

SCHEDULE III -- CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS

	December 31, 1993	December 31, 1992
	(In thousands)	
Assets:		
Cash and equivalents	$ 6,004	$ 11,353
Other current assets	143,607	158,640
Total current assets	149,611	169,993
Investments in subsidiaries	5,927,922	5,943,771
Accumulated deferred income taxes -- net	46,768	1,030
Other assets	258	552
Total assets	$6,124,559	$6,115,346
Liabilities and Shareholders' Equity:		
Accounts payable	$ 4,630	$ 3,353
Other current liabilities	162,348	158,256
Total current liabilities	166,978	161,609
Common shareholders' equity	5,957,581	5,953,737
Total liabilities and shareholders' equity	$6,124,559	$6,115,346

CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 1993, 1992, and 1991

	1993	1992	1991
	(In thousands, except per-share amounts)		
Operating revenue and interest income	$ 18,914	$13,974	$ 8,662
Operating expenses and income taxes	20,231	14,611	9,454
Loss before equity in earnings of subsidiaries	(1,317)	(637)	(792)
Equity in earnings of subsidiaries	640,364	739,357	703,397
Net income	$ 639,047	$738,720	$702,605
Weighted-average shares of common stock outstanding	447,754	445,489	437,321
Earnings per share	$ 1.43	$ 1.66	$ 1.61

Note: Per-share figures reflect the two-for-one split of SCEcorp common stock effective June 1, 1993.

SCEcorp

SCHEDULE III--CONDENSED FINANCIAL INFORMATION OF PARENT (Continued)

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 1993, 1992, and 1991

	1993	1992	1991
		(In thousands)	
Cash Flows From Operating Activities	$(46,143)	$ 1,404	$ (71)
Cash Flows From Financing Activities:			
Capital contributions	41,250	(64,020)	69,505
Cash Flows From Investing Activities	(456)	3,380	--
Increase (Decrease) in cash and equivalents	(5,349)	(59,236)	69,434
Cash and equivalents at beginning of period	11,353	70,589	1,155
Cash and Equivalents at the End of Period	$ 6,004	$ 11,353	$ 70,589
Cash dividends received from Southern California Edison Company	$631,325	$613,816	$588,513

SCEcorp

SCHEDULE V -- PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1993

Description	Balance at Beginning of Period	Add (Deduct) Additions at Cost	Retirements	Other Changes	Balance at End of Period
			(In thousands)		
Steam production	$2,151,082	$130,586	$ (33,221)	$ 4,687	$ 2,253,134
Nuclear production	5,380,457	61,597	(2,958)	--	5,439,096
Hydro production	571,859	11,864	(453)	--	583,270
Other production	396,095	19,391	(11,432)	391	404,445
Transmission	2,568,391	86,972	(12,499)	467	2,643,331
Distribution	5,608,233	342,022	(51,641)	11,980	5,910,594
General	1,072,671	121,986	(14,960)	177	1,179,874
Plant held for future use	16,043	(14,393)	(9)	--	1,641
Experimental electric plant unclassified	31,381	4,818	(6,221)	(17,946)	12,032
Other utility plant	8,419	343	(45)	--	8,717
Subtotal--utility plant	17,804,631	765,186	(133,439)	(244)	18,436,134
Construction work in progress	723,765	124,321(a)	9,139	--	857,225
Nuclear fuel	776,262	86,225	(129,442)	26(b)	733,071
Gross utility plant	$19,304,658	$975,732	$ (253,742)	$ (218)	$20,026,430
Nonutility property	$ 1,074,009	$320,326	$ (176,586)	$131,891	$ 1,349,640

(a) Reflects transfers to plant in service, which are net of additions to construction work in progress.

(b) Reflects prior-year adjustments.

SCEcorp

SCHEDULE V -- PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1992

Description	Balance at Beginning of Period	Add (Deduct) Additions at Cost	Retirements	Other Changes	Balance at End of Period
		(In thousands)			
Steam production	$ 2,054,404	$ 96,120	$ (15,578)	$ 16,136	$ 2,151,082
Nuclear production	5,915,872	70,661	(606,076)(b)	--	5,380,457
Hydro production	569,322	3,519	(982)	--	571,859
Other production	394,635	5,595	(4,135)	--	396,095
Transmission	2,468,478	106,779	(7,491)	625	2,568,391
Distribution	5,291,905	376,130	(59,909)	107	5,608,233
General	993,991	125,687	(48,290)	1,283	1,072,671
Plant held for future use	17,629	132	(61)	(1,657)	16,043
Experimental electric plant unclassified	58,145	263	(5,839)	(21,188)	31,381
Other utility plant	7,692	713	(150)	164	8,419
Subtotal--utility plant . . .	17,772,073	785,599	(748,511)	(4,530)	17,804,631
Construction work in progress	794,303	(60,531)(a)	9,054	(19,061)	723,765
Nuclear fuel	973,554	20,356	(182,978)	(34,670)(b)	776,262
Gross utility plant	$19,539,930	$745,424	$(922,435)	$(58,261)	$19,304,658
Nonutility property	$ 446,723	$ 22,689	$ (10,327)	$614,924	$ 1,074,009

(a) Reflects transfers to plant in service, which are net of additions to construction work in progress.

(b) Reflects removal from service of nuclear generating plant under an agreement reached with the California Public Utilities Commission.

SCEcorp

SCHEDULE V -- PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1991

Description	Balance at Beginning of Period	Add (Deduct) Additions at Cost	Retirements	Other Changes	Balance at End of Period
			(In thousands)		
Steam production	$ 1,960,914	$ 98,818	$ (5,328)	$ --	$ 2,054,404
Nuclear production	5,789,475	129,931	(3,534)	--	5,915,872
Hydro production	556,197	13,555	(373)	(57)	569,322
Other production	395,963	5,039	(6,367)	--	394,635
Transmission	2,405,526	74,072	(11,120)	--	2,468,478
Distribution	4,961,068	393,032	(61,807)	(388)	5,291,905
General	920,813	97,158	(21,714)	(2,266)	993,991
Plant held for future use	17,110	152	(21)	388	17,629
Experimental electric plant unclassified	30,314	27,831	--	--	58,145
Other utility plant	7,224	506	(38)	--	7,692
Subtotal--utility plant . . .	17,044,604	840,094	(110,302)	(2,323)	17,772,073
Construction work in progress	741,040	39,471(a)	13,792	--	794,303
Nuclear fuel	1,020,897	83,674	(131,017)	--	973,554
Gross utility plant	$18,806,541	$963,239	$(227,527)	$(2,323)	$19,539,930
Nonutility property	$ 418,658	$ 66,535	$ (51,136)	$12,666	$ 446,723

(a) Reflects transfers to plant in service, which are net of additions to construction work in progress.

(b) Restated to include consolidated statements from affiliates.

SCEcorp

SCHEDULE VI -- ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1993

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Charges(a)	Add (Deduct) Salvage	Balance at End of Period
			(In thousands)			
Steam production	$1,376,609	$109,929	$(21,637)	$ (15,890)	$3,279	$1,452,290
Nuclear production . . .	1,835,951	315,683	(2,757)	(60,047)	108	2,088,938
Hydro production	153,594	11,297	(445)	(302)	-	164,144
Other production	229,998	12,737	(6,080)	(3,288)	319	233,686
Transmission	843,228	60,655	(11,483)	(3,262)	2,631	891,769
Distribution	1,833,654	213,309	(51,555)	(27,201)	6,095	1,974,302
General	268,189	59,402	(14,542)	2,145	192	315,386
Experimental electric plant unclassified . .	19,590	7,600	(3,165)	(6,935)	--	17,090
Retirement work in progress	(22,514)	--	7,538	5,058	956	(8,962)
Other utility plant reserves	5,387	4,274	(14)	(1)	--	9,646
Subtotal	6,543,686	794,886	(104,140)	(109,723)	13,580	7,138,289
Nuclear fuel amortization	652,653	61,848	(129,442)	--	--	585,059
Total utility plant reserves	$7,196,339	$856,734	$(233,582)	$(109,723)	$13,580	$7,723,348
Nonutility property reserves	$ 50,478	$ 28,993	$ (9,252)	$ 2,950	$ --	$ 73,169

(a) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

SCEcorp

SCHEDULE VI -- ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1992

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Charges(a)	Add (Deduct) Salvage	Balance at End of Period
			(In thousands)			
Steam production	$1,301,013	$ 99,652	$ (15,798)	$ (8,588)	$ 330	$ 1,376,609
Nuclear production . . .	1,926,088	319,875	(777,264)(b)	367,166	86	1,835,951
Hydro production	143,797	11,223	(982)	(444)	--	153,594
Other production	228,740	11,116	(4,090)	(6,068)	300	229,998
Transmission	790,677	58,443	(7,017)	(476)	1,601	843,228
Distribution	1,712,575	201,666	(59,792)	(28,757)	7,962	1,833,654
General	254,535	56,665	(48,309)	4,981	317	268,189
Experimental electric plant unclassified . .	19,275	6,212	(5,839)	(58)	--	19,590
Retirement work in progress	(40,590)	--	4,785	9,462	3,829	(22,514)
Other utility plant reserves	3,038	2,425	(76)	--	--	5,387
Subtotal	6,339,148	767,277	(914,382)	337,218	14,425	6,543,686
Nuclear fuel amortization	726,327	109,266	(182,978)	38	--	652,653
Total utility plant reserves	$7,065,475	$876,543	$(1,097,360)	$337,256	$14,425	$7,196,339
Nonutility property reserves	$ 43,994	$ 11,402	$ (1,947)	$ (2,971)	$ --	$ 50,478

(a) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

(b) Reflects removal from service of nuclear generating plant under an agreement reached with the California Public Utilities Commission.

SCEcorp

SCHEDULE VI -- ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

For the Year Ended December 31, 1991

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Charges(a)	Add (Deduct) Salvage	Balance at End of Period
			(In thousands)			
Steam production	$1,217,709	$ 88,644	$(5,112)	$ (778)	$ 550	$1,301,013
Nuclear production	1,607,984	324,610	(3,508)	(3,050)	52	1,926,088
Hydro production	135,630	8,754	(387)	(240)	40	143,797
Other production	222,660	12,554	(6,365)	(109)	--	228,740
Transmission	724,070	76,608	(10,686)	(2,606)	3,291	790,677
Distribution	1,601,611	190,922	(61,709)	(27,789)	9,540	1,712,575
General	219,110	51,831	(21,809)	4,981	422	254,535
Experimental electric plant unclassified	11,003	8,272	--	--	--	19,275
Retirement work in progress	(46,557)	--	14,426	(8,239)	(220)	(40,590)
Other utility plant reserves	2,863	213	(39)	1	--	3,038
Subtotal	5,696,083	762,408	(95,189)	(37,829)	13,675	6,339,148
Nuclear fuel amortization	725,989	131,355	(131,017)	--	--	726,327
Total utility plant reserves	$6,422,072	$893,763	$(226,206)	$(37,829)	$13,675	$7,065,475
Nonutility property reserves(b)	$ 39,992	$ 8,493	$ (2,653)	$ (1,838)	$ --	$ 43,994

(a) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

(b) Restated to include consolidated statements from affiliates.

SCEcorp

SCHEDULE VII -- GUARANTEES OF SECURITIES OF OTHER ISSUERS

For the Year Ended December 31, 1993
(In Thousands)

Name of Issuer of securities guarantee by SCEcorp	Title of issue of each class of securities guaranteed	Total amount guaranteed and outstanding	Amount owned by Company	Amount in treasury of issuer of securities guaranteed	Nature of guarantee	Nature of any default by issuer of securities guaranteed in principal, interest, sinking fund redemption provisions, or payment of dividends
Ontario Lakeshore Partners	Construction Loan	$15,000	---	---	Principal and Interest	None
Centrelake Partners	Construction Loan	$5,000	---	---	Principal and Interest	None
Carol Stream Developers	Acquisition and Development Loan	$7,935	---	---	Principal and Interest	None

SCEcorp

SCHEDULE VIII -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1993

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Group A:					
Uncollectible accounts --					
Customers	$ 8,970	$ 38,314	$ 481	$ 31,374	$ 16,391
All other	32,572	12,772	(481)	3,321	41,542
Total	$ 41,542	$ 51,086	$ --	$ 34,695(a)	$ 57,933
Group B:					
Regulatory settlement	$113,380	$ 10,620	$ --	$124,000(b)	$ --
DOE Decontamination and Decommissioning	53,136	--	19,156(c)	5,164(d)	67,128
Pension and benefits	111,139	48,692	22,064(e)	50,131(f)	131,764
Insurance, casualty and other	64,019	51,843	--	48,159(g)	67,703
Total	$341,674	$111,155	$41,220	$227,454	$266,595

(a) Accounts written off, net.
(b) Represents final settlement with the California Public Utilities Commission's Division of Ratepayer Advocates regarding affiliated company power purchases.
(c) Represents new estimate based on actual billings.
(d) Represents amounts paid.
(e) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.
(f) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.
(g) Amounts charged to operations that were not covered by insurance.

SCEcorp

SCHEDULE VIII -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1992

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Group A:					
Uncollectible accounts ---					
Customers	$ 10,028	$ 23,041	$ ---	$ 24,099	$ 8,970
All other	11,934	25,846	---	5,208	32,572(a)
Total	$ 21,962	$ 48,887	$ ---	$ 29,307(b)	$ 41,542
Group B:					
Regulatory settlement	$ 124,000	$ ---	$ 9,320(c)	$ 19,940(d)	$ 113,380
DOE decontamination and decommissioning	---	---	53,136(e)	---	53,136
Environmental cleanup	40,000	---	5,000(e)	45,000(f)	---
Pension and benefits	112,007	30,905	20,562(g)	52,335(h)	111,139
Insurance, casualty and other	70,513	71,040	---	77,534(i)	64,019
Total	$ 346,520	$ 101,945	$ 88,018	$ 194,809	$ 341,674

(a) Includes reserve for net realizable value write-down.
(b) Accounts written off, net.
(c) Represents reserve addition for the settlement with the California Public Utilities Commission's Division of Ratepayer Advocates regarding affiliated company power purchases.
(d) Represents the amortization of the difference between the nominal value and the present value.
(e) Represents the estimated long-term costs to be incurred and recovered through rates over 15 years; reclassified from account 253.
(f) Represents an additional estimated liability established for environmental cleanup costs expected to be incurred and recovered through rates in future years.
(g) Amount reclassified to Account 253, other deferred credits.
(h) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.
(i) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.
(j) Amounts charged to operations that were not covered by insurance.

SCEcorp

SCHEDULE VIII -- VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1991

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
Group A:					
Uncollectible accounts ---					
Customers	$ 10,423	$ 22,533	$ ---	$ 22,928	$ 10,028
All other	7,814	9,358	---	5,238	11,934(a)
Total	$ 18,237	$ 31,891	$ ---	$ 28,166(b)	$ 21,962
Group B:					
Regulatory settlement	$ ---	$ 124,000(c)	$ ---	$ ---	$ 124,000
Environmental cleanup	---	---	40,000(d)	---	40,000
Pension and benefits	98,886	29,267	18,749(e)	34,895(f)	112,007
Insurance, casualty and other	61,620	63,901	---	55,008(g)	70,513
Total	$ 160,506	$ 217,168	$ 58,749	$ 89,903	$ 346,520

(a) Includes reserve for net realizable value write-down.
(b) Accounts written off, net.
(c) Represents reserve addition for a proposed settlement with the California Public Utilities Commission's Division of Ratepayer Advocates regarding affiliated company power purchases.
(d) Represents an estimated minimum liability established for environmental cleanup costs expected to be incurred and recovered through rates in future years.
(e) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.
(f) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.
(g) Amounts charged to operations that were not covered by insurance.

SCEcorp

SCHEDULE IX -- SHORT-TERM BORROWINGS

For Each of the Three Years in the Period Ended December 31, 1993

Description	Balance at End of Period	Weighted Average Interest Rate	Maximum Amount Outstanding During the Period	Average Amount Outstanding During the Period (a)	Weighted Average Interest Rate During the Period (b)
			(Dollars in thousands)		
December 31, 1993:					
Payable to holders of commercial paper--general purpose	$ 252,000	3.47%	$ 420,800	$ 201,800	3.36%
Payable to holders of commercial paper--balancing accounts	163,500	3.47	246,900	119,823	3.36
Payable to holders of commercial paper--fuel	269,600(c)	3.47	269,600	225,037	3.36
Payable to holders of commercial paper--leveraged leases	181,600(c)	3.40	181,600	181,600	6.92
Payable to bank--general purpose	22,250	10.37	209,781	120,321	7.91
Payable to unconsolidated subsidiary--fuel	---	---	31,000	28,367	3.90
December 31, 1992:					
Payable to holders of commercial paper--general purpose	$ 197,700	3.65%	$ 350,400	$ 87,000	4.03%
Payable to holders of commercial paper--balancing accounts	246,900	3.65	455,700	361,000	4.03
Payable to holders of commercial paper--fuel	228,300(c)	3.65	400,100	318,000	4.03
Payable to bank--leveraged leases .	181,600(c)	3.77	181,600	162,840	7.09
Payable to bank--general purpose	119,460	7.34	534,714	182,337	7.06
Payable to unconsolidated subsidiary--fuel	31,000	3.97	31,000	24,757	4.43
December 31, 1991:					
Payable to holders of commercial paper--general purpose	---	---	$ 461,900	$ 149,633	6.39%
Payable to holders of commercial paper--balancing accounts	$ 419,600	5.14%	506,700	476,000	6.36
Payable to holders of commercial paper--fuel	372,200(c)	5.14	436,100	397,000	6.36
Payable to holders of commercial paper--leveraged leases	181,600(c)	4.95	186,600	94,133	7.78
Payable to bank--general purpose	142,310	5.58	214,785	85,614	7.28
Payable to others--fuel	16,000	5.57	16,000	3,995	6.10

(a) Average amount outstanding during the period is computed by dividing the total of daily outstanding principal balances by 365.

(b) Weighted-average interest rate during the period is computed by dividing the total interest expense by the average amount outstanding.

(c) Under credit agreements with commercial banks which allow SCEcorp to refinance short-term borrowings on a long-term basis, borrowings of $252,000,000 as of December 31, 1993, $245,000,000 as of December 31, 1992, and $333,000,000 as of December 31, 1991, have been reclassified as long-term debt on the Consolidated Balance Sheet in the 1993 Annual Report.

SCEcorp

SCHEDULE X -- SUPPLEMENTARY INCOME STATEMENT INFORMATION

For Each of the Three Years in the Period Ended December 31, 1993

	Charged to Expense (In thousands)
Year ended December 31, 1993:	
Property taxes	$159,661
Year ended December 31, 1992:	
Property taxes	155,792
Year ended December 31, 1991:	
Property taxes	151,869

Note: Depreciation and maintenance expenses appear on the Consolidated Statements of Income. Royalties paid and advertising costs included in Other Operating Expenses are less than 1% of total operating revenue.

SCEcorp

SCHEDULE XIII -- OTHER INVESTMENTS

December 31, 1993
(In thousands)

Description	Number of shares or principal amount	Cost	Market value	Amount at which carried in balance sheet
Investments in nuclear decommissioning trusts:				
Qualified trust	--	$ 681,687	$ 732,314	$ 681,687
Non-qualified trust	--	106,888	121,028	106,888
		$ 788,575	$ 853,342	$ 788,575
Investments in partnerships and unconsolidated subsidiaries:				
Energy partnerships	--	$ 687,504	$ 669,346	$ 664,407
Real estate partnerships	--	260,073	260,073	218,543
Unconsolidated subsidiary	--	328,747	279,508	279,502
		$1,276,324	$1,208,927	$1,162,452
Investments in leveraged leases(a)	--	$ 354,449	$ 354,449	$ 497,469
Other investments	--	$ 20,577	$ 20,577	$ 20,577

(a) Market value is assumed to equal current unrecovered investment less deferred taxes.

SIGNATURES

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

SCEcorp

By W. J. Scilacci
(W. J. Scilacci,
Assistant Treasurer)

Date: March 17, 1994

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

Signature	Title	Date
Principal Executive Officer:		
John E. Bryson*	Chairman of the Board, Chief Executive Officer and Director	March 17, 1994
Principal Financial Officer:		
Alan J. Fohrer*	Senior Vice President, Treasurer and Chief Financial Officer	March 17, 1994
Controller or Principal Accounting Officer:		
Richard K. Bushey*	Vice President and Controller	March 17, 1994
Majority of Board of Directors:		
Howard P. Allen*	Director	March 17, 1994
Norman Barker, Jr.*	Director	March 17, 1994
Walter B. Gerken*	Director	March 17, 1994
Joan C. Hanley*	Director	March 17, 1994
Carl F. Huntsinger*	Director	March 17, 1994
Luis G. Nogales*	Director	March 17, 1994
J. J. Pinola*	Director	March 17, 1994
Henry T. Segerstrom*	Director	March 17, 1994
E. L. Shannon, Jr.*	Director	March 17, 1994
Daniel M. Tellep*	Director	March 17, 1994
James D. Watkins*	Director	March 17, 1994
Edward Zapanta*	Director	March 17, 1994

By W. J. Scilacci
(W. J. Scilacci, Attorney-in-Fact)

EXHIBIT INDEX

Exhibit Number	Description
3.1	Restated Articles of Incorporation as amended through April 25, 1988 (Registration No. 33-19541)* . . . .
3.2	Certificate of Amendment of Restated Articles of Incorporation of SCEcorp.(Registration No 33-37381)* . .
3.3	Bylaws as adopted by the Board of Directors on November 18, 1993 . . . .
4.1	Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)* . . . .
4.2	Supplemental Indenture, dated as of March 1,1927 (Registration No. 2-1369)* . . . .
4.3	Second Supplemental Indenture, dated as of April 25, 1935 (Registration No. 2-1472)* . . . .
4.4	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)* . . . .
4.5	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)* . . . .
4.6	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)* . . . .
4.7	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)* . . . .
4.8	Seventh Supplemental Indenture, dated as of January 15, 1948 (Registration No. 2-7369)* . . . .
4.9	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)* . . . .
4.10	Ninth Supplemental Indenture, dated as of February 15, 1951 (Registration No. 2-8781)* . . . .
4.11	Tenth Supplemental Indenture, dated as of August 15, 1951 (Registration No. 2-7968)* . . . .
4.12	Eleventh Supplemental Indenture, dated as of August 15, 1953 (Registration No. 2-10396)* . . . .
4.13	Twelfth Supplemental Indenture, dated as of August 15, 1954 (Registration No. 2-11049)* . . . .
4.14	Thirteenth Supplemental Indenture, dated as of April 15, 1956 (Registration No. 2-12341)* . . . .
4.15	Fourteenth Supplemental Indenture, dated as of February 15, 1957 (Registration No. 2-13030)* . . . .
4.16	Fifteenth Supplemental Indenture, dated as of July 1, 1957 (Registration No. 2-13418)* . . . .
4.17	Sixteenth Supplemental Indenture, dated as of August 15, 1957 (Registration No. 2-13516)* . . . .
4.18	Seventeenth Supplemental Indenture, dated as of August 15, 1958 (Registration No. 2-14285)* . . . .
4.19	Eighteenth Supplemental Indenture, dated as of January 15, 1960 (Registration No. 2-15906)* . . . .
4.20	Nineteenth Supplemental Indenture, dated as of August 15, 1960 (Registration No. 2-16820)* . . . .
4.21	Twentieth Supplemental Indenture, dated as of April 1, 1961 (Registration No. 2-17668)* . . . .
4.22	Twenty-First Supplemental Indenture, dated as of May 1, 1962 (Registration No. 2-20221)* . . . .
4.23	Twenty-Second Supplemental Indenture, dated as of October 15, 1962 (Registration No. 2-20791)* . . . . . .
4.24	Twenty-Third Supplemental Indenture, dated as of May 15, 1963 (Registration No. 2-21346)* . . . .

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Exhibit Number	Description
4.25	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)* . . . . . .
4.26	Twenty-Fifth Supplemental Indenture, dated as of February 1, 1965 (Registration No. 2-23082)* . . . . . .
4.27	Twenty-Sixth Supplemental Indenture, dated as of May 1, 1966 (Registration No. 2-24835)* . . . .
4.28	Twenty-Seventh Supplemental Indenture, dated as of August 15, 1966 (Registration No. 2-25314)* . . . .
4.29	Twenty-Eighth Supplemental Indenture, dated as of May 1, 1967 (Registration No. 2-26323)* . . . .
4.30	Twenty-Ninth Supplemental Indenture, dated as of February 1, 1968 (Registration No. 2-28000)* . . . . . .
4.31	Thirtieth Supplemental Indenture, dated as of January 15, 1969 (Registration No. 2-31044)* . . . .
4.32	Thirty-First Supplemental Indenture, dated as of October 1, 1969 (Registration No. 2-34839)* . . . .
4.33	Thirty-Second Supplemental Indenture, dated as of December 1, 1970 (Registration No. 2-38713)* . . . . . .
4.34	Thirty-Third Supplemental Indenture, dated as of September 15, 1971 (Registration No. 2-41527)* . . . . .
4.35	Thirty-Fourth Supplemental Indenture, dated as of August 15, 1972 (Registration No. 2-45046)* . . . .
4.36	Thirty-Fifth Supplemental Indenture, dated as of February 1, 1974 (Registration No. 2-50039)* . . . . . .
4.37	Thirty-Sixth Supplemental Indenture, dated as of July 1, 1974 (Registration No. 2-59199)* . . . .
4.38	Thirty-Seventh Supplemental Indenture, dated as of November 1, 1974 (Registration No. 2-52160)* . . . . . .
4.39	Thirty-Eighth Supplemental Indenture, dated as of March 1, 1975 (Registration No. 2-52776)* . . . .
4.40	Thirty-Ninth Supplemental Indenture, dated as of March 15, 1976 (Registration No. 2-55463)* . . . .
4.41	Fortieth Supplemental Indenture, dated as of July 1, 1977 (Registration No. 2-59199)* . . . .
4.42	Forty-First Supplemental Indenture, dated as of November 1, 1978 (Registration No. 2-62609)* . . . .
4.43	Forty-Second Supplemental Indenture, dated as of June 15, 1979 (File No.1-2313)* . . . .
4.44	Forty-Third Supplemental Indenture, dated as of September 15, 1979 (File No. 1-2313)* . . . .
4.45	Forty-Fourth Supplemental Indenture, dated as of October 1, 1979 (Registration No. 2-65493)* . . . .
4.46	Forty-Fifth Supplemental Indenture, dated as of April 1, 1980 (Registration No. 2-66896)* . . . .
4.47	Forty-Sixth Supplemental Indenture, dated as of November 15, 1980 (Registration No. 2-69609)* . . . . . .
4.48	Forty-Seventh Supplemental Indenture, dated as of May 15, 1981 (Registration No. 2-71948)* . . . .
4.49	Forty-Eighth Supplemental Indenture, dated as of August 1, 1981 (File No. 1-2313)* . . . .

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Exhibit Number	Description
4.50	Forty-Ninth Supplemental Indenture, dated as of December 1, 1981 (Registration No. 2-74339)* . . . .
4.51	Fiftieth Supplemental Indenture, dated as of January 16, 1982 (File No. 1-2313)* . . . .
4.52	Fifty-First Supplemental Indenture, dated as of April 15, 1982 (Registration No. 2-76626)* . . . .
4.53	Fifty-Second Supplemental Indenture, dated as of November 1, 1982 (Registration No. 2-79672)* . . . . . .
4.54	Fifty-Third Supplemental Indenture, dated as of November 1, 1982 (File No. 1-2313)* . . . .
4.55	Fifty-Fourth Supplemental Indenture, dated as of January 1, 1983 (File No. 1-2313)* . . . .
4.56	Fifty-Fifth Supplemental Indenture, dated as of May 1, 1983 (File No. 1-2313)* . . . .
4.57	Fifty-Sixth Supplemental Indenture, dated as of December 1, 1984 (Registration No. 2-94512)* . . . .
4.58	Fifty-Seventh Supplemental Indenture, dated as of March 15, 1985 (Registration No. 2-96181)* . . . .
4.59	Fifty-Eighth Supplemental Indenture, dated as of October 1, 1985 (File No. 1-2313)* . . . .
4.60	Fifty-Ninth Supplemental Indenture, dated as of October 15, 1985 (File No. 1-2313)* . . . .
4.61	Sixtieth Supplemental Indenture, dated as of March 1, 1986 (File No. 1-2313)* . . . .
4.62	Sixty-First Supplemental Indenture, dated as of March 15, 1986 (File No. 1-2313)* . . . .
4.63	Sixty-Second Supplemental Indenture, dated as of April 15, 1986 (File No. 1-2313)* . . . .
4.64	Sixty-Third Supplemental Indenture, dated as of April 15, 1986 (File No. 1-2313)* . . . .
4.65	Sixty-Fourth Supplemental Indenture, dated as of July 1, 1986 (File No. 1-2313)* . . . .
4.66	Sixty-Fifth Supplemental Indenture, dated as of September 1, 1986 (File No. 1-2313)* . . . .
4.67	Sixty-Sixth Supplemental Indenture, dated as of September 1, 1986 (File No. 1-2313)* . . . .
4.68	Sixty-Seventh Supplemental Indenture, dated as of December 1, 1986 (File No. 1-2313)* . . . .
4.69	Sixty-Eighth Supplemental Indenture, dated as of July 1, 1987 (Registration No. 33-19541)* . . . .
4.70	Sixty-Ninth Supplemental Indenture, dated as of October 15, 1987 (Registration No. 33-19541)* . . . .
4.71	Seventieth Supplemental Indenture, dated as of November 1, 1987 (File No. 1-2313)* . . . .
4.72	Seventy-First Supplemental Indenture, dated as of February 15, 1988 (File No. 1-2313)* . . . .
4.73	Seventy-Second Supplemental Indenture, dated as of April 15, 1988 (File No. 1-2313)* . . . .
4.74	Seventy-Third Supplemental Indenture, dated as of July 1, 1988 (File No. 1-2313)* . . . .

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Exhibit Number	Description
4.75	Seventy-Fourth Supplemental Indenture, dated as of August 15, 1988 (File No. 1-2313)* . . . .
4.76	Seventy-Fifth Supplemental Indenture, dated as of September 15, 1988 (File No. 1-2313)* . . . .
4.77	Seventy-Sixth Supplemental Indenture, dated as of January 15, 1989 (File No. 1-2313)* . . . .
4.78	Seventy-Seventh Supplemental Indenture, dated as of May 1, 1990 (File No. 1-2313)* . . . .
4.79	Seventy-Eighth Supplemental Indenture, dated as of June 15, 1990 (File No. 1-2313)* . . . .
4.80	Seventy-Ninth Supplemental Indenture, dated as of August 15, 1990 (File No. 1-2313)* . . . .
4.81	Eightieth Supplemental Indenture, dated as of December 1, 1990 (File No. 1-2313)* . . . .
4.82	Eighty-First Supplemental Indenture, dated as of April 1, 1991 (File No. 1-2313)* . . . .
4.83	Eighty-Second Supplemental Indenture, dated as of May 1, 1991 (File No. 1-2313)* . . . .
4.84	Eighty-Third Supplemental Indenture, dated as of June 1, 1991 (File No. 1-2313)* . . . .
4.85	Eighty-Fourth Supplemental Indenture, dated as of December 1, 1991 (File No. 1-2313)* . . . .
4.86	Eighty-Fifth Supplemental Indenture, dated as of February 1, 1992 (File No. 1-2313)* . . . .
4.87	Eighty-Sixth Supplemental Indenture, dated as of April 1, 1992 (File No. 1-2313)* . . . .
4.88	Eighty-Seventh Supplemental Indenture, dated as of July 1, 1992 (File No. 1-2313)* . . . .
4.89	Eighty-Eight Supplemental Indenture, dated as of July 15, 1992 (File No. 1-2313)* . . . .
4.90	Eighty-Ninth Supplemental Indenture, dated as of December 1, 1992 (File No. 1-2313)* . . . .
4.91	Ninetieth Supplemental Indenture, dated as of January 15, 1993 (File No. 1-2313)* . . . .
4.92	Ninety-First Supplemental Indenture, dated as of March 1, 1993 (File No. 1-2313)*
4.93	Ninety-Second Supplemental Indenture, dated as of June 1, 1993
4.94	Ninety-Third Supplemental Indenture, dated as of June 15, 1993 (File No. 1-2313)*
4.95	Ninety-Fourth Supplemental Indenture, dated as of July 15, 1993 (File No. 1-2313)*
4.96	Ninety-Fifth Supplemental Indenture, dated as of September 1, 1993 (File No. 1-2313)* . . . .
4.97	Ninety-Sixth Supplemental Indenture, dated as of October 1, 1993 (File No. 1-2313)* . . . .
10.1	Executive Supplemental Benefit Program (File No. 1-2313)* . . . .
10.2	1981 Deferred Compensation Agreement (File No. 1-2313)* .
10.3	1985 Deferred Compensation Agreement for Executives (File No. 1-2313)* . . . .
10.4	1985 Deferred Compensation Agreement for Directors (File No. 1-2313)* . . . .
10.5	1987 Deferred Compensation Plan for Executives (File No. 1-2313)* . . . .

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Exhibit Number	Description
10.6	1987 Deferred Compensation Plan for Directors (File No. 1-2313)* . . . .
10.7	1988 Deferred Compensation Plan for Executives (File No. 1-2313)* . . . .
10.8	1988 Deferred Compensation Plan for Directors (File No. 1-2313)* . . . .
10.9	1989 Deferred Compensation Plan for Executives (File No. 1-9936)* . . . .
10.10	1989 Deferred Compensation Plan for Directors (File No. 1-9936)* . . . .
10.11	1990 Deferred Compensation Plan for Executives (File No. 1-9936)* . . . .
10.12	1990 Deferred Compensation Plan for Directors (File No. 1-9936)* . . . .
10.13	Annual Deferred Compensation Plan for Executives (File No. 1-9936)* . . . .
10.14	Annual Deferred Compensation Plan for Directors (File No. 1-9936)* . . . .
10.15	Executive Retirement Plan (File No. 1-2313)* . . . .
10.16	Employment Agreement with Jack K. Horton (File No. 1-2313)*
10.17	Employment Agreement with Howard P. Allen (File No. 1-2313)* . . . .
10.18	1991 Executive Incentive Compensation Plan (File No. 1-9936)*
10.19	1992 Executive Incentive Compensation Plan (File No. 1-9936)*
10.20	1993 Executive Incentive Compensation Plan . . . .
10.21	Retirement Plan for Directors (File No. 1-2313)* . . . . .
10.22	Long-Term Incentive Plan for Executive Officers (Registration No. 33-19541)* . . . .
10.23	Estate and Financial Planning Program for Executive Officers (File No. 1-9936)* . . . .
10.24	Consulting Agreement with Jack K. Horton (File No. 1-9936)*
10.25	Consulting Agreement with Howard P. Allen (File No. 1-9936)*
10.26	Consulting Agreement with Michael R. Peevey (File No. 1-9936)* . . . .
10.27	Resignation and General Release Agreement with Michael R. Peevey (File No. 1-9936)* . . . .
10.28	Employment Agreement with Bryant C. Danner (File No. 1-9936)* . . . .
10.29	Employment Agreement with Charles W. Johnson (File No. 1-9936)* . . . .
10.30	Resignation Agreement with Charles B. McCarthy, Jr. . . . .
11.	Computation of Primary and Fully Diluted Earnings Per Share
12.	Computation of Ratios of Earnings to Fixed Charges . . . .
13.	Selected portions of the Annual Report to Shareholders for year ended December 31, 1993 . . . .
21.	Subsidiaries of the Registrant . . . .
23.	Consent of Independent Public Accountants - Arthur Andersen & Co. . . . .
24.1	Power of Attorney . . . .
24.2	Certified copy of Resolution of Board of Directors Authorizing Signature . . . .

* Incorporated by reference pursuant to Rule 12b-32.