SAN ONOFRE
NUCLEAR GENERATING STATION
UNITS 2&3

AMENDMENT NO. 6
TO
APPLICANTS' ENVIRONMENTAL REPORT
OPERATING LICENSE STAGE

SOUTHERN CALIFORNIA EDISON COMPANY
SAN DIEGO GAS AND ELECTRIC COMPANY

INTRODUCTION

Amendment No. 6 to the Applicant's Environmental Report-Operating License Stage, for the San Onofre Nuclear Generating Station, Units 2 and 3, comprises insert pages that provide:

1. Changes to the text to update, correct, or clarify the discussion. These are indicated by a change bar and a number "6" in the margin, and "Amendment 6" at the bottom of the page. When an entire page has been revised, "Amendment 6" is footnoted on the page and the marginal notation is not provided. When an insert page has the same number as an existing page in the Environmental Report, the existing page has been superseded and should be deleted. When an insert page does not duplicate an existing page, the insert page is new and should be placed in its proper location in the Environmental Report.

2. Revisions to the proposed Environmental Technical Specifications (non-radiological) for San Onofre Nuclear Generating Station, Units 2 and 3. The proposed ETS program was revised to reduce regulatory overlap and is included as amended Appendix 6B.

AMENDMENT 6

LIST OF CHANGED PAGES

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Figure 3.4-1/3.4-2	Amended Figure 3.4-1/3.4-2
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1. INTRODUCTION

1.1 NEED FOR POWER FOR SOUTHERN CALIFORNIA EDISON COMPANY

The Southern California Edison Company (SCE) serves customers in 15 southern and central California counties. In 1975, SCE served 2.75 million customers in a territory of approximately 50,000 square miles, with a population in excess of 7.5 million. Residential customers totaled 2.44 million. From 1964 to 1975, SCE experienced average annual growth rates in area peak demands and area energy requirements of 5.7 and 5.5 6
percent, respectively.

The forecast of annual peak demand in the SCE area, reported in Table 1.1-1, shows an increase of 4700 MW between 1975 and 1985 6
which is an average annual growth rate of 3.8 percent. To reliably serve this increase in peak demand, an increase of approximately 3900 MW in installed capacity is required in the 6
1975 to 1985 period. The SCE 1760 MW share of SONGS Units 2 and 3 will provide approximately 45 percent of this increase. 6
Installation of SONGS Units 2 and 3 will also reduce SCE dependence on imported fuel oil supplies, and will provide needed additional base load capacity.

1.1.1 FORECAST OF THE NEED FOR POWER

Long-range SCE forecasts of energy and peak demand are its best predictions based upon the latest information available. In recent years, the forecasts have been reduced in response to significant changes in the social and economic environment in the SCE service territory, including reductions due to

Table 1.1-1 (Page 1 of 2)

SOUTHERN CALIFORNIA EDISON COMPANY

Year	Year End Population (Thousands)	1973 Forecast of Area (b) Peak Demand (Megawatts)	1978 Forecast of Area (b) Peak Demand (Megawatts)	1973 Forecast of Area Energy Require-ments(d) (10^6 kWhr)	1978 Forecast of Area Energy Require-ments(d) (10^6 kWhr)	1978 Planned Generation Capacity(c)(a) (Megawatts)	Generating Reserve(a) Margin(c) %
1955	4308		2454		14228	2778	13.2
1960	5406		3690		21136	4175	13.4
1965	6581		6034		33011	7088	17.5
1970	7244		8556		49422	11016	28.7
1971	7308		9817		52667	11483	17.0
1972	7375		10317		55784	12719	23.3
1973	7466		10535		57886	13400	27.2
1974	7571		10279		54900	13650	32.8
1975	7690	12217	10369	70664	54960	13736	32.8
1976	7817	13050	11315	75765	57902	13858	22.5
1977	7941	13903	11882	80812	62153	14264	20.0
1978	8062	14766	12159	86197	61681	14753	21.3
1979*	8186	15689	12393	91798	65254	14970	20.8
1980	8313	16683	12671	97618	67016	15017	18.5
1981	8441	17686	13173	103647	69164	15429	17.1
1982	8571	18718	13716	110127	71525	16255	18.5
1983	8704	19832	14091	116878	73380	16685	18.4
1984	8839	20956	14621	123425	76284	17144	17.3
1985	8974	22123	15071	130305	78672	17597	16.8
1986	9109	23301	15551	137259	81462	18189	17.0
1987	9242	24567	16051	143769	83682	18818	17.2
1988	9372	25883	16551	151301	85755	19598	18.4
1989	9499	27270	17025	159320	88655	20018	17.6
1990	9622	28687	17509	167458	91680	20595	17.6

*Years preceding asterisked year reflect actual recorded data.

Table 1.1-1 (Page 2 of 2)

Year	Year End Population	1973 Forecast of Area (b) Peak Demand	1978 Forecast of Area (b) Peak Demand	1973 Forecast of Area Energy Requirements(d)	1978 Forecast of Area Energy Requirements(d)
	Average Annual Compound Growth Rates (%) (e)				
1960-65	4.0		10.3		9.3
1965-70	1.9		7.2		8.4
1970-75	1.2		3.9		2.1
1975-80	1.6	6.4	4.1	6.7	4.1
1980-85	1.5	5.8	3.5	5.9	3.3
1985-90	1.4	5.3	3.0	5.2	3.1

(a) Based on recorded data in years 1955-1977 and on 1978 forecast figures for years 1978-1990.

(b) Area demand = Edison's net main system demand, total MWD demand and other contractual obligations.

(c) At time of area peak demand.

(d) Area energy requirements = Edison net main system, total MWD transmitted, and other contractual obligations.

(e) Recorded data in years 1955-1977.

conservation, higher energy prices and load management. For example, the forecast of average annual growth rate for the SCE main system peak demand made in 1973 for the period 1975 to 1985 was 6.2 percent (Table 1.1.-1). This compares to 3.8 6
percent currently forecast for the same period, resulting in a reduction of 6,800 MW in the 1985 peak demand forecast. 6

1.1.1.1 Methods of Forecasting

The major variables which determine the growth of electric energy consumption and peak demands in the SCE service territory, and which are used by SCE in its forecasting methodology, are population, economic indicators, conservation and higher energy prices, and weather. Energy forecasts are made for the following customer classes: residential, industrial, commercial, agricultural, other public authorities, and resale. The forecasts are based on the relationships between the energy sales by customer class and the casual economic and demographic variables. In the development of the residential energy sales forecasting equation, historical data 6
is normalized for average weather conditions.

The impact of conservation and energy prices is incorporated in the sales forecast by an adjustment based on elasticity coefficients and projections of energy prices. Energy data is normalized for weather in developing price and cross elasticity 6
coefficients for the residential customer class.

Peak demand is forecast by analyzing weather sensitive demand and non-weather sensitive (or base) demand. The weather sensitive demand is related to maximum daily temperatures in nine weather areas representing the SCE service territory, population by weather areas, the number of residential and commercial customers, saturation of residential and commercial air conditioners, and the temperature sensitivity of an average air conditioner. The base demand is related to energy sales and economic variables through linear regression. The effects of conservation and energy prices are also incorporated in the peak demand forecast.

1.1.1.2 Impact of Conservation on Forecasts

Table 1.1-2 compares the SCE main system monthly peak demands and energy requirements from October 1972 to June 1976 with the experience in corresponding months in the preceding year. The comparison illustrates the reductions due to the oil embargo in the latter part of 1973, to energy conservation, to higher energy prices, to an economic recession, and to varying weather conditions.

Reductions due to conservation were the result of the California Public Utilities Commission orders on November 13, 1973, January 3, 1974, and May 15, 1974, SCE conservation programs, as discussed in Section 1.1.1.3, and an increased 6
awareness of the energy crisis by the general public. Higher electricity prices in 1974 were primarily the result of rapid

increases in the price of oil. The SCE average oil cost for electric power generation requirements had increased from $2 per barrel in 1967 to $6 per barrel in early 1973. Since November 1973, the average cost of oil increased from $8 per barrel to $15 per barrel of oil purchased in September 1974.

Conservation and energy prices have significantly reduced the present forecast in Table 1.1-1 from pre-embargo forecasts. For example, the forecast of the 1985 area peak demand made in 1973 was 22,123 MW compared to the present forecast of 15,071 MW; this results in a reduction of 7,052 MW or 31.9 percent. 6

Table 1.1-2 also shows significant increases in peak demand and energy transmitted in the first half of 1976. This represents a combination of economic recovery and growth plus an early summer heat spell in June 1976.

1.1.1.3 Energy Conservation Programs

SCE energy conservation activities and public education programs, as reported to the Federal Power Commission in FPC Dkt. No. R-454, pursuant to FPC Order No. 495, issued November 13, 1973, are set forth in Appendix 1A.

1.1.1.4 Load Management

SCE currently is extensively involved in testing and implementing methods of reducing future peak demands through price incentives (time-of-day and interruptible rates) and direct utility control of customer loads (air conditioning and

electric water heaters). The forecast peak demands listed in
Table 1.1-1 include reductions attributed to load management
beginning with 356 MW in 1980 and reaching 746 MW by 1990. 6

1.1.2 LOAD CHARACTERISTICS

Annual peak demand and energy requirements for the SCE area are
shown in Table 1.1-1. Area peak demand has grown at a rate of
5.6 percent per year from 1965 to 1975, and is forecast to grow 6
at 3.8 percent per year between 1975 and 1985. By 1985 it is
expected that the SCE demand will be growing at a rate of more
than 500 MW per year. The projected growth rates, which are 6
lower than the historical growth rates, reflect the long term
effects of anticipated slower growth of population and economic
activity, continuing energy conservation, and higher energy
prices.

SCE is a summer peaking utility due to the extensive use of air
conditioning within the service territory. Since the oil
embargo of 1973, the effect of energy conservation has been to
reduce energy sales more than peak demand, resulting in lower
system load factors. This trend is expected to continue until
partially offset in the long run by more efficient air
conditioners, increased use of building insulation and load
management impacts. The SCE main system load factor is
forecast to decline from 60.3 percent in 1975 to 57.1 percent
in 1978, and then gradually recover to approximately 59.2 6
percent after 1990.

1.1.3 POWER SUPPLY

SCE system capabilities at the time of expected annual peak demand are shown in Table 1.1-1 for the years 1955 through 1990. The planned generation resource additions shown in the table were scheduled based on the SCE system load forecast shown in that same table.

Table 1.1-3 lists all the existing generation resources as of June 1, 1976 in the Southern California Edison area. The 13,859 MW net effective capacity shown includes reductions for losses outside the Edison system and derating assuming adverse year hydro conditions.

The resources shown in SCE's 1976-1990 resource plan (Table 1.1-4) are required to reliably serve the forecast load as discussed in Section 1.1.4.

The SCE need for SONGS Units 2 and 3 is based on a need for base load capacity, a desire to reduce dependence upon foreign oil, and a need for additional generating capacity to serve load growth. SONGS Units 2 and 3 is the most economical generation resource alternative to satisfy these three requirements.

Table 1.1-3 (Sheet 7 of 11)

SOUTHERN CALIFORNIA EDISON COMPANY DESCRIPTION OF RESOURCES

Plant Name	Location, County(a)	Unit No.	Year in Operation	Loading Category(b)	Energy Source(c)	Effective Operating Capacity(kW)
Thermal Plants.						
Long Beach No. 3	Los Angeles	8CC	1976			280,000
		9CC	1977			210,000
		10	1928			106,000
		11	1930			50,000
	Total Plant			S	O/G	646,000
Redondo	Los Angeles	1	1948			74,000
		2	1948			74,000
		3	1948			70,000
		4	1949			74,000
		5	1954			175,000
		6	1957			175,000
	Total Plant			S	O/G	642,000
	Los Angeles	7	1967			480,000
		8	1967			480,000
	Total Plant			I	O/G	960,000
Highgrove	San Bernardino	1	1952			32,500
		2	1952			32,500
		3	1953			44,500
		4	1955			44,500
	Total Plant			S	O/G	154,000
Etiwanda	San Bernardino	1	1953	S		132,000
		2	1953	S		132,000
		3	1963	I		320,000
		4	1963	I		320,000
	Subtotal				O/G	904,000
	San Bernardino	5CT	1969	P	O/G	121,000
	Total Plant					1,025,000

Table 1.1-3 (Sheet 8 of 11)

SOUTHERN CALIFORNIA EDISON COMPANY DESCRIPTION OF RESOURCES

Plant Name	Location, County[(a)]	Unit No.	Year in Operation	Loading Category[(b)]	Energy Source[(c)]	Effective Operating Capacity (kW)
Thermal Plants (cont'd):						
El Segundo	Los Angeles	1	1955	S		175,000
		2	1956	S		175,000
		3	1964	I		335,000
		4	1965	I		335,000
	Total Plant				O/G	1,020,000
Alamitos	Los Angeles	1	1956	S		175,000
		2	1957	S		175,000
		3	1961	I		320,000
		4	1962	I		320,000
		5	1966	I		480,000
		6	1966	I		480,000
	Subtotal				O/G	1,950,000
	Los Angeles	7CT	1969	P	O/G	121,000
	Total Plant					2,071,000
San Bernardino	San Bernardino	1	1957			63,000
		2	1958			63,000
	Total Plant			S	O/G	126,000
Huntington Beach	Orange	1	1958			215,000
		2	1958			215,000
		3	1961			215,000
		4	1961			225,000
	Subtotal			I	O/G	870,000
	Orange	5CT	1969	P	O/G	121,000
	Total Plant					991,000

Table 1.1-3 (Sheet 9 of 11)

SOUTHERN CALIFORNIA EDISON COMPANY DESCRIPTION OF RESOURCES

Plant Name	Location, County[a]	Unit No.	Year in Operation	Loading Category[b]	Energy Source[c]	Effective Operating Capacity(kW)
Mandalay	Ventura	1	1959	I	O/G	215,000
		2	1959	I	O/G	215,000
		3CT	1970	P	O/G	121,000
	Total Plant					551,000
Cool Water	San Bernardino	1	1961			65,000
		2	1964			81,000
		3CC	1978			180,000
		4CC	1978			180,000
	Total Plant			S	O/G	506,000
Garden State	Los Angeles	1CT	1967	I	O/G	12,000
San Onofre (Nuclear) (Edison - 80%)	San Diego	1	1968	B	N	348,800
Four Corners (Edison - 48%)	San Juan, N.M.	4	1969			384,000
		5	1970			384,000
	Total Plant			B	C	768,000
Mohave (Edison - 56%)	Clark Co., Nevada	1	1971			442,400
		2	1971			442,400
	Total Plant			B	C	884,800
Ormond Beach	Ventura	1	1971			750,000
		2	1973			750,000
	Total Plant			I	O/G	1,500,000
Ellwood	Santa Barbara	1CT	1974	P	O/G	54,000
TOTAL THERMAL PLANTS						12,259,600

Table 1.1-3 (Sheet 10 of 11)

SOUTHERN CALIFORNIA EDISON COMPANY DESCRIPTION OF RESOURCES

Plant Name	Location, County(a)	Unit No.	Year in Operation	Loading Category(b)	Energy Source(c)	Effective Operating Capacity(kW)
FIRM PURCHASES						
Hoover Plant (leased)	Mohave-Arizona	A-5	1943			100,000
	Mohave-Arizona	A-6	1939			100,000
	Mohave-Arizona	A-7	1939			100,000
	Mohave-Arizona	A-8	1937			50,000
	Total Plant (Edison Operated)			P	H	350,000
BPA Exchange Power			1970	P	H	550,000
Oroville-Thermalito Power			1969	P	H	340,000
Navajo Project Layoff			1974	B	C	327,503
PGE Assignment Agreement			1975	P		100,000
APPA Sale			1978	P	H	-18,337
Total Firm Purchases						1,649,166
Total Main System Resources						14,776 MW
less adverse-year derate of Edison owned, leased, or purchased hydro						-210
less off-system losses						-83
plus Metropolitan Water District hydro resources						354
less adverse-year derate of MWD hydro						-15
Net Existing Area Resources in Generation Capacity Planning (as of January 24, 1980)						14,822 MW

Table 1.1-3 (Sheet 11 of 11)

SOUTHERN CALIFORNIA EDISON COMPANY DESCRIPTION OF RESOURCES

Plant Name	Location, County(a)	Unit No.	Year in Operation	Loading Category(b)	Energy Source(c)	Effective Operating Capacity(kW)
ISOLATED SYSTEMS						
Yuma Axis (Steam) (Edison - 33.3%)	Yuma, Arizona	1	1959	S	O/G	25,000
Yuma Axis (Combustion Turbine)	Yuma, Arizona	2 CT	1978	S	O/G	21,600
Pebbly Beach	Catalina (Los Angeles)	7	1958			1,000
		8	1963			1,500
		10	1966			1,125
		11	1973			1,000
		12	1976			1,575
	Total Plant			B	O/G	6,200
USBR Parker-Davis (Transfer)	Blythe, California			P	H	18,500
	TOTAL ISOLATED SYSTEMS					71,300

Table 1.1-4
Southern California Edison Company
Generating Capacity Additions
(Sheet 1 of 5)

Date	Resource Addition	Location	Loading Category	Energy Source	Effective Operating Capacity (MW)
	Aggregate System Capacity as of September 1, 1978				14753 (1)
6-1-79	Cool Water 3 and 4 Rerate	Daggett, California	Intermediate	Oil/Gas	108.
6-1-79	Long Beach 8 Combined Cycle	Long Beach, California	Semi-peaking	Oil/Gas	31. (3)
6-1-79	Long Beach 9 Combined Cycle	Long Beach, California	Semi-peaking	Oil/Gas	22. (3)
7-1-79	Recondition Long Beach 11	Long Beach, California	Semi-peaking	Oil/Gas	56. (5)
	System Capacity at Time of 1979 Peak				14970.
1-1-80	Increase Sale to APPA				-2. (6)
3-1-80	Big Creek 3 Unit 5	Big Creek, California	Peaking	Hydro	31.
4-1-80	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-4. (8)
6-1-80	Decrease Sale to APPA				1. (6)
6-1-80	Cogeneration				24. (4)
7-1-80	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-3. (8)
	System Capacity at Time of 1980 Peak				15017.
10-1-80	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-14. (8)
10-1-80	San Onofre 2	San Clemente, California		Nuclear	176. (9)
1-1-81	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-6. (8)
4-1-81	Decrease Sale to APPA				1. (6)
4-1-81	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-12. (8)

Table 1.1-4
Southern California Edison Company
Generating Capacity Additions
(Sheet 2 of 5)

Date	Resource Addition	Location	Loading Category	Energy Source	Effective Operating Capacity (MW)
4-1-81	Edwards AFB Exchange	Blythe, California	Intermediate	System Exchange	18.(10)
4-1-81	Interconnect Axis Generation with Main System	Yuma, Arizona	Peaking	Oil/Gas	47.(11)
6-1-81	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
6-1-81	PGE Exchange		Peaking	System Exchange	212.(12)
7-1-81	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-14. (8)
	System Peak at Time of 1981 Peak				15429.
10-1-81	Decrease Navajo Layoff	Page, Arizona	Base	Coal	-3 .(8)
10-1-81	Rerate San Onofre 2	San Clemente, California	Base	Nuclear	704. (9)
10-1-81	Terminate PGE Exchange	-	Peaking	System Exchange	-212.(12)
1-1-82	Increase Sale to APPA				-16. (6)
1-1-82	San Onofre 3	San Clemente, California	Base	Nuclear	176. (9)
5-1-82	Palo Verde 1	Wintersburg, Arizona	Base	Nuclear	187.(14)
6-1-82	Derate Four Corners 4 and 5	Four Corners, New Mexico		Coal	-14.(15)
6-1-82	Cogeneration	Unsited	Base	Oil/Gas	4.(15)
	System Peak at Time of 1982 Peak				16255.
1-1-83	Rerate San Onofre 3	San Clemente, California	Base	Nuclear	704. (9)
4-1-83	Terminate Oroville-Thermalito		Peaking	Hydro	-326.(16)

Table 1.1-4
Southern California Edison Company
Generating Capacity Additions
(Sheet 3 of 5)

Date	Resource Addition	Location	Loading Category	Energy Source	Effective Operating Capacity (MW)
4-1-83	Dry Year Derate Adjustment to Remove Oroville		Peaking	Hydro	20.(16)
6-1-83	Wind 1	Unsited	Peaking	Wind	1. (2)
6-1-83	Cogeneration	Unsited	Base	Oil/Gas	5. (4)
7-1-83	Fuel Cell 1	Unsited	Semi-peaking	Oil/Gas	26.(17)
	System Peak at Time of 1983 Peak				16685.
5-1-84	Northwest Diversity Exchange		Peaking	System Exchange	259.(18)
5-1-84	Palo Verde 2	Wintersburg, Arizona	Base	Nuclear	187.(14)
6-1-84	Geothermal 1-Brawley	Brawley, California	Base	Geothermal Steam	9.7
6-1-84	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
	System Peak at Time of 1984 Peak				17144.
1-1-85	End Sale to APPA				32. (6)
1-1-85	Terminate Navajo Layoff	Page, Arizona	Base	Coal	-263. (8)
6-1-85	Combined Cycle Project	Unsited	Intermediate	Oil/Gas	540.(19)
6-1-85	Balsam Meadow	Big Creek, California	Peaking	Hydro	140.(20)
6-1-85	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
	System Peak at Time of 1985 Peak				17597.
3-31-86	Terminate Edwards AFC Exchange		Peaking	System Exchange	-18.(10)

Table 1.1-4
Southern California Edison Company
Generating Capacity Additions
(Sheet 4 of 5)

Date	Resource Addition	Location	Loading Category	Energy Source	Effective Operating Capacity (MW)
5-1-86	Fuel Cells 2 and 3	Unsited	Semi-peaking	Oil/Gas	52.(17)
5-1-86	Palo Verde 3	Wintersburg, California	Base	Nuclear	188.(14)
6-1-86	Wind 2	Unsited	Peaking	Wind	2. (2)
6-1-86	Combined Cycle Project	Unsited	Intermediate	Oil/Gas	310.(19)
6-1-86	Geothermal 2-Niland	Niland, California	Base	Geothermal Steam	9. (7)
6-1-86	Geothermal 3-Heber	Heber, California	Base	Geothermal Steam	45. (7)
6-1-86	Cogeneration	Unsited	Base	Out/Gas	4. (4)
	System Peak at Time of 1986 Peak				18189.
5-1-87	Fuel Cells 4 and 5	Unsited	Semi-peaking	Oil/Gas	52.(17)
6-1-87	Wind 3	Unsited	Peaking	Wind	5. (2)
6-1-87	Terminate Hoover			Hydro	-331.(22)
6-1-87	Dry Year Derate Adjustment to Remove Hoover			Hydro	54.(22)
6-1-87	Combined Cycle Project	Unsited	Intermediate	Oil/Gas	440.(19)
6-1-87	California Coal 1	Unsited	Base	Coal	250.(23)
6-1-87	Combustion Turbine	Unsited	Peaking	Oil/Gas	110.(24)
6-1-87	Geothermal 4	Unsited	Base	Geothermal Steam	45. (7)
6-1-87	Cogeneration	Unsited			4. (4)
	System Peak at 1987 Peak				18818.

Table 1.1-4
Southern California Edison Company
Generating Capacity Additions
(Sheet 5 of 5)

Date.	Resource Addition	Location	Loading Category	Energy Source	Effective Operating Capacity (MW)
8-1-87	Northwest Diversity Exchange		Peaking	System Exchange	517.(18)
8-1-87	Terminate BPA Exchange		Peaking	System Exchange	-517.(18)
5-1-88	Fuel Cells 6-9	Unsited	Semi-peaking	Oil/Gas	104.(17)
5-1-88	Palo Verde 4	Wintersburg, California	Base	Nuclear	412.(25)
6-1-88	Wind 4	Unsited	Peaking	Wind	10. (2)
6-1-88	California Coal 2	Unsited	Base	Coal	250.(23)
6-1-88	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
	System peak at Time of 1988 Peak				19598.
5-1-89	Fuel Cells 10-15	Unsited	Semi-peaking	Oil/Gas	156.(17)
6-1-89	Wind 5	Unsited	Peaking	Wind	10. (2)
6-1-89	California Coal 3	Unsited	Base	Coal	250.(23)
6-1-89	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
	System Peak at Time of 1989 Peak				20018.
5-1-90	Palo Verde 5	Wintersburg, California	Base	Nuclear	413.(25)
6-1-90	Wind 6	Unsited	Peaking	Wind	15. (2)
6-1-90	Combustion Turbine	Unsited	Peaking	Oil/Gas	55.(24)
6-1-90	Geothermal 5	Unsited	Base	Geothermal Steam	90. (7)
6-1-90	Cogeneration	Unsited	Base	Oil/Gas	4. (4)
	System peak at time of 1990 peak				20595.

TABLE 1.1-4
Southern California Edison Company
Generating Capacity Additions

Notes

1. Aggregate rated capacity is in accord with the January 1, 1979, revision of "Generator Ratings and Effective Operating Capacity of Resources," adjusted to include MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), and reduced by Edison, Hoover and Oroville-Thermalito dry year hydro derates.

2. A 3 MW demonstration wind unit is scheduled for June 1, 1979, near Devers Substation for testing. The rated capacity is based on a 40 mph wind speed with the firm capacity value of the unit estimated to be 1 MW. Contingent upon a successful demonstration, this unit is scheduled for firm commercial operation on June 1, 1983. All wind units are expected to yield a firm capacity value of 1/3 of their nameplate ratings. Construction of units in 1986-1998 is contingent upon successful research and development and competitive costs.

3. Long Beach 8 and 9 Combined Cycle units are currently rated at 280 MW and 210 MW, respectively. Dependent upon field performance tests, on June 1, 1979 they are expected to be rerated at 311 MW and 232 MW, respectively (total = 543 MW), which is an additional 31 MW and 22 MW increase for Units 8 and 9, respectively.

4. Firm co-generation capacity as estimated in the May, 1978, Load Management Forecast has been added during the 1980-1998 time period. For planning purposes, integration with the system is shown to commence on June 1 of each year. Existing cogeneration (12 MW) is shown in 1979. In addition, non-firm cogeneration, adjusted for diversity, has been deducted from the load forecast.

5. Prior to completion of reconditioning in 1979, Long Beach Unit 11 has been derated from 106 to 50 MW.

6. The Arizona Power Pooling Association (APPA) has executed an agreement with Edison, Arizona Public Service, Nevada Power and Tucson Gas and Electric to sell capacity and associated energy to APPA based on the availability and cost of Navajo Power from March 1, 1978, until termination of Navajo layoff to Edison. Edison's share of the capacity sale will range from 16.5 MW in 1978 to 33.4 MW in 1982.

7. Geothermal additions are scheduled as follows: a 9 MW demonstration unit located at Brawley in 1980; a 9 MW demonstration unit located at Niland in 1982; and a 45 MW commercial unit located at Heber in 1982. Assuming successful testing, these units will be released for firm operation after four years, and will contribute 9 MW of firm capacity in 1984, and 9 MW and 45 MW of firm capacity in 1986, respectively. Addition of future commercial geothermal units shown in the resource plan is contingent upon successful research and development and competitive costs.

8. A contract has been executed with the Western Area power Authority (WAPA) (formerly the U.S. Bureau of Reclamation) for layoff of power from the Navajo Project. At such time as WAPA needs this power for the Central Arizona Project, WAPA has the right to terminate this layoff, effective on or after January 1, 1980, upon at least five years' advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased to provide power for WAPA's desalination project (contingent upon execution of a letter agreement providing for staged withdrawal of layoff power) as follows:

Date	Total Withdrawal
4-1-80	4.3 MW
7-1-80	7.7 MW
10-1-80	21.4 MW
1-1-81	28.3 MW
4-1-81	40.5 MW
7-1-81	54.8 MW
10-1-81	57.4 MW

9. For planning reporting purposes, San Onofre Units 2 and 3 are considered a firm capacity resource at 20% of their full power rating (880 MW total SCE share each unit) starting one year prior to their respective full power firm operating dates of October 1, 1981, and January 1, 1983. The capacity shown is 80% of the Project, which includes Edison's share and the resale cities' potential share (Anaheim - 1.66% or 36.5 MW and Riverside - 1.79% or 39.4 MW of the total project).

10. Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually until March 31, 1986. The capacity is added to the Edison Main System in 1981 with the interconnection of the Blythe System.

11. The 22 MW Axis combustion turbine was released for firm operation on December 28, 1978, to serve the Blythe area load. Loads and resources of the Blythe Isolated System are interconnected with the Edison Main System in 1981.

12. A firm capacity exchange agreement was executed with Portland General Electric in October, 1978. Under this agreement, Edison provided 225 MW of firm capacity to PGE during the period October 15, 1978 through January 15, 1979. In exchange, during the period June 1, 1981 through September 30, 1981, PGE will provide 225 MW (212 MW after losses) of firm capacity to Edison.

13. A 10 MW solar-thermal demonstration unit is scheduled for operation on October 1, 1981. Because this is a jointly-owned, prototype unit with uncertain commercial operation, no firm capacity addition is assumed at any future date. Solar Units 1-5 in the 1994 to 1998 period (100 MW each) are contingent upon successful research and development and competitive costs.

14. Edison is participating in the three-unit, 3666 MW Palo Verde Nuclear Project in Arizona with a 15.8% share (562 MW after off-system losses). Firm operating dates are scheduled for May 1, 1982; May 1, 1984; and May 1, 1986.

The project is allocated as follows:

	Participation Percentage
Arizona Public Service Company	29.1
Salt River Project	23.4*
El Paso Electric Company	15.8
Southern California Edison Company	15.8
Public Service Company of New Mexico	10.2
Los Angeles Department of Water & Power	5.7*
TOTAL	100.0

*SRP's current share is 29.1%. Upon the date of commercial operation of Palo Verde Unit 1, 5.7% of SRP's entitlement will be transferred to LADWP in exchange for LADWP's share of Coronado Units 1 and 2.

15. Additional air pollution control equipment is required for Four Corners Units 4 and 5 by January 1, 1983, to comply with the November, 1977, ruling of the Environment Improvement Board of the State of New Mexico. This is expected to result in a capacity reduction of approximately 15 MW per unit (SCE's share is 7 MW per unit). For planning purposes, these reductions are shown to commence on June 1, 1982.

16. Edison has been notified by the California Department of Water Resources (CDWR), that, on April 1, 1983, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility will be terminated. The Edison capacity allocation of 340 MW is adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions. Concurrent with the termination of the capacity assignment, it is assumed that Edison's load obligation to CDWR will terminate.

17. In March, 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1983-1989 is contingent upon both competitive costs and successful validation of a demonstrator unit.

18. A seasonal diversity exchange of 275 MW capacity commencing on May 1, 1984, is being discussed with the Pacific Northwest. To replace the 550 MW capacity/energy exchange with Bonneville Power Authority, which terminates on

August 1, 1987, an additional seasonal diversity exchange is also being discussed. The effect of these seasonal diversity exchanges on Edison's resources is equivalent to a capacity purchase in the summer (May 1 through October 31) and a capacity sale in the winter. Exchange amounts have been adjusted for Edison's net loss obligations.

19. The capacities shown are for the proposed 1290 MW Combined Cycle Project (Lucerne Valley site assumed for evaluation). Combustion turbines are installed prior to integrated combined cycle operation, which will commence as soon as respective steam turbine components are in service. Combustion turbines are alternatives to the combined cycle units.

20. It is planned to construct a new 140 MW hydro facility at Balsam Meadow (in the Big Creek area) in 1985.

21. Edison is evaluating participation in the proposed 2500 MW Harry Allen-Warner Valley Project. Edison could receive up to 1045 MW of firm capacity from the project in the 1984-88 period. Participation in this project could potentially replace other planned capacity additions in this period.

22. Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U.S. Department of Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW. MWD's Hoover capacity (261 MW) is assumed to continue.

23. Edison is planning to construct the 3-500 MW unit California Coal Project in Southern California (Edison share 50%). Five potential sites have been identified. Participation in the project is currently being determined.

24. Specific sites for 1980 MW of combustion turbines in the 1987-1998 time frame have not been determined.

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1.1.3.1 Need for Base Load Capacity

Characteristics of base load generation are operation at or near full capacity during all hours that the generating unit is available, and low energy costs per kilowatthour generated. SCE-owned base load resources include nuclear and coal generating units as well as some hydroelectric generating units. The proportion of total installed capacity required by an electric utility to be base load is dependent on the magnitude and ratio of the fixed and variable costs of specific resources; the type, age and condition of individual units; operating constraints applicable to each unit; characteristics of the system load pattern; and the interactions of the particular units within the system. As shown in the SCE load duration curve, Figure 1.1-1, approximately 40 percent of annual peak load is continuously demanded throughout the year. Based on this information and an evaluation of the other determining factors discussed above, base load capacity of approximately 40 to 50 percent of the total system capacity is considered desirable for the SCE system.

By the end of 1979, less than 19 percent of installed SCE 6
capacity will consist of base load resources. Thus, in order to serve the remaining base load, SCE must utilize production from oil and gas consuming resources. Although present resource expansion plans call for installation of several nuclear and coal plants, due to lead times of between 10 and 14 years, none of these resources can be installed prior to

1980. With the completion of San Onofre 2 & 3 by 1983 and Palo Verde 1, 2 & 3 by 1986, the proportion of base load capacity in 1986 will still be under 25 percent of system capacity, of which 9 percent will be supplied by the SCE share of SONGS Units 2 and 3.

1.1.3.2 Reduced Dependence on Fuel Oil

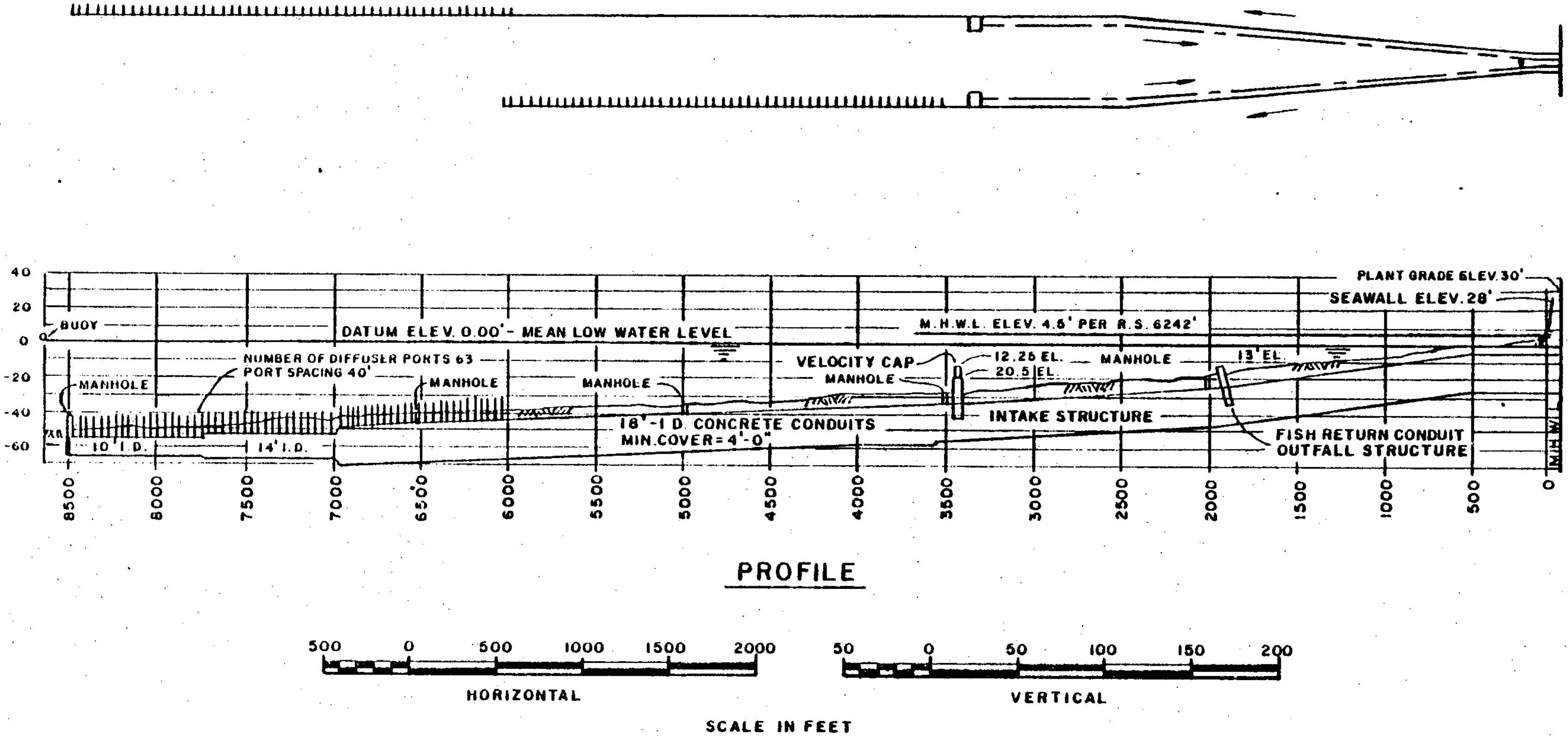
In 1976, the SCE fuel oil requirement is expected to exceed 48 million barrels. By the end of 1983, dependence upon fuel oil is expected to increase to an estimated 66 million barrels, even with Edison's 1760 MW share of San Onofre Units 2 and 3. Unless energy is obtained from non-oil consuming sources, dependence upon oil will continue to increase. Edison's 80% share of SONGS Units 2 and 3 will reduce fuel oil consumption by about 19 million barrels per year.

1.1.4 CAPACITY REQUIREMENTS

For each of the years of the future generation resource expansion plan, sufficient capacity must be installed to provide reliable electric service. (Installed capacity is equal to company owned generation, plus firm purchases, less off-system losses). For the SCE system, the following reliability criteria are used to develop and evaluate resource plans. Satisfaction of all three criteria is deemed necessary to provide reliable service to SCE customers:

A. an objective of installed capacity reserve margin of 18 ± 2 percent of annual peak demand, 6

B. minimum installed capacity reserve margin, after

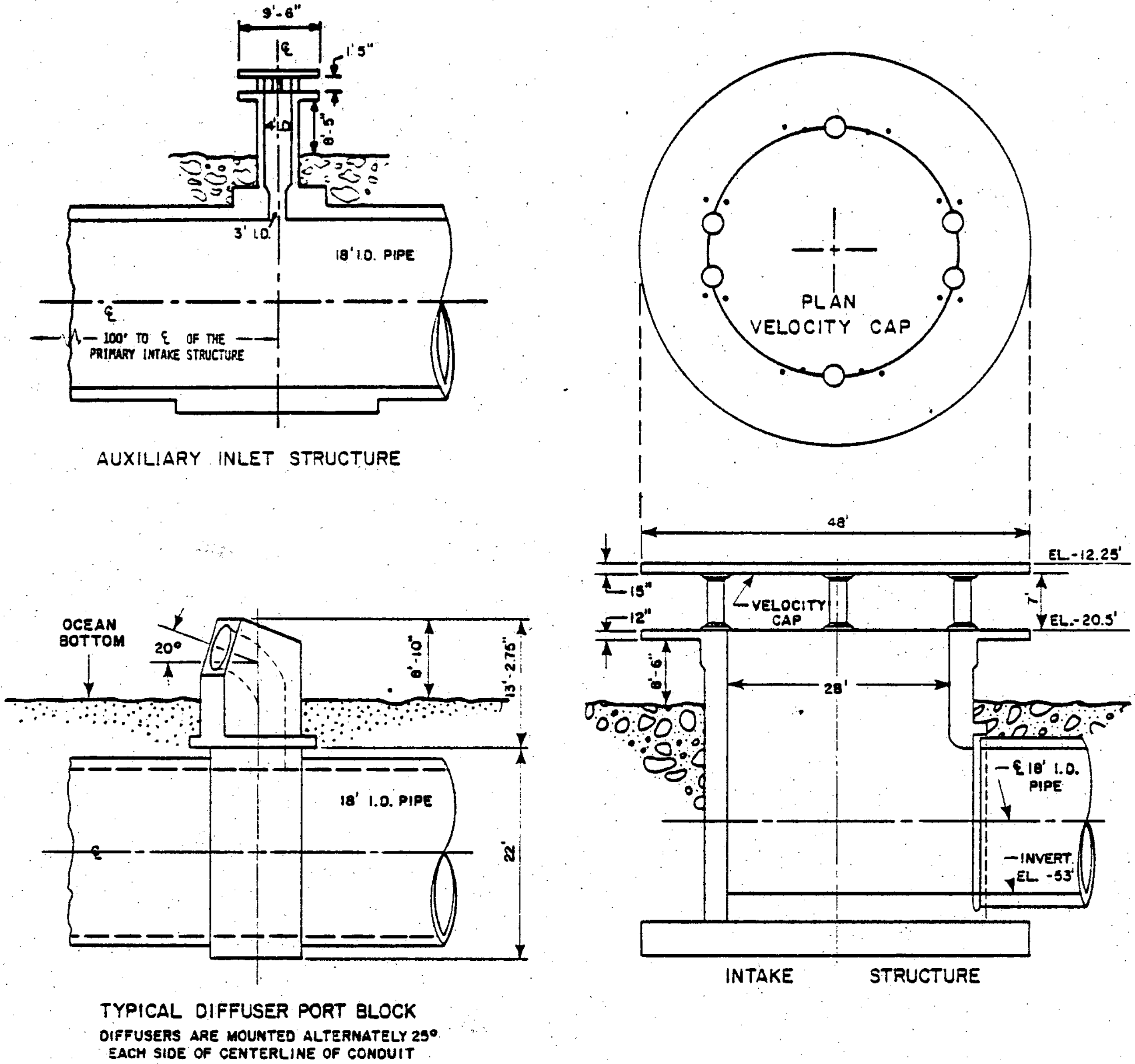


SAN ONOFRE
NUCLEAR GENERATING STATION
Units 2 & 3

PLAN AND PROFILE OF
OFFSHORE CONDUIT SYSTEM

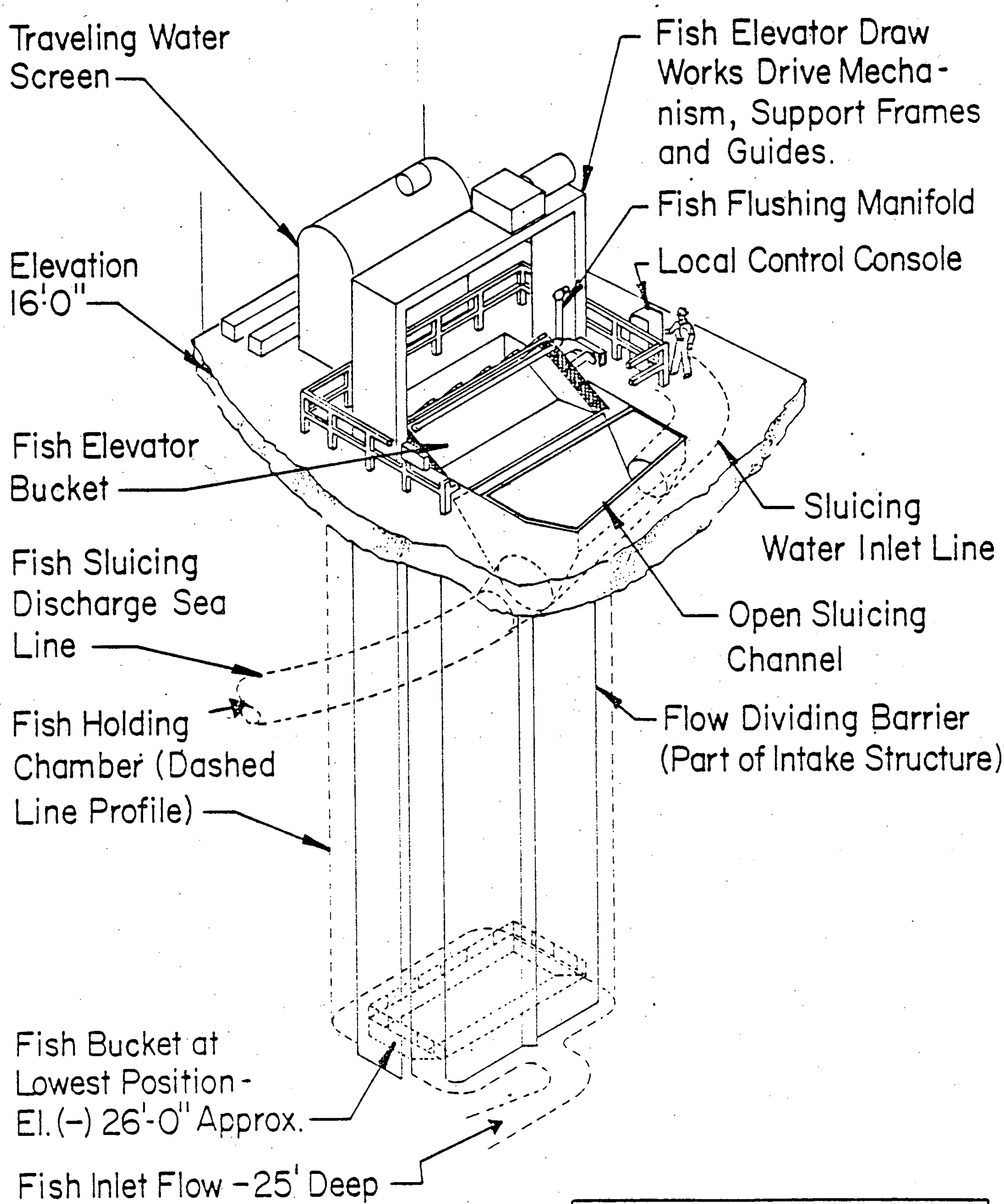
ER-OLS Figure 3.4-1

AMENDMENT 2



SECTIONS OF TERMINAL STRUCTURES

SAN ONOFRE NUCLEAR GENERATING STATION Units 2 & 3
OFFSHORE CONDUIT SYSTEM TERMINAL STRUCTURES
ER-OLS Figure 3.4-2

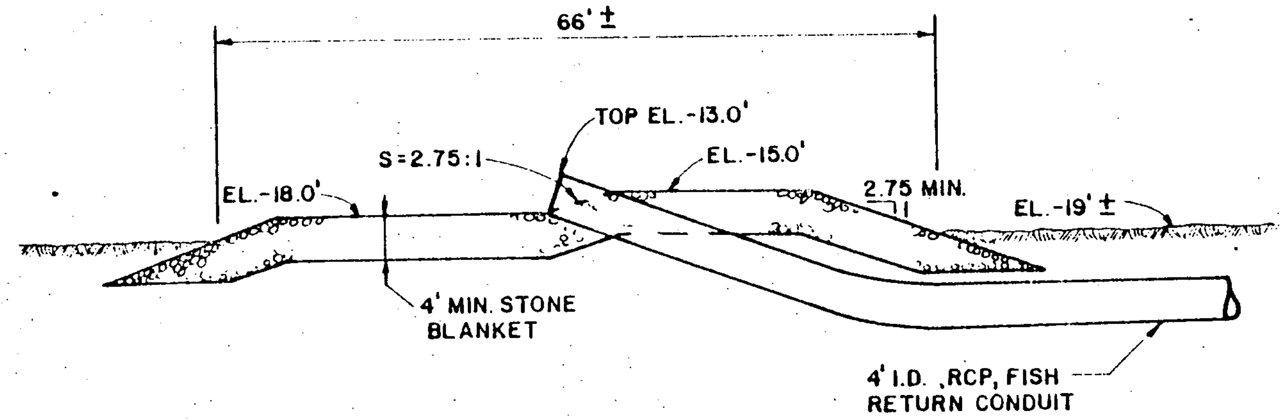


SAN ONOFRE
NUCLEAR GENERATING STATION
Units 2 & 3

FISH REMOVAL ELEVATOR AND SLUICING CHANNEL

ER-OLS Figure 3.4-5

AMENDMENT 6



FISH OUTFALL STRUCTURE

SAN ONOFRE
NUCLEAR GENERATING STATION
Units 2 & 3

FISH RETURN LINE
DISCHARGE STRUCTURE

ER-OLS Figure 3.4-6

6. EFFLUENT AND ENVIRONMENTAL MEASUREMENTS AND MONITORING PROGRAMS

6.1 PREOPERATIONAL ENVIRONMENTAL MONITORING PROGRAMS

The Preoperational Monitoring Program was approved by NRC on July 6, 1978. A copy of this program, dated May 31, 1978, is included as Appendix 6A. Two years of baseline data have been collected and the program was terminated in June, 1980. In a letter dated September 11, 1980, the NRC approved the termination of the program. 6

6.1.1 MARINE BIOLOGICAL MONITORING PROGRAMS

Monitoring of marine communities at San Onofre began in 1963, ten months before the Unit 1 groundbreaking, and has continued through all phases of construction and operation of Unit 1. The monitoring program was conducted by Bendix Marine Advisers, Inc., Intersea Research Corporation, and Lockheed Ocean Laboratory.

Biological communities investigated were intertidal sand and rock habitats, benthic sand and rock habitats, and sand. As part of the Units 2 and 3 Construction Monitoring Program, a kelp monitoring program was initiated in 1974. However, kelp observations have been made in the San Onofre area since 1911. Fish populations have been monitored by the California Department of Fish and Game since construction began for Unit 1. Beginning in late 1974, fish populations off San Onofre have

been investigated as a part of the Unit 1 Environmental Technical Specifications (ETS).

The objectives of the monitoring programs have been to (1) characterize the marine environment, and (2) to understand and monitor the effects on the environment during all phases of plant construction and operation.

Unit 1 ETS

A. Plankton Studies

Zooplankton and phytoplankton are sampled bi-monthly and at least 5 times per year from at least 2 stations in Zone 0A, 2 stations in Zone 1A, 2 stations in Zone 2A, and 1 in Zone 6 (see Figure 6.1-1). Replicate zooplankton sampling is conducted at all stations twice per year. Sampling is conducted to obtain representative zooplankton taxonomic groups throughout the entire water column. The plankton composition and numbers of organisms per unit volume obtained at stations in Zones 0A, 1A and 2A are compared to similar data collected at control stations in Zone 6. For phytoplankton at least 2 whole water samples near surface and near bottom in the water column are taken at each station. A zooplankton net with a mesh size not greater than 363 nor less than 153 microns is used to collect zooplankton samples.

B. Nekton Studies

California Department of Fish and Game fish catch statistics for the fish block including the Station and the blocks

APPENDIX 6B

PROPOSED ENVIRONMENTAL TECHNICAL SPECIFICATIONS

APPENDIX 6B

PROPOSED ENVIRONMENTAL TECHNICAL SPECIFICATIONS

BACKGROUND

National Pollution Discharge Elimination System (NPDES) Permit No. CA0003395 issued in 1976 by Order No. 76-21 of the California Regional Water Quality Control Board - San Diego Region (CRWQCB) sets forth environmental monitoring program requirements for SONGS 2 and 3. The NPDES Permit became effective on June 8, 1976 and expires on June 8, 1981. Applicants must file a Report of Waste Discharge with the CRWQCB in accordance with Title 23, California Administrative Code, not later than 180 days in advance of the expiration date as application for issuance of new waste discharge requirements.

Construction Monitoring Program studies of the effects of SONGS 2 and 3 construction were initiated in 1974 as required by the CRWQCB. These studies focused on the impacts of sand disposal onto the beach from onshore construction site excavations and on the construction activities for the offshore portions of SONGS 2 and 3 cooling systems.

In 1978, a Preoperational Monitoring Program (PMP) was initiated in compliance with requirements of the Nuclear Regulatory Commission. The PMP along with other programs, provides a baseline of oceanographic and marine biological data prior to the operation of SONGS 2 and 3. The PMP is complementary to the SONGS 1 ETS program and essentially expands the study area further offshore into the area of SONGS 2 and 3 diffusers. The PMP was started in June 1978 and was terminated in June 1980, with 24 months of oceanographic and biological studies.

BASIS

The basis for the proposed ETS is the fact that the U. S. Environmental Protection Agency and the State of California have been charged with the responsibility to regulate pollutant discharges into water bodies under the authority of the Federal Water Pollution Control Act (FWPCA). Section 511 of the FWPCA provides that nothing under the National Environmental Policy Act shall be deemed to authorize any Federal Agency to review any effluent limitation or other requirement established pursuant to the FWPCA, or to impose, as a condition of any license or permit, any effluent limitation other than any such limitation established pursuant to FWPCA. The intent of this proposed change, to eliminate regulatory overlap, is fully consistent with Section 101 (f) of the FWPCA, where it is stated that:

> "It is the national policy that to the maximum extent possible the procedures utilized for implementing this Act shall encourage the drastic minimization of paperwork and interagency decision procedures, and make the best use of available manpower and funds, so as to prevent needless duplication and unnecessary delays at all levels of government."

The proposed ETS include no limiting conditions for operation (LCO), no environmental monitoring requirements and no special stuoies and requirements. Administrative controls are consistent with the exclusion of LCO and program requirements and subsequent sole reliance upon the NPDES Permit for protection of the environment. Effluent limitations and surveillance and reporting requirements specified in the NPDES Permit for SONGS 2 and 3 are more than adequate to assure protection of the beneficial uses of the receiving water.

ENVIRONMENTAL TECHNICAL SPECIFICATIONS (NON-RADIOLOGICAL) FOR SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 & 3

DOCKET NOS. 50-361 AND 50-362

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

SAN ONOFRE NUCLEAR GENERATING STATION

UNITS 2&3

ENVIRONMENTAL TECHNICAL SPECIFICATIONS

(NON-RADIOLOGICAL)

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5.1	Station Reporting Requirements	1-1

1.0 Definitions

None

2.0 Limiting Conditions for Operation

None required.*

3.0 Environmental Monitoring

None required.*

4.0 Special Studies and Requirements

None required.*

5.0 Administrative Controls

5.1 Station Reporting Requirements

The following information shall be submitted to the Director of the appropriate Regional Inspection and Enforcement Office (with copy to the Director, Office of Nuclear Reactor Regulation):

a. Copies of the reports as required by the National Pollution Discharge Elimination System Permit (or otherwise required pursuant to the Federal Water Pollution Control Act).

b. Copies of the reports as required by other permits of federal (other than NRC), state, local and regional authorities charged with protection of the environment.

The information noted in a. and b., above, shall be submitted in accordance with the frequency, content and schedules set forth in those permits.

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*In consideration of the provisions of the Clean Water Act (33 USC 1251, _et seq._) and the interest of avoiding duplication of effort, the conditions, monitoring requirements and special studies related to water quality and aquatic biota are specified in the National Pollution Discharge Elimination System (NPDES) Permit No. CA0003395 issued by the California Regional Water Quality Control Board - San Diego Region to the Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). This permit authorizes SCE and SDG&E to discharge controlled waste water from the San Onofre Nuclear Generating Station, Units 2&3, into the Pacific Ocean.

The Nuclear Regulatory Commission will be relying on the NPDES permit for protection of the aquatic environment from non-radiological effluents.

8. ECONOMIC AND SOCIAL EFFECTS OF PLANT CONSTRUCTION AND OPERATION

8.1 PRIMARY BENEFITS AND COSTS

8.1.1 BENEFITS

The electric energy generated by the San Onofre Nuclear Generating Station Units 2 and 3 with a total capacity of 2220 MW represents the primary benefit from the facility. The operation of Units 2 and 3 at an assumed 70% capacity factor will result in the generation of about 1.36×10^{10} kilowatthours of electricity annually.

This energy will be distributed among the customer rate classes as follows: industrial 25.7%, commercial 25.0%, residential 31.1%, and other 18.2%. The main benefit to the customers will result from increased system reliability.

The operation of San Onofre Units 2 and 3 at an assumed 70% capacity factor will preclude the utilization of about 22 million barrels of oil per year, at an approximate cost of $700,000,000. In addition, the operation of the facility will reduce air emissions by the following rate per year: NOx by about 19,000 tons, SO_2 by about 30,000 tons and particulates by 3,000 tons.

8.1.2 COSTS

The primary costs associated with San Onofre Units 2 and 3 are those costs related to site and plant development. As noted in Table 8.1.1, the total plant cost is estimated to be $3.04 billion.

In addition to the cost of constructing the facility, certain costs are incurred during operation. These costs include operation and maintenance costs of approximately $15,000,000 per year, and fuel costs of approximately 17 mills per kilowatthour. Table 8.1-2 contains a breakdown of the fuel costs.

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Table 8.1-1

PLANT COSTS

1.	Allowance for Funds used During Construction (AFUDC)	7.8% (1980) 9.0% (1981) plus .25%/yr. 1982,1983, 1984 compounded	
2.	Cost of Capital	15%	
3.	Length of Construction Work Week	120 hrs./wk.	
4.	Estimated Site Labor Requirements	18.0 mhrs./KW	
5.	Average Site Labor Pay Rate (w/fringes)		
	A. Manual Labor (1980 $'s)	$19.18 $/hr.	
	B. Nonmanual Labor (1980 $'s)	$12.91 $/hr.	
6.	Escalation Rates	1980,1981	1982 & After
	A. Site Labor	14%	12%/yr.
	B. Material	10%	8%/yr.
	C. Composite	12%	10%/yr.
7.	Power Plant Costs ($ x 1,000)	UNIT 2	UNIT 3
	A. Land & Land Rights	2,700	1,800
	B. Structures & Facilities	561,000	376,000
	C. Reactor Plant Equipment	670,000	446,000
	D. Turbogenerators	380,000	253,000
	E. Heat Rejection System	Included in "D"	

Table 8.1-1 (Cont.)

PLANT COSTS

	F. Electric Plant Equipment	161,000	108,000
	G. Misc. Plant Equipment	49,300	31,200
	TOTAL PLANT	1,824,000	1,216,000
	H. Spares (included in A-G above)	8,700	5,800
	I. Contingency (included in A-G above)	N/A	N/A
	J. Allowance for Funds used during Construction (included in A-G above)	379,000	252,800
8.	Escalation during Construction	N/A	N/A
9.	Total Plant Cost ($ x 1,000)	1,824,000	1,216,000
	TOTAL COMBINED COST OF UNITS 2 AND 3		3,040,000,000