State of California
The Resources Agency

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Small Hydroelectric Potential at Existing Hydraulic Structures in California

Bulletin 211
April 1981

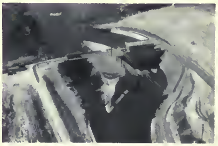
[redacted]

Bulletin 211 was partially funded by a cooperative agreement (No. DE-FC-49-80-R9-10019.000) with the U.S. Department of Energy.

This Bulletin responds to Chapter 933, Statutes of 1978:

". . . It is in the best interests of the state that the existing dams and hydraulic structures identified in the Department of Water Resources' previous surveys be further studied to determine the feasibility and cost-effectiveness of equipping these dams and hydraulic structures with electric power-generating facilities . . ."

The legislation, Senate Bill 1834, was authored by Senator Alfred Alquist.



ON THE COVER: Turlock Lake Powerhouse, located on the Turlock Main Canal in Stanislaus County, is owned by the Turlock Irrigation District. This 3 300-kilowatt hydroelectric power plant generates 12.2 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 20,000 barrels of oil annually in a fossil fuel plant.

Photo courtesy of Turlock Irrigation District.

Department of
Water Resources

Bulletin 211

Small Hydroelectric Potential at Existing Hydraulic Structures in California

Appendixes: Data and Guidelines for Development

April 1981

Huey D. Johnson
Secretary for Resources
The Resources Agency

Edmund G. Brown Jr.
Governor
State of California

Ronald B. Robie
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APPENDIX A

Lists of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California

Section A-1: Alphabetical Listing, by Owner

Section A-2: Alphabetical Listing, by Facility Name

Section A-3: Alphabetical Listing, by County

Section A-1

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California

(Alphabetical by Owner)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Adamson Companies			
Rindge Dam	Los Angeles	600	0.9
Amador County Water Agency			
Central Amador Water Project	Amador	250	0.7
Jackson-Sutter Creek Outfall Pipeline	Amador	60	0.2
Anderson-Cottonwood Irrigation District			
Anderson Flume Diversion	Shasta	50	0.2
Lake Redding (ACID Diversion Dam)	Shasta	9 000	50.0
Parkview Station (Canal)	Shasta	150	0.5
Arrowhead Lake Association			
Lake Arrowhead Dam	San Bernardino	75	0.3
Bakersfield, City of & Kern Delta Water District & North Kern Water District			
Beardsley Canal Control Structure	Kern	260	1.1
Beardsley Diversion Structure (Canal)	Kern	500	1.7
Kern Island Canal Control Structure	Kern	700	3.1
Rocky Point Diversion Structure (Canal)	Kern	300	0.7
Browns Valley Irrigation District			
Harding Canal	Yuba	1 000	6.6
Merle Collins Reservoir (Virginia Ranch Dam)	Yuba	900	5.6
Upper Main Canal	Yuba	200	0.9
Calaveras County Water District			
White Pines Dam	Calaveras	100	0.4
Calaveras Public Utility District			
Schaads Reservoir (Middle Fork Dam)	Calaveras	75	0.4
California-American Water Company			
Los Padres Dam	Monterey	75	0.3

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
California Department of Finance			
Rector Creek Dam	Napa	100	0.5
California Department of Water Resources			
Antelope Dam	Plumas	450	1.4
Castaic Outlet (Dam)	Los Angeles	275	1.4
Cottonwood No. 1 (Canal)	Los Angeles	17 000	115.0
Cottonwood No. 2 (Canal)	Los Angeles	12 000	90.0
Del Valle Stream Release (Dam)	Alameda	400	1.1
Frenchman Dam	Plumas	450	1.0
Lake Davis (Grizzly Valley Dam)	Plumas	510	1.5
Las Flores Turnout (Pipeline)	San Bernardino	210	0.7
Mojave Siphon No. 1 (Silverwood Lake Inlet, Pipeline)	San Bernardino	6 000	47.0
Mojave Siphon No. 2 (Silverwood Lake Inlet, Pipeline)	San Bernardino	10 000	78.0
Palermo Canal Release (Dam)	Butte	400	1.5
Pyramid Stream Release (Dam)	Los Angeles	1 000	4.0
Thermalito Afterbay River Outlet (Dam)	Butte	13 000	42.6
Thermalito Diversion Dam	Butte	3 500	23.0
Calleguas Municipal Water District			
Conejo Pump Station (Pipeline)	Ventura	600	3.0
Chowchilla Water District			
Ash Main Canal	Madera	150	0.7
Califa Canal	Madera	200	0.9
Chowchilla Main Canal			
Station 0+00	Madera	250	1.1
Station 101+80	Madera	250	1.1
Station 175+00	Madera	250	1.1
Contra Costa County Water District			
Mallard Reservoir (Pipeline)	Contra Costa	200	0.9
Cucamonga County Water District			
Deer Creek Collection Pipeline	San Bernardino	200	1.0
Desert Water Agency			
Snow Creek (Pipeline)	Riverside	300	1.7
Whitewater River (Pipeline)	Riverside	300	2.4

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
East Bay Municipal Utility District			
Camanche Dam (Lower Mokelumne River Project)	San Joaquin	10 680	35.0
El Dorado Irrigation District			
El Dorado Distribution System (Pipelines)			
Reservoir A	El Dorado	730	3.2
Reservoir 2	El Dorado	50	0.2
Reservoir 2A	El Dorado	480	2.1
Reservoir 2A-3	El Dorado	360	1.6
Reservoir 3	El Dorado	200	0.9
			0.3
Reservoir 5	El Dorado	60	0.3
Reservoir 6	El Dorado	80	0.3
Reservoir 8	El Dorado	175	0.8
Reservoir 9A	El Dorado	175	0.8
Reservoir 9B	El Dorado	90	0.4
Reservoir 10A	El Dorado	175	0.8
Reservoir 10B	El Dorado	60	0.3
Webber Dam	El Dorado	75	0.3
El Segundo, City of			
El Segundo Distribution System (Pipeline)	Los Angeles	500	3.9
Escondido Mutual Water Company			
Bear Valley Powerplant Rehabilitation (At Lake Wohlford Dam)	San Diego	700	3.7
Fresno Irrigation District			
Fresno Main Canal			
Headworks	Fresno	650	2.6
Boos Check	Fresno	650	2.6
Dresser Check	Fresno	650	2.6
Gould Weir Diversion Dam	Fresno	850	3.5
George Costa			
Del Loma Tunnel	Trinity	250	1.9

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Georgetown Divide Public Utility District			
Buckeye Conduit	El Dorado	350	2.4
Buffalo Hill Siphon (Pipeline)	El Dorado	160	0.5
Kaiser Pipeline	El Dorado	120	0.3
Stumpy Meadows Reservoir (Mark Edson Dam)	El Dorado	325	2.2
Glendale, City of			
Glendale Distribution System (Pipeline)	Los Angeles	400	2.0
Goleta County Water District			
Carneros Power Project (Pipeline)	Santa Barbara	700	1.6
Hidden Valley Lake Association			
Coyote Creek (Dam)	Lake	90	0.4
Hot Springs Valley Irrigation District			
Big Sage Dam	Modoc	175	0.7
Humboldt Bay Municipal Water District			
Ruth Reservoir (Robert W. Matthews Dam)	Trinity	4 000	14.2
Imperial Irrigation District			
Alamo Drop 3A (Canal)	Imperial	1 200	6.7
Dahlia Drop (Canal)	Imperial	225	1.0
East Highline Canal Turnout	Imperial	1 800	10.0
Newside Drop (Canal)	Imperial	200	0.9
No. 8 Heading (Canal)	Imperial	750	3.9
Tuberose Check (Canal)	Imperial	200	1.3
Vail Heading (Canal)	Imperial	225	1.0
Irvine Ranch Water District			
Irvine Lake Pipeline (Rattlesnake Reservoir)	Orange	500	1.0
Jack and Thomas Swickward			
Round Valley Dam	Lassen	90	0.4

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Jackson Valley Irrigation District			
Lake Amador (Jackson Creek Dam)	Amador	350	2.5
La Habra, City of			
Orange County (OC) 45 (Pipeline)	Orange	100	1/
Lake Hemet Municipal Water District			
Lake Hemet Dam	Riverside	75	0.1
Lake Wildwood Association			
Anthony House Dam	Nevada	50	0.2
Lassen Irrigation Company			
McCoy Flat Dam	Lassen	50	0.2
Lockheed Missiles & Space Company, Inc.			
Big Creek Hydroelectric Plant Rehabilitation (Pipeline)	Santa Cruz	800	3.0
Los Angeles, City of			
Franklin Inlet (Pipeline)	Los Angeles	800	6.8
Grant Lake (Dam)	Mono	1 500	3.0
Los Angeles Distribution System (Pipeline)			
Location 1	Los Angeles	610	3.3
Location 2	Los Angeles	270	2.2
Location 3	Los Angeles	420	2.1
Location 4	Los Angeles	270	1.8
Location 5	Los Angeles	140	1.2
Location 6	Los Angeles	190	1.1
Location 7	Los Angeles	120	1.0
Location 8	Los Angeles	130	0.8
Location 9	Los Angeles	70	0.6
Location 10	Los Angeles	100	0.6
Location 11	Los Angeles	70	0.6
Location 12	Los Angeles	100	0.6
Location 13	Los Angeles	60	0.5
Location 14	Los Angeles	60	0.5
Location 15	Los Angeles	1 000	8.2
Location 16	Los Angeles	1 800	9.0
Los Angeles Reservoir (Dam)	Los Angeles	6 200	37.0
Stone Canyon Dam	Los Angeles	300	2.0
Tinemaha Dam	Inyo	1 600	8.3
Van Owen Regulating (Pipeline)	Los Angeles	600	5.0

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Oakdale and South San Joan Irrigation Districts			
Goodwin Dam	Calaveras	970	5.0
Sand Bar Project (Dam)	Tuolumne	12 000	70.0
Orange Cove Irrigation District			
Dodge Ave Check (Canal)	Tulare	475	2.4
Sand Creek Check (Canal)	Tulare	200	1.5
Orange County Water District			
OC 28 (Pipeline)	Orange	6 300	12.0
OC 59 (Pipeline)	San Bernardino	5 000	9.4
Oroville-Wyandotte Irrigation District			
Little Grass Valley Dam	Plumas	2 600	6.5
Ponderosa Diversion Dam	Butte	3 300	14.0
Sly Creek Dam	Butte	13 200	48.2
Pacheco Pass Water District			
Pacheco Lake (North Fork Dam)	Santa Clara	60	0.3
Pacific Gas and Electric Company			
Bucks Lake (Bucks Storage Dam)	Plumas	740	3.2
Lake Fordyce Dam	Nevada	900	4.0
Lake Pillsbury (Scott Dam)	Lake	5 000	15.0
Lake Valley Dam	Placer	75	0.3
Lyons Dam	Tuolumne	300	1.5
McCloud Dam	Shasta	1 200	5.4
South Canal	Placer	8 000	37.0
Spicers Meadows Dam	Tuolumne	750	3.3
Volta No. 2 Powerhouse (Canal)	Shasta	1 000	5.0
Palmdale Water District			
Littlerock Dam	Los Angeles	50	0.2
Paradise Irrigation District			
Paradise Dam	Butte	300	1.2
People's Ditch Company			
People's Weir (Canal)	Tulare	2 200	3.5

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
San Luis Obispo County Flood Control & Water Conservation District			
Lopez Dam	San Luis Obispo	50	0.4
Terminal Reservoir Inlet (Pipeline)	San Luis Obispo	75	0.6
Santa Barbara, City of			
Gibraltar Dam	Santa Barbara	1 500	4.0
Santa Clara Valley Water District			
Anderson Lake (Leroy Anderson Dam)	Santa Clara	500	2.2
Calero Dam	Santa Clara	100	0.5
Coyote Dam	Santa Clara	600	1.3
Guadalupe Dam	Santa Clara	60	0.3
Lexington Dam	Santa Clara	500	2.9
Stevens Creek Dam	Santa Clara	75	0.3
Santa Monica, City of			
Mount Olivette (Pipeline)	Los Angeles	150	1.1
Semitropic Water Storage District			
Semitropic Intake Canal	Kern	1/	1/
Siskiyou County Flood Control & Water Conservation District			
Lake Siskiyou (Box Canyon Dam)	Siskiyou	6 000	21.9
South Bay Irrigation District			
Lake Loveland Dam	San Diego	100	0.5
Southern California Edison			
Cardinal Power House	Mono	2 500	10.3
Lake Thomas A. Edison (Vermillion Valley Dam)	Fresno	2 000	8.6
Mono Creek Diversion Dam	Fresno	1/	1/
South Fork Pit River Irrigation District			
West Valley Dam	Modoc	900	3.8
South San Joaquin Irrigation District			
Frankenheimer Drop (Canal)	Stanislaus	4 700	18.7
Parker Drop (Canal)	San Joaquin	300	0.8
Woodward Dam	Stanislaus	2 300	6.9

1/ Insufficient data received

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Los Angeles County Flood Control District			
Alamitos Barrier (Dam)	Los Angeles	300	1.0
Big Dalton Dam	Los Angeles	50	0.1
Big Tujunga No. 1 Dam	Los Angeles	300	1.3
Cogswell Dam	Los Angeles	500	3.0
Dominguez Gap Barrier (Pipeline)	Los Angeles	500	2.0
Pacoima Dam	Los Angeles	400	1.0
San Dimas Dam	Los Angeles	100	0.3
San Gabriel Dam	Los Angeles	500	3.0
Santa Anita Dam	Los Angeles	300	0.7
West Coast Basin Barrier (Pipeline)	Los Angeles	500	4.2
Lost Hills Water District			
Eastside Pipeline	Kern	1 000	3.0
Mammoth County Water District			
Lake Mary & Twin Lakes Open Diversion (Pipeline)	Mono	300	0.8
Marin Municipal Water District			
Kent Lake (Peters Dam)	Marin	150	0.4
Nicasio Dam	Marin	400	1.7
Merced Irrigation District			
Buhach Drop (Canal)	Merced	60	0.3
Canal Creek	Merced	940	3.6
Escaladian Headworks (Canal)	Merced	300	1.2
Fairfield Drop (Canal)	Merced	900	3.6
Fisher Drop (Canal)	Merced	75	0.3
Lake Yosemite Dam	Merced	1 200	2.3
Richard B. Parker (on Main Canal)	Merced	2 800	9.2
Youd Drop (Canal)	Merced	100	0.5
Metropolitan Water District of Southern California			
Balboa (Pipeline)	Orange	1 200	9.1
Corona (Pipeline)	Riverside	2 800	18.0
Covina (Pipeline)	Los Angeles	2 500	16.9
Coyote Creek (Pipeline)	Orange	2 900	19.6
Perris Power Project (Pipeline)	Riverside	7 900	40.3

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Metropolitan Water District of Southern California (Continued)			
Rio Hondo (Pipeline)	Los Angeles	2 000	12.3
Robert A. Skinner Dam	Riverside	1 400	6.3
San Dimas (Pipeline)	Los Angeles	9 900	68.2
Santiago Creek (Pipeline)	Orange	3 000	15.6
Sepulveda Canyon (Pipeline)	Los Angeles	8 600	56.2
Temescal (Pipeline)	Riverside	2 800	18.0
Valley View (Pipeline)	Orange	2 400	14.2
Venice (Pipeline)	Los Angeles	10 100	60.0
Yorba Linda Feeder (Pipeline)	Orange	5 100	33.5
Modesto Irrigation District			
Canyon Creek Diversion Dam	Trinity	1 060	9.3
Modesto Reservoir (Dam)	Stanislaus	1 000	3.4
Stone Drop (Canal)	Stanislaus	1 000	4.0
Montague Water Conservation District			
Lake Shastina (Shasta River Dam)	Siskiyou	200	0.7
Pumping Plant Lower (Canal)	Siskiyou	65	0.2
Monte Vista County Water District			
Benson Feeder Pipeline	San Bernardino	1/	1/
Montecito County Water District			
Jameson Lake (Juncal Dam)	Santa Barbara	60	0.4
South Portal Doulton Tunnel	Santa Barbara	200	0.5
Monterey County Flood Control & Water Conservation District			
San Antonio Dam	Monterey	6 000	25.6
Napa, City of			
Lake Hennessey (Conn Creek Dam)	Napa	500	2.3
Nevada Irrigation District			
Bowman Dam	Nevada	3 000	14.7
Combie Dam	Nevada	1 000	4.0
French Lake (Dam)	Nevada	200	0.8
Jackson Meadows Dam	Nevada	4 000	8.9
Scotts Flat Dam	Nevada	1 300	5.5

1/ Insufficient data received

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Petan Company			
Alisal Creek Dam	Santa Barbara	50	0.2
Placer County Water Agency			
Hell Hole Reservoir (Lower Hell Hole Dam)	Placer	550	3.0
Plumas County Flood Control & Water Conservation District			
Lake Davis-Portola Pipeline	Plumas	60	0.3
Rancho California Water District			
Vail Dam	Riverside	200	0.9
Redlands, City of			
Highland Avenue Pumping Plant (Pipeline)	San Bernardino	600	2.6
Redlands Water Treatment Plant (Pipeline)	San Bernardino	200	0.9
Rock Creek Water District			
Salt Spring Valley Reservoir (Dam)	Amador	90	0.4
R. W. Akers			
Tule Lake (Dam)	Lassen	75	0.3
Sacramento Municipal Utility District			
Ice House Reservoir (Dam)	El Dorado	10 000	22.0
Slab Creek Dam	El Dorado	400	3.0
San Bernardino Valley Municipal Water District			
City Creek Turnout (Pipeline)	San Bernardino	2 000	3.0
Lytle Creek Turnout (Pipeline)	San Bernardino	1 300	7.8
Santa Ana Low Turnout (Pipeline)	San Bernardino	1 400	3.8
Sweetwater Turnout (Pipeline)	San Bernardino	875	2.2
Waterman Canyon Turnout (Pipeline)	San Bernardino	4 000	7.0
San Diego, City of			
Alvarado Treatment Plant (Pipeline)	San Diego	1 700	8.4
Barrett Dam	San Diego	60	0.2

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
San Diego, City of (Continued)			
Lake Hodges Dam	San Diego	270	1.2
Miramar Treatment Plant (Pipeline)	San Diego	1 300	5.7
Point Loma Wastewater Treatment Plant (Pipeline)	San Diego	1 200	8.0
San Diego County Water Authority			
San Vicente Reservoir (Pipeline)	San Diego	850	3.4
San Dieguito Water District & Santa Fe Irrigation District			
San Dieguito Treatment Plant (Pipeline)	San Diego	1 000	4.5
Sweetwater Treatment Plant (Pipeline)	San Diego	1 400	6.3
San Francisco, City and County of			
Calaveras Dam	Alameda	700	3.2
Early Intake Dam	Tuolumne	1 300	8.7
Hetch Hetchy Reservoir (O'Shaughnessy Dam)	Tuolumne	1 600	6.0
Lake Eleanor Dam	Tuolumne	60	0.3
Moccasin Lower Dam	Tuolumne	1 600	7.0
Pilarcitos Dam	San Mateo	200	0.8
San Gabriel Valley Municipal Water District			
Azusa Flow Control Structure (Pipeline)	Los Angeles	740	3.2
Big Dalton Pressure Reducing Station (Pipeline)	Los Angeles	280	1.2
Emerald Pressure Reducing Station (Pipeline)	Los Angeles	340	1.5
Etiwanda Pressure Reducing Station (Pipeline)	Los Angeles	250	1.1
San Juan Suburban Water District			
Sidney N. Peterson Water Treatment Plant (Pipeline)	Placer	175	0.4

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
South Santa Clara Valley Water Conservation District			
Chesbro Reservoir (Elmer J. Chesbro Dam)	Santa Clara	100	0.2
Uvas Dam	Santa Clara	300	1.0
South Sutter Water District			
Camp Far West Dam	Placer	6 800	26.9
South Tahoe Public Utility District			
Indian Creek Dam	Alpine	50	0.1
Thermalito Irrigation District & Table Mountain Irrigation District			
Concow Dam	Butte	130	0.4
Tulare Lake Basin Water Storage District			
Lateral A (Chute)	Kings	1 600	7.0
Lateral B (Chute)	Kings	900	4.0
Turlock Irrigation District			
Turlock Main Canal			
Canal Drop No. 2	Stanislaus	700	2.1
Canal Drop No. 6	Stanislaus	900	2.9
Canal Drop No. 7	Stanislaus	700	2.1
Ceres Spillway (Canal)	Stanislaus	2 100	4.5
Hickman Spillway (Canal)	Stanislaus	2 100	4.5
Upper Dawson Power Plant (Canal)	Stanislaus	4 000	15.9
United Water Conservation District			
Lake Piru (Santa Felicia Dam)	Ventura	3 600	7.8
U.S. Army Corps of Engineers			
Black Butte Dam	Tehama	9 200	31.3
Farmington Dam	San Joaquin	400	2.0
Hensley Lake (Hidden Dam)	Madera	1 300	4.0
H. V. Eastman Lake (Buchanan Dam)	Madera	3 000	9.0
Isabella Dam	Kern	8 000	18.5
Lake Clementine (North Fork Dam)	Placer	12 000	63.5
Lake Kaweah (Terminus Dam)	Tulare	4 000	20.0
Lake Mendocino (Coyote Dam)	Mendocino	4 000	21.0

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
U.S. Army Corps of Engineers (Continued)			
Lemoncove Ditch (At Terminus Dam)	Tulare	650	3.5
Martis Creek (Dam)	Nevada	250	1.1
New Hogan Dam	Calaveras	2 250	9.5
Success Dam	Tulare	4 000	12.0
Warm Springs Dam	Sonoma	3 000	15.0
U.S. Fish and Wildlife Service			
Doris Dam	Modoc	50	0.1
U.S. Forest Service			
Hume Lake (Dam)	Fresno	1 050	4.6
Lost Creek Diversion Dam	Shasta	1 800	10.0
U.S. Water and Power Resources Service			
All American Canal Drop No. 1	Imperial	4 700	27.0
All American Canal Drop No. 5	Imperial	5 000	24.0
Boca Dam	Nevada	2 000	5.6
Casitas Dam	Ventura	700	2.0
Clear Lake (Dam)	Modoc	430	1.9
East Park Dam	Colusa	900	2.0
Folsom Lake Pipeline	Placer	500	2.4
Jenkinson Lake (Sly Park Dam)	El Dorado	650	1.8
Lake Berryessa (Monticello Dam)	Napa	16 000	43.0
Los Banos Detention Dam	Merced	100	0.5
Madera Canal			
Station 980+65	Madera	2 000	5.5
Station 1064+67	Madera	560	1.9
Station 1910+60	Madera	650	2.6
Millerton Lake (Friant Dam)			
Friant-Kern Canal	Fresno	15 000	68.0
Madera Canal	Fresno	5 000	23.0
San Joaquin River	Fresno	2 700	10.0
New Siphon Drop (Canal)	Imperial	1 410	11.3
North Portal Tecolote Tunnel	Santa Barbara	175	0.7
Palo Verde Diversion Dam	Riverside	8 700	65.0
Prosser Creek Dam	Nevada	1 000	3.5
Red Bluff Diversion Dam	Tehama	14 000	70.0
Stampede Dam	Sierra	3 000	17.0
Stony Gorge Dam	Glenn	6 000	18.0
Whiskeytown Dam	Shasta	3 000	12.5
Vallejo, City of			
Cache Slough (Pipeline)	Napa	600	4.1
Lake Curry (Pipeline)	Napa	50	0.3

Table A-1. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Owner and Facility	County	Estimated Capacity (kW)	Estimated Energy (GWh/yr)
Ventura County Flood Control District			
Matilija Dam	Ventura	700	2.0
Vista Irrigation District			
Henshaw Dam	San Diego	200	1.0
Whitewater Canyon Mutual Water Company			
Whitewater Canyon Irrigation System (Pipeline)	Riverside	400	2.5
Yolo County Flood Control & Water Conservation District			
Clear Lake Impounding Dam	Lake	2 000	7.5
Indian Valley Dam	Lake	3 200	7.2
Yuba County Water Agency			
Hour House Dam	Nevada	100	0.3

SECTION A-2

(Table A-2)

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California

(Alphabetical by Facility Name)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
ACID Diversion Dam	(See Lake Redding)							
Alamo Drop 3A (Canal)	Imperial Irrigation District	2	1 200	6.7	4.6	15	31.2	1,100
Alamitos Barrier (Dam)	Los Angeles County Flood Control District	1	300	1.0	73.2	240	0.5	17
Alisal Creek Dam	Petan Company	1	50	0.2	25.9	85	0.2	8
All-American Canal Drop No. 1	U. S. Water and Power Resources Service	2	4 700	27.0	3.4	11	169.9	6,000
All-American Canal Drop No. 5	U. S. Water and Power Resources Service	2	5 000	24.0	7.0	23	85.0	3,000
Alvarado Treatment Plant (Pipeline)	City of San Diego	2	1 700	8.4	48.8	160	4.2	150
Anderson Flume Diversion (Canal)	Anderson-Cottonwood Irrigation District	2	50	0.2	7.0	23	1.0	35
Anderson Lake (Leroy Anderson Dam)	Santa Clara Valley Water District	2	500	2.2	38.1	125	1.4	50
Antelope Dam	California Department of Water Resources	2	450	1.4	22.9	75	2.4	85
Anthony House Dam	Lake Wildwood Association	1	50	0.2	21.3	70	0.3	10
Ash Main Canal	Chowchilla Water District	1	150	0.7	2.4	8	7.4	260
Azusa Flow Control Structure (Pipeline)	San Gabriel Valley Municipal Water District	2	740	3.2	91.4	300	1.0	35
Balboa (Pipeline)	Metropolitan Water District of Southern California	2,5	1 200	9.1	6.7	22	19.8	700
Barret Dam	City of San Diego	1	60	0.2	21.3	70	0.3	12
Bear Valley Powerplant (Rehabilitation)	Escondido Mutual Water Company	2,5	700	3.7	146.3	480	0.7	25
Beardsley Canal Control Structure	City of Bakersfield, et al	3	260	1.1	1.8	6	17.0	600
Beardsley Diversion Structure (Canal)	City of Bakersfield, et al	2,3	500	1.7	1.5	5	42.5	1,500

1. Status Unknown
2. Appraisal or Feasibility Study Completed
3. Application Filed for FERC Preliminary Permit
4. FERC Preliminary Permit Issued
5. Application Filed for FERC Exemption or License
6. FERC Exemption or License Issued
7. Under Construction
8. Insufficient Data Received

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Benson Feeder Pipeline	Monte Vista County Water District	1	8/	8/		8/	8/	
Big Creek Hydraulic Plant (Rehabilitation)	Lockhead Missles and Space Company, Inc.	2	800	3.0	298.7	980	0.3	12
Big Dalton Dam	Los Angeles County Flood Control District	1	50	0.1	25.9	85	1.0	8
Big Dalton Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	280	1.2	35.1	115	1.0	35
Big Sage Dam	Hot Springs Valley Irrigation District	1	175	0.7	13.7	45	1.5	52
Big Tujunga No. 1 Dam	Los Angeles County Flood Control District	1	300	1.3	39.6	130	0.8	30
Black Butte Dam	U. S. Army Corps of Engineers	2,4	9 200	31.3	24.4	80	45.3	1,600
Boca Dam	U. S. Water and Power Resources Service	2,4	2 000	5.6	27.4	90	8.8	310
Box Canyon Dam	(See Lake Siskiyou)							
Bowman Dam	Nevada Irrigation District	2	3 000	14.7	40.8	134	8.5	300
Buckeye Conduit	Georgetown Divide Public Utility District	2	350	2.4	54.9	180	0.8	27
Bucks Lake (Bucks Storage Dam)	Pacific Gas and Electric Company	1	740	3.2	30.5	100	2.8	100
Buffalo Hill Siphon (Pipeline)	Georgetown Divide Public Utility District	1	160	0.5	33.5	110	0.6	20
Buhach Drop (Canal)	Merced Irrigation District	1	60	0.3	0.9	3	8.5	300
Buchanan Dam	(See H.V. Eastman Lake)							
Bucks Storage Dam	(See Bucks Lake)							
Cache Slough (Pipeline)	City of Vallejo	1	600	4.1	85.3	280	0.8	30
Calaveras Dam	City and County of San Francisco	1	700	3.2	45.7	150	1.8	65
Calero Dam	Santa Clara Valley Water District	1	100	0.5	27.4	90	0.4	15
Califa Canal	Chowchilla Water District	1	200	0.9	4.6	15	5.2	185
Camanche Dam (Lower Mokelumne River Project)	East Bay Municipal Utility District	5	10 680	35.0	45.7	150	28.3	1,000
Camp Far West Dam	South Sutter Water District	5	6 800	26.9	41.1	135	19.8	700
Canal Creek	Merced Irrigation District	2,6	940	3.6	9.8	32	10.8	380
Canal Drop No. 2, 6, and 7	(See Turlock Main Canal)							
Canyon Creek Diversion Dam	Modesto Irrigation District	3	1 060	9.3	167.6	550	0.8	27
Carneros Power Project (Pipeline)	Goleta County Water District	1	700	1.6	109.7	360	0.8	27
Cardinal Power House	Southern California Edison	2	2 500	10.3		8/	8/	
Carrier Canal Project	(See Rocky Point Diversion Dam)							
Casitas Dam	U. S. Water and Power Resources Service	1	700	2.0	76.2	250	1.1	40
Casitas Dam	California Department of Water Resources	2	275	1.4	91.4	300	0.4	15

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Central Amador Water Project	Amador County Water Agency	2	250	0.7	365.8	1,200	0.1	3
Ceres Spillway (Canal)	Turlock Irrigation District	1	2 100	4.5	13.7	45	19.8	700
Chesbro Reservoir (Elmer J. Chesbro Dam)	South Santa Clara Valley Water and Conservation District	2	100	0.2	18.3	60	0.7	25
Chowchilla Main Canal								
Station 0+00	Chowchilla Water District	2	250	1.1	2.1	7	14.2	500
Station 101+80	Chowchilla Water District	2	250	1.1	3.0	10	9.9	350
Station 175+00	Chowchilla Water District	2	250	1.1	3.0	10	9.9	350
City Creek Turnout (Pipeline)	San Bernardino Valley Municipal Water District	1	2 000	3.0	137.2	450	1.8	63
Clear Lake Dam	U. S. Water and Power Resources Service	1	430	1.9	8.2	27	6.2	220
Clear Lake Impounding Dam	Yolo County Flood Control and Water Conservation District	2	2 000	7.5	9.1	30	26.9	950
Cogswell Dam	Los Angeles County Flood Control District	1	500	3.0	54.9	180	1.1	40
Combie Dam	Nevada Irrigation District	2,4	1 000	4.0	21.3	70	5.7	200
Concow Dam	Thermalito Irrigation District and Table Mountain Irrigation District	1	130	0.5	25.9	85	0.6	21
Conejo Pump Station (Pipeline)	Calleguas Municipal Water District	2	600	3.0	51.8	170	1.4	50
Conn Creek Dam	(See Lake Hennessey)							
Corona (Pipeline)	Metropolitan Water District of Southern California	2,5	2 800	18.0	41.1	135	8.5	300
Cottonwood No. 1 (Canal)	California Department of Water Resources	2,7	17 000	115.0	41.1	135	48.1	1,700
Cottonwood No. 2 (Canal)	California Department of Water Resources	2	12 000	90.0	38.1	125	36.8	1,300
Covina (Pipeline)	Metropolitan Water District of Southern California	2,5	2 500	16.9	61.0	200	5.0	175
Coyote Creek (Dam)	Hidden Valley Lake Association	1	90	0.4	25.9	85	0.4	15
Coyote Creek (Pipeline)	Metropolitan Water District of Southern California	2,5	2 900	19.6	67.1	220	5.0	175
Coyote Dam	(See Lake Mendocino)							
Coyote Dam	Santa Clara Valley Water District	2	600	1.3	30.5	100	2.3	80
Dahlia Drop (Canal)	Imperial Irrigation District	1	225	1.0	2.7	9	9.9	350
Deer Creek Colletion Pipeline	Cucamonga County Water District	1	200	1.0	213.4	700	0.1	4

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Del Loma (Trinity) Tunnel	George Costa	2,3	250	1.9	3.4	11	8.5	300
Del Valle Stream Release (Dam)	California Department of Water Resources	2	400	1.1	36.6	120	1.4	50
Dodge Ave Check (Canal)	Orange Cove Irrigation District	2	475	2.4	1.8	6	42.5	1,500
Dominguez Gap Barrier (Pipeline)	Los Angeles County Flood Control District	1	500	2.0	103.6	340	0.6	20
Doris Dam	U. S. Fish and Wildlife Service	1	50	0.1	6.7	22	0.9	32
Early Intake Dam	City and County of San Francisco	1	1 300	8.7	15.2	50	10.6	375
East Highline Canal Turnout	Imperial Irrigation District	1	1 800	10.0	3.4	11	66.1	2,335
East Park Dam	U. S. Water and Power Resources Service	3	900	2.0	19.8	65	5.4	190
Eastside Pipeline	Lost Hills Water District	1	1 000	3.0	15.2	50	8.5	300
El Dorado Distribution System (Pipelines)								
Reservoir A	El Dorado Irrigation District	1	730	3.2	45.7	150	1.9	68
Reservoir B	El Dorado Irrigation District	2	50	0.2	36.6	120	0.2	6
Reservoir 2A	El Dorado Irrigation District	1	480	2.1	51.8	170	1.1	40
Reservoir 2A-3	El Dorado Irrigation District	2	360	1.6	36.6	120	1.2	42
Reservoir 3	El Dorado Irrigation District	1	200	0.9	36.6	120	0.7	23
Reservoir 4	El Dorado Irrigation District	1	70	0.3	36.6	120	0.2	8
Reservoir 5	El Dorado Irrigation District	1	60	0.3	36.6	120	0.2	7
Reservoir 6	El Dorado Irrigation District	1	80	0.3	36.6	120	0.3	9
Reservoir 8	El Dorado Irrigation District	1	175	0.8	36.6	120	0.6	20
Reservoir 9A	El Dorado Irrigation District	1	175	0.8	36.6	120	0.6	20
Reservoir 9B	El Dorado Irrigation District	1	90	0.4	36.6	120	0.3	10
Reservoir 10A	El Dorado Irrigation District	1	175	0.8	36.6	120	0.6	20
Reservoir 10B	El Dorado Irrigation District	1	60	0.3	36.6	120	0.2	7
El Segundo Distribution System (Pipeline)	City of El Segundo	2	500	3.9	76.2	250	0.8	28
Emerald Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	340	1.5	42.7	140	1.0	35
Elmer J. Chesbro Dam	(See Chesbro Reservoir)							
Escaladian Headworks (Canal)	Merced Irrigation District	2,6	300	1.2	4.6	15	7.9	280
Etiwanda Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	250	1.1	30.5	100	1.0	35

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Fairfield Drop (Canal)	Merced Irrigation District	2,6	900	3.6	9.4	31	11.9	420
Farmington Dam	U. S. Army Corps of Engineers	1	400	2.0	16.8	55	2.8	100
Fisher Drop (Canal)	Merced Irrigation District	1	75	0.3	1.2	4	7.4	260
Folsom Lake Pipeline	U. S. Water and Power Resources Service	2,4	500	2.4	7.6	25	7.9	280
Frankenheimer Drop (Canal)	South San Joaquin Irrigation District	2,5	4 700	18.7	23.8	78	25.5	900
Franklin Inlet (Pipeline)	City of Los Angeles	1	800	6.8	30.5	100	3.1	110
French Lake (Dam)	Nevada Irrigation District	1	200	0.8	22.9	75	1.1	40
Frenchman Dam	California Department of Water Resources	2	450	1.0	31.7	104	1.8	65
Fresno Main Canal								
Headworks	Fresno Irrigation District	1	650	2.6	3.0	10	25.5	900
Boos Check	Fresno Irrigation District	1	650	2.6	3.0	10	25.5	900
Dresser Check	Fresno Irrigation District	1	650	2.6	3.0	10	25.5	900
Friant Dam	(See Millerton Lake)							
Gibraltar Dam	City of Santa Barbara	3	1 500	4.0	42.7	140	4.2	150
Glendale Distribution System (Pipeline)	City of Glendale	2	400	2.0	61.0	200	0.8	28
Goodwin Dam	Oakdale and South San Joaquin Irrigation District	2,3	970	5.0	3.0	10	34.0	1,200
Gould Weir Diversion Dam	Fresno Irrigation District	2	850	3.5	1.8	6	56.6	2,000
Grant Lake (Dam)	City of Los Angeles	1	1 500	3.0	19.2	63	9.9	350
Grizzly Valley Dam	(See Lake Davis)							
Guadalupe Dam	Santa Clara Valley Water District	1	60	0.3	33.5	110	0.2	8
Harding Canal	Browns Valley Irrigation District	2,4	1 000	6.6	91.4	300	1.4	50
Hell Hole Reservoir (Lower Hell Hole Dam)	Placer County Water District	2,5	550	3.0	91.4	300	0.7	25
Henshaw Dam	Vista Irrigation District	1	200	1.0	33.5	110	0.1	25
Hensley Lake (Hidden Dam)	U. S. Army Corps of Engineers	4	1 300	4.0	30.5	100	5.9	210
Hetch Hetchy Reservoir (O'Shaughnessy Dam)	City and County of San Francisco	2	1 600	6.0	91.4	300	2.1	75
Hickman Spillway	Turlock Irrigation District	1	2 100	4.5	13.7	45	19.8	700
Hidden Dam	(See Hensley Lake)							
Highland Avenue Pumping Plant (Pipeline)	City of Redlands	2	600	2.6	152.4	500	0.5	17

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Hour House Dam	Yuba County Water Agency	1	100	0.3	9.1	30	1.4	50
Hume Lake (Dam)	U. S. Forest Service	4	1 050	4.6	8/		8/	
H.V. Eastman Lake (Buchanan Dam)	U. S. Army Corps of Engineers	4	3 000	9.0	41.1	135	8.8	310
Ice House Reservoir (Dam)	Sacramento Municipal Utility District	2	10 000	22.0	167.6	550	6.8	240
Indian Creek Dam	South Tahoe Public Utility District	1	50	0.1	6.1	20	1.1	40
Indian Valley Dam	Yolo County Flood Control & Water Conservation District	2	3 200	7.2	17.1	56	22.5	795
Irvine Lake Pipeline	Irvine Ranch Water District	2	500	1.0	67.1	220	0.8	30
Isabella Dam	U. S. Army Corps of Engineers	3	13 000	45.0	39.6	130	39.6	1,400
Jackson Creek Dam	(See Lake Amador)							
Jackson Meadows Dam	Nevada Irrigation District	2	4 000	8.9	51.8	170	8.5	300
Jackson-Sutter Creek Outfall Pipeline	Amador County Water Agency	1	60	0.2	85.3	280	0.1	3
Jameson Lake (Juncal Dam)	Montecito County Water District	1	60	0.4	85.3	280	0.1	3
Jenkinson Lake (Sly Park Dam)	U. S. Water and Power Resources Service	2,3	650	1.8	44.2	145	1.8	65
Juncal Dam	(See Jameson Lake)							
Kaiser Pipeline	Georgetown Divide Public Utility District	1	120	0.3	33.8	111	0.4	15
Kent Lake (Peters Dam)	Marin Municipal Water District	1	150	0.4	64.0	210	3.0	10
Kern Island Canal Control Structure	City of Bakersfield, et al	1	700	3.1	2.4	8	34.0	1,200
Lake Amador (Jackson Creek Dam)	Jackson Valley Irrigation District	2	350	2.5	51.2	168	0.8	30
Lake Arrowhead Dam	Arrowhead Lake Association	1	75	0.3	54.9	180	0.2	6
Lake Berryessa (Monticello Dam)	U. S. Water and Power Resources Service	2,5	16 000	43.0	61.0	200	31.1	1,100
Lake Clementine (North Fork Dam)	U. S. Army Corps of Engineers	3	11 000	60.0	36.6	120	36.0	1,275
Lake Curry (Pipeline)	City of Vallejo	1	50	0.3	76.2	250	0.2	3
Lake Davis (Grizzly Valley Dam)	California Department of Water Resources	2	510	1.5	33.5	110	1.8	65
Lake Davis - Portola Pipeline	Plumas County Flood Control and Water Conservation District	1	60	0.3	152.4	500	0.1	2
Lake Eleanor Dam	City of San Francisco	1	60	0.3	16.8	55	0.4	15
Lake Fordyce Dam	Pacific Gas and Electric Company	1	900	4.0	36.6	120	3.0	105
Lake Hemet Dam	Lake Hemet Municipal Water District	1	75	0.1	25.9	85	0.3	12

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities In California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Lake Hennessey (Conn Creek Dam)	City of Napa	1	500	2.3	33.5	110	1.8	65
Lake Hodges Dam	City of San Diego	1	270	1.2	18.6	61	1.7	61
Lake Kaweah (Terminus Dam)	U. S. Army Corps of Engineers	1	4 000	20.0	48.8	160	9.9	350
Lake Loveland Dam	South Bay Irrigation District	1	100	0.5	43.6	143	0.3	10
Lake Mary and Twin Lakes Open Diversion (Pipeline)	Mammoth County Water District	1	300	0.8	304.8	1,000	0.1	5
Lake Mendocino (Coyote Dam)	U. S. Army Corps of Engineers	2,4	4 000	21.0	33.5	110	14.2	500
Lake Pillsbury (Scott Dam)	Pacific Gas and Electric Company	3	5 000	15.0	35.1	115	9.6	340
Lake Piru (Santa Felicia Dam)	United Water Conservation District	3	3 600	7.8	57.9	190	7.5	265
Lake Redding (ACID Diversion Dam)	Anderson-Cottonwood Irrigation District	2,4	14 500	79.0	4.3	14	424.8	15,000
Lake Shastina (Shasta River Dam)	Montague Water Conservation District	2	200	0.7	15.2	50	1.7	60
Lake Siskiyou (Box Canyon Dam)	Siskiyou County Flood Control and Water Conservation District	2,4	6 000	21.9	56.4	185	12.7	450
Lake Thomas A. Edison (Vermillion Valley Dam)	Southern California Edison	1	2 000	9.6	42.7	140	5.7	200
Lake Valley Dam	Pacific Gas and Electric Company	1	75	0.3	19.8	65	0.5	16
Lake Yosemite Dam	Merced Irrigation District	1	1 200	2.3	12.2	40	12.2	430
Las Flores Turnout (Pipeline)	California Department of Water Resources	2	210	0.7	67.1	220	0.4	13
Lateral A (Chute)	Tulare Lake Basin Water Storage District	1	1 600	7.0	16.8	55	11.3	400
Lateral B (Chute)	Tulare Lake Basin Water Storage District	1	900	4.0	9.8	32	11.3	400
Lemoncove Ditch (At Terminus Dam)	U. S. Army Corps of Engineers	2	650	3.5	48.8	160	1.6	57
Leroy Anderson Dam	(See Anderson Lake)							
Lexington Dam	Santa Clara Valley Water District	1	500	2.9	45.7	150	1.3	45
Littlerock Dam	Palmdale Water District	1	50	0.2	32.0	105	0.2	7
Lopez Dam	San Luis Obispo County Flood Control and Water Conservation District	1	50	0.4	38.1	125	0.2	6
Los Angeles Distribution System (Pipelines)								
Location 1	City of Los Angeles	1	610	3.3	106.7	350	0.7	24
Location 2	City of Los Angeles	1	270	2.2	39.6	130	0.8	29

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Location 3	City of Los Angeles	1	420	2.1	36.6	120	1.4	49
Location 4	City of Los Angeles	1	270	1.8	61.0	200	0.5	19
Location 5	City of Los Angeles	1	140	1.2	39.6	130	0.4	15
Location 6	City of Los Angeles	1	190	1.1	91.4	300	0.3	9
Location 7	City of Los Angeles	1	120	1.0	48.8	160	0.3	10
Location 8	City of Los Angeles	1	130	0.8	38.1	125	0.4	14
Location 9	City of Los Angeles	1	70	0.6	64.0	210	0.1	5
Location 10	City of Los Angeles	1	100	0.6	48.8	160	0.3	9
Location 11	City of Los Angeles	1	70	0.6	21.3	70	0.4	14
Location 12	City of Los Angeles	1	100	0.6	73.2	240	0.2	6
Location 13	City of Los Angeles	1	60	0.5	27.4	90	0.3	9
Location 14	City of Los Angeles	1	60	0.5	30.5	100	0.2	8
Location 15	City of Los Angeles	1	1 000	8.2	11.9	39	10.2	360
Location 16	City of Los Angeles	1	1 800	9.0	29.6	97	7.4	260
Los Angeles Reservoir (Dam)	City of Los Angeles	1	6 200	37.0	33.5	110	22.7	800
Los Banos Detention Dam	U. S. Water and Power Resources Service	1	100	0.5	38.7	127	0.3	12
Los Padres Dam	California American Water Company	1	75	0.3	39.6	130	0.2	8
Lost Creek Diversion Dam	U. S. Forest Service	3	1 800	10.0	94.5	310	2.3	81
Lower Hell Hole Dam	(See Hell Hole Reservoir)							
Lower Mokelumne River Project	(See Camanche Dam)							
Lyons Dam	Pacific Gas and Electric Company	2	300	1.5	29.0	95	1.3	45
Lytle Creek Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	1 300	7.8	100.6	330	1.5	55
Madera Canal								
Station 980+65	U. S. Water and Power Resources Service	2	2 000	5.5	8.5	28	28.3	1,000
Station 1064+67	U. S. Water and Power Resources Service	2	560	1.9	30.4	10	22.7	800
Station 1910+60	U. S. Water and Power Resources Service	2	650	2.6	7.0	23	11.3	400
Mallard Reservoir (Pipeline)	Contra Costa County Water District	1	200	0.9	18.3	60	1.3	45
Mark Edson Dam	(See Stumpy Meadows Reservoir)							
Martilija Dam	Ventura County Flood Control District	1	700	2.0	35.1	115	2.4	85
Martis Creek Dam	U. S. Army Corps of Engineers	1	250	1.1	32.0	105	0.9	33
McCloud Dam	Pacific Gas and Electric Company	1	1 200	5.4	59.4	195	2.4	85
McCoy Flat Dam	Lassen Irrigation Company	1	50	0.2	4.6	15	1.3	46

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Merle Collins Reservoir (Virginia Ranch Dam)	Brown Valley Irrigation District	2,4	900	5.6	32.0	105	3.4	120
Middle Fork Dam	(See Schadds Reservoir)							
Millerton Lake								
Friant-Kern Canal	U. S. Water and Power Resources Service	2,4	15 000	68.0	26.5	87	68.0	2,400
Madera Canal	U. S. Water and Power Resources Service	2,4	5 000	23.0	32.6	107	18.4	650
San Joaquin River	U. S. Water and Power Resources Service	2,4	2 700	10.0	71.0	233	4.5	160
Miramar Treatment Plant (Pipeline)	City of San Diego	2	1 300	5.7	30.5	100	5.1	180
Moccasin Lower Dam	City of San Francisco	2	1 600	7.0	13.7	45	15.9	560
Modesto Reservoir (Dam)	Modesto Irrigation District	2	1 000	3.4	5.5	18	243.8	800
Mojave Siphon No. 1 (Silverwood Lake Inlet, Pipeline)	California Department of Water Resources	2	6 000	47.4	20.4	67	31.1	1,100
Mojave Siphon No. 2 (Silverwood Lake Inlet, Pipeline)	California Department of Water Resources	2	10 000	78.0	20.4	67	62.2	2,200
Mono Creek Diversion Dam	Southern California Edison	1	8/	8/	8/		8/	
Monticello Dam	(See Lake Berryessa)							
Mount Olivette (Pipeline)	City of Santa Monica	2	150	1.1	61.0	200	0.4	14
New Hogan Dam	U. S. Army Corps of Engineers	2,4	2 250	9.5	41.1	135	6.5	230
Newside Drop (Canal)	Imperial Irrigation District	1	200	0.9	2.7	9	8.8	310
New Siphon Drop (Yuma Main Canal)	U. S. Water and Power Resources Service	2,3	1 410	11.3	9.8	32	17.2	610
Nicasio Dam	Marin Municipal Water District	1	400	1.7	25.9	85	1.8	65
North Fork Dam	(See Pacheco Lake)							
North Fork Dam	(See Lake Clementine)							
No. 8 Heading (Canal)	Imperial Irrigation District	2	750	3.9	4.6	15	21.9	775
North Portal Tecolote Tunnel	U. S. Water and Power Resources Service	2	175	0.7	25.9	85	0.8	30
Orange County (OC) 28 (Pipeline)	Orange County Water District	1	6 300	12.0	106.7	350	7.1	250
Orange County (OC) 45 (Pipeline)	City of La Habra	1	100	8/	8/		8/	
Orange County (OC) 59 (Pipeline)	Orange County Water District	1	5 000	9.0	85.3	280	7.1	250
O'Shaughnessy Dam	(See Hetch Hetchy Reservoir)							
Pacheco Lake (North Fork Dam)	Pacheco Pass Water District	1	60	0.3	24.4	80	0.3	10

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Pacoima Dam	Los Angeles County Flood Control District	1	400	1.0	61.0	200	0.8	30
Palermo Canal Release	California Department of Water Resources	2	400	1.5	91.4	300	0.5	19
Palo Verde Diversion Dam	U. S. Water and Power Resources Service	2,3	8 700	65.0	4.6	15	229.4	8,100
Paradise Dam	Paradise Irrigation District	2	300	1.2	45.7	150	0.8	30
Parker Drop (Canal)	South San Joaquin Irrigation District	1	300	0.8	30.5	10	11.3	400
Parkview Station (Canal)	Anderson-Cottonwood Irrigation District	2	150	0.5	4.6	15	4.2	150
People's Weir (Canal)	People's Ditch Company	1	2 200	3.5	3.0	10	85.0	3,000
Perris Power Project (Pipeline)	Metropolitan Water District of Southern California	2,5	7 900	40.3	48.8	160	18.4	650
Peters Dam	(See Kent Lake)							
Pilarcitos Dam	City of San Francisco	1	200	0.8	85.3	280	0.3	10
Point Loma Wastewater Treatment Plant (Pipeline)	City of San Diego	1	1 200	8.0	23.2	76	6.2	220
Ponderosa Diversion Dam	Oroville-Wyandotte Irrigation District	1	3 300	14.0	18.3	60	21.5	760
Prosser Creek Dam	U. S. Water and Power Resources Service	2,4	1 000	3.5	28.7	94	4.2	150
Pumping Plant Lower (Canal)	Montague Water Conservation District	2	65	0.2	12.2	40	0.7	25
Pyramid Stream Release (Dam)	California Department of Water Resources	2	1 000	4.0	91.4	300	1.3	46
Rector Creek Dam	California Department of Finance	1	100	0.5	45.7	150	0.3	10
Red Bluff Diversion Dam	U. S. Water and Power Resources Service	2,4	14 000	70.0	4.0	13	424.8	15,000
Redlands Water Treatment Plant (Pipeline)	City of Redlands	2	200	0.9	22.9	75	1.0	37
Richard B. Parker (On Main Canal)	Merced Irrigation District	2,6	2 800	9.2	6.1	20	53.8	1,900
Rindge Dam	Adamson Companies	1	600	0.9	30.4	100	2.3	80
Rio Hondo (Pipeline)	Metropolitan Water District of Southern California	2,5	2 000	12.3	67.1	220	3.1	110
Robert A. Skinner Dam	Metropolitan Water District of Southern California	1	1 400	6.3	24.4	80	6.8	240
Robert W. Matthews Dam	(See Ruth Reservoir)							
Rocky Point Diversion Structure (Carrier Canal Project)	City of Bakersfield, et al	2,3	300	0.7	3.0	10	14.2	500
Round Valley Dam	Jack and Thomas Swickward	2	90	0.4	12.2	40	1.0	35

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Ruth Reservoir (Robert W. Matthews Dam)	Humboldt Bay Municipal Water District	2,4	4 000	14.2	41.1	135	11.6	410
Salt Spring Valley Reservoir (Dam)	Rock Creek Water District	1	90	0.4	7.6	25	1.4	50
San Antonio Dam	Monterey County Flood Control and Water Conservation District	2,4	6 000	25.6	51.8	170	15.3	540
Sand Creek Check (Canal)	Orange Cove Irrigation District	1	200	1.5	1.8	6	14.2	500
Sand Bar Project (Dam)	Oakdale and South San Joaquin Irrigation Districts	4	12 000	70.0	118.9	390	12.2	430
San Dieguito Treatment Plant (Pipeline)	San Dieguito Water District and Santa Fe Irrigation District	2	1 000	4.5	128.0	420	1.0	34
San Dimas Dam	Los Angeles County Flood Control District	1	100	0.3	25.9	85	0.5	16
San Dimas (Pipeline)	Metropolitan Water District of Southern California	2,7	9 900	68.2	121.9	400	8.5	300
San Gabriel Dam	Los Angeles County Flood Control District	2	500	3.0	61.0	200	1.3	45
Santa Ana Low Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	1 400	3.8	67.1	220	2.8	100
Santa Anita Dam	Los Angeles County Flood Control District	1	300	0.7	33.5	110	1.1	38
Santa Felicia Dam	(See Lake Piru)							
Santiago Creek (Pipeline)	Metropolitan Water District of Southern California	2,3	3 000	15.6	68.6	225	5.1	180
San Vicente Reservoir (Pipeline)	San Diego County Water Authority	2	850	3.4	45.7	150	2.3	80
Schaads Reservoir (Middle Fork Dam)	Calaveras Public Utility District	1	75	0.4	21.3	70	0.4	15
Scotts Flat Dam	Nevada Irrigation District	1	1 300	5.5	45.7	150	3.4	120
Scott Dam	(See Lake Pillsbury)							
Semitropic Intake Canal	Semitropic Water Storage District	1	8/	8/	8/		8/	
Sepulveda Canyon (Pipeline)	Metropolitan Water District of Southern California	2,5,7	8 600	56.2	91.4	300	13.5	475
Sidney N. Peterson Water Treatment Plant (Pipeline)	San Juan Suburban Water District	2	175	0.4	7.6	25	2.8	100
Slab Creek Dam	Sacramento Municipal Utility District	6	400	3.0	61.0	200	0.8	30

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities in California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Sly Creek Dam	Oroville-Wyandotte Irrigation District	2,5	13 200	48.2	68.6	225	23.1	815
Sly Park Dam	(See Jenkinson Lake)							
Snow Creek (Pipeline)	Desert Water Agency	1	300	1.7	22.9	750	0.1	5
South Canal	Pacific Gas and Electric Company	2	8 000	37.0	91.4	300	10.5	370
South Portal Doulton Tunnel	Montecito County Water District	1	200	0.5	213.4	700	0.1	4
Spicers Meadows Dam	Pacific Gas and Electric Company	1	750	3.3	14.6	48	6.2	220
Stampede Dam	U. S. Water and Power Resources Service	2,3	3 000	17.0	64.0	210	5.7	200
Stevens Creek Dam	Santa Clara Valley Water District	1	75	0.3	32.0	105	0.3	10
Stone Canyon Dam	City of Los Angeles	2	300	2.0	19.8	65	1.8	64
Stone Drop (Canal)	Modesto Irrigation District	2	1 000	4.0	5.5	18	22.7	800
Stony Gorge Dam	U. S. Water and Power Resources Service	4	6 000	18.0	30.5	100	24.1	850
Stumpy Meadows Reservoir (Mark Edson Dam)	Georgetown Divide Public Utility District	2	325	2.2	45.7	150	0.8	30
Success Dam	U. S. Army Corps of Engineers	4	4 000	12.0	36.6	120	13.0	460
Sweetwater Treatment Plant (Pipeline)	San Dieguito Water District and Santa Fe Irrigation District	2	1 400	6.3	121.9	400	1.4	50
Sweetwater Turnout (Pipeline)	San Bernardino Valley Municipal Water District of Southern California	2,4	875	2.2	61.0	200	2.4	85
Temescal (Pipeline)	Metropolitan Water District of Southern California	2,5	2 800	18.0	41.1	135	8.5	300
Terminal Reservoir Inlet (Pipeline)	San Luis Obispo County Flood Control and Water Conservation District	2	75	0.6	57.9	190	0.2	6
Terminus Dam	(See Lake Kaweah)							
Thermalito Afterbay River Outlet (Dam)	California Department of Water Resources	2,6	13 000	42.6	9.1	30	184.1	6,500
Thermalito Diversion Dam	California Department of Water Resources	2,6	3 500	23.0	21.3	70	19.8	700
Tinemaha Dam	City of Los Angeles	2	1 600	8.3	8.8	29	22.7	800
Trinity Tunnel	(See Del Loma Tunnel)							
Tuberose Check (Canal)	Imperial Irrigation District	1	200	1.3	3.0	10	7.9	280
Tule Lake (Dam)	R. W. Akers	1	75	0.3	4.3	14	2.3	80
Turlock Main Canal								
Drop No. 2	Turlock Irrigation District	2	700	2.1	1.8	6	48.1	1,700
Drop No. 6	Turlock Irrigation District	2,5	900	2.9	2.4	8	48.1	1,700

See footnotes on first page

Table A-2. List of Potential Small Hydroelectric Projects At Existing Hydraulic Facilities In California (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)
Drop No. 7	Turlock Irrigation District	2	700	2.1	2.4	8	36.8	1,300
Upper Dawson Powerplant (Canal)	Turlock Irrigation District	5	4 000	15.9	8.5	28	56.6	2,000
Upper Main Canal	Browns Valley Irrigation District	1	200	0.9	91.4	300	0.3	10
Uvas Dam	South Santa Clara Valley Water Conservation District	2	300	1.0	22.9	75	1.7	60
Vail Dam	Rancho California Water District	1	200	0.9	36.6	120	0.7	25
Vail Heading (Canal)	Imperial Irrigation District	2	225	1.0	4.9	16	5.7	200
Valley View (Pipeline)	Metropolitan Water District of Southern California	2,5	2 400	14.2	119.5	392	2.4	84
Van Owen Regulating (Pipeline)	City of Los Angeles	1	600	5.0	36.6	120	2.0	70
Venice (Pipeline)	Metropolitan Water District of Southern California	2,7	10 100	60.0	85.3	280	13.5	475
Vermilion Valley Dam	(See Lake Thomas A. Edison)							
Volta No. 2 Powerhouse (Canal)	Pacific Gas and Electric Company	7	1 000	5.0	36.6	120	3.3	115
Warm Springs Dam	U. S. Army Corps of Engineers	2,3	3 000	15.0	54.9	180	6.5	230
Waterman Canyon Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	4 000	7.0	153.9	505	3.3	115
Webber Dam	El Dorado Irrigation District	1	75	0.3	27.4	90	0.3	12
West Coast Basin Barrier (Pipeline)	Los Angeles County Flood Control District	2	500	4.2	56.4	185	1.1	40
West Valley Dam	South Fork Pit River Irrigation District	1	900	3.8	73.2	240	1.4	50
Whale Rock Dam	California Department of Finance	1	250	1.0	53.3	175	0.6	20
Whiskeytown Dam	U. S. Water and Power Resources Service	2,4	3 000	12.5	76.2	250	4.7	165
White Pines Dam	Calaveras County Water District	1	100	0.4	18.3	60	0.7	25
Whitewater Canyon Irrigation System (Pipeline)	Whitewater Canyon Mutual Water Company	2	400	2.5	182.9	600	0.3	9
Whitewater River (Pipeline)	Desert Water Agency	1	400	2.4	18.3	60	2.8	100
Woodward Dam	South San Joaquin Irrigation District	2,6	2 300	6.9	12.5	41	22.7	800
Yorba Linda Feeder (Pipeline)	Metropolitan Water District of Southern California	2,7	5 100	33.5	61.0	200	9.6	340
Youd Drop (Canal)	Merced Irrigation District	1	100	0.5	2.1	7	6.5	230
Yuma Main Canal	(See New Siphon Drop)							

See footnotes on first page

SECTION A-3

(Table A-3)

Table A-3 List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California

(Alphabetical by County)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Alameda				
Calaveras Dam	City & County of San Francisco	700	3.2	7.7
Del Valle Stream Release (Dam)	California Dept. of Water Resources	400	1.1	16.9
Alpine				
Indian Creek Dam	South Tahoe Public Utility District	50	0.1	54.6
Amador				
Central Amador Water Project	Amador County Water Agency	250	0.7	20.3
Jackson-Sutter Creek Outfall Pipeline	Amador County Water Agency	60	0.2	31.6
Lake Amador (Jackson Creek Dam)	Jackson Valley Irrigation District	350	2.5	5.1
Salt Spring Valley Reservoir (Dam)	Rock Creek Water District	90	0.4	18.4
Butte				
Concow Dam	Thermalito I.D. & Table Mt. I.D.	130	0.4	24.0
Palermo Canal Release (Dam)	California Dept. of Water Resources	400	1.5	14.5
Paradise Dam	Paradise Irrigation District	300	1.2	10.7
Ponderosa Diversion Dam	Oroville-Wyandotte Irrigation District	3 300	14.0	5.0
Sly Creek Dam	Oroville-Wyandotte Irrigation District	13 200	48.2	4.5
Thermalito Afterbay River Outlet (Dam)	California Dept. of Water Resources	13 000	42.6	12.1
Thermalito Diversion Dam	California Dept. of Water Resources	3 500	23.0	5.1
Calaveras				
Goodwin Dam	Oakdale & So. San Joaquin I.D.	970	4.7	4.6
New Hogan Dam	U.S. Army Corps of Engineers	2 250	9.5	5.7
Schaads Reservoir (Middle Fork Dam)	Calaveras Public Utility District	75	0.4	16.0
White Pines Dam	Calaveras County Water District	100	0.4	20.4

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Colusa				
East Park Dam	U.S. Water & Power Resources Service	900	2.0	13.5
Contra Costa				
Mallard Reservoir (Pipeline)	Contra Costa County Water District	200	0.9	14.0
El Dorado				
Buckeye Conduit	Georgetown Divide Public Utility District	350	2.4	5.4
Buffalo Hill Siphon	Georgetown Divide Public Utility District	160	0.5	20.3
El Dorado Distribution System	El Dorado Irrigation District			
Reservoir A		730	3.2	7.9
Reservoir 2		50	0.2	27.3
Reservoir 2A		480	2.1	9.9
Reservoir 2A-3		360	1.6	11.1
Reservoir 3		200	0.9	14.0
Reservoir 5		60	0.3	21.8
Reservoir 6		80	0.3	22.7
Reservoir 8		175	0.8	14.4
Reservoir 9A		175	0.8	14.4
Reservoir 9B		90	0.4	18.4
Reservoir 10A		175	0.8	14.4
Reservoir 10B		60	0.3	21.8
Ice House Reservoir (Dam)	Sacramento Municipal Utility District	10 000	22.0	--
Jenkinson Lake (Sly Park Dam)	U.S. Water & Power Resources Service	650	1.8	10.9
Kaiser Pipeline	Georgetown Divide Public Utility District	120	0.3	29.1
Slab Creek Dam	Sacramento Municipal Utility District	400	3.0	6.2
Stumpy Meadows Reservoir (Mark Edson Dam)	Georgetown Divide Public Utility	325	2.2	8.5
Webber Dam	El Dorado Irrigation District	75	0.3	24.1

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Fresno				
Fresno Main Canal	Fresno Irrigation District			
Headworks		650	2.6	9.1
Boos Check		650	2.6	9.1
Dresser Check		650	2.6	9.1
Gould Weir Diversion Dam	Fresno Irrigation District	850	3.5	23.7
Lake Thomas A. Edison (Vermillion Valley Dam)	Southern California Edison	2 000	9.6	4.9
Millerton Lake (Friant Dam)	U.S. Water & Power Resources Service			
Friant-Kern Canal		15 000	68.0	3.7
Madera Canal		5 000	23.0	4.0
San Joaquin River		2 700	10.0	5.9
Mono Creek Diversion Dam	Southern California Edison	1/	1/	--
Glenn				
Stony Gorge Dam	U.S. Water & Power Resources Service	6 000	18.0	6.4
Imperial				
All-American Canal Drop No. 1	U.S. Water & Power Resources Service	4 700	27.0	3.3
All-American Canal Drop No. 5	U.S. Water & Power Resources Service	5 000	24.0	4.0
Alamo Drop 3A (Canal)	Imperial Irrigation District	1 200	6.7	6.4
Dahlia Drop (Canal)	Imperial Irrigation District	225	1.0	13.2
East Highline Canal Turnout	Imperial Irrigation District	1 800	10.0	4.4
Newside Drop (Canal)	Imperial Irrigation District	200	0.9	14.0
No. 8 Heading (Canal)	Imperial Irrigation District	750	3.9	10.4
Tuberose Check (Canal)	Imperial Irrigation District	200	1.3	10.0
Vail Heading (Canal)	Imperial Irrigation District	225	1.0	17.8
Inyo				
Tinemaha Dam	City of Los Angeles	1 600	8.3	5.0

1/ Head and flow data not available

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Kern				
Beardsley Canal Control Structure	City of Bakersfield, et al	260	1.1	13.4
Beardsley Diversion Structure (Canal)	City of Bakersfield, et al	500	1.7	31.5
Eastside Pipeline	Lost Hills Water District	1 000	3.0	9.3
Isabella Dam	U.S. Army Corps of Engineers	8 000	18.5	8.0
Kern Island Canal Control Structure	City of Bakersfield & et al	700	3.1	7.9
Rocky Point Diversion Structure (Canal)	City of Bakersfield & et al	300	0.7	24.8
Semitropic Intake Canal	Semitropic Water Storage District	1/	1/	--
Kings				
Lateral A (Chute)	Tulare Lake Basin Water Storage District	1 600	7.0	5.9
Lateral B (Chute)	Tulare Lake Basin Water Storage District	900	4.0	6.7
Lake				
Clear Lake Impounding Dam	Yolo County F.C.&W.C.D	2 000	7.5	8.2
Coyote Creek (Dam)	Hidden Valley Lake Association	90	0.4	18.3
Indian Valley Dam	Yolo County F.C.&W.C.D	3 200	7.2	10.5
Lake Pillsbury (Scott Dam)	Pacific Gas & Electric Company	5 000	15.0	6.4
Lassen				
McCoy Flat Dam	Lassen Irrigation Company	50	0.2	27.3
Round Valley Dam	Jack & Thomas Swickward	90	0.4	18.4
Tule Lake (Dam)	R. W. Akers	75	0.3	24.1
Los Angeles				
Alamitos Barrier (Dam)	Los Angeles County F.C. District	300	1.0	15.8
Azusa Flow Control Structure (Pipeline)	San Gabriel Valley Municipal W.D.	740	3.2	7.7

1/ Head and flow data not available

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Los Angeles (Continued)				
Big Dalton Dam	Los Angeles County F.C. District	50	0.1	53.2
Big Dalton Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal W.D.	280	1.2	13.1
Big Tujunga No. 1 Dam	Los Angeles County F.C. District	300	1.3	12.2
Castaic Outlet (Dam)	California Dept. of Water Resources	275	1.4	10.7
Cogswell Dam	Los Angeles County F.C. District	500	3.0	7.0
Cottonwood No. 1 (Canal)	California Dept. of Water Resources	17 000	115.0	5.0
Cottonwood No. 2 (Canal)	California Dept. of Water Resources	12 000	90.0	2.3
Covina (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 500	16.9	3.3
Dominguez Gap Barrier (Pipeline)	Los Angeles County F.C. District	500	2.0	10.5
El Segundo Distribution System (Pipeline)	City of El Segundo	500	3.9	5.4
Emerald Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal W.D.	340	1.5	11.3
Etiwanda Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal W.D.	250	1.1	12.9
Franklin Inlet (Pipeline)	City of Los Angeles	800	6.8	3.9
Glendale Distribution System (Pipeline)	City of Glendale	400	2.0	6.9
Littlerock Dam	Palmdale Water District	50	0.2	27.3
Los Angeles Distribution System	City of Los Angeles			
Location 1		610	3.3	7.1
Location 2		270	2.2	6.9
Location 3		420	2.1	9.1
Location 4		270	1.8	8.4
Location 5		140	1.2	8.1
Location 6		190	1.1	10.9
Location 7		120	1.0	8.9
Location 8		130	0.8	12.0
Location 9		70	0.6	11.6

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Los Angeles (Continued)				
Location 10		100	0.6	13.6
Location 11		70	0.6	11.6
Location 12		100	0.6	13.6
Location 13		60	0.5	13.1
Location 14		60	0.5	13.1
Location 15		1 000	8.2	3.4
Location 16		1 800	9.0	4.9
Los Angeles Reservoir (Dam)	City of Los Angeles	6 200	37.0	3.2
Mount Olivette (Pipeline)	City of Santa Monica	150	1.1	7.9
Pacoima Dam	Los Angeles County F.C. District	400	1.0	18.6
Pyramid Stream Release (Dam)	California Dept. of Water Resources	1 000	3.2	9.0
Rindge Dam	Adamson Co.	600	0.9	25.7
Rio Hondo (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 000	12.3	4.0
San Dimas Dam	Los Angeles County F.C. District	100	0.3	27.3
San Dimas (Pipeline)	Metropolitan Water Dist. of So. Cal.	9 900	68.2	2.6
San Gabriel Dam	Los Angeles County F.C. District	500	3.0	7.0
Santa Anita Dam	Los Angeles County F.C. District	300	0.7	22.6
Sepulveda Canyon (Pipeline)	Metropolitan Water Dist. of So. Cal.	8 600	56.2	2.8
Stone Canyon Dam	City of Los Angeles	300	2.0	7.9
Van Owen Regulating (Pipeline)	City of Los Angeles	600	5.0	4.6
Venice (Pipeline)	Metropolitan Water Dist. of So. Cal.	10 100	60.0	3.0
West Coast Basin Barrier (Pipeline)	Los Angeles County F.C.D.	500	4.2	4.1
Madera				
Ash Main Canal	Chowchilla Water District	150	0.7	14.9
Califa Canal	Chowchilla Water District	200	0.9	14.0
Hensley Lake (Hidden Dam)	U.S. Army Corps of Engineers	1 300	4.0	8.7
H. V. Eastman Lake (Buchanan Dam)	U.S. Army Corps of Engineers	3 000	9.0	7.1

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Madera (Continued)				
Madera Canal	U.S. Water & Power Resources Service			
Station 985+65		2 000	5.5	3.8
Station 1064+67		560	1.9	11.8
Station 1910+60		650	2.6	9.1
Chowchilla Main Canal	Chowchilla Water District			
Station 0+00		250	1.1	12.9
Station 101+80		250	1.1	12.9
Station 175+00		250	1.1	12.9
Marin				
Kent Lake (Peters Dam)	Marin Municipal Water District	150	0.4	26.0
Nicasio Dam	Marin Municipal Water District	400	1.7	11.0
Mendocino				
Lake Mendocino (Coyote Dam)	U.S. Army Corps of Engineers	4 000	21.0	3.8
Merced				
Buhach (Canal)	Merced Irrigation District	60	0.3	21.8
Canal Creek	Merced Irrigation District	940	3.3	5.7
Escaladian Headworks (Canal)	Merced Irrigation District	270	0.8	8.3
Fairfield Drop (Canal)	Merced Irrigation District	970	2.8	6.3
Fisher Drop (Canal)	Merced Irrigation District	75	0.3	24.1
Lake Yosemite Dam	Merced Irrigation District	1 200	2.3	13.9
Los Banos Detention Dam	U.S. Water & Power Resources Service	100	0.5	16.4
Richard B. Parker (on Main Canal)	Merced Irrigation District	2 800	9.2	5.4
Youd Drop (Canal)	Merced Irrigation District	100	0.5	16.4
Modoc				
Big Sage Dam	Hot Springs Valley Irrigation District	175	0.7	16.5
Clear Lake (Dam)	U.S. Water & Power Resources Service	430	1.9	10.2

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Modoc (Continued)				
Doris Dam	U.S. Fish & Wildlife Service	50	0.1	54.6
West Valley Dam	South Fork Pit River Irrigation Dist.	900	3.8	7.1
Mono				
Cardinal Power House	Southern California Edison Co.	2 500	10.3	5.5
Lake Mary & Twin Lakes Open Diversion (Pipeline)	Mammoth County Water District	300	0.8	19.7
Monterey				
Los Padres Dam	California-American Water Company	75	0.3	24.1
San Antonio Dam	Monterey County F.C. & W.C.D.	6 000	25.6	11.8
Napa				
Cache Slough (Pipeline)	City of Vallejo	600	4.1	5.6
Lake Berryessa (Monticello Dam)	U.S. Water & Power Resources Service	16 000	43.0	4.1
Lake Curry (Pipeline)	City of Vallejo	50	0.3	27.3
Lake Hennessey (Conn Creek Dam)	City of Napa	500	2.3	9.1
Rector Creek Dam	California State Dept. of Finance	100	0.5	16.4
Nevada				
Anthony House Dam	Lake Wildwood Association	50	0.2	27.3
Boca Dam	U.S. Water & Power Resources Service	2 000	5.6	8.5
Bowman Dam	Nevada Irrigation District	3 000	14.7	2.7
Combie Dam	Nevada Irrigation District	525	2.9	7.5
French Lake (Dam)	Nevada Irrigation District	200	0.8	15.8
Hour House (Dam)	Yuba County Water Agency	100	0.3	27.3
Jackson Meadows Dam	Nevada Irrigation District	4 000	8.9	5.4
Lake Fordyce Dam	Pacific Gas & Electric Company	900	4.0	6.7
Martis Creek (Dam)	U.S. Army Corps of Engineers	250	1.1	12.9
Prosser Creek Dam	U.S. Water & Power Resources Service	1 000	3.5	8.0
Scotts Flat Dam	Nevada Irrigation District	1 300	5.5	6.3

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Modoc (Continued)				
Doris Dam	U.S. Fish & Wildlife Service	50	0.1	54.6
West Valley Dam	South Fork Pit River Irrigation Dist.	900	3.8	7.1
Mono				
Cardinal Power House	Southern California Edison Co.	2 500	10.3	5.5
Lake Mary & Twin Lakes Open Diversion (Pipeline)	Mammoth County Water District	300	0.8	19.7
Monterey				
Los Padres Dam	California-American Water Company	75	0.3	24.1
San Antonio Dam	Monterey County F.C. & W.C.D.	6 000	25.6	11.8
Napa				
Cache Slough (Pipeline)	City of Vallejo	600	4.1	5.6
Lake Berryessa (Monticello Dam)	U.S. Water & Power Resources Service	16 000	43.0	4.1
Lake Curry (Pipeline)	City of Vallejo	50	0.3	27.3
Lake Hennessey (Conn Creek Dam)	City of Napa	500	2.3	9.1
Rector Creek Dam	California State Dept. of Finance	100	0.5	16.4
Nevada				
Anthony House Dam	Lake Wildwood Association	50	0.2	27.3
Boca Dam	U.S. Water & Power Resources Service	2 000	5.6	8.5
Bowman Dam	Nevada Irrigation District	3 000	14.7	2.7
Combie Dam	Nevada Irrigation District	525	2.9	7.5
French Lake (Dam)	Nevada Irrigation District	200	0.8	15.8
Hour House (Dam)	Yuba County Water Agency	100	0.3	27.3
Jackson Meadows Dam	Nevada Irrigation District	4 000	8.9	5.4
Lake Fordyce Dam	Pacific Gas & Electric Company	900	4.0	6.7
Martis Creek (Dam)	U.S. Army Corps of Engineers	250	1.1	12.9
Prosser Creek Dam	U.S. Water & Power Resources Service	1 000	3.5	8.0
Scotts Flat Dam	Nevada Irrigation District	1 300	5.5	6.3

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Orange				
Balboa (Pipeline)	Metropolitan Water Dist. of So. Cal.	1 200	9.1	3.5
Coyote Creek (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 900	19.6	3.1
Irvine Lake Pipeline (Rattlesnake Reservoir)	Irvine Ranch Water District	500	1.0	20.9
Orange County (OC) 28 (Pipeline)	Orange County Water District	6 300	12.0	10.2
Orange County (OC) 45 (Pipeline)	City of La Habra	100	1/	--
Santiago Creek (Pipeline)	Metropolitan Water Dist. of So. Cal.	3 000	15.6	4.1
Valley View (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 400	14.2	3.8
Yorba Linda Feeder (Pipeline)	Metropolitan Water Dist. of So. Cal.	5 100	33.5	2.9
Placer				
Camp Far West Dam	South Sutter Water District	6 800	26.9	4.7
Folsom Lake Pipeline	U. S. Water & Power Resources Service	500	2.4	8.7
Hell Hole Reservoir (Lower Hell Hole Dam)	Placer County Water Agency	550	3.0	7.4
Lake Clementine (North Fork Dam)	U.S. Army Corps of Engineers	12 000	63.5	3.2
Lake Valley Dam	Pacific Gas & Electric Company	75	0.3	24.1
Sidney N. Peterson Water Treatment Plant (Pipeline)	San Juan Suburban Water District	175	0.4	28.8
South Canal	Pacific Gas & Electric Company	8 000	37.0	4.0
Plumas				
Antelope Dam	California Dept. of Water Resources	450	1.4	22.8
Bucks Lake (Bucks Storage Dam)	Pacific Gas & Electric Company	740	3.2	8.0
Frenchman Dam	California Dept. of Water Resources	450	1.0	20.0
Lake Davis (Grizzly Valley Dam)	California Dept. of Water Resources	510	1.5	15.5
Lake Davis-Portola Pipeline	Plumas County Water Conservation District	60	0.3	21.8
Little Grass Valley Dam	Oroville-Wyandotte Irrigation District	2 600	6.5	8.8

1/ Head and flow data not available

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Riverside				
Corona (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 800	18.0	3.3
Lake Hemet Dam	Lake Hemet Municipal Water District	75	0.1	72.2
Palo Verde Diversion Dam	U.S. Water & Power Resources Service	8 700	65.0	2.6
Perris Power Project (Pipeline)	Metropolitan Water Dist. of So. Cal.	7 900	40.3	3.6
Snow Creek (Pipeline)	Desert Water Agency	300	1.7	9.3
Robert A. Skinner Dam	Metropolitan Water Dist. of So. Cal.	1 400	6.3	5.8
Temescal (Pipeline)	Metropolitan Water Dist. of So. Cal.	2 800	18.0	3.3
Vail Dam	Rancho California Water District	200	0.9	14.0
Whitewater Canyon Irrigation System (Pipeline)	Whitewater Canyon Mutual Water Company	400	2.5	7.8
Whitewater River (Pipeline)	Desert Water Agency	400	2.4	7.7
San Bernardino				
Benson Feeder Pipeline	Monte Vista County Water District	1/	1/	--
City Creek Turnout (Pipeline)	San Bernardino Valley Municipal W.D.	2 000	3.0	15.8
Deer Creek Collection Pipeline	Cucamonga County Water District	200	1.0	12.2
Highland Avenue Pumping Plant (Pipeline)	City of Redlands	600	2.6	8.9
Lake Arrowhead Dam	Arrowhead Lake Association	75	0.3	24.1
Las Flores Turnout (Pipeline)	California Dept. of Water Resources	210	0.7	20.0
Lytle Creek Turnout (Pipeline)	San Bernardino Valley Municipal W.D.	1 300	7.8	4.6
Mojave Siphon No. 1 (Silverwood Lake Inlet, Pipeline)	California Dept. of Water Resources	6 000	47.0	6.2
Mojave Siphon No. 2 (Silverwood Lake Inlet, Pipeline)	California Dept. of Water Resources	10 000	78.0	2.3
Orange County (OC) 59 (Pipeline)	Orange County Water District	5 000	9.4	10.1
Redlands Water Treatment Plant (Pipeline)	City of Redlands	200	0.9	14.0
Santa Ana Low Turnout (Pipeline)	San Bernardino Valley Municipal W.D.	1 400	3.8	8.0

1/ Head and flow data not available

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
San Bernardino (Continued)				
Sweetwater Turnout (Pipeline)	San Bernardino Valley Municipal W.D.	875	2.2	9.5
Waterman Canyon Turnout (Pipeline)	San Bernardino Valley Municipal W.D.	4 000	7.0	7.5
San Diego				
Alvarado Treatment Plant (Pipeline)	City of San Diego	1 700	8.4	5.1
Barrett Dam	City of San Diego	60	0.2	32.8
Bear Valley Powerplant Rehabilitation (at Lake Wohlford Dam)	Escondido Mutual Water Company	700	3.7	6.6
Henshaw Dam	Vista Irrigation District	200	1.0	12.6
Lake Hodges Dam	City of San Diego	270	1.2	12.6
Lake Loveland Dam	South Bay Irrigation District	100	0.5	16.4
Miramar Treatment Plant (Pipeline)	City of San Diego	1 300	5.7	6.1
Point Loma Wastewater Treatment Plant (Pipeline)	City of San Diego	1 200	8.0	4.0
San Dieguito Treatment Plant (Pipeline)	San Dieguito W.D. & Santa Fe I.D.	1 000	4.5	6.2
San Vicente Reservoir (Pipeline)	San Diego County Water Authority	850	3.4	7.7
Sweetwater Treatment Plant (Pipeline)	San Dieguito W.D. & Santa Fe I.D.	1 400	6.3	5.8
San Joaquin				
Camache Dam	East Bay Municipal Utility District	10 680	35.0	5.5
Farmington Dam	U.S. Army Corps of Engineers	400	2.0	9.3
Parker Drop (Canal)	South San Joaquin Irrigation District	300	0.8	19.7
San Luis Obispo				
Lopez Dam	San Luis Obispo County F.C. & W.C.D.	50	0.4	13.7
Terminal Reservoir Inlet (Pipeline)	San Luis Obispo County F.C. & W.C.D.	75	0.6	10.7

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
San Mateo				
Pilarcitos Dam	City & County of San Francisco	200	0.8	15.8
Santa Barbara				
Alisal Creek Dam	Petan Company	50	0.2	27.3
Carneros Power Project (Pipeline)	Goleta County Water District	700	1.6	15.4
Gibraltar Dam	City of Santa Barbara	1 500	4.0	9.8
Jameson Lake (Juncal Dam)	Montecito County Water District	60	0.4	16.4
North Portal Tecolote Tunnel	U.S. Water & Power Resources Service	175	0.7	22.4
South Portal Doulton Tunnel	Montecito County Water District	200	0.5	25.2
Santa Clara				
Anderson Lake (Leroy Anderson Dam)	Santa Clara Valley Water District	500	2.2	8.0
Calero Dam	Santa Clara Valley Water District	100	0.5	16.4
Chesbro Reservoir (Elmer J. Chesboro Dam)	South Santa Clara Valley W & C.D.	100	0.2	36.8
Coyote Dam	Santa Clara Valley Water District	600	1.3	12.4
Guadalupe Dam	Santa Clara Valley Water District	60	0.3	21.8
Lexington Dam	Santa Clara Valley Water District	500	2.9	7.2
Pacheco Lake (North Fork Dam)	Pacheco Pass Water District	60	0.3	21.8
Stevens Creek Dam	Santa Clara Valley Water District	75	0.3	24.1
Uvas Dam	South Santa Clara Valley W & C.D.	300	1.0	13.1
Santa Cruz				
Big Creek Hydroelectric Plant Rehabilitation (Pipeline)	Lockheed Missiles & Space Company, Inc.	800	3.0	8.8
Shasta				
Anderson Flume Diversion	Anderson-Cottonwood Irrigation District	50	0.2	28.5
Lake Redding (ACID Diversion Dam)	Anderson-Cottonwood Irrigation District	14 500	79.0	9.7

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Shasta (Continued)				
Lost Creek Diversion Dam	U.S. Forest Service	1 800	10.0	4.4
McCloud Dam	Pacific Gas & Electric Company	1 200	5.4	5.9
Parkview Station (Canal)	Anderson-Cottonwood Irrigation District	150	0.5	15.8
Volta No. 2 Powerhouse (Canal)	Pacific Gas & Electric Company	1 000	5.0	6.0
Whiskeytown Dam	U.S. Water & Power Resources Service	4 000	19.5	3.6
Sierra				
Stampede Dam	U.S. Water & Power Resources Service	3 000	16.0	4.3
Siskiyou				
Lake Shastina (Shasta River Dam)	Montague Water Conservation District	200	0.7	13.4
Lake Siskiyou (Box Canyon Dam)	Siskiyou County F.C. & W.C.D.	6 000	21.9	5.3
Pumping Plant Lower (Canal)	Montague Water Conservation District	65	0.2	34.4
Stanislaus				
Turlock Main Canal	Turlock Irrigation District			
Canal Drop No. 2		660	2.1	7.6
Canal Drop No. 6		920	2.9	6.7
Canal Drop No. 7		700	2.1	8.0
Ceres Spillway (Canal)	Turlock Irrigation District	2 100	4.5	10.8
Frankenheimer Drop (Canal)	South San Joaquin Irrigation District	4 700	17.0	4.4
Hickman Spillway (Canal)	Turlock Irrigation District	2 100	4.5	10.8
Modesto Reservoir (Dam)	Modesto Irrigation District	1 000	3.4	9.6
Stone Drop (Canal)	Modesto Irrigation District	1 000	4.0	9.6
Upper Dawson Power Plant	Turlock Irrigation District	4 000	15.9	5.0
Woodward Dam	South San Joaquin Irrigation District	2 300	6.9	5.0

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Tehama				
Black Butte Dam	U.S. Army Corps of Engineers	9 200	31.3	6.4
Red Bluff Diversion Dam	U.S. Water & Power Resources Service	14 000	70.0	3.4
Trinity				
Del Loma Tunnel	George Costa	250	1.9	10.2
Ruth Reservoir (Robert W. Matthews Dam)	Humboldt Bay Municipal Water District	4 000	14.2	5.6
Tulare				
Dodge Ave Check (Canal)	Orange Cove Irrigation District	475	2.4	8.6
Lake Kaweah (Terminus Dam)	U.S. Army Corps of Engineers	4 000	20.0	4.0
Lemoncove Ditch (At Terminus Dam)	U.S. Army Corps of Engineers	650	3.5	7.7
People's Weir (Canal)	People's Ditch Company	2 200	3.5	14.5
Sand Creek Check (Canal)	Orange Cove Irrigation District	200	1.5	8.4
Success Dam	U.S. Army Corps of Engineers	4 000	12.0	6.6
Tuolumne				
Early Intake Dam	City & County of San Francisco	1 300	8.7	4.0
Hetch Hetchy Reservoir (O'Shaughnessy Dam)	City & County of San Francisco	1 600	6.0	6.9
Lake Eleanor Dam	City & County of San Francisco	60	0.3	21.8
Lyons Dam	Pacific Gas & Electric Company	300	1.5	10.5
Moccasin Lower Dam	City & County of San Francisco	1 600	7.0	5.9
Sand Bar Project (Dam)	Oakdale & South San Joaquin I.D.	12 000	70.0	2.9
Spicers Meadows Dam	Pacific Gas & Electric Co.	750	3.3	7.8
Ventura				
Casitas Dam	U.S. Water & Power Resources Service	700	2.0	12.3
Conejo Pump Station	Calleguas Municipal Water District	600	3.0	7.7

Table A-3. List of Potential Small Hydroelectric Projects at Existing Hydraulic Facilities in California (Continued)

County/Facility	Owner	Capacity (kW)	Energy (GWh/yr)	1984 Energy Cost (¢/kWH)
Ventura (Continued)				
Lake Piru (Santa Felicia Dam)	United Water Conservation District	3 600	7.8	9.1
Matilija Dam	Ventura County Flood Control District	700	2.0	12.3
Yuba				
Harding Canal	Browns Valley Irrigation District	1 000	6.6	4.5
Merle Collins Reservoir (Virginia Ranch Dam)	Browns Valley Irrigation District	900	5.6	4.9
Upper Main Canal	Browns Valley Irrigation District	200	0.9	14.0

APPENDIX B

Field Investigations Conducted by the Department of Water Resources

Field Investigations Conducted by the Department of Water Resources

From the total inventory of 285 existing facilities with a potential for hydroelectric power development the Department selected 49 representative hydraulic structures for on-site inspections. During these inspections, the physical characteristics of the site were noted, including head and flow, types of conduits, gates and valves, and environmental data. The following is a brief description of each of the 49 facilities examined.

1. Anderson Flume

The Anderson Flume is the elevated concrete section of the Anderson Canal that crosses Anderson Creek in the City of Anderson in Shasta County. The flume and canal are owned and operated by the Anderson-Cottonwood Irrigation District. The site is a short distance upstream from where canal's flow enters the flume; there, water is dropped from the canal to a lower irrigation ditch for local use on the north side of Anderson Creek. The head is about 7 metres (m) or 23 feet (ft), and the average flow for the five-month period from May to September is about 1 cubic metre per second (cms) or 35 cubic feet per second (cfs). The potential capacity of the site is 50 kilowatt (kW), and the average annual output would be about 180 000 kilowatthours (kWh). A 13 kV transmission line owned by PGandE is located about 61 m (200 ft) from the site.

2. Parkview Station

Parkview Station is an overflow spillway for the Anderson Canal in Redding in Shasta County. It is owned and operated by the Anderson-Cottonwood Irrigation District. At this point on the canal, the flow can be blocked by installing stoplogs to divert the flow through the spillway to a ditch that connects to the Sacramento River. In this way, the canal can be used as a forebay for a hydroelectric plant during the nonirrigating season of November through March. The head is about 4.6 m (15 ft), and the flow available is about 4.2 cms (150 cfs). The potential capacity is 150 kW, and the average annual output would be about 548 000 kWh. A 13 kV transmission line is located about 30.5 m (100 ft) from the facility.

3. Harding Canal

The Harding Canal, a water conveyance facility near Browns Valley in Yuba County, is also owned and operated by the Browns Valley Irrigation District. It is a lateral canal that begins near the outlet of the Virginia Ranch Dam diversion tunnel on Dry Creek and extends southward to Tennesee Creek which conveys the water to the District's main canal. By extending the existing Harding Canal about 0.8 km (0.5 mi) along the 335 m (1100 ft) elevation contour, a penstock and powerhouse could be constructed to develop about 91 m (300 ft) of head for hydroelectric generation. After water flows through the powerhouse, it would be delivered to the District's main canal. Assuming an average flow of 1.4 cms (50 cfs) during the irrigation season, the Harding Canal site could develop about 1 000 kW of capacity, with an annual output of about 6.6 million kWh. It would be necessary to build about 1.6 kilometres (km) or 1 mile (mi) of 13 kV transmission line across undeveloped lands to connect to an existing PGandE transmission line.

4. Merle Collins Reservoir (Virginia Ranch Dam)

Virginia Ranch Dam is an earthfill structure on Dry Creek near the community of Browns Valley in Yuba County. It is owned and operated by the Browns Valley Irrigation District. The dam forms Merle Collins Reservoir from where irrigation water is diverted by a tunnel and canal system to Browns Valley. Water is released through a valve to a concrete energy dissipator channel from where it flows, by gravity, to the District's canal system. Irrigation releases are made April through October; the largest releases of 3.4 cms (120 cfs) are made during July and August. The net operating head varies from about 32 m (105 ft) at the beginning of the irrigation season to about 24 m (80 ft) at the end of the season. A 900 kW generating unit at the facility could produce about 5.6 million kWh annually. A 13 kV transmission line owned by PGandE is located about 1.6 km (1 mi) from the power plant site.

5. Frenchman Dam

Frenchman Dam is an earthfill structure on Little Last Chance Creek near Portola. It is owned and operated by the Department of Water Resources. Irrigation water is released under contract to the Sierra Valley. When the dam was constructed, provisions were made for later installation of hydroelectric generation capacity. A turbine/generator unit could be installed at the site after modifying of the existing outlet works. The potential hydroelectric capacity is about 450 kW, and the estimated annual output is about 1 million kWh. The nearest transmission line is located about 8 km (5 mi) from the facility and is owned by the Sierra-Plumas Rural Electric Cooperative.

6. Beardsley Diversion Dam

Beardsley Diversion Dam is another timber dam on the Kern River near Bakersfield. It is also owned and operated by the City of Bakersfield, Kern Delta Water District, and North Kern Water District. Water diverted into a canal north of and running parallel to the Kern River is also used for municipal and industrial use in Bakersfield. The dam is 1.6 km (1 mi) upstream from the Rocky Point Diversion Dam. A hydroelectric power facility constructed here could use the flow of the Kern River that is not diverted into the Beardsley Canal. At Rocky Point downstream, this water is diverted into a canal on the south side of the river. The Beardsley Diversion Dam provides about a 1.5 m (5 ft) head for hydroelectric generation. The potential generation capacity is about 500 kW, and the annual output would be about 1 747 000 kWh. A 13 kV transmission line is located near the facility.

7. Rocky Point Diversion Dam

Rocky Point Diversion Dam is a timber dam on the Kern River at Bakersfield. It is owned and operated by the City of Bakersfield, Kern Delta Water District, and North Kern Water District. Water diverted into a canal south of and running parallel to the Kern River is used for municipal and industrial purposes in Bakersfield. The canal contains two check structures, one at the head of the canal near the Rocky Point Diversion dam and the other about 1.6 km (1 mi) downstream. It may be possible to combine the two check structures to develop a hydroelectric facility which would result in about a 3.1 m (10 ft) head. The potential hydroelectric capacity is about 300 kW, and the estimated annual output is 660 000 kWh. A 13 kV transmission line owned by PGandE is located near the site.

8. Glendale Distribution

The Glendale Distribution System is owned and operated by the City of Glendale in Los Angeles County. The system distributes water over a 79 sq km (30 sq mi) area. The source of water is the Metropolitan Water District of Southern California (MWD), which is connected to the Glendale Distribution System by a pressure-reducing valve used to drop the 61 m (200 ft) of pressure differential between MWD and Glendale. The average daily flow is about 0.3 cms (10 cfs). During April, May, and June, the months of maximum water demand, the average daily flow is 0.7 cms (25 cfs).

Water flows through the system continuously, and yields between 8600 and 9300 cubic dekametres (7000 and 7500 acre-feet) per year. The site proposed for a hydroelectric facility is on property owned by the City of Glendale at the northeast corner of Glendale Avenue and Glenoaks Boulevard. The potential capacity is 400 kW, and the average annual output would be about 1.98 million kWh. A 4 kV transmission line owned by the City of Glendale, is located about 16 m (50 ft) from the site. The power generated would be used by the city-owned electric utility.

9. Alvarado Treatment Plant

The Alvarado facility is a pressure reduction vault at the Alvarado Water Treatment Plant located near Lake Murray. It is owned and operated by the Water Utilities Department of San Diego. Water from the second San Diego aqueduct is delivered to the site at a relatively high pressure. The pressure is then reduced by globe valves for delivery to the El Monte pipeline. The potential hydroelectric capacity is about 800 kW, and the estimated annual output would be about 5 645 000 kWh based on flows measured in 1975-76. With a projected 33 percent increase in these flows over the next five years, reconnaissance-level studies may indicate that a 1000 kW generating unit could be installed at the Alvarado facility. A transmission connection can be made.

10. Miramar Treatment Plant

The Miramar facility is a pressure reduction vault near the Miramar Water Treatment Plant located east of Route 15 and north of Pomerado Road in San Diego. It is owned and operated by the Water Utilities Department of San Diego. Water from the second San Diego Aqueduct is delivered to the site at relatively high pressure. The pressure is reduced by globe valves suitable for use at this plant. The potential hydroelectric capacity is about 500 kW, and the annual output would be about 4 million kWh based on flows measured in 1975-76. These flows are expected to increase between 1980 and 1985. A transmission line owned by San Diego Gas and Electric (SDG&E) is located at the site.

11. Moccasin Reregulating Dam

The Moccasin Reregulating facility (also called the Moccasin Lower site) is the afterbay for the Hetch-Hetchy hydroelectric plant; it provides the headwaters for the diversion tunnel that carries water to San Francisco via the Hetch-Hetchy Aqueduct. The site is owned and operated by the City and County of San Francisco and is located on Moccasin Creek east of Sonora in Tuolumne County. Only the water that is not diverted to the aqueduct would be available for hydroelectric generation. A 1979 feasibility study by the City of San Francisco indicated the potential capacity of the site to be 1600 kW. The average annual output was estimated at about 7 million kWh, and the cost of power production was estimated at 1.65 cents per kWh.

12. Mount Olivette Pressure Break

Mount Olivette is a pipeline pressure break owned and operated by the city of Santa Monica in Los Angeles County. Water is delivered to the site from the Metropolitan Water District via a 457 millimetre (18-inch) cast-iron pipeline 1066 m (3500 ft) long. The water is delivered to the Santa Monica water distribution system for the 107 m (350 ft) pressure zone. The net operating head varies with the water flow from about 58 m to 67 m (185 ft to 215 ft) due to friction losses in the long pipeline. A 150 kW generating unit at the site could produce about 1 116 000 kWh annually. A 4 kV transmission line owned by Southern California Edison Company (SCE) is located at the site.

13. Chowchilla Main Canal

The Chowchilla Main Canal carries irrigation flows diverted from the Chowchilla River. It is owned and operated by the Chowchilla Water District in Madera County. Three check structures along the canal might be used for hydroelectric generation; they are characterized by very low heads of less than 3 m (10 ft) during periods of high flows. Flows during March to June are about 7.6 cms (250 cfs) and increase to about 11.4 cms (375 cfs) from June through August. The potential capacity at each of the three sites is 150 kW to 200 kW, and the total energy output of the three sites for the five-month irrigation season would be about 2 million kWh. The District has a feasibility study in progress.

14. Fresno Main Canal

The Fresno Main Canal carries irrigation flows diverted from the Kings River east of Fresno County. It is owned and operated by the Fresno Irrigation District. Six check structures, located along the canal, including the head gate, have been identified by the District as potential hydroelectric sites. The sites are characterized by very low heads of 1 m to 2 m (3 ft to 6 ft) and high flows of 27 cms (900 cfs). The District has feasibility studies in progress for the three most promising sites, which have a combined potential of 1150 kW.

15. Gould Weir Diversion

Gould Weir, a diversion structure on the Kings River, is located east of Fresno downstream from Pine Flat Reservoir in Fresno County. It is owned and operated by the Fresno Irrigation District. The weir diverts water into the Enterprise Canal for irrigation. Hydroelectric development at the facility would use water that now flows over the weir. The facility is characterized by a low head of about 2 m (6 ft) and high flows of 60 cms to 105 cms (2000 cfs to 3700 cfs) during the summer months. The potential capacity is about 850 kW, and the estimated annual output would be about 3 490 000 kWh. A 13 kV transmission line is located about 152 m (500 ft) from the facility.

16. Del Loma Tunnel

The Del Loma Tunnel was constructed in the late 1800s to serve as a by-pass for waters of the Trinity River to permit gold mining in the streambed where the river makes a horseshoe bend. The tunnel is on privately-owned property about 32 km (20 mi) west of Weaverville in Trinity County. The tunnel's intake is at an elevation that allows a small part of the existing streamflow to pass through the tunnel. The available head is about 3.4 m (11 ft). The potential capacity is about 250 kW, and the average annual output would be about 1.9 million kWh. A 13 kV transmission line owned by PGandE is located about 61 m (200 ft) from the structure. Since the Trinity River has been designated as a Wild and Scenic River, any environmental impact may be significant. It would be difficult to develop the hydroelectric potential at this facility.

17. Buckeye Conduit

Buckeye Conduit is an irrigation pipeline located about 3.2 km (2 mi) northeast of Georgetown in El Dorado County. It is owned and operated by the Georgetown Divide Public Utility District. The conduit carries water about 3.2 km (2 mi) from Lake Walton to the Georgetown Divide Ditch. The net head is 56 m (180 ft), with summer flows of approximately 0.8 cms (230 cfs). During wet years, this flow could be extended into the winter months. The flow is controlled by a butterfly valve and a concrete energy-dissipation structure. The potential capacity is 350 kW and the average annual output would be about 2.4 million kWh. A 13 kV transmission line owned by PGandE is located about 94 m (300 ft) from the facility.

18. Stumpy Meadows Reservoir (Mark Edson Dam)

Stumpy Meadows is a reservoir formed by Mark Edson Dam, an earthfill structure on Pilot Creek 8 km (5 mi) east of Quintette in El Dorado County. It is owned and operated by the Georgetown Divide Public Utility District. The dam conserves water for irrigation and domestic us. The net head varies from 40 m to 48 m (127 ft to 154 ft), and the flow is 0.8 cms (30 cfs) for 9.5 months of the year. The potential capacity is 325 kW, and the average annual output would be about 2.2 million kWh. A single-phase, 35 kV transmission line is located about 6.4 km (4 mi) from the site. Development of a hydroelectric plant at the site would require the construction of 6.4 km (4 mi) of a 13 kV transmission line and upgrading the existing 14.5 km (9 mi) single-phase transmission line to a three-phase line.

19. Ruth Reservoir (Robert W. Matthews Dam)

Robert W. Matthews Dam is an earthfill structure owned and operated by the Humboldt Bay Municipal Water District on the Mad River. It is located about 8 km (5 mi) west of Forest Glen in Trinity County. The dam, which creates Ruth Reservoir, was constructed in 1962 to provide water for Humboldt Bay, Eureka, Arcata, McKinleyville, and several other agencies. The average flow into the reservoir exceeds its storage capacity and is discharged through the spillway. The potential capacity is about 1600 kW, and the average annual output would be about 8.3 million kWh. The District has received a loan from the U.S. Department of Energy to study the feasibility of installing hydroelectric facilities at Matthews Dam.

20. Alamo Drop 3A

Alamo Drop 3A, a concrete overflow structure on the agriculture drainage system flowing into the Salton Sea, is located near Calipatria in Imperial County. It is owned and operated by the Imperial Irrigation District. The net head is about 4.9 m (16 ft), and the maximum design flow would be about 33 cms (1100 cfs). The potential capacity is about 1200 kW, and the average annual output would be about 6.7 million kWh. Construction of 1.6 km (1 mi) of 13 kV transmission line along a dirt road through agriculture lands to the District's electric system would be required.

21. No. 8 Heading

No. 8 Heading is a check structure on the Westside Main Canal about 8 km (5 mi) northwest of Imperial in Imperial County. It is owned and operated by the Imperial Irrigation District. The net head is about 4.6 m (15 ft) and the maximum design flow is about 22 cms (775 cfs). The potential capacity is about 750 kW, and average annual output would be about 3 911 000 kWh. A 13 kV transmission line owned by the District is located at the site.

22. Tuberose Check

Tuberose is a check structure on the Eastside Main Canal located about 11 km (7 mi) north of Imperial in Imperial County. It is owned and operated by the Imperial Irrigation District. The site is just upstream from Turnip Check where the District installed hydroelectric generation in 1964. The nominal head at Turnip Check is 5 m (16 ft), and the installed capacity is 420 kW; the annual output is about 2 million kWh. The net head at Tuberose is about 3 m (10 ft), and the available flows would be the same as at the downstream Turnip site. The potential capacity at Tuberose is about 200 kW, and the average annual output would be about 1.3 million kWh. A 13 kV transmission line owned by the District is located at the site.

23. Vail Heading

Vail Heading is a series of low-head check structures closely spaced in staircase fashion along the Vail Supply Canal about 9.7 km (6 mi) east of Calipatria in Imperial County. The canal is owned and operated by the Imperial Irrigation District. Vail Heading includes eleven drops with a total height of 13.7 m (45 ft). The greatest drop occurs in the first 0.8 km (0.5 mi) at the rate of 5 m (16 ft) per 305 m (1000 ft) of canal length. About 500 kW of capacity could be developed at the first drop of the Vail Supply Canal using a steel conduit about 610 m (2000 ft) long. A 13 kV transmission line owned by the District is located at the facility.

24. Lake Amador Jackson Creek Dam

Lake Amador is formed by Jackson Creek Dam, an earthfill structure about 1.6 km (1 mi) southeast of Ione in Amador County. It is owned and operated by the Jackson Valley Irrigation District. Lake Amador provides water for irrigation and domestic uses. Reservoir releases are divided at the outlet works to divert one-half of the discharge into a pipeline into Jackson Creek. The Jackson Creek discharges could be used for hydroelectric generation. In an average year, the reservoir yield could maintain a discharge rate of 0.8 cms (30 cfs) from January through October. The net head would range from 52 m (168 ft) in winter months to 47 m (150 ft) in October. The potential capacity is 350 kW, and the average annual output would be about 2.5 million kWh. A 13 kV transmission line owned by PGandE is located at the facility.

25. Pacoima Dam

Pacoima Dam, a concrete arch structure, is located near San Fernando in Los Angeles County. It is owned and operated by the Los Angeles County Flood Control District in Pacoima Canyon. The Pacoima Reservoir regulates flood flows which result from brief but intense storms that normally occur during the winter months. Thus, the releases are of short durations that extend from a few days to two weeks and vary widely in flow between 0.3 cms to 4.5 cms (10 cfs to 150 cfs). Based on the field investigation and on a preliminary review of discharge data, the installation of hydroelectric facilities at Pacoima Dam was not considered to be compatible with the dam's primary purpose of flood control.

26. San Gabriel Dam

San Gabriel Dam, an earthfill structure, is located on the San Gabriel River near Glendora in Los Angeles County. It is owned and operated by the Los Angeles County Flood Control District. The dam is used for flood control and to deliver water to the Azusa conduit. Hydroelectric generation units could be installed on the Azusa conduit at the existing regulating valve and energy dissipators. The net head would vary from about 30.5 m to 45.7 m (100 ft to 150 ft). The potential power capacity is about 500 kW, and the average annual output would be about 3 million kWh. A 13 kV transmission line is located at the facility. The District is studying the feasibility of installing hydroelectric facilities.

27. West Coast Basin Barrier

The West Coast Basin site is a pressure-reduction facility on a pipeline located in a vault under El Segundo Boulevard, near the Los Angeles International Airport. It is owned and operated by the Los Angeles County Flood Control District. Valves reduce water pressure from 1138 to 552 kilopascals (165 psi to 80 psi). The site is a part of the West Coast Basin Barrier Project where water is injected into wells along the coastline to repel seawater intrusion into the ground water basin. The potential capacity is about 500 kW, and the average annual output would be about 4.2 million kWh. The facility can be connected to the electricity distribution system.

28. Eastside Pipeline

The Eastside Pipeline is a water conveyance facility located near Lost Hills in Kern County. It is owned and operated by the Lost Hills Water District. The pipeline, constructed of precast concrete sections, is about 3000 m (10,000 ft) long. It delivers water from the State Water Project's California Aqueduct to an irrigation ditch in the District. The drop over the length of the pipeline is about 16 m (52 ft) and the capacity is 8.5 cms (300 cfs), although the pipeline has never operated at full capacity. The field inspection showed the pipeline to be unsuitable for hydroelectric generation because the concrete pipe cannot be pressurized.

29. Lake Shastina (Shasta River Dam)

The Shasta River Dam at Lake Shastina is a hydraulic-fill earthfill structure owned and operated by the Montague Water Conservation District. It is located about 16 km (10 mi) southeast of Grenada in Siskiyou County. The dam, built in 1928, is used to conserve water for irrigation in the Shasta Valley and for urban use in Montague. Water is released during the irrigation season from mid-April through mid-September. The net head is about 15 m (50 ft) at the beginning of the irrigation season and decreases to about 10 m (32 ft) at the end of the season. The potential capacity is about 200 kW, and the average annual output would be about 741 000 kWh. A 13 kV transmission line owned and operated by the Pacific Power and Light Company is about 300 m (1000 ft) from the site.

30. Pumping Plant Lower

Pumping Plant Lower, a drop between upper and lower irrigation canals, is located about 6.4 km (4 mi) east of Montague in Siskiyou County. It is owned and operated by the Montague Water Conservation District. The plant was constructed in the 1920s to use the hydraulic energy of water falling from the upper canal to the lower canal to pump a part of that water to an elevation higher than the upper canal. However, the facilities were not used for that purpose. The site is now operated to drop water 12 m (40 ft) during the irrigation season from mid-April to mid-September. Flows range from 0.3 cms to 0.7 cms (10 cfs to 24 cfs), with the higher flows occurring in June, July, and August. The potential capacity is 65 kW, and the average annual output would be about 172,000 kWh. A 13 kV transmission line owned by Pacific Power and Light Company is located at the facility.

31. Picay Pressure Break

The Picay Pressure Break is an unpressurized, concrete vault owned and operated by the Montecito County Water District near Santa Barbara in Santa Barbara County. It is located on a water conveyance facility that carries water from Jameson Lake through the Santa Ynez Mountains via the Doulton Tunnel, and then, by way of a steel pipe about 1558 m (5000 ft) long to the Picay vault. The average flow is about 0.1 cms (2.5 cfs), and the gross head is 200 m (655 ft). The water level in the Picay vault provides the head for conveying water to the Bella Vista Reservoir via another pipeline. Since all of the gross head is lost through friction in the pipeline, the existing facility provides no head for hydroelectric generation.

32. Lyons Dam

Lyons Dam is a concrete arch structure owned and operated by PGandE on the South Fork of the Stanislaus River, about 24 km (15 mi) northeast of Sonora in Tuolumne County. The dam diverts river water into the Tuolumne Canal for municipal and industrial use. The existing discharge is dropped into a stilling basin at the foot of the dam; this serves as an energy dissipator. The potential capacity of the facility is about 300 kW, using one of the two existing outlet valves, and the annual output would be about 1.5 million kWh. A 13 kV transmission line owned by PGandE is located at the facility.

33. San Vicente

The San Vicente site is at the outlet of a tunnel that conveys water from the first San Diego Aqueduct to San Vicente Lake. The facility is owned and operated by the Water Utilities Department of San Diego and is located north of Lakeside and east of Route 67. The outfall basin at the tunnel outlet also provides head pressure for a pipeline that by-passes San Vicente Lake. A hydroelectric facility could be constructed at the facility by installing a penstock from the tunnel outfall basin to a power plant on the shore of San Vicente Lake. This facility has a potential of about 850 kW. If the tunnel flow were discharged through the power plant into San Vicente Lake rather than diverted through the pipeline, the estimated annual output would be about 3.4 million kWh. It would be necessary to build a 13 kV transmission line for a distance of about 8 km (5 mi).

34. Sidney N. Peterson Treatment Plant

The Sidney N. Peterson water treatment plant is located near Folsom on the boundary between Placer and Sacramento Counties. It is owned and operated by the San Juan Suburban Water District. Water from Folsom Reservoir is carried to the site by a pipe tapped into the Folsom-Roseville Pipeline. The pipeline is pressurized by the head from the Folsom Reservoir. The gross head at the plant varies from zero to 9.4 m (30 ft) usually with a net head of 5.6 m to 7.8 m (18 ft to 25 ft) during May through July. The potential capacity is about 175 kW, and the annual output would be about 350 000 kWh.

35. Chesbro Dam

Chesbro Dam, an earthfill structure on Llagas Creek, is located about 13 km (8 mi) northwest of Gilroy in Santa Clara County. It is owned and operated by the South Santa Clara Valley Water Conservation District. The dam conserves water which is released between January and June for percolation into the groundwater basin from where it will be pumped from wells for irrigation. The releases are coordinated with diversions from Uvas Dam to Llagas Creek. The net head varies from about 11 m to 18 m (35 ft to 60 ft), and the discharge varies from 0.3 cms to 1.3 cms (10 cfs to 47 cfs). The potential capacity is 100 kW, and the average annual output would be about 216 300 kWh. A 13 kV transmission line owned by PGandE is about 156 m (500 ft) from the facility.

36. Uvas Dam

Uvas Dam, an earth structure on Uvas Creek, about 10 km (6 mi) northwest of Gilroy in Santa Clara. It is owned and operated by the South Santa Clara Valley Water Conservation District. This dam also conserves water for percolation and later use for irrigation. Releases are either discharged into Uvas Creek or diverted to Llagas Creek via a 6.4 km (4 mi) concrete pipeline. The water released into Uvas Creek could be used for hydroelectric generation. The effective head ranges from 10 m to 25 m (34 ft to 82 ft). Water is released between January and August. The potential capacity is 300 kW, and the average annual output would be about 1 042 000 kWh. A 13 kV transmission line is about 150 m (500 ft) from the site.

37. Black Butte Dam

Black Butte Dam is an earthfill structure located on Stoney Creek near Orland in Glenn and Tehama Counties. It is owned and operated by the U.S. Army Corps of Engineers. The dam provides flood control, irrigation, and recreation. Its flood control operation requires the availability of storage space from September through June. Irrigation water is diverted through a gate house adjacent to the energy dissipator at the outlet works. The net head varies from 21 m to 31 m (70 ft to 100 ft), and the average monthly flows vary from 6 cms to 65 cms (200 cfs to 2300 cfs). The potential capacity is about 9200 kW, and the annual output would be about 31.3 million kWh. To develop the full potential capacity, a transmission line of either 34 kV or 69 kV and about 14.5 km (9 mi) long would be needed.

38. Hensley Lake (Hidden Dam)

Hidden Dam is a federally-owned earthfill structure operated by the U.S. Army Corps of Engineers on the Fresno River, east of Madera in Madera County. The dam's primary function is flood control. The net head varies from 17 m to 31 m (55 ft to 100 ft), and the flows range from 0.3 cms to 6.4 cms (10 cfs to 210 cfs). The potential capacity is about 1500 kW, and the average annual output is about 4 million kWh. A 13 kV transmission line owned by PGandE is located at the facility.

39. H.V. Eastman Lake (Buchanan Dam)

Buchanan Dam is a federally-owned earthfill structure operated by the U.S. Army Corps of Engineers on the Chowchilla River, east of Chowchilla in Madera County. The dam's primary function is flood control. The net head varies from 39 m to 42 m (125 ft to 135 ft) and the average monthly flows range from 0.3 cms to 8.8 cms (10 cfs to 310 cfs). The potential capacity is 3000 kW and the average annual output would be about 9 million kWh. A 13 kV transmission line owned by PGandE is located at the facility.

40. Lake Kaweah (Terminus Dam)

Terminus Dam is a federally-owned earthfill structure operated by the U.S. Army Corps of Engineers on the Kaweah River about 32 km (20 mi) upstream from Visalia in Tulare County. Although the dam provides both flood control and irrigation, its primary function is flood control. The net head varies from 22 m to 50 m (70 ft to 160 ft), and the flows vary from 3 cms to 41 cms (100 cfs to 1450 cfs). The potential capacity is about 4000 kW and the annual output would be about 20 million kWh. A 13 kV transmission line owned by PGandE is located at the facility.

41. Lemoncove Ditch

The Lemoncove facility is an alternate, partially-hydroelectric development of Terminus Dam. Terminus Dam is a flood control dam located about 32 km (20 mi) upstream from Visalia on the Kaweah River in Tulare County. It is owned and operated by the U.S. Army Corps of Engineers. The dam outlet works contain a separate conduit used exclusively to deliver water to Lemoncove Ditch. Since the conduit can carry flows in excess of the water required for Lemoncove Ditch, it could be redeveloped and used for both water deliveries and hydroelectric generation. The potential capacity is about 650 kW, and the annual output would be about 3 482 000 kWh. A 13 kV transmission line owned by PGandE is located at the site.

42. New Hogan Dam

New Hogan Dam is a federally-owned earthfill structure operated by the U.S. Army Corps of Engineers on the Calaveras River, near the community of Jenny Lind in Calaveras County. The dam's primary function is flood control. The net head varies from 41 m to 47 m (130 ft to 150 ft), and the flows vary from 0.8 cms to 15 cms (30 cfs to 530 cfs). The potential capacity is about 2250 kW and the annual output would be about 8 million kWh. A 13 kV transmission line is located at the facility.

43. All-American Canal Drop No. 5

Drop No. 5 is a check structure on the All-American Canal and is located about 8 km (5 mi) east of Calexico in Imperial County. It is owned by WPRS and is operated by the Imperial Irrigation District. Under a contract with WPRS, the District is amortizing the federal investment and will own the site when the contract expires in a few years. When the structure was built, the foundations and radial gates for a future powerhouse were included. The net head is about 7.3 m (24 ft) and design flow for hydroelectric generation is 91 cms (3000 cfs). The District estimates the potential capacity to be 5000 kW and annual output would be 24 million kWh. The District is studying the feasibility of installing hydroelectric facilities at Drop No. 5.

44. Jenkinson Lake (Sly Park Dam)

Sly Park Dam, an earthfill structure owned by WPRS and operated by the El Dorado Irrigation District, is located on Sly Park Creek near Pollock Pines in El Dorado County. Sly Park Creek joins Camp Creek downstream from the dam and flows into the Consumnes River. The facility stores water for irrigation and domestic use throughout western El Dorado County. The net head varies from 37 m to 53 m (120 ft to 170 ft). The average monthly flows during the irrigation season vary from 0.7 cms to 1.9 cms (24 cfs to 67 cfs). The potential capacity is about 650 kW, and the annual output would be about 1 848 000 kWh. A 13 kV transmission line owned by PGandE is located at the facility.

45. North Portal Tecolote

Tecolote Intake, a diversion facility at the north portal of the Tecolote Tunnel, diverts water from Lake Cachuma to the South Coast area of Santa Barbara County. The Cachuma Project, of which the Tecolote Tunnel is a part, was designed and built by the U.S. Water and Power Resources Service (WPRS) for the Santa Barbara County Water Agency. The Cachuma Operation and Maintenance Board operates the facility for four water districts and the City of Santa Barbara. It may be possible to install a small turbine/generator unit in the gate chamber structure at the Tecolote Intake. The design of the unit would present a challenge due to the size of the gate chamber which requires entry through an elevator. Assuming an average flow of 0.9 cms (32 cfs) and a head of 26 m (85 ft) the potential hydroelectric capacity is about 175 kW, and the estimated annual output is 720 000 kWh. A 13 kV transmission line owned by PGandE is located at the facility.

46. Stampede Dam

Stampede Dam is an earthfill structure owned and operated by WPRS. It is located on the Little Truckee River, near Truckee in Sierra County. The dam is used for flood control and water conservation. Large releases of about 14 cms to 28 cms (500 cfs to 1000 cfs) are made during May to replenish Pyramid Lake. When the facility was constructed, provisions were made to install hydroelectric generation later. The net head varies from 57 m to 65 m (186 ft to 212 ft), and the average monthly flows, excluding the Pyramid Lake releases, vary from 1.7 cms to 5.7 cms (60 cfs to 200 cfs). The potential capacity is about 3000 kW, and the annual output would be about 17 million kWh. A 13 kV transmission line owned by Sierra-Pacific Power Company is located at the facility.

47. Sonoma Reservoir

Sonoma Reservoir consists of two tanks which contain 7.6 and 22.7 megalitres (2 million and 6 million gallons) of water in the City of Sonoma, in Sonoma County. The tanks provide both storage and water pressure for water distribution. They are owned and operated by the Valley of the Moon Water District. A valve at the reservoir inlet reduces pressure from the Sonoma pipeline, which carries water from the Russian River. The valve is an altitude-control type which responds to the level of water stored in the tanks. It may be possible to install a hydroelectric generation unit at this site, but the design would pose a significant challenge due to the wide range of heads and flows. The potential capacity is about 50 kW; the average annual output would be about 210 000 kWh. A 13 kV transmission line owned by PGandE is located at the site.

48. Clear Lake Dam

Clear Lake Dam is a concrete structure located about 4 km (2.5 mi) east of Lower Lake in Lake County. It is owned and operated by the Yolo County Flood and Water Conservation District. The dam, built in 1914, determines the water surface level of Clear Lake. The stored water is used for irrigation in Yolo County. The net head varies from 7.5 m to 9.3 m (24.5 ft to 30.5 ft), and the flows range between 0.09 cms and 42.4 cms (3 cfs and 1400 cfs). The greatest discharges occur January through March, when flows average about 34 cms (1200 cfs). Summer discharges (June through August) average about 13 cms (450 cfs). The potential capacity is about 2000 kW; the average annual output would be about 7.5 million kWh. A single-phase 13 kV transmission line owned by PGandE is located at the site. It would be necessary to upgrade about 2.4 km (1.5 mi) of the existing transmission line to three-phase by adding a third conductor.

49. Indian Valley Dam

Indian Valley Dam is an earthfill structure on Cache Creek, near Clear Lake in Lake County. It is owned and operated by the Yolo County Flood Control and Water Conservation District. The dam is used for flood control and irrigation. Since the dam was completed in 1976, the reservoir has never been filled to capacity. Based on the reservoir yield indicated in a feasibility report supporting a loan application under Public Law 984, the potential capacity is about 3200 kW, and the average annual output would be about 7.2 million kWh. Since electrical transmission facilities are not available at the site, a 13 kV transmission line 15 km to 16 km (9 mi to 10 mi) long would be needed.

APPENDIX C

Preliminary Feasibility Studies for 28 Representative Facilities, Prepared by the Department of Water Resources

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Preliminary Feasibility Studies for 28 Representative Facilities, Prepared by the Department of Water Resources

Preliminary feasibility studies are made to determine if a proposed hydroelectric project has sufficient merit and potential value to warrant further investigation and the commitment of development funds. This type of study is also called an appraisal or reconnaissance study.

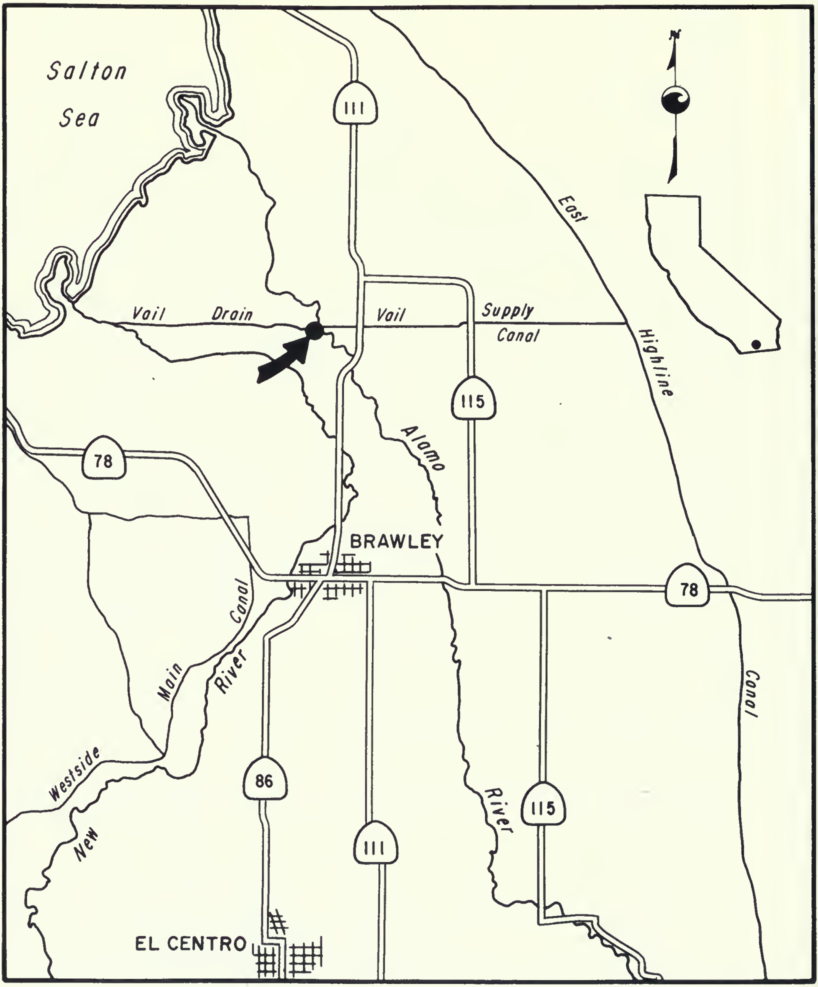
The amount of detail covered in a preliminary study depends on the availability of site-specific information such as construction drawings of the existing hydraulic structures, records of water flow covering a period long enough to allow the average monthly flow to be estimated, and enough data to determine the average monthly head at the proposed power facility.

Such site-specific information was available for some of the 28 representative sites discussed below. When it was available, a reasonably complete study was made. For other sites, however, much of this information was lacking and only general estimates were prepared. With only sketchy information and a visual inspection of the site, the study was superficial. Because of this, the 28 preliminary feasibility studies discussed here vary in scope from detailed quantitative analyses to relatively qualitative narratives with conclusions based largely on professional judgment. However, in all cases the preliminary feasibility studies were sufficient to enable the site developer to apply to the Federal Energy Regulatory Commission (FERC) for a Preliminary Permit or a License Exemption (see Appendix F), or to the U.S. Department of Energy (DOE) for a feasibility study loan (see Appendix H). The 28 facilities are described in this chapter, and the results of a preliminary feasibility study of each are summarized in Table C.

Table C. Summary of Preliminary Feasibility Studies for 28 Representative Facilities

Site	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Cost ($/kW)	Annual Cost (% of Project Cost) 20-yr Debt 9%	12%	15%	35-yr Debt 9%	12%	15%	Average Cost of Generation (¢/kWh) 20-yr Debt 9%	12%	15%	35-yr Debt 9%	12%	15%
1. Alamo Drop 3A (Canal)	1200	6.7	64	2312	19.6	--	--	15.4	--	--	7.2	--	--	6.4	--	--
2. Anderson Flume	50	0.2	41	5518	20.5	24.0	25.8	18.6	22.4	24.2	31.4	36.7	39.5	28.5	34.3	37.0
3. Beardsley Diversion	500	1.7	40	8062	15.5	19.0	20.8	13.6	17.4	19.2	35.8	43.9	48.1	31.5	40.2	44.4
4. Black Butte Dam	9200	31.3	39	1717	14.6	18.1	19.9	12.7	16.5	18.3	7.4	9.1	10.0	6.4	8.3	9.2
5. Buckeye Conduit	350	2.4	79	2451	17.2	20.7	22.5	15.3	19.1	20.9	6.1	7.4	8.0	5.4	6.8	7.4
6. Chesbro Reservoir	100	0.2	25	5343	16.8	20.3	22.1	14.9	18.7	20.5	41.5	50.1	54.6	36.8	46.2	50.6
7. Clear Lake Imp. Dam	2000	7.5	43	2469	14.4	17.9	19.7	12.5	16.3	18.1	9.5	11.7	12.9	8.2	10.7	11.9
8. Del Loma Tunnel	250	1.9	87	5138	17.0	20.5	22.3	15.1	18.9	20.7	11.5	13.9	15.1	10.2	12.8	14.0
9. Frenchman Dam	450	1.0	26	3657	14.4	17.9	19.7	12.5	16.3	18.1	23.0	28.6	31.4	20.0	26.0	28.9
10. Glendale Distribution	400	2.0	57	2558	15.3	--	--	13.3	--	--	7.9	--	--	6.9	--	--
11. Gould Weir Diversion	850	3.5	47	7499	14.9	18.4	20.2	13.0	16.8	18.6	27.1	33.5	36.8	23.7	30.6	33.9
12. Harding Canal	1000	6.6	75	2077	16.1	19.6	21.4	14.2	18.0	19.8	5.1	6.2	6.8	4.5	5.7	6.3
13. Indian Valley Dam	3200	7.2	26	1648	16.2	19.7	21.5	14.3	18.1	19.9	11.8	14.4	15.7	10.5	13.2	14.6
14. Jenkinson Lake (Sly Park Dam)	650	1.8	33	2208	16.0	19.5	21.3	14.1	15.5	19.7	12.4	15.1	16.5	10.9	12.0	15.3
15. Lake Amador (Jackson Creek Dam)	350	2.5	83	2566	16.0	19.5	21.4	14.2	17.9	19.7	5.7	6.9	7.5	5.0	6.3	7.0
16. Lake Shastina (Shasta River Dam)	200	0.7	40	3608	15.7	19.2	21.0	13.8	17.6	19.4	15.2	18.7	20.4	13.4	17.1	18.9
17. Lemoncove Ditch (At Terminus Dam)	650	3.5	61	2754	16.8	20.3	22.1	14.9	19.3	20.5	8.6	10.4	11.4	7.7	9.6	10.5
18. Merle Collins Reservoir (Virginia Ranch Dam)	900	5.6	71	2314	15.0	18.5	20.3	13.1	16.9	18.7	5.5	6.8	7.5	4.8	6.2	6.9
19. Mount Olivette	150	1.1	84	3646	18.1	21.6	23.4	16.2	20.0	21.8	8.8	10.6	11.4	7.9	9.8	10.7
20. No. 8 Heading (Canal)	750	3.9	59	3362	17.4	--	--	15.4	--	--	11.3	--	--	10.0	--	--
21. North Purtal Tecolote	175	0.7	46	6993	15.1	18.6	20.4	13.2	17.0	18.8	25.7	31.6	34.7	22.4	28.9	32.0
22. Parkview Station	150	0.5	38	4030	16.2	20.0	21.6	14.4	18.2	20.0	18.0	21.[illegible]	23.8	15.8	20.0	22.0
23. Pumping Plant Lower	65	0.2	30	5331	19.0	22.5	24.3	17.1	20.9	22.7	38.3	45.3	48.9	34.4	42.1	45.7
24. Rocky Point Diversion	300	0.7	25	4150	15.1	18.6	20.4	13.2	17.0	18.8	28.4	35.0	38.4	24.8	32.0	35.4
25. Stumpy Meadows Reservoir (Mark Edson Dam)	325	2.2	76	4652	14.1	17.6	19.4	12.2	16.0	17.8	9.9	12.3	13.6	8.5	11.2	12.4
26. Uvas Dam	300	1.0	40	3267	15.8	19.3	21.1	13.9	17.7	19.5	14.9	18.2	19.9	13.1	16.7	18.4
27. Vail Heading (Canal)	225	1.0	52	6167	15.2	--	--	13.1	--	--	20.6	--	--	17.8	--	--
28. West Coast Basin Barrier	500	4.2	96	2270	17.0	20.5	22.3	15.1	18.0	20.7	4.6	5.5	6.0	4.1	5.1	5.6

Figure C-1A Alamo Drop 3A Powerplant



1. Alamo Drop 3A

The Alamo Drop 3A site is a concrete overflow structure near Calipatria in Imperial County on the agriculture drainage system flowing into the Salton Sea (Fig. C-1A). It is owned and operated by the Imperial Irrigation District.

Site Characteristics. The existing structure is about 13.7 metres (m) or 45 feet (ft) wide, and discharges streamflows over a 4.9 m (16 ft) drop. The structure includes two spillways, one on each side of a concrete overflow section. The spillways have radial gates 2.4 m (8 ft) wide; the ungated center section is 16.8 m (55 ft) wide. Under normal-flow conditions the water is discharged through the spillways; water overflows the center section only during high-water conditions. The spillways and the central ungated weir have a series of short baffle piers near their downstream ends.

Potential Generation. A horizontal, tube-type turbine is considered for installation at this site because of the constantly low head of about 4.6 m (15 ft). Since the flows range between 20 cms and 34 cms (700 cfs and 1200 cfs)--cubic-metre-per-second and cubic-feet-per-second--for eleven months of the year, a fixed-propeller runner would produce about 90 percent of the potential energy at the site.

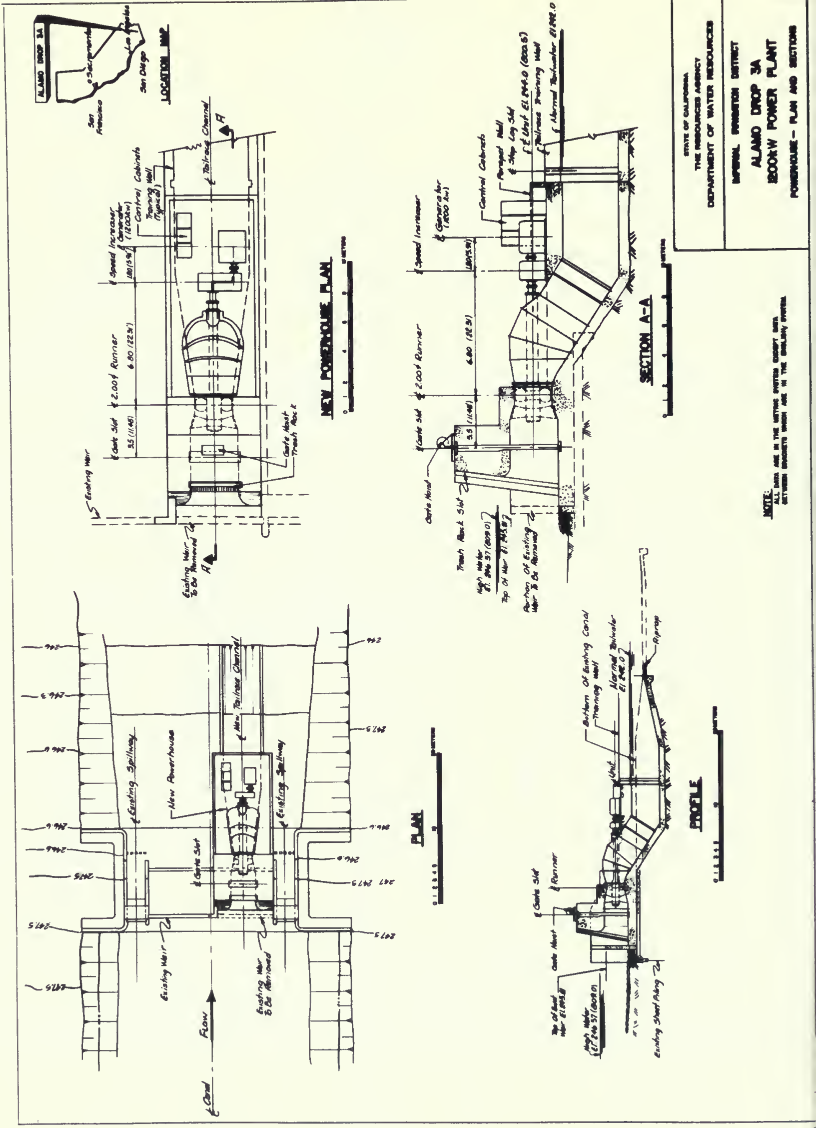
The potential installed capacity would be 1200 kW, and the estimated annual generation is about 6.7 million kWh (Table C-1A).

Table C-1A. Energy Generation for Alamo Drop 3A Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	4.8	15.8	11.2	396	--	--	--
February	4.7	15.4	17.8	624	60	487	328 000
March	4.6	15.0	26.0	916	77	893	666 000
April	4.5	14.8	35.0	1235	84	1296	935 000
May	4.5	14.8	29.9	1055	84	1107	826 000
June	4.6	15.0	22.0	777	73	723	522 000
July	4.6	15.0	24.1	852	74	798	595 000
August	4.6	15.0	24.9	880	75	835	623 000
September	4.6	15.0	27.4	966	79	966	697 000
October	4.6	15.0	25.3	892	76	858	640 000
November	4.6	15.0	20.2	713	67	613	442 000
December	4.7	15.3	19.3	681	65	572	426 000
Total							6 700 000

New Power Plant Structures. The proposed generating facility includes an intake, about 5.7 m (18.7 ft) wide, on the right side of the existing ungated weir; a horizontal standard tube-type turbine; and a tailrace channel about 15 m (49.2 ft) long (Fig. C-1B). The turbine would develop 1600 hp under the available head and would be connected, through a speed increaser, to a horizontal air-cooled synchronous generator with a rated

Figure C-1B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
IMPERIAL IRRIGATION DISTRICT
ALAMO DROP 3A
1200kW POWER PLANT
POWERHOUSE - PLAN AND SECTIONS
ALAMO DROP 3A
LOCATION MAP
Sacramento
San Francisco
Los Angeles
San Diego
NEW POWERHOUSE PLAN
SECTION A-A
PLAN
PROFILE
Speed Increaser
Generator (1200 kw)
Control Cabinets
Training Wall (Typical)
Tailrace Channel
2.00 Ø Runner
Gate Slot
Gate Hoist
Trash Rack
Existing Weir
Existing Weir To Be Removed
Existing Spillway
New Powerhouse
New Tailrace Channel
Flow
Canal
Riprap
Existing Sheet Piling
NOTE: ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM

output of 1200 kW. An inlet gate installed in front of the turbine would enable dewatering of the turbine for maintenance.

Since the water at this site is relatively salty agriculture waste water, the potential effect of this water on the turbine runner was discussed with a turbine manufacturer. The water is not expected to cause significant problems since the turbine would have stainless steel blades and would be working under a low head, well out of the range where cavitation could occur.

About 1.6 kilometres (km) or 1 mile (mi) of a 13 kV transmission line would have to be built from the site to the District's distribution system. The new transmission line would follow a dirt road through agricultural land.

Cost of the New Power Plant. The estimated cost of the new generating facility is $1,699,300, based on January 1980 prices. About 36 months will be required for completing the feasibility study, obtaining approvals, and building. Although most of the water used for generation will be agricultural waste water, the stream channel at the site is a natural river bed and, as such, may not be exempt from federal licensing requirements. (The exemption provision is discussed in detail in Appendix F.)

If the project were initiated in 1981 and 36 months were required to obtain approvals, arrange financing, design, and build the project, the work would be completed in early 1984. At an inflation rate of 12 percent, the estimated project cost in 1984 is $2,773,900 (Table C-1B).

Table C-1B. Project Cost for Alamo Drop 3A Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$1,219,300
Transmission Facilities	45,000
Subtotal	$1,264,300
Contingencies (20%)	252,900
Total	$1,517,200
Engineering and Administration (12%)	182,100
Total Construction Cost (January 1980 Prices)	$1,699,300
Escalation (4 yrs. at 12% per year)	974,600
Total Construction Cost (January 1984 Prices)	$2,673,900
Studies, Licensing, Permits, and Approvals	100,000
Total	$2,773,900
Cost per kW (1200 kW)	$ 2,312

Cost of Generation. Since this facility and the electric transmission and distribution system are owned and operated by the Imperial Irrigation

District, it is assumed that the District would develop and use the power in its own electric system. The annual cost of owning and operating the project would include debt repayment, operation and maintenance costs, insurance, replacements, administration, and overhead.

It is assumed that the District would finance construction by issuing tax-exempt revenue bonds, and that the bonds could be issued for a 35-year term at 9 percent interest. The actual interest rate would depend on financial conditions when the bonds were issued. It is expected that initial development would be financed from electric system revenues or short-term loans and that the bonds would not be issued until about 12 months before the project is completed. The additional cost of operating the plant would be insignificant, since the District already has a full staff of operating personnel. Regular maintenance could be scheduled during the nonirrigation season when there would be no water for power generation.

If the project were scheduled for an on-line date early in 1984, the bond issue would be about $3,350,000, based on January 1980 bid prices, with a 12 percent annual inflation rate for 35-year bonds and a one-year construction period (Table C-1C).

Table C-1C. Annual Cost for Alamo Drop 3A Project

Cost Item	Amount 20-year Bonds	35-year Bonds
Project Cost	$2,773,900	$2,773,900
Capitalized Interest	249,600	249,600
Interest Earnings	(124,800)	(124,800)
Total Capital Cost	$2,898,700	$2,898,700
Bond Reserve Fund	373,600	317,000
Financing Cost	134,700	134,300
Bond Issue	$3,407,000	$3,350,000
Debt Service (9% interest)	$ 373,200	$ 317,000
Operation and Maintenance	27,200	27,200
Insurance	107,700	107,700
Interim Replacements	6,100	6,100
Interest Earnings	(28,500)	(28,500)
Total Annual Cost	$ 485,700	$ 429,500
Annual Cost (% of Project Cost)	19.6	15.4
Average Cost (per kWh)	7.2¢	6.4¢

The estimated average generation cost, assuming 35-year bonds, is $429,500 or 6.4 cents per kWh (Table C-1C). With 20-year bonds, the estimated average generation cost would increase to 7.2 cents per kWh.

Since the District has experience with small hydroelectric facilities, it might elect to be self-insured--in full or in part--to reduce the annual insurance premium on mechanical and electrical equipment. This would reduce its annual generation cost substantially.

Value of Generation. Since the District would probably use the energy produced in its own electric system, the estimated average avoidable cost is about 4.5 cents per kWh, at 1980 price levels. This will be discussed in the preliminary feasibility study for the "No. 8 Heading" site which is also owned by the District. The projected value of energy is discussed in Appendix G, and the estimates of partial-peak energy are assumed to be applicable to the Alamo Drop 3A output. The assumed value for capacity is $100 per kW per year.

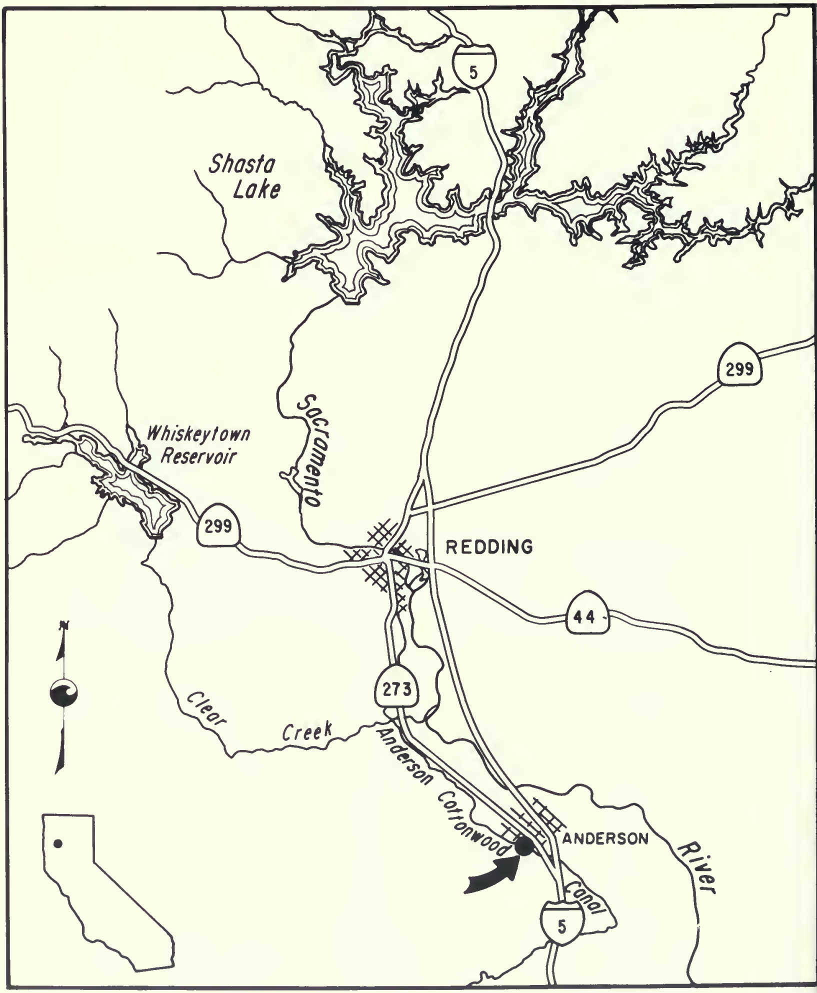
Based on this, the estimated value of Alamo Drop 3A generation in 1984 is $742,500 or 11.1¢ per kWh (Table C-1D).

Table C-1D. Generation Value for Alamo Drop 3A Project

Item	Amount
Capacity (June Capacity)	
725 kW at $100 per kW	$ 72,500
Energy	
6.7 million kWh at 10¢ per kWh	670,000
Total	$742,500
Average Value (per kWh)	11.1¢

Conclusions. Since the estimated value of Alamo Drop 3A generation, exceeds the estimated cost of generation (6.4 to 7.2 cents per kWh), the project would be cost effective during its first year of operation, and additional benefits would accrue during subsequent years as the price of oil increases. The cost of Alamo Drop 3A generation would change little from year to year, since only the cost of maintaining the facility is subject to inflation.

Figure C-2A Anderson Flume Powerplant



2. Anderson Flume

The Anderson Flume site is a turnout on the Anderson Canal, a short distance upstream from the point where the canal enters an overhead concrete flume across Anderson Creek. The canal and turnout are owned and operated by the Anderson-Cottonwood Irrigation District, and are located in Anderson in Shasta County (Fig. C-2A). The turnout drops water from the canal to a lower irrigation ditch for local use on the north side of Anderson Creek.

Site Characteristics. The existing structures consist of an intake in the Anderson Canal with a small diameter steel pipe of unknown size. The water discharges into a concrete energy dissipater box from where it then flows into a lower irrigation ditch. The difference in elevation between the water surface in the canal and the lower ditch is about 7 m (23 ft). Detailed flow records are not maintained, but operating personnel estimate an average flow of about 1 cms (35 cfs) between May and September. A 13 kV transmission line, owned by PGandE, is located about 61 m (200 ft) from the site.

Potential Generation. Assuming an average flow of 1 cms (35 cfs), the potential installed capacity would be 50 kW, and the estimated average annual output would be 180 000 kWh. Since the Sacramento River provides water for both the canal and the proposed hydroelectric site, it is expected that the 180 000 kWh output could be sustained even during dry years.

New Power Plant Structures. A turbine-generator installed at the downstream end of the steel turnout pipe (where the concrete energy dissipater is located) could use the 7 m (23 ft) available head. The proposed generating facility includes an intake structure and new steel penstock, 0.9 m (3 ft) in diameter, to carry water to a vertical turbine which could develop 83 hp under the available head (Fig. C-2B). The turbine would be connected, through a speed increaser, to a horizontal generator with a rated output of 50 kW. Since the turbine would have wicket gates, a shutoff valve would be unnecessary. The intake structure would include a small gate for dewatering the entire penstock and powerhouse. If a more in-depth study of this site is made, the use of other types of turbines, such as a constant flow propeller-type, should be considered.

Cost of the New Power Plant. The estimated cost of the new generating facility is $160,100, based on January 1980 prices. Since the new facility would be located on a manmade conduit and would use existing property, it would probably be exempt from federal licensing requirements, and the environmental approval process would be simplified.

If the project were initiated in 1981 and about 18 months were needed to obtain approvals and build the project, work should be completed in late 1982 for operation in 1983. The estimated project cost in late 1983, with 12 percent inflation, is $251,900 (Table C-2A).

Figure C-2B

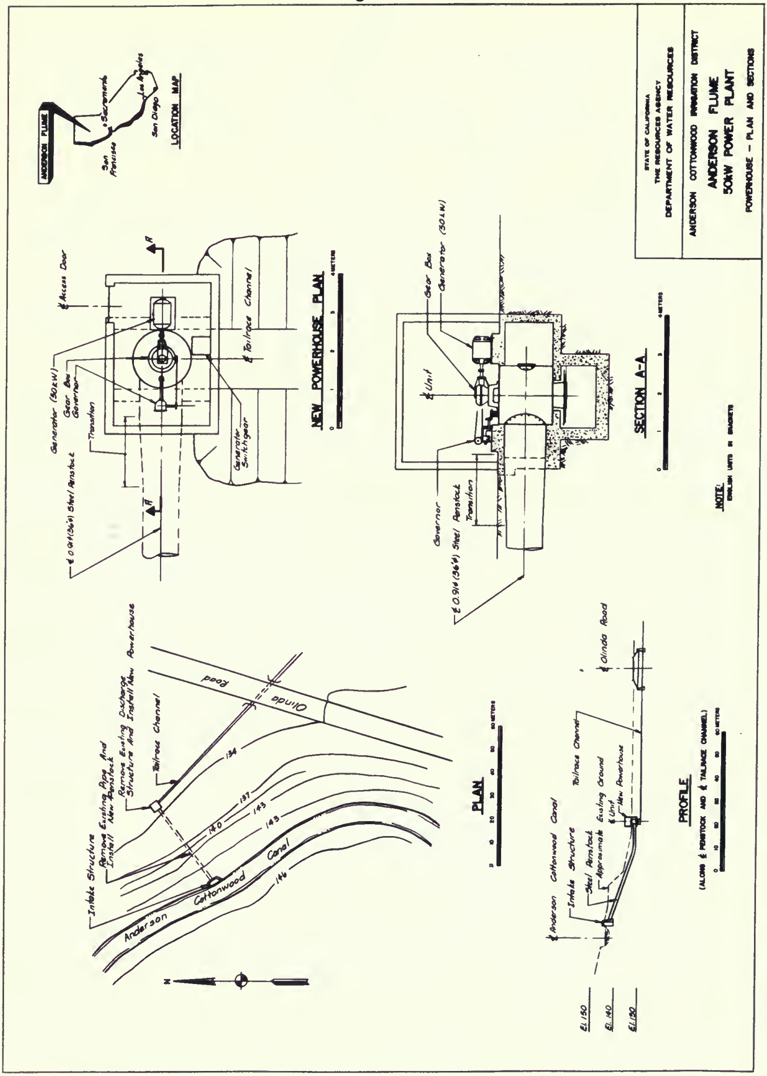

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
ANDERSON COTTONWOOD IRRIGATION DISTRICT
ANDERSON FLUME
50kW POWER PLANT
POWERHOUSE – PLAN AND SECTIONS
LOCATION MAP
ANDERSON FLUME
San Francisco
Sacramento
Los Angeles
San Diego
NEW POWERHOUSE PLAN
Access Door
Generator (30kW)
Gear Box
Governor
Transition
Tailrace Channel
Generator Switchgear
0.914(36") Steel Penstock
SECTION A-A
Gear Box
Generator (30kW)
Unit
Governor
0.914 (36") Steel Penstock
Transition
NOTE:
ENGLISH UNITS IN BRACKETS
PLAN
Intake Structure
Remove Existing Pipe And Install New Penstock
Remove Existing Discharge Structure And Install New Powerhouse
Tailrace Channel
Olinda Road
Anderson Cottonwood Canal
PROFILE
(ALONG PENSTOCK AND TAILRACE CHANNEL)
Anderson Cottonwood Canal
Intake Structure
Steel Penstock
Approximate Existing Ground
Unit
New Powerhouse
Tailrace Channel
Olinda Road
El. 150
El. 140
El. 130

Table C-2A. Project Cost for Anderson Flume Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 106,000
Transmission Facilities	10,000
Subtotal	$ 116,000
Contingencies (20%)	23,200
Total	$ 139,200
Engineering and Administration (15%)	20,900
Total Construction Cost (January 1980 Prices)	$ 160,100
Escalation (4 yrs. at 12% per year)	91,800
Total Construction Cost (January 1984 Prices)	$ 251,900
Studies, Licensing, Permits and Approvals	24,000
Total	$ 275,900
Cost per kW (50 kW)	$ 5,518

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-2B). Regular maintenance could be scheduled during the winter months when there is insufficient water for generation.

Table C-2B. Annual Operating Cost for Anderson Flume Project

Cost Item	Amount
Operation and Maintenance	$13,000
Insurance	8,500
Interim Replacements	500
Total	$22,000

The annual cost of owning and operating the project range between 19 and 27 percent of the direct project cost of $251,900 depending on financing. The estimated cost of generation ranges between 28.5 cents and 39.5 cents per kWh (Table C-2C).

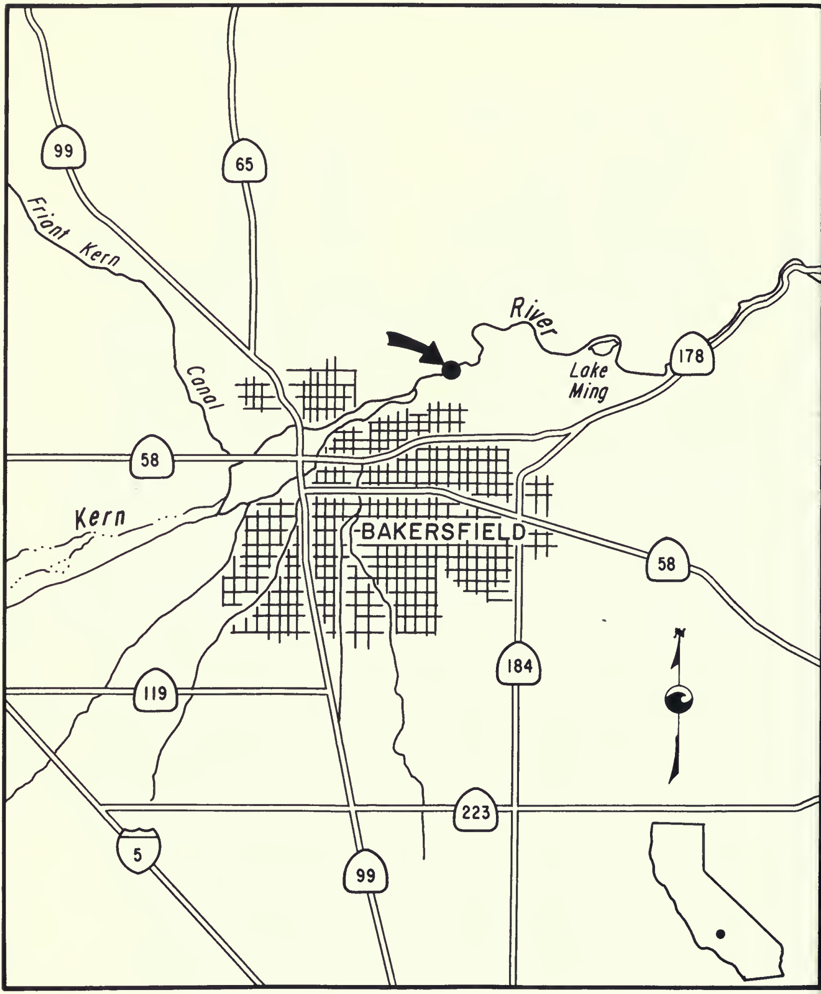
Table C-2C. Average Energy Cost of Anderson Flume Project

Cost Item	Amount — Interest Rate 9%	12%	15%
For 20-year term of debt			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 34,500	$ 44,100	$ 49,100
Operating Cost	22,000	22,000	22,000
Total Annual Cost	$ 56,500	$ 66,100	$ 71,100
Average Cost (per kWh)	31.4¢	36.7¢	39.5¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 29,200	$ 39,700	$ 44,700
Operating Cost	22,000	22,000	22,000
Total Annual Cost	$ 51,200	$ 61,700	$ 66,700
Average Cost (per kWh)	28.5¢	34.3¢	37.0¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the median CEC oil-cost projection for future costs of electrical energy.

Conclusions. Since the estimated value of Anderson Flume generation is significantly less than the estimated cost of generation (28.5 to 39.5 cents per kWh), the project if constructed by 1984 would probably not be cost effective until 1993. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-3A Beardsley Diversion Dam Powerplant



3. Beardsley Diversion Dam

Beardsley Dam is a diversion structure on the Kern River in Bakersfield in Kern County (Fig. C-3A). It is owned and operated by the City of Bakersfield, Kern Delta Water District, and North Kern Water District. The dam diverts water into a canal which parallels the north side of the Kern River. The site is characterized by a low head and relatively large flows during the summer months.

Site Characteristics. The Beardsley Diversion Dam is a wood timber structure about 80 m (262 ft) long and 3 m (10 ft) high. Timber construction was used because of the sandy stream bed. A 13 kV transmission line is located about 100 m (300 ft) from the site.

Potential Generation. The potential installed capacity is 500 kW, and the estimated average annual output is about 1.7 million kWh (Table C-3A).

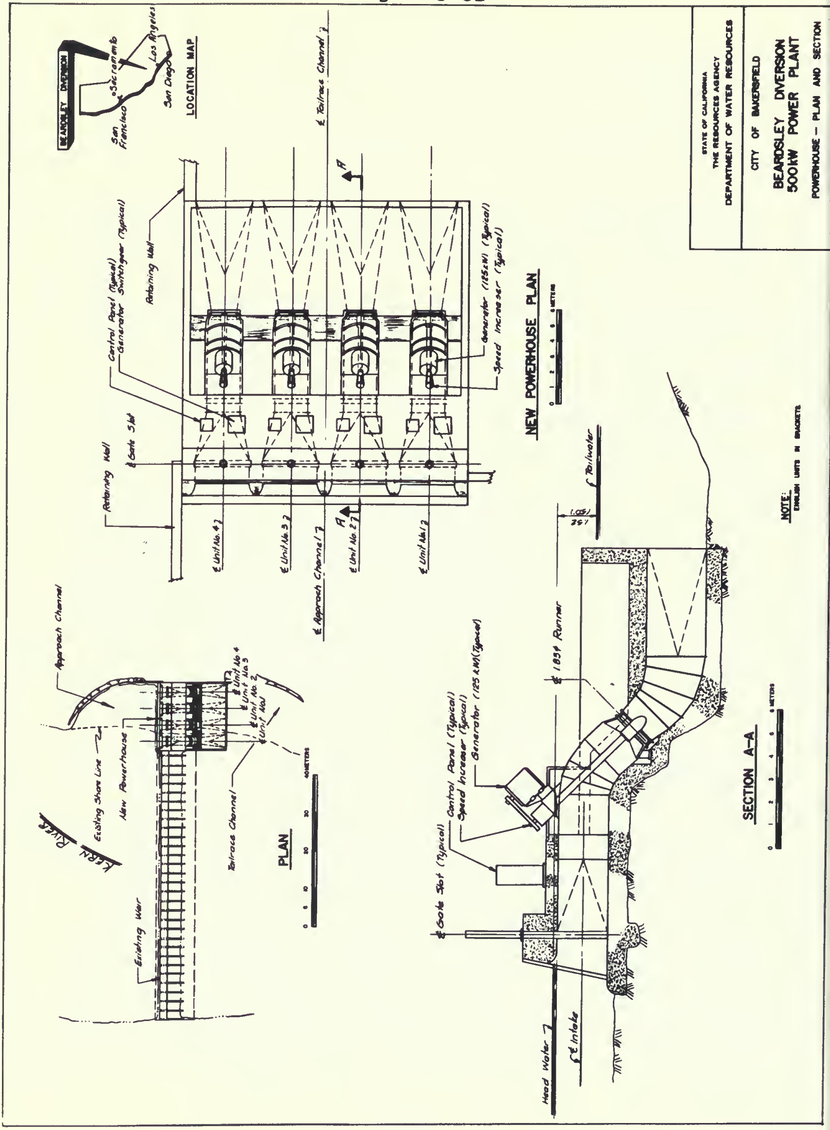
Table C-3A. Energy Generation for Beardsley Diversion Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	1.5	5	11.3	399	84	125	93 000
February	1.5	5	8.8	310	83	109	73 000
March	1.5	5	16.0	564	79	188	140 000
April	1.5	5	13.8	488	77	159	114 000
May	1.5	5	16.2	571	80	193	144 000
June	1.5	5	35.7	1262	84	448	323 000
July	1.5	5	41.4	1463	80	495	368 000
August	1.5	5	36.8	1301	84	462	344 000
September	1.5	5	9.8	345	84	123	88 000
October	1.5	5	6.9	243	78	80	60,000
November	1.5	5	3.5	125	--	--	--
December	1.5	5	4.9	172	--	--	--
Total							1 747 000

New Power Plant Structures. Four small turbine-generator units could be installed at the dam because of the widely varying flow. They would use the 1.5 m (5 ft) head available at the site. The proposed generating facility would include an approach channel, about 22 m (72 ft) long, excavated into the river bank on the left abutment of the dam; the channel would carry water to the four standard propeller-type turbines then return it to the river through a short tailrace channel (Fig. C-3B).

The four fixed-blade turbines with runners 1829 mm (72 in)--milimetres and inches, respectively--in diameter could develop 168 hp each under the available head. Each turbine would be connected, through a gear box speed increaser, to a generator with a rated output of 125 kW. The total power plant capacity would be 500 kW. Inlet gates installed upstream from the turbines would be used to partially dewater the units for inspection. Only one or two intake gates would be needed, since all units would not be inspected at the same time.

Figure C-3B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CITY OF BAKERSFIELD
BEARDSLEY DIVERSION
500kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
LOCATION MAP
BEARDSLEY DIVERSION
Sacramento
San Francisco
Los Angeles
San Diego
NEW POWERHOUSE PLAN
Control Panel (Typical)
Generator Switchgear (Typical)
Retaining Wall
Generator (185kW) (Typical)
Speed Increaser (Typical)
Gate Slot
Tailwater
Unit No. 4
Unit No. 3
Approach Channel
Unit No. 2
Unit No. 1
Tailrace Channel
PLAN
Existing Shore Line
New Powerhouse
Kern River
Existing Weir
SECTION A-A
Control Panel (Typical)
Speed Increaser (Typical)
Generator (125 kW) (Typical)
Gate Slot (Typical)
Runner
Head Water
Intake
NOTE: ENGLISH UNITS IN BRACKETS

Cost of the New Power Plant. The estimated cost of building the generating facility is $2,498,500, based on January 1980 prices (Table 3B). If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $4,031,400 (Table C-3B).

Table C-3B. Project Cost for Beardsley Diversion Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$1,784,000
Transmission Facilities	75,000
Subtotal	$1,859,000
Contingencies (20%)	371,800
Total	$2,230,800
Engineering and Administration (12%)	267,700
Total Construction Cost (January 1980 Prices)	$2,498,500
Escalation (4 yrs. at 12% per year)	1,432,900
Total Construction Cost (January 1984 Prices)	$3,931,400
Studies, Licensing, Permits, and Approvals	100,000
Total	$4,031,400
Cost per kW (500 kW)	$ 8,062

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-3C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-3C. Annual Operating Cost for Beardsley Diversion Project

Cost Item	Amount
Operation and Maintenance	$ 52,000
Insurance	59,500
Interim Replacements	10,700
Total	$122,200

The annual costs of owning and operating the project would range between 14 and 21 percent of the direct project cost of $4,031,400, depending on financing. The estimated cost of generation ranges between 31.5 cents and 48.1 cents per kWh (Table C-3D).

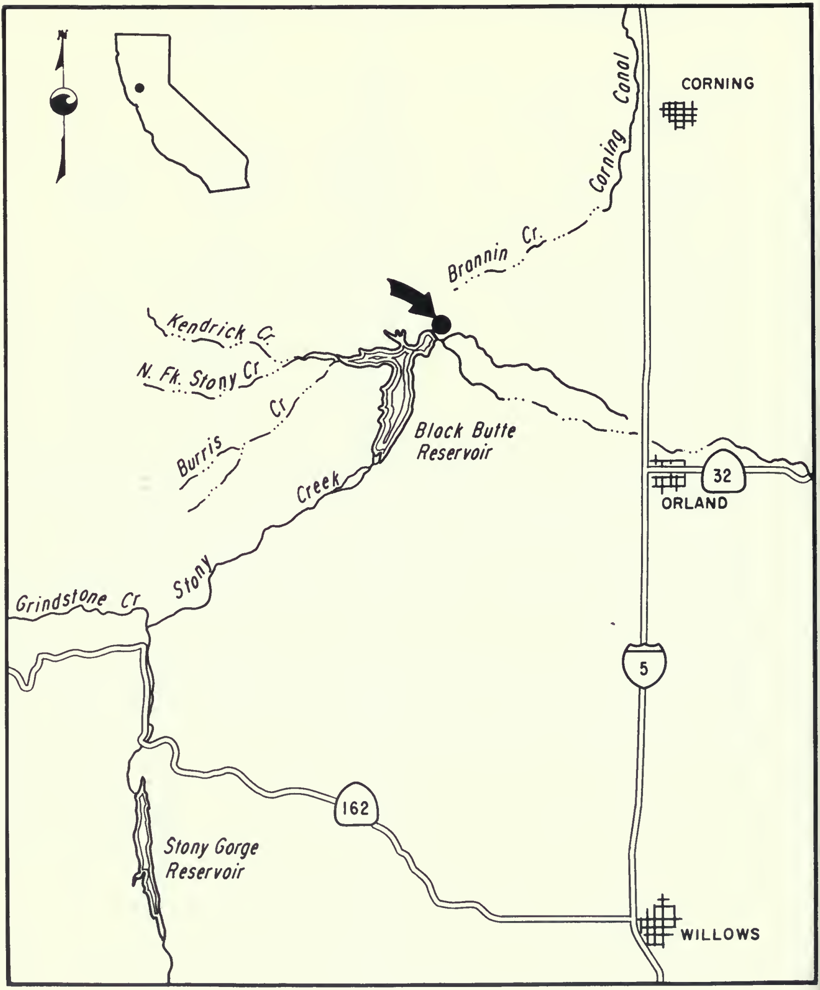
Table C-3D. Average Cost of Energy for Beardsley Diversion Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$503,900	$645,000	$717,600
Operating Cost	122,200	122,200	122,200
Total Annual Cost	$626,100	$767,200	$839,800
Average Cost (per kWh)	35.8¢	43.9¢	48.1¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$427,300	$580,500	$653,100
Operating Cost	122,200	122,200	122,200
Total Annual Cost	$549,500	$702,700	$775,300
Average Cost (per kWh)	31.5¢	40.2¢	44.4¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of energy produced at the Beardsley Diversion facility is significantly less than the estimated generation cost (31.5 to 48.1 cents per kWh), the project if constructed by 1984 is not expected to be cost effective until 1994. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-4A Black Butte Dam Powerplant



4. Black Butte Dam

Black Butte Dam is a rolled earthfill structure, owned and operated by the U. S. Army Corps of Engineers on Stony Creek near Orland in Glenn and Tehama Counties (Fig. C-4A). The dam provides flood control, irrigation, and recreation.

The reservoir is operated primarily for flood control and water conservation. Flood control operation requires the availability of water storage from September through June. Storage amounts to a maximum of 197 000 cubic dekametres (160,000 ac-ft) between October 1 and March 1. The dam's flood protection is vital to the urban areas of Orland and Hamilton City, and to about 25 900 hectares (64,000 acres) of highly-developed agriculture land along the lower reaches of Stony Creek. The project is a unit of the comprehensive plan for flood control and other uses in the Sacramento River Basin.

Black Butte Reservoir also provides an average of 70 100 cubic dekametres (56,800 ac-ft) of water for downstream irrigation. The irrigation water is delivered to the Orland South Main Canal.

Site Characteristics. Black Butte Dam has a maximum height of about 73 m (140 ft) above the streambed and a crest length of 905 m (2,970 ft). Controlled releases from the reservoir are made through the dam's lower outlet located in the right abutment of the dam. The outlet works consist of a combined intake and control tower, control house, circular concrete lined tunnel, 7 m (23 ft) in diameter, outlet portal, energy dissipater, and irrigation diversion structure. Combined flood-control and irrigation releases are regulated by five 2 m by 4.3 m (6.5 ft by 14 ft) hydraulically-operated service gates and five similar emergency slide gates housed in the gate chamber of the control tower. Diversion to the South Side Canal for irrigation is made by a gate house at the tunnel outlet adjacent to the energy dissipater.

Potential Generation. Two vertical Francis turbines with electric generators, rated at 4600 kW each, are considered for installation at Black Butte. The potential annual output is estimated at about 31.3 million kWh (Table C-4A).

Figure C-4B

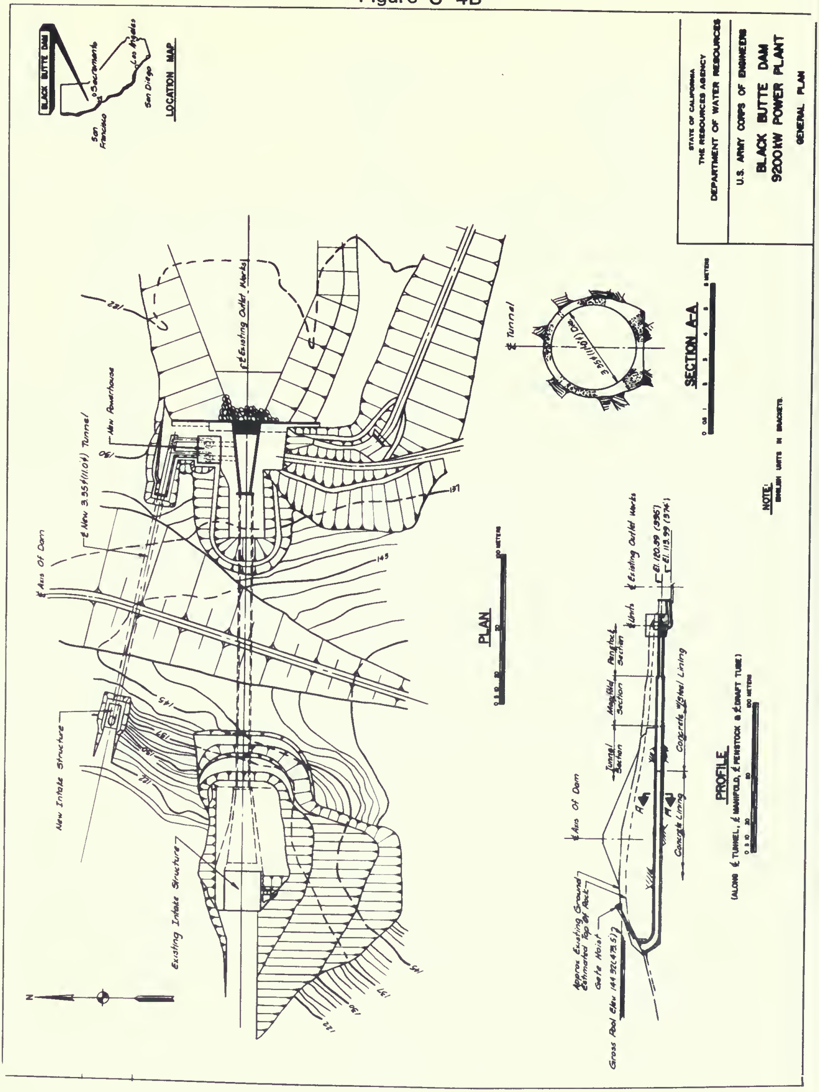

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
U.S. ARMY CORPS OF ENGINEERS
BLACK BUTTE DAM
9200kW POWER PLANT
GENERAL PLAN
LOCATION MAP
BLACK BUTTE DAM
Sacramento
San Francisco
Los Angeles
San Diego
PLAN
SECTION A-A
PROFILE
(ALONG ℄ TUNNEL, ℄ MANIFOLD, ℄ PENSTOCK & ℄ DRAFT TUBE)
NOTE: ENGLISH UNITS IN BRACKETS.
New Intake Structure
Existing Intake Structure
℄ Axis Of Dam
℄ New 3.35 ϕ (11.0 ϕ) Tunnel
New Powerhouse
℄ Existing Outlet Works
℄ Tunnel
Gross Pool Elev 144.32 (473.5)
Gate Hoist
Approx Existing Ground Estimated Top Of Rock
Tunnel Section
Manifold Section
Penstock Section
℄ Units
℄ Existing Outlet Works
El. 120.99 (396)
El. 113.99 (374)
Concrete Lining
Concrete W/Steel Lining

Table C-4A. Energy Generation for Black Butte Dam Project

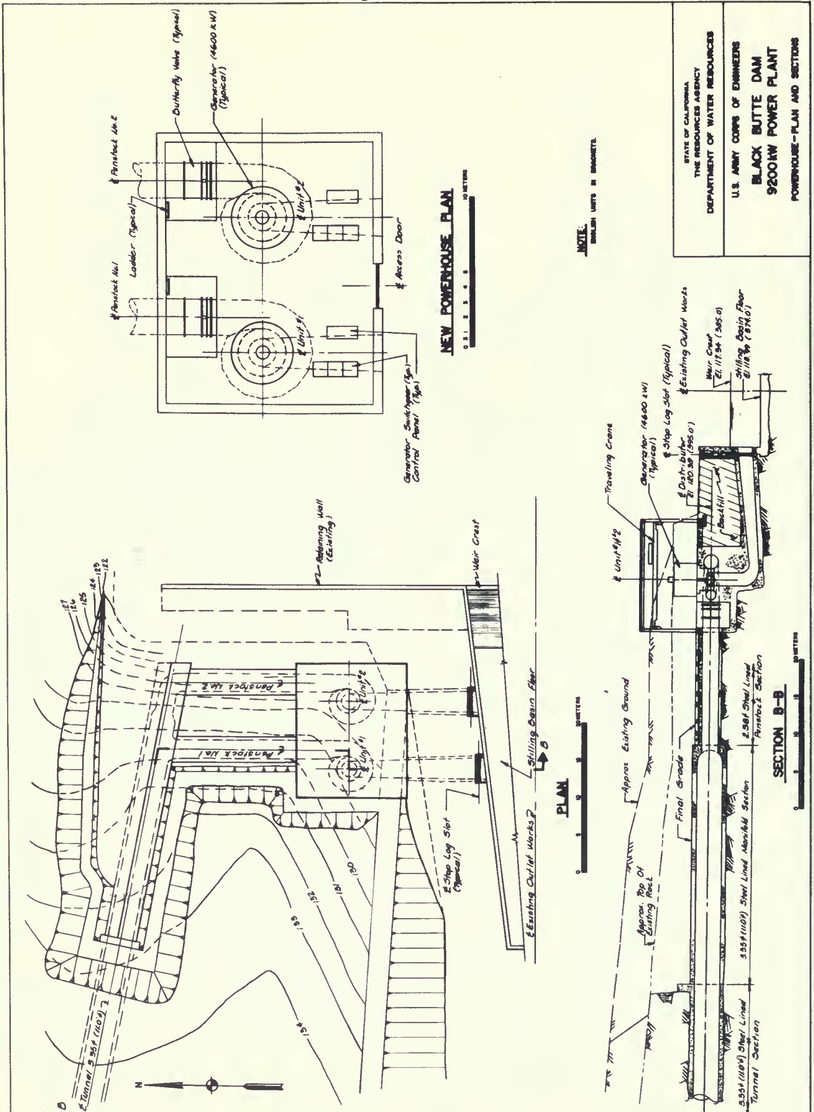
Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	24.7	81	66.1	2334	84	9200	6 844 000
February	25.9	85	46.6	1644	84	9200	6 182 000
March	29.9	98	30.2	1067	72	6370	4 739 000
April	30.5	100	20.6	729	84	5181	3 730 000
May	29.3	96	19.4	697	82	4642	3 454 000
June	27.1	89	17.1	605	77	3508	2 526 000
July	25.0	82	16.1	569	76	3000	2 232 000
August	23.2	76	13.9	491	68	2147	1 597 000
September	21.3	70	10.6	373	--	--	--
October	19.8	65	5.7	200	--	--	--
November	21.3	70	1.5	52	--	--	--
December	23.8	78	10.3	365	--	--	--
Total							31 304 000

New Power Plant Structures. A hydroelectric facility installed near the downstream end of the lower outlet could use the available head of about 14 m to 24.7 m (46 ft to 81 ft). The proposed generating facility includes a new intake about 135 m (443 ft) northeasterly of the existing intake, a short 3.4 m (11 ft) diameter concrete lined shaft, a 3.4 m (11 ft) diameter concrete lined tunnel, a 3.4 m (11 ft) manifold, and two 2.4 m (7.8 ft) steel penstocks, which would convey the water to two vertical Francis turbines (Figs. C-4B and C-4C).

Each turbine could develop 6160 hp under the available head and would be connected directly to a vertical, air-cooled synchronous generator with a rated output of 4600 kW. The turbine draft tubes discharge the water into the existing energy dissipater. Each unit can be dewatered for maintenance without interfering with the operation of the other unit by closing the upstream butterfly valve, and by installing stop logs downstream of the draft tube. The intake, which houses a slide gate with a hoist mechanism, is located at an elevation of 144.5 m (474 ft), which is the elevation of the existing ungated spillway crest. Construction of the new generating facilities would probably have minimal impact on the operation of the existing installation.

Transmission Facilities. A 13 kV transmission line is available at the site; the nearest high voltage line is about 14.5 km (9 mi) away. Since the 9200 kW generating capacity being considered for the Black Butte project is significantly larger than what can be carried by the 13 kV line, a detailed study of the transmission capacity and power flows in the project area should be made to determine what additional facilities would be required to handle project generation. Alternatives to be considered include increasing the conductor size of the existing transmission system or building a higher voltage line about 14.5 km (9 mi) long. Reconductoring the existing line would be the preferable alternative both economically and environmentally. However, a new higher voltage line may be necessary

Figure C-4C


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
U.S. ARMY CORPS OF ENGINEERS
BLACK BUTTE DAM
9200KW POWER PLANT
POWERHOUSE-PLAN AND SECTIONS
NOTE:
ENGLISH UNITS IN BRACKETS.
NEW POWERHOUSE PLAN
PLAN
SECTION B-B
Penstock No.2
Penstock No.1
Butterfly Valve (Typical)
Generator (4600 kW) (Typical)
Ladder (Typical)
Unit #2
Unit #1
Access Door
Generator Switchgear (Typ.) Control Panel (Typ.)
Retaining Wall (Existing)
Weir Crest
Stilling Basin Floor
Stop Log Slot (Typical)
Existing Outlet Works
Tunnel 3.35ф (11.0')
Traveling Crane
Distributor
Backfill
Approx. Existing Ground
Final Grade
Approx. Top Of Existing Rock
2.38ф Steel Lined Penstock Section
3.35ф (11.0') Steel Lined Manifold Section
3.35ф (11.0') Steel Lined Tunnel Section

to increase transmission capacity. For this preliminary feasibility study, it was assumed that a new transmission line of higher cost would be required.

Cost of the New Power Plant. The estimated cost of building the new generating facilities is $9,977,900, based on January 1980 prices (Table 4B). If the project were initiated in 1981, and about 24 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $15,800,400 (Table C-4B).

Table C-4B. Project Cost for Black Butte Dam Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 6,924,000
Transmission Facilities	500,000
Subtotal	$ 7,424,000
Contingencies (20%)	1,484,800
Total	$ 8,908,800
Engineering and Administration (12%)	1,069,100
Total Construction Cost (January 1980 Prices)	$ 9,977,900
Escalation (4 yrs. at 12% per year)	5,722,500
Total Construction Cost (January 1984 Prices)	$15,700,400
Studies, Licensing, Permits, and Approvals	100,000
Total	$15,800,400
Cost per kW (9 200 kW)	$ 1,717

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-4C). Regular maintenance could be scheduled during the autumn months when there is insufficient water for power generation.

Table C-4C. Annual Operating Cost for Black Butte Dam Project

Cost Item	Amount
Operation and Maintenance	$126,000
Insurance	170,000
Interim Replacements	31,800
Total	$327,800

The annual cost of owning and operating the project would range between 13 and 20 percent of the direct project costs of $15,800,400, depending on financing. The estimated cost of generation ranges between 6.4 cents and 10.0 cents per kWh (Table C-4D).

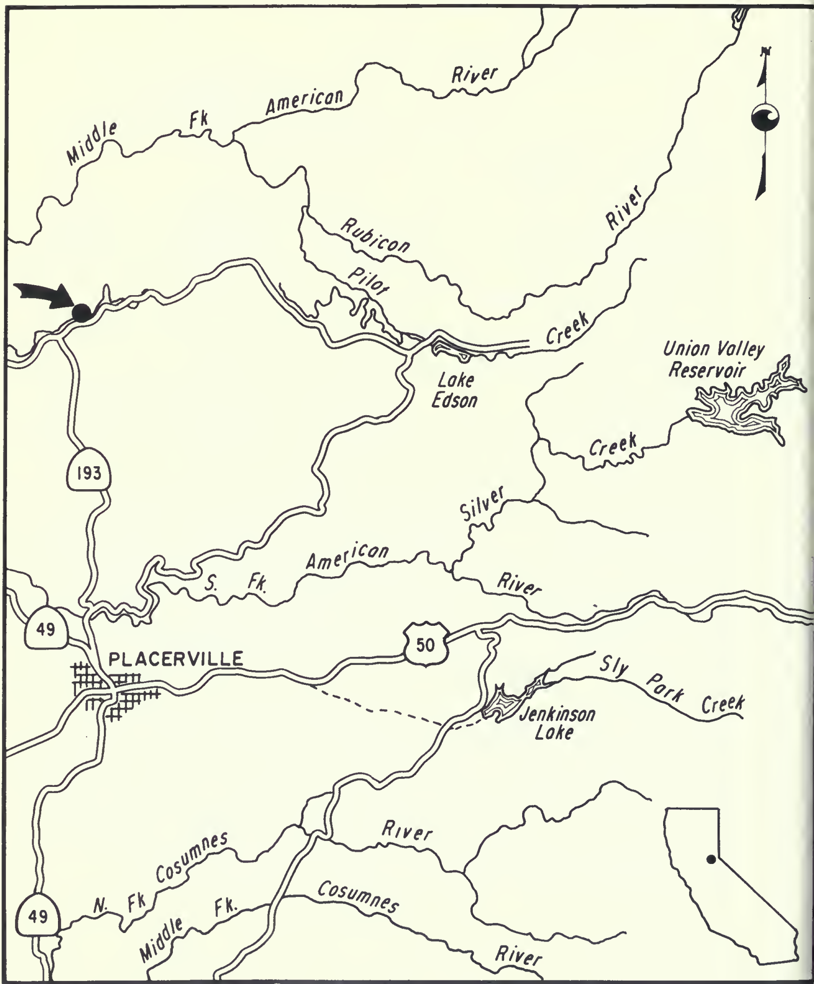
Table C-4D. Average Cost of Energy for Black Butte Dam Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$1,975,000	$2,528,000	$2,812,400
Operating Cost	327,800	327,800	327,800
Total Annual Cost	$2,302,800	$2,855,800	$3,140,200
Average Cost (per kWh)	7.4¢	9.1¢	10.0¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$1,674,800	$2,275,200	$2,559,600
Operating Cost	327,800	327,800	327,800
Total Annual Cost	$2,002,600	$2,603,000	$2,887,400
Average Cost (per kWh)	6.4¢	8.3¢	9.2¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of Black Butte generation exceeds the estimated cost of generation for interest rates from 9 to 12 percent (6.4 to 10.0 cents per kWh). Thus, the project would be cost effective during the first year of operation for interest rates up to about 11.5 percent for a 20-year debt, and would break even during the second year of operation for interest rate of 15 percent. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Black Butte generation would change little from year to year, since only the maintenance cost of the facility is subject to inflation.

Figure C-5A Buckeye Powerplant



5. Buckeye Conduit

Buckeye Conduit is an irrigation pipeline owned and operated by the Georgetown Divide Public Utility District. It is located about 3.2 km (2 mi) northeast of Georgetown in El Dorado County (Fig. C-5A). The conduit carries water about 3.2 km (2 mi) from Lake Walton to the Georgetown Divide Ditch.

Site Characteristics. The hydraulic structure consists of a concrete pipe, 762 mm (30 in) in diameter and about 3.2 km (2 mi) long, that tapers to a 457 mm (18 in) pipe where the conduit enters a concrete energy dissipater box. The flow is controlled by a 457 mm (18 in) butterfly valve. When the water leaves the energy dissipater it flows through a reinforced-concrete pipe 1067 mm (42 in) in diameter and is discharged into the Georgetown Divide Ditch. A 13 kV transmission line is located about 91 m (300 ft) from the site.

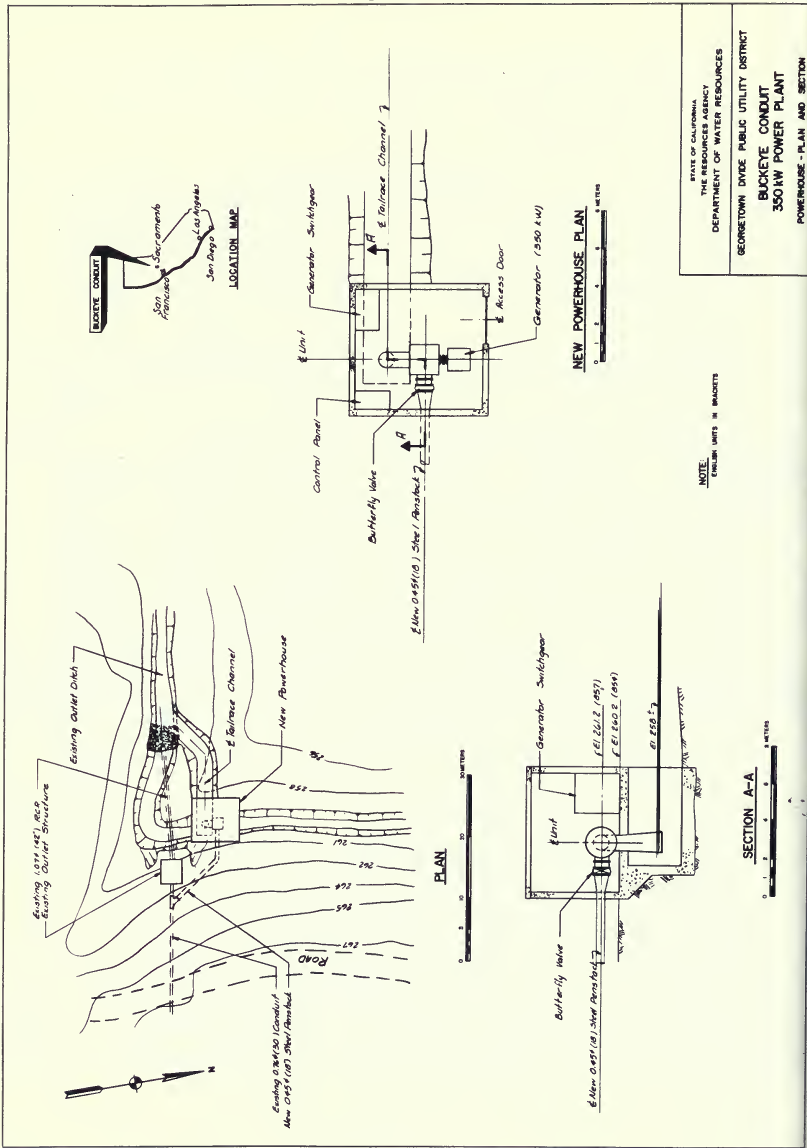
Potential Generation. The potential capacity of the site would be about 350 kW, and the estimated average annual output is about 2.4 million kWh (Table C-5A).

Table C-5A. Energy Generation for Buckeye Conduit Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	54.9	180	0.8	27	85	350	126 000
February	54.9	180	0.8	27	85	350	234 000
March	54.9	180	0.8	27	85	350	259 000
April	54.9	180	0.8	27	85	350	251 000
May	54.9	180	0.8	27	85	350	259 000
June	54.9	180	0.8	27	85	350	251 000
July	54.9	180	0.8	27	85	350	259 000
August	54.9	180	0.8	27	85	350	259 000
September	54.9	180	0.8	27	85	350	251 000
October	54.9	180	0.8	27	85	350	259 000
November	54.9	180	--	--	--	--	--
December	54.9	180	--	--	--	--	--
Total							2 408 000

New Power Plant Structures. A turbine-generator installed at the Buckeye Conduit outlet could use the 55 m (180 ft) available head. The proposed generating facility includes a steel pipe by-pass, 457 m (18 in) in diameter, beginning about 4 m (13 ft) upstream from the existing energy dissipater and carrying the water to a horizontal Francis turbine (Fig. C-5B). The turbine could develop 470 hp under the available head and would be connected directly to a horizontal, air-cooled synchronous generator with a rated output of 350 kW. The operation of the hydroelectric plant would be separated from that of the existing installation by a butterfly valve installed upstream from the turbine. A short tailrace channel would discharge the water into the Georgetown Divide Ditch.

Figure C-5B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
GEORGETOWN DIVIDE PUBLIC UTILITY DISTRICT
BUCKEYE CONDUIT
350 kW POWER PLANT
POWERHOUSE - PLAN AND SECTION
BUCKEYE CONDUIT
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Generator Switchgear
℄ Tailrace Channel
℄ Unit
Access Door
Generator (350 kW)
Control Panel
Butterfly Valve
℄ New 0.45ϕ (18) Steel Penstock
NEW POWERHOUSE PLAN
NOTE:
ENGLISH UNITS IN BRACKETS
Existing Outlet Ditch
℄ Tailrace Channel
New Powerhouse
Existing 1.07ϕ (42") RCP
Existing Outlet Structure
ROAD
Existing 0.76ϕ (30) Conduit
New 0.45ϕ (18) Steel Penstock
PLAN
Generator Switchgear
El 261.2 (857)
El 260.2 (854)
El 258±
℄ Unit
Butterfly Valve
℄ New 0.45ϕ (18) Steel Penstock
SECTION A-A

Cost of the New Power Plant. The estimated cost of building the new generating facility is $513,400, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $857,800 (Table C-5B).

Table C-5B. Project Cost for Buckeye Conduit Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 367,000
Transmission Facilities	15,000
Subtotal	$ 382,000
Contingencies (20%)	76,400
Total	$ 458,400
Engineering and Administration (12%)	55,000
Total Construction Cost (January 1980 prices)	$ 513,400
Escalation (4 yrs. at 12% per year)	294,400
Total Construction Cost (January 1984 prices)	$ 807,800
Studies, Licensing, Permits, and Approvals	50,000
Total	$ 857,800
Cost per kW (350 kW)	$ 2,451

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-5C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-5C. Annual Operating Cost for Buckeye Conduit Project

Cost Item	Amount
Operation and Maintenance	$ 20,400
Insurance	17,000
Interim Replacements	3,000
Total	$ 40,400

The annual cost of owning and operating the project would range between 15.3 and 22.5 percent of the direct project costs depending on financing. The estimated cost of generation ranges between 5.4 cents and 8.0 cents per kWh (Table C-5D).

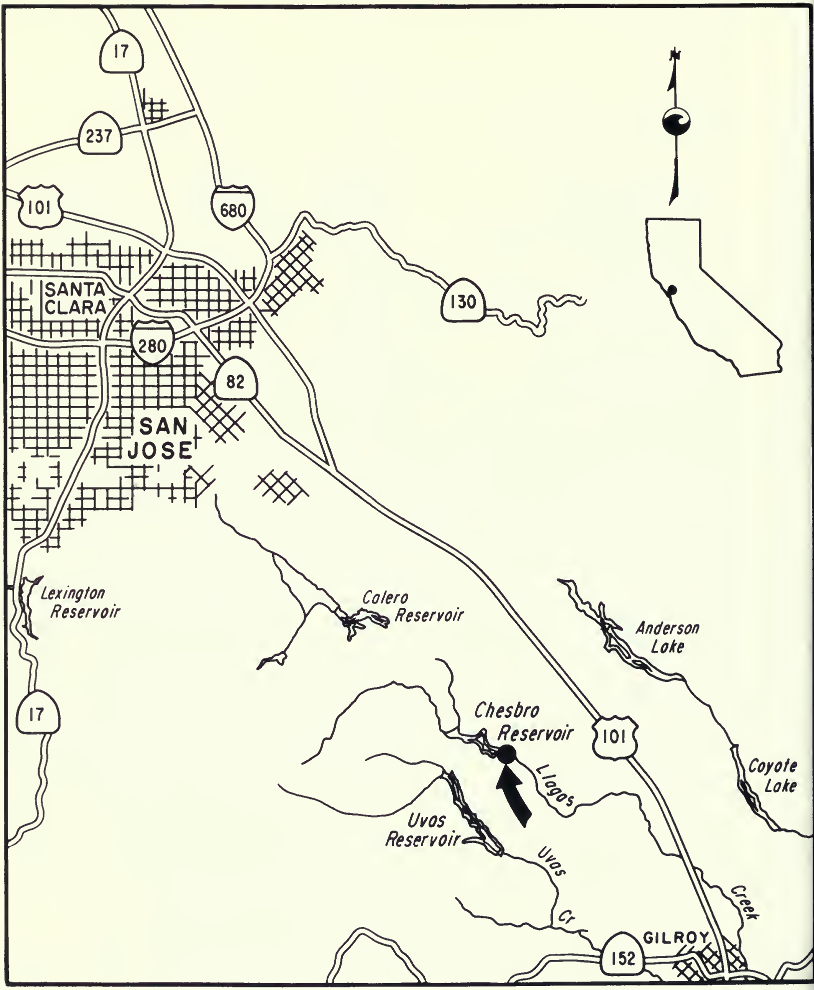
Table C-5D. Average Cost of Energy for Buckeye Conduit Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$107,200	$137,200	$152,700
Operating Cost	40,400	40,400	40,400
Total Annual Cost	$147,600	$177,600	$193,100
Average Cost (per kWh)	6.1¢	7.4¢	8.0¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 90,900	$123,500	$139,000
Operating Cost	40,400	40,400	40,400
Total Annual Cost	$131,300	$163,900	$179,400
Average Cost (per kWh)	5.4¢	6.8¢	7.4¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future costs of electrical energy.

Conclusions. Since the estimated value of Buckeye Conduit generation exceeds the estimated cost of generation (5.4 to 8.0 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Buckeye Conduit generation would change little from year to year because only the maintenance cost of the facility is subject to inflation.

Figure C-6A Chesbro Dam Powerplant



6. Chesbro Reservoir

Chesbro Reservoir is a water conservation facility owned and operated by the South Santa Clara Valley Water Conservation District. It is located on Llagas Creek about 13 km (8 mi) northwest of Gilroy in Santa Clara County (Fig. C-6A). Water released during the irrigation season percolates into the ground water basin from where it is pumped from wells and used for irrigation.

Site Characteristics. Chesbro Dam, officially Elmer J. Chesbro Dam, is an earth structure approximately 32 m (105 ft) high and 210 m (690 ft) long, at its crest. The intake in the reservoir has two 1.1 m (3.5 ft) square horizontal hydraulic slide gates.

Controlled releases are made from the reservoir through the dam's lower outlet--a steel pipe, 1.4 m (4.7 ft) in diameter and 185 m (607 ft) long, encased in a reinforced-concrete jacket. Flow through the outlet is controlled by a 1.4 m (4.5 ft) valve in a control structure at the downstream end of the outlet pipe. A 13 kV transmission line is located 152 m (500 ft) from the site.

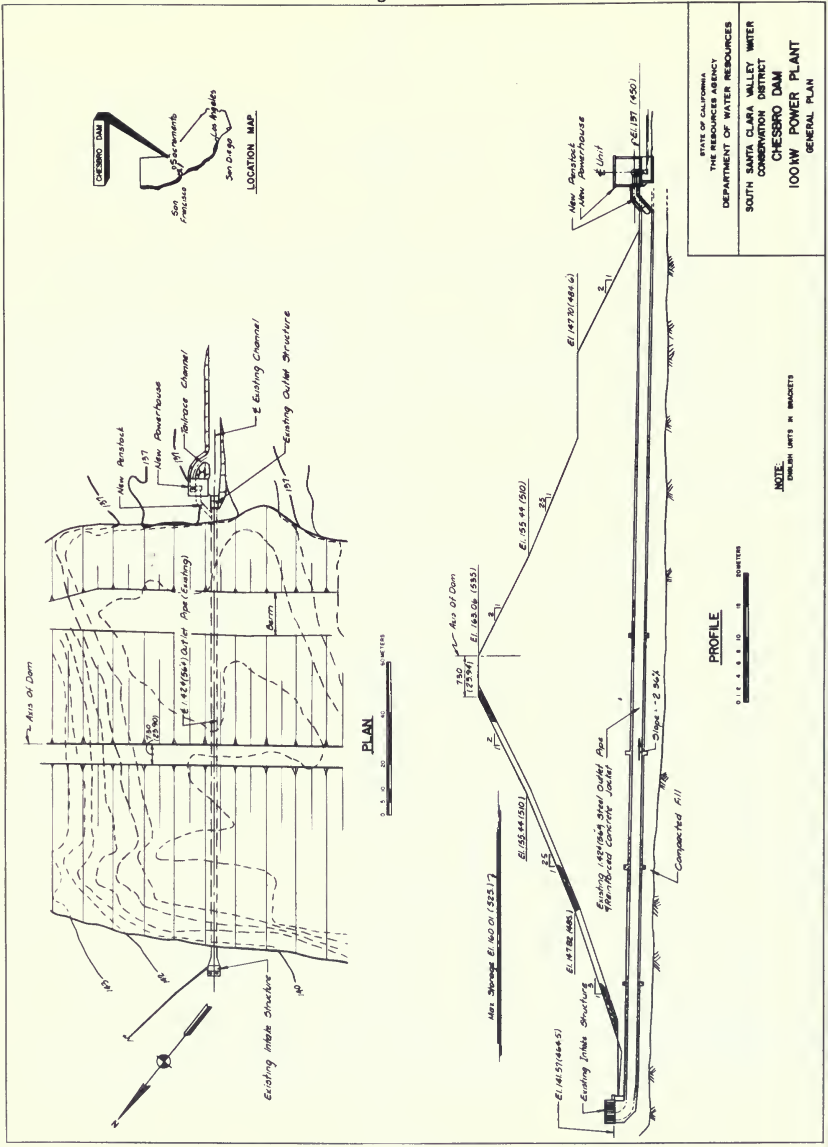
Potentital Generation. The potential capacity would be 100 kW, and the estimated average annual output is 216 600 kWh (Table C-6A).

Table C-6A. Energy Generation for Chesbro Reservoir Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	11.6	38	0.3	11	--	--	--
February	17.4	57	1.0	36	84	100	67 200
March	18.6	61	0.5	19	65	64	47 600
April	10.7	35	0.3	10	--	--	--
May	10.7	35	1.3	47	84	100	74 400
June	14.6	48	0.5	17	55	38	27 400
July	11.3	37	--	--	--	--	--
August	--	--	--	--	--	--	--
September	--	--	--	--	--	--	--
October	--	--	--	--	--	--	--
November	--	--	--	--	--	--	--
December	--	--	--	--	--	--	--
Total							216 600

New Power Plant Structures. A turbine-generator installed at the downstream end of the existing lower outlet pipe could use the 11.6 m to 19.8 m (38 ft to 65 ft) available head at the Chesbro site. The proposed generating facility includes a 1.4 m (4.7 ft) diameter steel pipe by-pass starting about 4 m (13 ft) upstream from the existing outlet control structure which carries water to a Francis turbine (Fig. C-6B). The turbine could develop 160 hp under a 20 m (65 ft) head. The turbine would be connected, through a gear box speed increaser, to a generator having a rated output of 100 kW. The operation of the hydroelectric plant and of the existing

Figure C-6B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
SOUTH SANTA CLARA VALLEY WATER CONSERVATION DISTRICT
CHESBRO DAM
100kW POWER PLANT
GENERAL PLAN
CHESBRO DAM
San Francisco
Sacramento
Los Angeles
San Diego
LOCATION MAP
Axis Of Dam
New Penstock
New Powerhouse
Tailrace Channel
℄ Existing Channel
Existing Outlet Structure
Berm
Existing Intake Structure
PLAN
El. 163.06 (535)
El. 155.44 (510)
El. 147.70 (484.6)
El. 137 (450)
Max Storage El. 160.01 (525.1)
El. 147.82 (485)
El. 141.57 (464.5)
Existing 1.424(56") Steel Outlet Pipe & Reinforced Concrete Jacket
Slope = 2.36%
Compacted Fill
New Penstock
New Powerhouse
℄ Unit
PROFILE
NOTE: ENGLISH UNITS IN BRACKETS

installation would be kept separate by a butterfly valve installed upstream from the turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $307,800, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were needed to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $534,300 (Table C-6B).

Table C-6B. Project Cost for Chesbro Reservoir Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$214,000
Transmission Facilities	15,000
Subtotal	$229,000
Contingencies (20%)	45,800
Total	$274,800
Engineering and Administration (12%)	33,000
Total Construction Cost (January 1980 prices)	$307,800
Escalation (4 yrs. at 12% per year)	176,500
Total Construction Cost (January 1984 prices)	$484,300
Studies, Licensing, Permits, and Approvals	$ 50,000
Total	$534,300
Cost per kW (100 kW)	$ 5,343

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-6C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-6C. Annual Operating Cost for Chesbro Reservoir Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	8,500
Interim Replacements	1,300
Total	$ 22,800

The annual cost of owning and operating the project would range between 15 and 22 percent of the direct project cost of $534,300,

depending on financing. The estimated cost of generation ranges between 36.8 cents and 54.6 cents per kWh (Table C-6D).

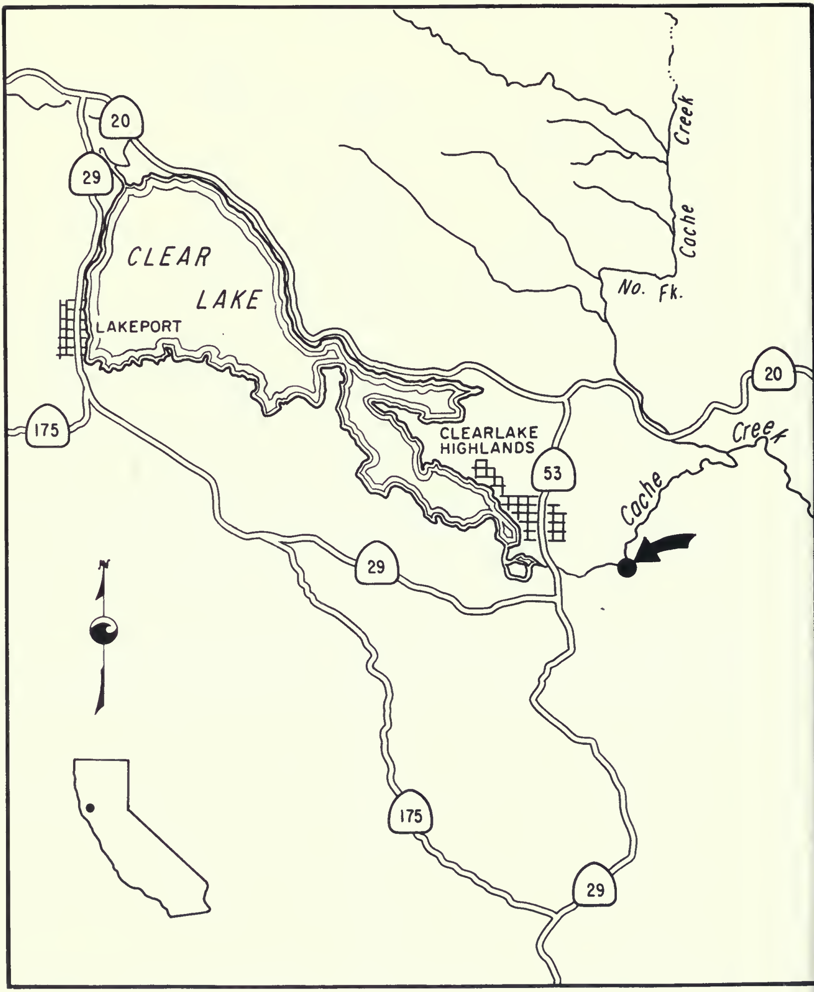
Table C-6D. Average Cost of Energy for Chesbro Reservoir Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 66,800	$ 85,500	$ 95,100
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$ 89,600	$108,300	$117,900
Average Cost (per kWh)	41.5¢	50.1¢	54.6¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 56,600	$ 76,900	$ 86,600
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$ 79,400	$ 99,700	$109,400
Average Cost (per kWh)	36.8¢	46.2¢	50.6¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE at its published price for small hydroelectric facilities of 100 kW or less. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Chesbro Dam generation is significantly less than the estimated cost of generation (36.8 to 54.6 cents per kWh), the project if constructed by 1984 would probably not be cost effective until 1996. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-7A Clear Lake Dam Powerplant



7. Clear Lake Impounding Dam

Clear Lake Impounding Dam is owned and operated by the Yolo County Flood Control and Water Conservation District. It is located about 4 km (2.5 mi) east of Lower Lake in Lake County (Fig. C-7A). The dam, built in 1914, establishes the water level of Clear Lake; stored waters are released for irrigation.

Site Characteristics. The dam is a concrete structure about 12 m (40 ft) high and 90 m (295 ft) long. Controlled releases from the reservoir can be made through fifteen lower outlets which have hydraulically-operated slide gates. Originally, a small water wheel located in a concrete structure at the north end of the dam was used to generate the power that operated the slide gates, but the waterwheel has been removed.

A single-phase 13 kV transmission line is located at the site. It would be necessary to upgrade about 2.4 km (1.5 mi) of this existing line to three-phase capacity by adding a third conductor.

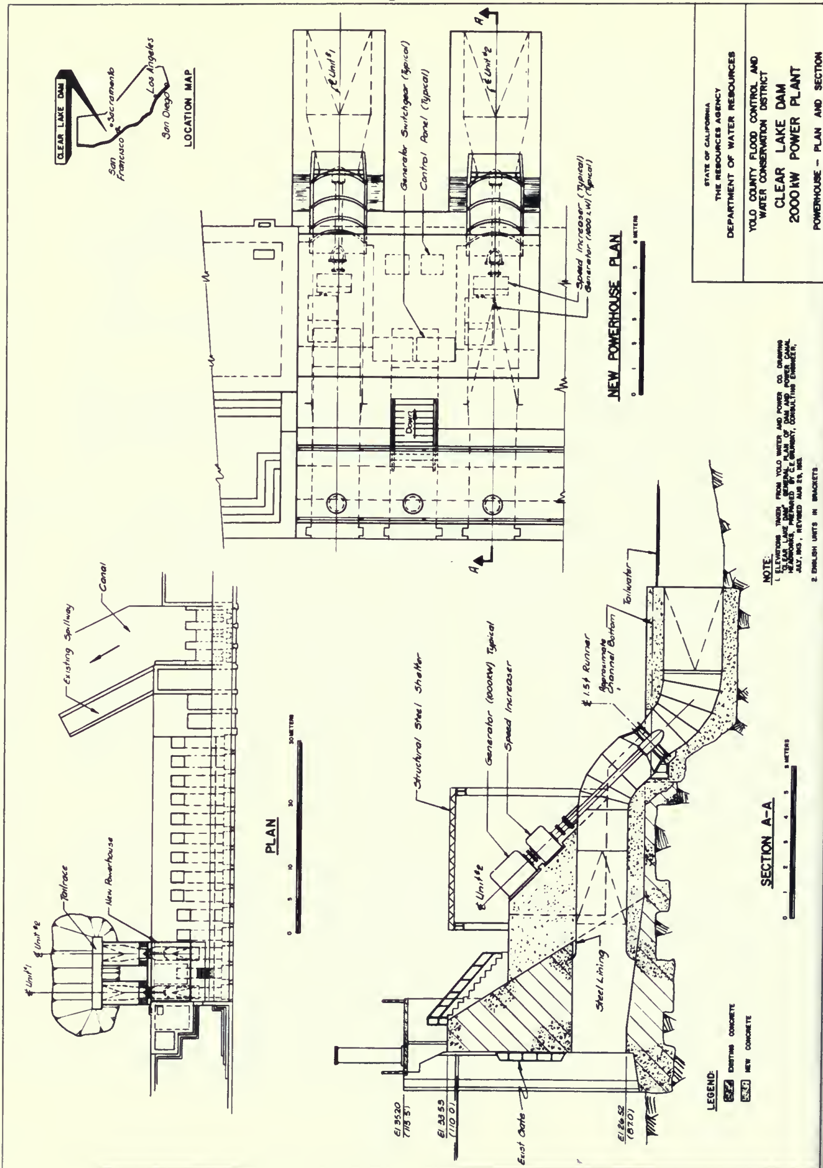
Potential Generation. Two turbine-generator units are considered for installation at Clear Lake Dam because of the monthly pattern of releases. The potential capacity would be 2000 kW, and the estimated average annual output is 7.5 million kWh (Table C-7A).

Table C-7A. Energy Generation for Clear Lake Impounding Dam Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	9.1	30	28.6	1009	84	2000	1 488 000
February	9.1	30	39.0	1378	84	2000	1 344 000
March	9.1	30	30.0	1060	84	2000	1 488 000
April	9.1	30	17.3	609	84	1000	720 000
May	9.1	30	11.5	407	84	868	646 000
June	8.5	28	13.6	481	84	957	689 000
July	8.2	27	13.8	486	84	933	694 000
August	7.9	26	10.5	372	78	638	475 000
September	7.6	25	5.4	188	--	--	--
October	7.3	24	1.2	42	--	--	--
November	7.6	25	0.1	3	--	--	--
December	7.9	26	3.5	123	--	--	--
Total							7 544 000

New Power Plant Structures. Turbines and generators installed at the existing Clear Lake Impounding Dam could use the 9.1 m (30 ft) available head. The proposed generating facility would use the two (of the existing fifteen) lower outlets nearest the left abutment of the dam as intakes for two standard tube-type turbine units (Fig. C-7B). The turbines would have 1.5 m (5 ft) diameter runners and could develop 1341 hp each under the available head. Each turbine would be connected, through a gear box speed increaser, to an air-cooled synchronous generator with a rated output of

Figure C-7B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
YOLO COUNTY FLOOD CONTROL AND WATER CONSERVATION DISTRICT
CLEAR LAKE DAM
2000 kW POWER PLANT
POWERHOUSE - PLAN AND SECTION
CLEAR LAKE DAM
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
NEW POWERHOUSE PLAN
Unit #1
Unit #2
Generator Switchgear (Typical)
Control Panel (Typical)
Speed Increaser (Typical)
Generator (1000 kW) (Typical)
Down
Canal
Existing Spillway
Tailrace
New Powerhouse
PLAN
SECTION A-A
Structural Steel Shelter
Generator (1000KW) Typical
Speed Increaser
1.5 ¢ Runner
Approximate Channel Bottom
Tailwater
Steel Lining
Exist Gate
El 352.0 (115.5)
El 335.5 (110.0)
El 265.2 (87.0)
LEGEND:
EXISTING CONCRETE
NEW CONCRETE
NOTE:
1. ELEVATIONS TAKEN FROM YOLO WATER AND POWER CO. DRAWING "CLEAR LAKE DAM GENERAL PLAN OF DAM AND POWER CANAL HEADWORKS," PREPARED BY F.L.E. GRUNSKY, CONSULTING ENGINEER, JULY, 1913, REVISED AUG 25, 1913.
2. ENGLISH UNITS IN BRACKETS

1000 kW for a total capacity of 2000 kW. An inclined turbine-generator arrangement was selected to minimize cost.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $3,075,100, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were needed to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $4,938,400 (Table C-7B).

Table C-7B. Project Cost for Clear Lake Impounding Dam Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$2,238,000
Transmission Facilities	50,000
Subtotal	$2,288,000
Contingencies (20%)	457,600
Total	$2,745,600
Engineering and Administration (12%)	329,500
Total Construction Cost (January 1980 prices)	$3,075,100
Escalation (4 yrs. at 12% per year)	1,763,300
Total Construction Cost (January 1984 prices)	$4,838,400
Studies, Licensing, Permits, and Approvals	100,000
Total	$4,938,400
Cost per kW (2 000 kW)	$ 2,469

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-7C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-7C. Annual Operating Cost for Clear Lake Impounding Dam Project

Cost Item	Amount
Operation and Maintenance	$ 26,000
Insurance	59,500
Interim Replacements	10,200
Total	$ 95,700

The annual cost of owning and operating the project would range between 12.5 and 20 percent of the direct project cost of $4,938,400, depending on financing. The estimated cost of generation ranges between 8.2 cents and 12.9 cents per kWh (Table C-7D).

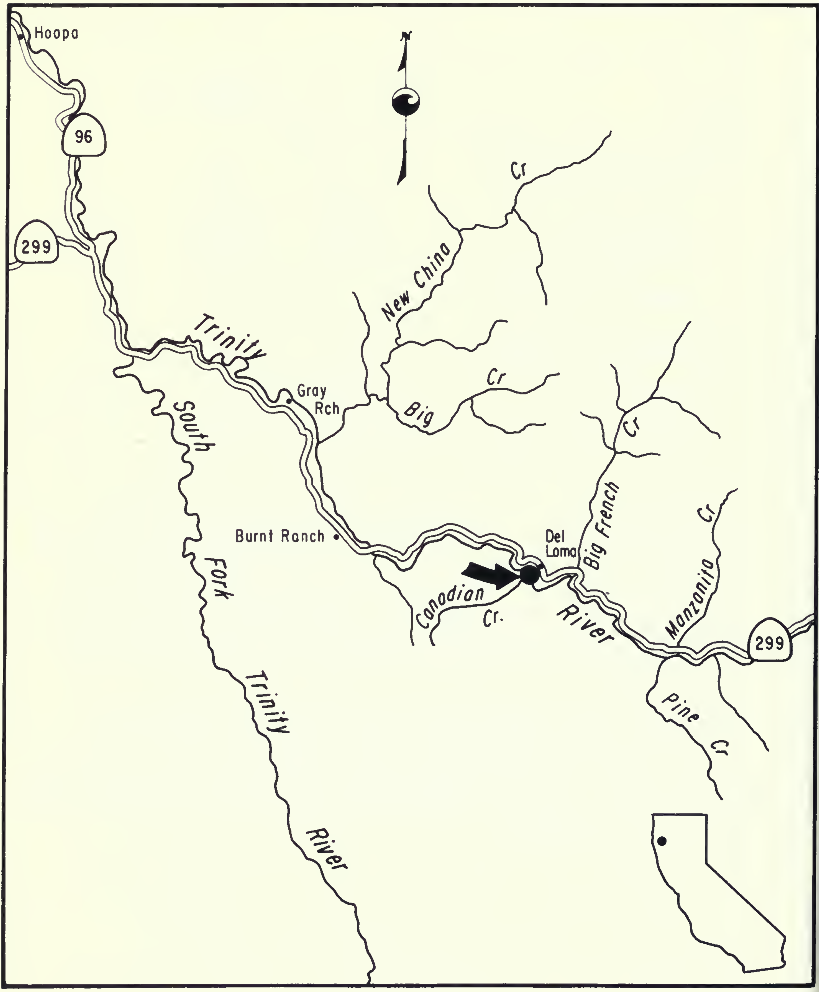
Table C-7D. Average Cost of Energy for Clear Lake Impounding Dam Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$617,300	$790,100	$879,000
Operating Cost	95,700	95,700	95,700
Total Annual Cost	$713,000	$885,800	$974,700
Average Cost (per kWh)	9.5¢	11.7¢	12.9¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$523,500	$711,100	$800,000
Operating Cost	95,700	95,700	95,700
Total Annual Cost	$619,200	$806,800	$895,700
Average Cost (per kWh)	8.2¢	10.7¢	11.9¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated minimum value of Clear Lake generation is within the range of estimated costs to develop the site (8.2 to 12.9 cents per kWh). Thus, the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Clear Lake generation would change little from year to year because only the maintenance cost of the facility is subject to inflation.

Figure C-8A Del Loma Powerplant



8. Del Loma Tunnel

The Del Loma Tunnel was constructed in the late 1800s as a by-pass for the Trinity River to enable gold mining in the stream bed where the river makes a horseshoe bend. The tunnel is owned by Mr. George Costa, and is located about 32 km (20 mi) west of the community of Weaverville in Trinity County (Fig. C-8A). The Trinity River was designated a federal Wild and Scenic River, and any development, including hydroelectric power, cannot alter the existing environment.

Site Characteristics. The existing hydraulic facility consists of a rectangular concrete intake structure, located on the river bank just upstream from the point where the river begins to make a horseshoe bend; a tunnel, about 2.7 m (9 ft) in diameter and 137 m (450 ft) long, cut through solid rock; and an outlet which returns the water to the river at the other end of the horseshoe bend. The intake structure consists of a rectangular opening 8.5 m (28 ft) wide with three vertical railroad rails spaced 2.1 m (7 ft) apart. The depth of the Trinity River at the opening of the intake structure determines how much water flows through the tunnel. The elevation at the intake invert is 338 m (1109 ft), and the elevation at the outlet invert is 337 m (1105 ft). The outlet is located about 1.5 m (5 ft) above the stream bed resulting in a net available head of about 3.4 m (11 ft). A 13 kV transmission line is located about 61 m (200 ft) from the site.

Potential Generation. No records are available for water flows through the tunnel. Considering the location of the intake structure along the river bank, the estimated flow through the tunnel is 8.5 cms (300 cfs). The potential capacity would be 250 kW, and the estimated average annual output is about 1.9 million kWh allowing 700 hours per year for routine maintenance.

New Power Plant Structures. A hydraulic turbine and electric generator installed at the downstream end of the tunnel could use the 3.4 m (11 ft) head. The proposed generating facility includes an unproved vertical Samson-type of Francis turbine which could develop 352 hp under the available head (Fig. C-8B). The turbine would be connected, through a gear box speed increaser, to a horizontal generator with a rated output of 250 kW.

An open-flume type of power plant would be situated against the hill at the existing tunnel outlet portal. About 15 m to 20 m (50 ft to 66 ft) of the tunnel approach to the powerhouse would be lined with concrete to provide a uniform flow to the turbine. It might be necessary to line other portions of the tunnel if weak zones of rock are present.

Cost of the New Power Plant. The estimated package cost of the new generating facility is $752,800, based on January 1980 prices. If the project were initiated in 1981 and about 30 to 36 months were required to obtain approvals, arrange financing, design, and build the project, the work could be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $1,284,500 (Table C-8A).

Figure C-8B

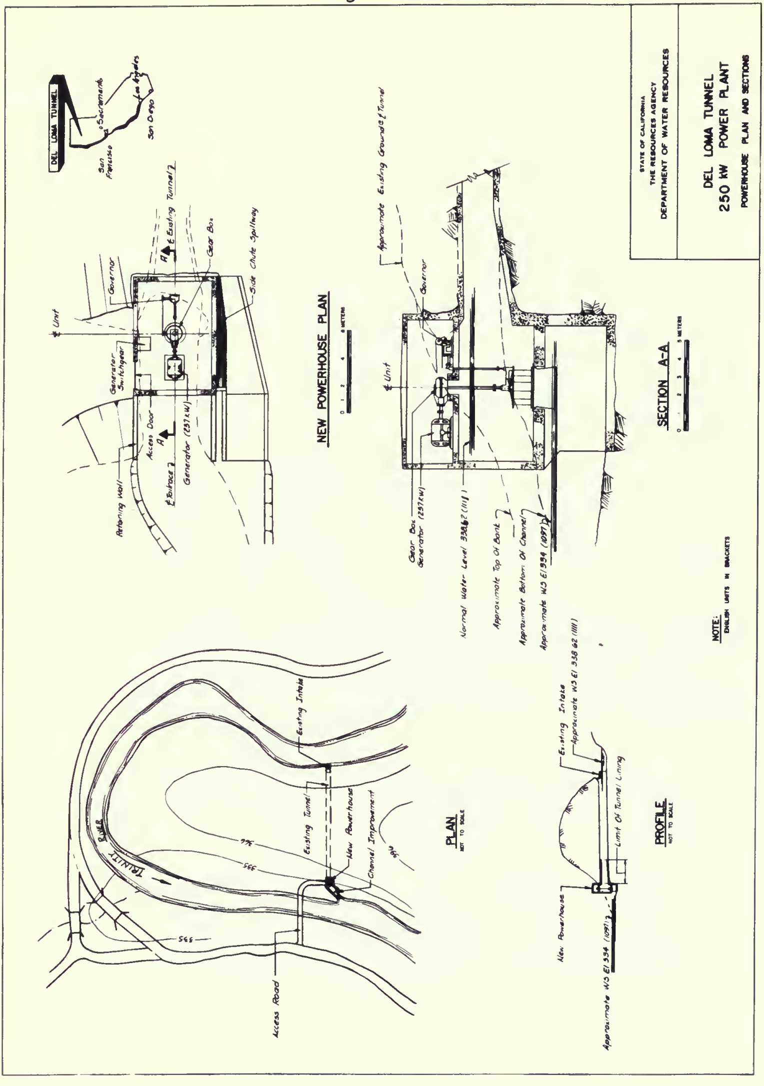

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
DEL LOMA TUNNEL
250 KW POWER PLANT
POWERHOUSE PLAN AND SECTIONS
DEL LOMA TUNNEL
San Francisco
Sacramento
Los Angeles
San Diego
NEW POWERHOUSE PLAN
Governor
Generator Switchgear
Access Door
Retaining Wall
Generator (257 kW)
Gear Box
Side Chute Spillway
℄ Unit
℄ Entrace
℄ Existing Tunnel
SECTION A-A
Approximate Existing Ground ℄ Tunnel
Governor
℄ Unit
Gear Box
Generator (257 kW)
Normal Water Level 338.62 (1111)
Approximate Top Of Bank
Approximate Bottom Of Channel
Approximate WS El 334 (1097)
NOTE:
ENGLISH UNITS IN BRACKETS
PLAN
NOT TO SCALE
TRINITY RIVER
Existing Intake
Existing Tunnel
New Powerhouse
Channel Improvement
Access Road
PROFILE
NOT TO SCALE
Existing Intake
Approximate WS El 338.62 (1111)
Limit Of Tunnel Lining
New Powerhouse
Approximate WS El 334 (1097)

Table C-8A. Project Cost for Del Loma Tunnel Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 528,500
Transmission Facilities	17,000
Subtotal	$ 545,500
Contingencies (20%)	109,100
Total	$ 654,600
Engineering and Administration (15%)	98,200
Total Construction Cost (January 1980 Prices)	$ 752,800
Escalation (4 yrs. at 12% per year)	431,700
Total Construction Cost (January 1983 Prices)	$1,184,500
Studies, Licensing, Permits, and Approvals	100,000
Total	$1,284,500
Cost per kW (250 kW)	$ 5,138

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-8B). Since water for generation is available throughout the year, regular maintenance could be scheduled at the convenience of purchaser.

Table C-8B. Annual Operating Cost for Del Loma Tunnel Project

Cost Item	Amount
Operation and Maintenance	$ 47,600
Insurance	8,500
Interim Replacements	1,600
Total	$ 57,700

The annual cost of owning and operating the project would range between 15 and 22 percent of the direct project cost of $1,284,500, depending on financing. The estimated cost of generation ranges between 10.2 cents and 15.1 cents per kWh (Table C-8C).

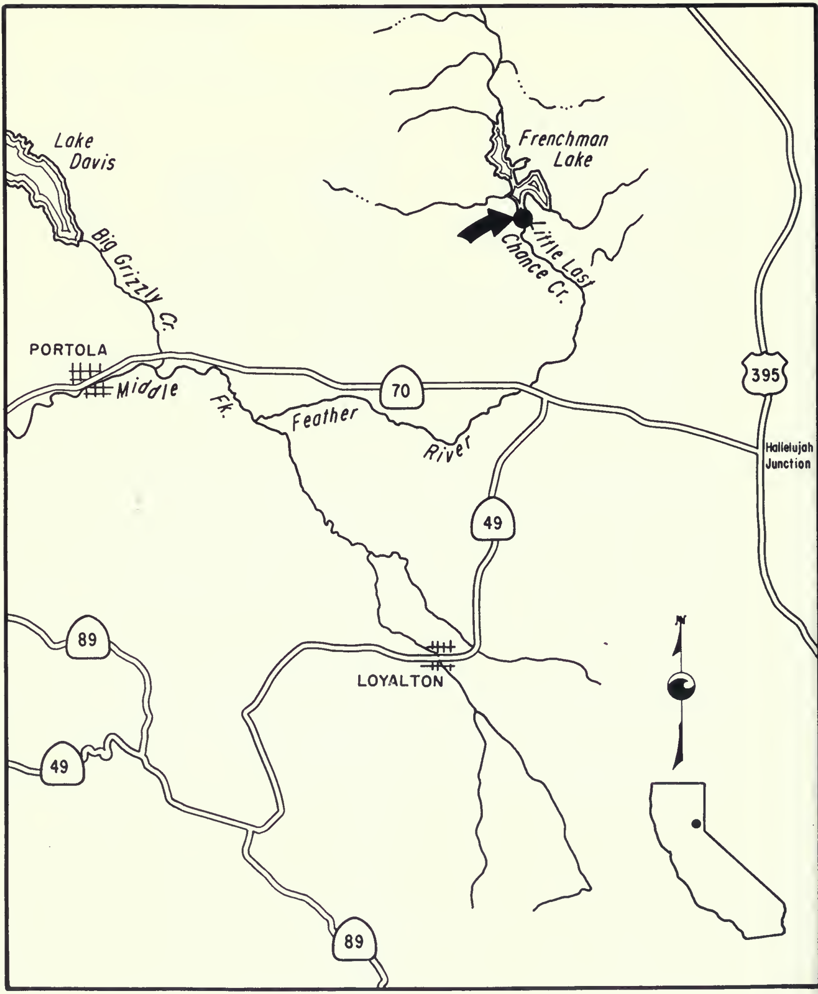
Table C-8C. Average Cost of Energy for Del Loma Tunnel Project

Cost Item	Amount		
	Interest Rate		
	9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$160,600	$205,500	$228,600
Operating Cost	57,700	57,700	57,700
Total Annual Cost	$218,300	$263,200	$286,300
Average Cost (per kWh)	11.5¢	13.9¢	15.1¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$136,200	$185,000	$208,100
Operating Cost	57,700	57,700	57,700
Total Annual Cost	$193,900	$242,700	$265,800
Average Cost (per kWh)	10.2¢	12.8¢	14.0¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. Since water would flow through the tunnel during all months of the year (even during dry years), the Del Loma site would have a capacity value in addition to its energy value. The capacity value is estimated at about $15,900 annually, representing an average of 0.8 cent per kWh in 1980. The total value of project generation (including both capacity and energy) in 1984, is 11.1 cents per kWh using the CEC median oil-price projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of Del Loma generation is within the range of the estimated generation cost (10.2 to 15.1 cents per kWh). The project would probably be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Del Loma generation would change little from year to year since only the maintenance cost of the facility is subject to inflation.

Figure C-9A Frenchman Dam Powerplant



9. Frenchman Dam

Frenchman Dam, owned and operated by the DWR, is located on Little Last Chance Creek near Chilcoot in Plumas County (Fig. C-9A). The dam and reservoir are used for flood control, water conservation, and recreation. Water is released in accordance with contracts for water deliveries in the Sierra Valley.

Site Characteristics. The dam is an earth structure approximately 38 m (125 ft) long. Controlled releases from the reservoir are made through the dam's lower outlet which is about 155 m (510 ft) long. For the first 60 m (197 ft) from the reservoir intake structure to a valve chamber, the outlet consists of a 914 mm (36 in) diameter concrete conduit. From the valve chamber for about 95 m (312 ft) to the outlet control house, the outlet consists of a 0.8 m (2.5 ft) diameter steel pipe enclosed by a horseshoe-shaped concrete conduit having an inside diameter of 2 m (6.5 ft). The main valve, located in the outlet control house, is a 0.6 m (2 ft) hollow cone-type valve. About 2.7 m (9 ft) upstream from the outlet control house, the steel pipe is tapped with a 0.5 m (1.5 ft) steel pipe stubbed and capped for future use for hydroelectric generation.

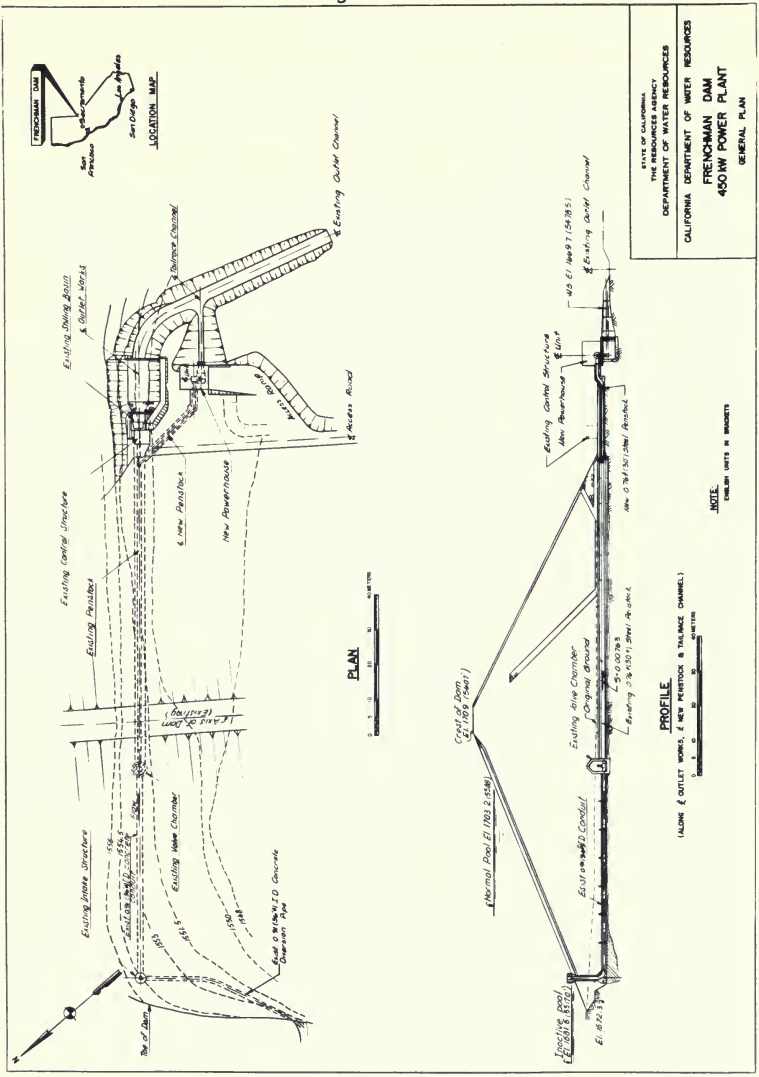
Potential Generation. A horizontal Francis turbine is considered for installation at the dam using a new tap into the existing 0.8 m (2.5 ft) steel pipe. The potential installed capacity would be 450 kW, and the estimated annual generation is about 1 million kWh (Table C-9A).

Table C-9A. Energy Generation for Frenchman Dam Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	30.2	99	0.1	2	--	--	--
February	30.5	100	0.1	3	--	--	--
March	31.1	102	0.3	10	--	--	--
April	31.7	104	0.5	19	--	--	--
May	31.7	104	1.1	39	73	250	186 000
June	31.1	102	1.8	63	79	429	309 000
July	30.2	99	1.3	47	82	323	240 000
August	29.0	95	1.8	63	79	400	298 000
September	28.7	94	0.5	19	--	--	--
October	28.4	93	0.3	10	--	--	--
November	28.4	93	0.1	2	--	--	--
December	28.7	94	0.1	2	--	--	--
Total							1 033 000

New Power Plant Structures. A hydraulic turbine and electric generator installed at the downstream end of the existing lower outlet pipe could use the 29 m to 31.7 m (95 ft to 104 ft) head available at Frenchman Dam. The proposed generating facility would include a 0.8 m (2.5 ft) steel pipe by-pass from about 5 m (16.5 ft) upstream of the existing outlet control house to carry water to a horizontal Francis turbine (Figs C-9B and C-9C). The turbine could develop 605 hp under the available head and would be

Figure C-9B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CALIFORNIA DEPARTMENT OF WATER RESOURCES
FRENCHMAN DAM
450 KW POWER PLANT
GENERAL PLAN
LOCATION MAP
FRENCHMAN DAM
Sacramento
San Francisco
Los Angeles
San Diego
PLAN
PROFILE
(ALONG ℄ OUTLET WORKS, ℄ NEW PENSTOCK & TAILRACE CHANNEL)
NOTE
ENGLISH UNITS IN BRACKETS
Existing Intake Structure
Existing Valve Chamber
Existing Penstock
Existing Control Structure
Existing Stilling Basin
℄ Outlet Works
℄ Tailrace Channel
℄ Existing Outlet Channel
℄ New Penstock
New Powerhouse
Access Road
℄ Access Road
℄ Axis of Dam (Existing)
Toe of Dam
Exist. 0.91 (36") I.D. Concrete Diversion Pipe
Crest of Dam El. 1709 (5607)
Normal Pool El 1703.2 (5588)
Inactive pool El 1681.6 (5517.2)
El. 1672.3
Existing Valve Chamber
Original Ground
Existing 0.76 (30") Steel Penstock
New 0.76 (30") Steel Penstock
Existing Control Structure
New Powerhouse
℄ Unit
W.S. El 1669.7 (5478.5)
℄ Existing Outlet Channel

connected directly to a horizontal, air-cooled synchronous generator with a rated output of 450 kW.

The operations of the hydroelectric plant and of the existing installation would be kept separate by a butterfly valve installed upstream from the turbine. Although a 0.5 m (1.5 ft) steel pipe was installed when Frenchman Dam was built, it would not be used for the proposed installation because its small diameter would prevent the full use of the available flows, and because its physical location is such that construction of a powerhouse using it would require considerable rock and earth excavation.

Transmission Facilities. The nearest transmission line is owned and operated by the Sierra-Plumas Rural Electric Cooperative. It would be necessary to construct about 8 km (5 mi) of 13 kV transmission line to connect the proposed project with the existing transmission grid.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $982,400, based on January 1980 prices. If the project were initiated in 1981, and about 24 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $1,645,800 (Table C-9B).

Table C-9B. Project Cost for Frenchman Dam Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 555,900
Transmission Facilities	175,000
Subtotal	$ 730,900
Contingencies (20%)	146,200
Total	$ 877,100
Engineering and Administration (12%)	105,300
Total Construction Cost (January 1980 Prices)	$ 982,400
Escalation (4 yrs. at 12% per year)	563,400
Total Construction Cost (January 1984 Prices)	$1,545,800
Studies, Licensing, Permits, and Approvals	100,000
Total	$1,645,800
Cost per kW (450 kW)	$ 3,657

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-9C). Regular maintenance could be scheduled during winter months when there is insufficient water for power generation.

Figure C-9C

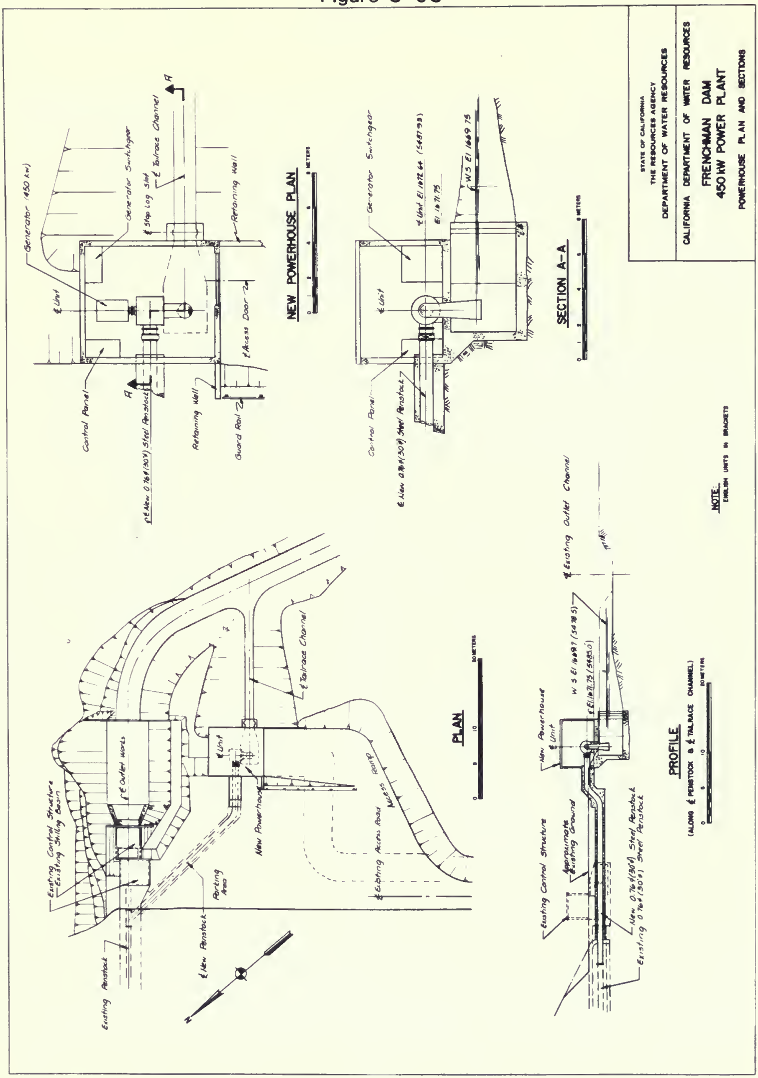

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CALIFORNIA DEPARTMENT OF WATER RESOURCES
FRENCHMAN DAM
450 kW POWER PLANT
POWERHOUSE PLAN AND SECTIONS
NEW POWERHOUSE PLAN
SECTION A-A
PLAN
PROFILE
(ALONG ℄ PENSTOCK & ℄ TAILRACE CHANNEL)
NOTE:
ENGLISH UNITS IN BRACKETS
Generator (450 kW)
Generator Switchgear
℄ Tailrace Channel
℄ Stop Log Slot
Retaining Wall
℄ Unit
℄ Access Door
Control Panel
℄ New 0.76ϕ(30ϕ) Steel Penstock
Guard Rail
℄ Unit El 1672.64 (5487.93)
El 1671.75
W S El 1669.75
Existing Control Structure
Existing Stilling Basin
℄ Outlet Works
New Powerhouse
Existing Access Road
Access Ramp
Parking Area
℄ New Penstock
Existing Penstock
℄ Existing Outlet Channel
W S El 1669.97 (5478.5)
℄ El 1671.75 (5485.0)
New Powerhouse
Approximate Existing Ground
New 0.76ϕ(30ϕ) Steel Penstock
Existing 0.76ϕ(30ϕ) Steel Penstock

Table C-9C. Annual Operating Cost for Frenchman Dam Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	16,000
Interim Replacements	2,700
Total	$ 31,700

The annual costs of owning and operating the project would range between 13 and 20 percent of the direct project cost of $1,645,800, depending on financing. The estimated cost of generation ranges between 20.0 cents and 31.4 cents per kWh (Table C-9D).

Table C-9D. Average Cost of Energy for Frenchman Dam Project

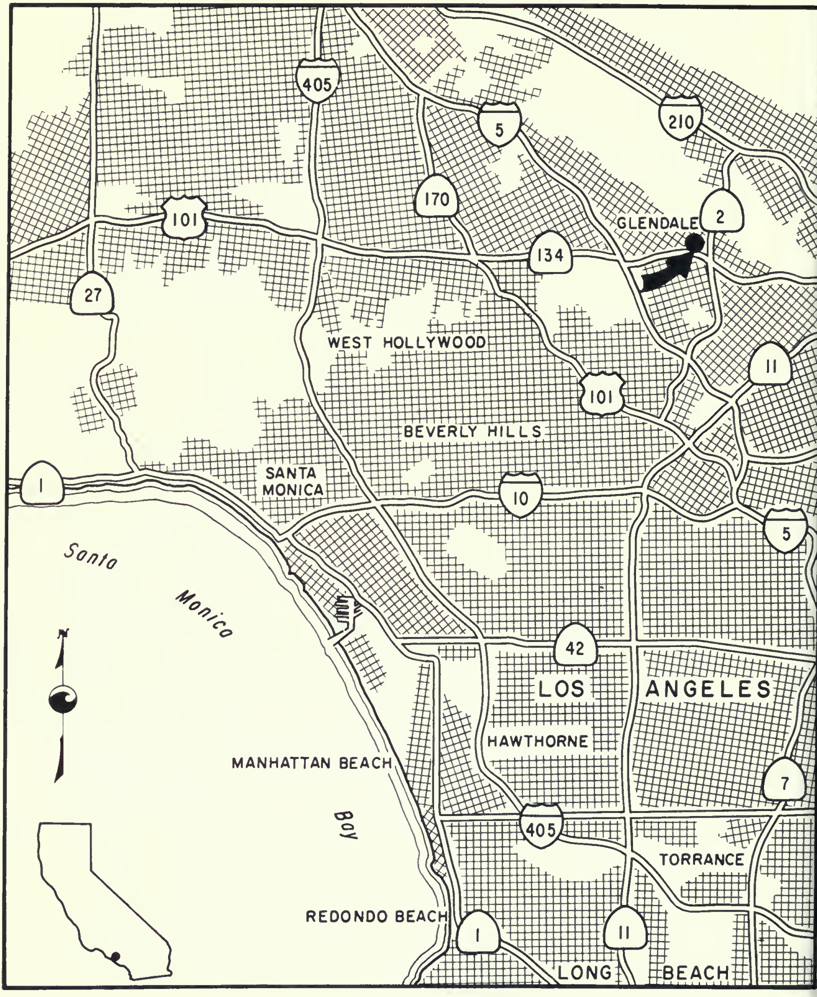
Cost Item	Amount Interest Rate		
	9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$205,700	$263,300	$293,000
Operating Cost	31,700	31,700	31,700
Total Annual Cost	$237,400	$295,000	$324,700
Average Cost (per kWh)	23.0¢	28.6¢	31.4¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$174,500	$237,000	$266,600
Operating Cost	31,700	31,700	31,700
Total Annual Cost	$206,200	$268,700	$298,300
Average Cost per (kWh)	20.0¢	26.0¢	28.9¢

Value of Generation. Project generation from Frenchman Dam could be wheeled through Plumas-Sierra Rural Electric Coop., Inc., California-Pacific Utilities Company, and PGandE for use on the State Water Project. It is assumed that the value of this energy to DWR is comparable to the rates that utilities will be required to pay under Section 210 of PURPA. The estimated value of this generation is 11.1 cents per kWh in 1984 and 22.9 cents per kWh in 1990, based on the median CEC oil cost projection for future costs of electrical energy.

Conclusions. By 1989, the value of Frenchman Dam generation is within the range of the generation cost (20.0 to 31.4 cents per kWh).

For approximately the first 5 years of operation, project costs would exceed the value of the energy. However, during subsequent years as the price of oil increases the value of this resource will more than offset the high initial cost of the project.

Figure C-10A Glendale Distribution System Powerplant



10. Glendale Distribution System

The Glendale Distribution System facility is a water distribution system owned and operated by the City of Glendale in Los Angeles County (Fig. C-10A). Water is delivered to the site by a pipeline pressurized at the source by the Metropolitan Water District of Southern California. A valve is used to reduce the water pressure for the Glendale water distribution system. The system covers an area of 78 sq km (30 sq mi) and serves over 128 000 people.

Site Characteristics. The hydraulic facility consists of a 1.5 m (59 in) diameter water main operated at a pressure equal to an elevation of 282 m (925 ft), connected through a pressure-reducing valve to a 762 mm (30 in) diameter pipeline operated at a pressure equal to an elevation 221 m (724 ft). A 4 kV transmission line is located adjacent to the site.

Potential Generation. The potential capacity of the Glendale Distribution System facility would be about 400 kW, and the estimated average annual output is about 2 million kWh (Table C-10A).

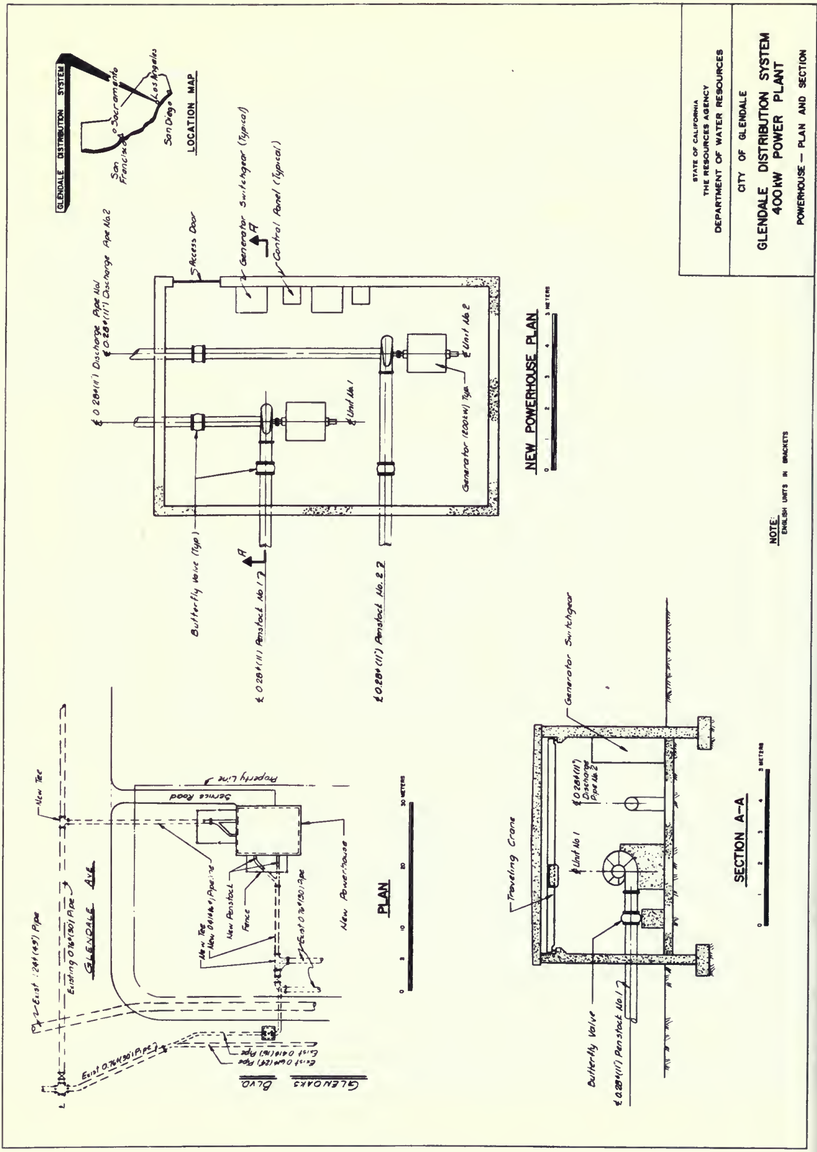
Table C-10A. Energy Generation for Glendale Distribution Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	57.3	188	0.3	11	85	149	111 000
February	58.2	191	0.3	12	85	165	111 000
March	56.4	185	0.3	12	85	160	119 000
April	59.1	194	0.8	28	85	391	282 000
May	60.0	197	0.8	27	85	383	285 000
June	56.4	185	0.7	25	85	333	240 000
July	60.3	198	0.4	13	85	185	138 000
August	58.2	191	0.3	12	85	165	123 000
September	57.9	190	0.4	13	85	178	128 000
October	61.0	200	0.4	14	85	202	150 000
November	55.2	181	0.4	15	85	195	140 000
December	59.1	194	0.4	15	85	210	156 000
Total							1 983 000

New Power Plant Facilities. Hydraulic turbines and electric generators installed at the site could use the available head of about 61 m (200 ft). The proposed generating facility includes a new pipeline, 406 mm (16 in) in diameter and about 17 m (55.7 ft) long; a powerhouse; and a discharge pipeline, 406 mm (16 in) in diameter and about 27 m (89 ft) long (Fig. C-10B). The upstream pipe would take water through a T-connection from the existing 0.8 m (2.5 ft) pipe operated at an elevation pressure of 282 m (925 ft). The downstream pipe would discharge the water through a new T-connection into the existing Glendale pipeline which operates at elevation pressure of 221 m (724 ft).

The powerhouse would contain two horizontal, modified pump-type turbines, each capable of developing 268 hp under the available head. The

Figure C-10B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CITY OF GLENDALE
GLENDALE DISTRIBUTION SYSTEM
400 kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
GLENDALE DISTRIBUTION SYSTEM
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Access Door
Generator Switchgear (Typical)
Control Panel (Typical)
Butterfly Valve (Typ)
Unit No 1
Unit No 2
Generator (200kW) Typ.
NEW POWERHOUSE PLAN
SECTION A-A
NOTE: ENGLISH UNITS IN BRACKETS
Generator Switchgear
Traveling Crane
Butterfly Valve
Property Line
Service Road
New Tee
New Penstock
Fence
New Powerhouse
GLENDALE AVE
GLENOAKS BLVD
PLAN

turbines would be connected directly to horizontal generators with a rated output of 200 kW each. The operations of the power plant and the existing water supply system would be separated by butterfly valves installed both upstream and downstream from each turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $573,900, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were needed to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $1,023,000 (Table C-10B).

Table C-10B. Project Cost for Glendale Distribution Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 412,000
Transmission Facilities	15,000
Subtotal	$ 427,000
Contingencies (20%)	85,400
Total	$ 512,400
Engineering and Administration (12%)	61,500
Total Construction Cost (January 1980 prices)	$ 573,900
Escalation (4 yrs. at 12% per year)	399,100
Total Construction Cost (January 1984 prices)	$ 973,000
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,023,000
Cost per kW (400 kW)	$ 2,558

Cost of Generation. Since the Glendale Distribution System site, and an electric transmission and distribution system are owned and operated by the City of Glendale, it is assumed that the city would develop and use the power in its own electric system. The annual cost of owning and operating the project include debt repayment, operation and maintenance, insurance, replacements, administration, and overhead.

It is assumed that the city would finance the construction of the hydroelectric facility by issuing tax-exempt revenue bonds at a 9 percent interest rate. The actual interest rate would depend on financial conditions at the time of issue. It is anticipated that initial development would be financed from electric system revenues or short-term loans, and that the bonds would not be issued until about 12 months before the project is completed. The additional cost to operate the plant would be insignificant, since the city has a full staff of operating personnel.

Assuming that the project will be scheduled to be on-line late in 1983, the bond issue would amount to about $1,220,000, based on January 1980 bid prices, with 12 percent annual inflation, and a one-year construction period (Table C-10C).

Table C-10C. Annual Cost for Glendale Distribution Project

Cost Item	Amount 20-Year Bonds	Amount 35-Year Bonds
Project Cost	$1,023,000	$1,023,000
Capitalized Interest	85,800	85,800
Interest Earnings	(42,900)	(42,900)
Total Capital Cost	$1,065,900	$1,065,900
Bond Reserve Fund	128,700	108,800
Financing Costs	50,400	45,300
Bond Issue	$1,245,000	$1,220,000
Debt Service (9% interest)	$ 136,400	$ 115,500
Operation and Maintenance	20,400	20,400
Insurance	8,500	8,500
Interim Replacements	1,500	1,500
Interest Earnings	(9,800)	(9,800)
Total Annual Cost	$ 157,000	$ 136,000
Annual Cost (% of Project Cost)	15.3	13.3
Average Cost (per kWh)	7.9¢	6.9¢

The annual cost of owning and operating the project, if it were constructed in 1983 and first operated in 1984, is estimated to be between $136,100 and $157,000 (Table C-10C).

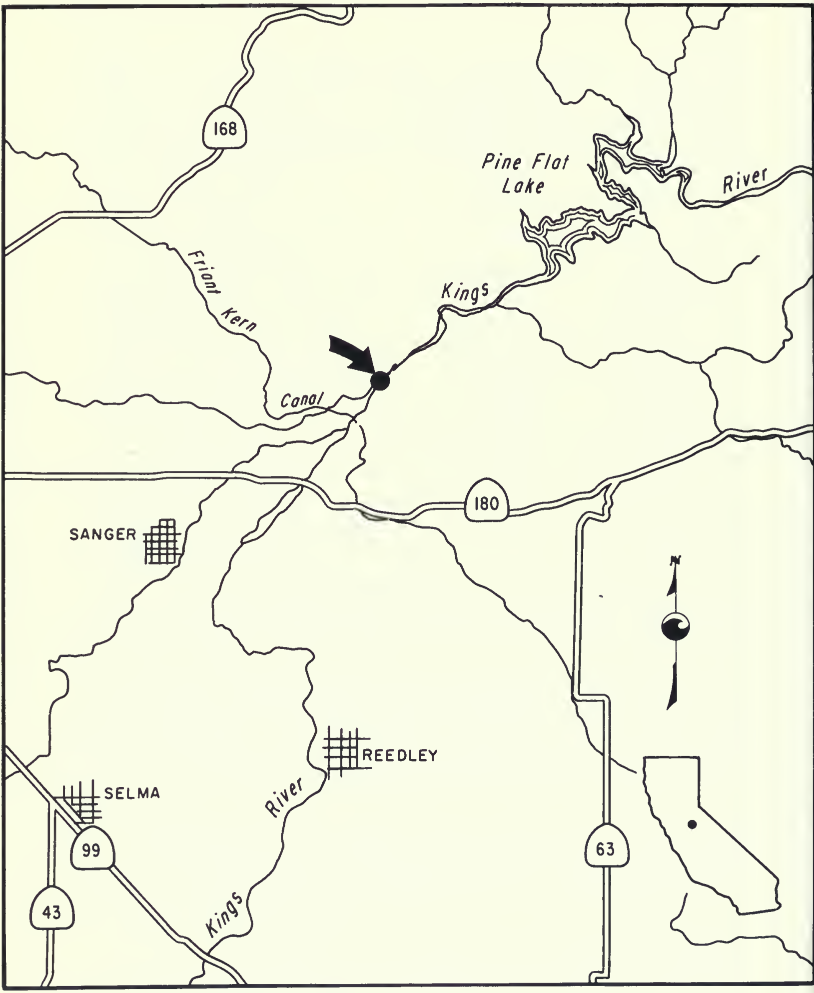
The estimated average generation cost (assuming 35-year bonds) is 6.5 cents per kWh. With 20-year bonds, the estimated average cost of generation increases to 7.9 cents per kWh. Since the city is experienced in owing and operating electric facilities, it might elect to be self-insured--in full or in part--to reduce the annual insurance premium on mechanical and electrical equipment. This would reduce its annual generation cost.

Value of Generation. It is assumed that the city would use the energy produced at the Glendale Distribution System site in its own electric system. The value of such hydroelectric generation to the city would be equal to the energy that it would otherwise have to purchase if the new hydroelectric facility were not built.

Computing this avoided cost to the city is beyond the scope of this study. However, the annual average avoided cost can be estimated based on the rates established by SCE for the purchase of energy from small power facilities. The SCE rate for mid-peak energy, and thus the estimated value of avoided energy for the city, can be taken from the partial-peak projection shown in Appendix G. The estimated value of project generation in 1984 would be 10.1 cents per kWh, plus 0.8 cent per kW for capacity.

Conclusions. Since the estimated value of Glendale Distribution System generation (10.9 cents per kWh in 1984) exceeds the estimated cost of generation (6.9 cents per kWh for 35-year financing at 9 percent), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of generation would change little from year to year, since only the cost of maintaining the facility is subject to inflation.

Figure C-11A Gould Weir Powerplant



11. Gould Weir

Gould Weir is a diversion structure owned and operated by the Fresno Irrigation District on the Kings River. It is located east of Fresno and downstream from the Pine Flat Reservoir in Fresno County (Fig. C-11A). The weir diverts water into the Enterprise Canal for distribution by the District. The site is characterized by a low head of about 1.8 m (6 ft) and high flows of 57 cms to 85 cms (2000 cfs to 3000 cfs) during the summer months.

Site Characteristics. The diversion structure consists of five bays, each containing stop logs held in place by a reinforced-concrete framework. The structure was repaired in 1969 after the bank opposite the canal headworks had eroded during a period of high flows. The bank was repaired by constructing a dike riprapped with quarry rock. Because of the repair work, the structure, which originally contained seven bays, was left with five bays, each about 4.7 m (15.4 ft) wide. The structure is about 4.6 m (15 ft) high.

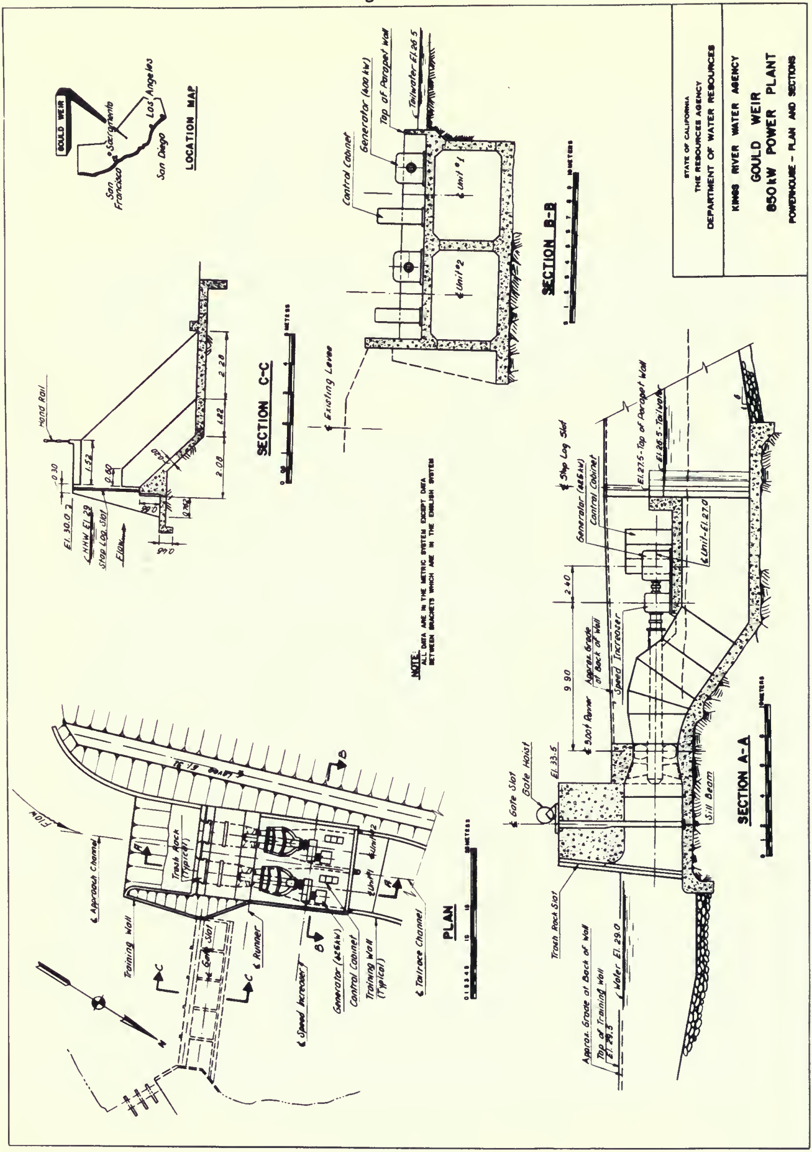
Potential Generation. Two horizontal, standard tube-type turbines are considered for installation at Gould Weir because of the low 1.8 m (6 ft) head and high flows. The generators would be 425 kW each, and the estimated annual generation is about 3.5 million kWh (Table C-11A).

Table C-11A. Energy Generation for Gould Weir Diversion Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	1.8	6	6.6	233	--	--	--
February	1.8	6	12.7	447	66	150	101 000
March	1.8	6	31.9	1128	84	425	316 000
April	1.8	6	37.0	1308	84	425	306 000
May	1.8	6	61.8	2184	84	850	632 000
June	1.8	6	104.8	3700	84	850	612 000
July	1.8	6	90.6	3201	84	850	632 000
August	1.8	6	55.4	1958	84	850	632 000
September	1.8	6	24.0	847	84	363	261 000
October	1.8	6	4.4	155	--	--	--
November	1.8	6	1.8	65	--	--	--
December	1.8	6	3.7	131	--	--	--
Total							3 492 000

New Power Plant Structures. The proposed generating facility would include an approach channel, 14 m (46 ft) wide and 12 m (39.4 ft) long, on the weir's left abutment to the powerhouse (Fig. C-11B). The water would be returned to the river through a short tailrace channel. The turbines, with runners 3 m (9.8 ft) in diameter (the largest size available for standard tube type units), could develop 570 hp each under a 1.8 m (6 ft) head and a 28 cms (980 cfs) flow. Each turbine would be connected, through a speed increaser, to a horizontal air-cooled synchronous generator having a rated output of 425 kW. Inlet gates would be installed in front of the turbines

Figure C-11B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
KINGS RIVER WATER AGENCY
GOULD WEIR
850kW POWER PLANT
POWERHOUSE – PLAN AND SECTIONS
LOCATION MAP
GOULD WEIR
San Francisco
Sacramento
Los Angeles
San Diego
SECTION C-C
Hand Rail
El. 30.0
NHW El. 29
Stop Log Slot
Flow
SECTION B-B
Control Cabinet
Generator (400 kW)
Top of Parapet wall
Tailwater El. 26.5
Unit #1
Unit #2
Existing Levee
NOTE: ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
SECTION A-A
Stop Log Slot
Generator (425 kW)
Control Cabinet
El. 27.5 - Top of Parapet Wall
El. 26.5 - Tailwater
Unit - El. 27.0
Approx. Grade of Back of Wall
Speed Increaser
Runner
Gate Slot
Gate Hoist
El. 33.5
Sill Beam
Trash Rack Slot
Approx. Grade at Back of Wall
Top of Training Wall El. 29.5
Water El. 29.0
PLAN
Flow
Approach Channel
Training Wall
Trash Rack (Typical)
Gate Slot
Runner
Speed Increaser
Generator (425 kW)
Control Cabinet
Training Wall (Typical)
Tailrace Channel
Unit #1
Unit #2
METERS

and draft-tube gates would be installed downstream from the turbines so the units could be dewatered for maintenance.

The possiblity of installing three turbine-generator units rated at 336 kW each, using 2.8 m (9 ft) runners, was also considered. The three-unit arrangement was less economical because the installation cost would be increased by 40 percent while the saleable capacity would not change due to reduced streamflows in August. In addition, the three-unit arrangement would require that one of the five weir discharge bays be used for the powerhouse.

Minimal new transmission facilities are required, since a 13 kV transmission line is located about 152 m (500 ft) from the site.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $3,987,400, based on January 1980 prices. From 24 to 36 months will be required for completing the feasibility study, obtaining approvals, and building. If the project were initiated in 1981, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $6,374,200 (Table C-11B).

Table C-11B. Project Cost for Gould Weir Diversion Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$2,951,800
Transmission Facilities	15,000
Subtotal	$2,966,800
Contingencies (20%)	593,400
Total	$3,560,200
Engineering and Administration (12%)	427,200
Total Construction Cost (January 1980 Prices)	$3,987,400
Escalation (4 yrs. at 12% per year)	2,286,800
Total Construction Cost (January 1984 Prices)	$6,274,200
Studies, Licensing, Permits, and Approvals	100,000
Total	$6,374,200
Cost per kW (850 kW)	$ 7,499

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-11C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-11C. Annual Operating Cost for Gould Weir Diversion Project

Cost Item	Amount
Operation and Maintenance	$ 50,500
Insurance	85,000
Interim Replacements	15,000
Total	$150,500

The annual costs of owning and operating the project would range between 13 and 20 percent of the direct project cost of $6,374,200, depending on financing. The estimated cost of generation ranges between 23.7 cents and 36.8 cents per kWh (Table C-11D).

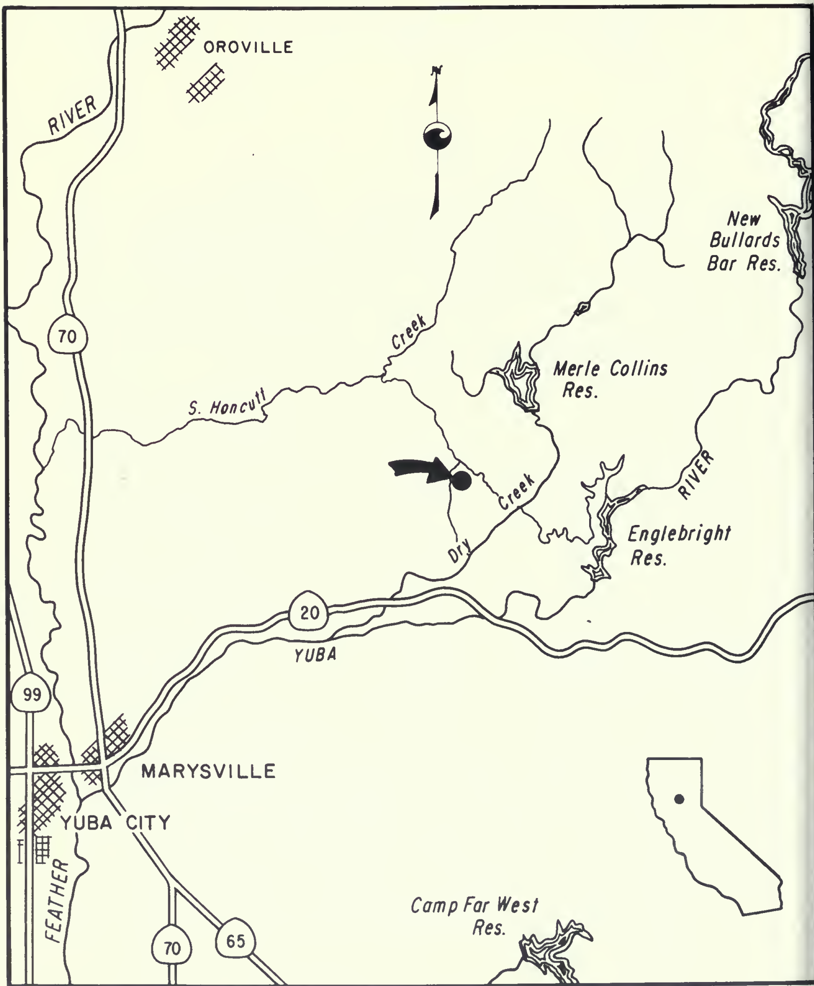
Table C-11D. Average Cost of Energy for Gould Weir Diversion Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$796,800	$1,019,900	$1,134,600
Operating Cost	150,500	150,500	150,500
Total Annual Cost	$947,300	$1,170,400	$1,285,100
Average Cost (per kWh)	27.1¢	33.5¢	36.8¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$675,700	$ 917,900	$1,032,600
Operating Cost	150,500	150,500	150,500
Total Annual Cost	$826,200	$1,068,400	$1,183,100
Average Cost (per kWh)	23.7¢	30.6¢	33.9¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of energy produced in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the value of Gould Weir hydroelectric generation is less than the cost of generation (23.7 to 36.8 cents per kWh), the project if constructed by 1984 would probably not be cost effective until 1991. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-12A Harding Canal Powerplant



12. Harding Canal

Harding Canal, a water conveyance facility owned and operated by the Browns Valley Irrigation District, islocated near the community of Browns Valley in Yuba County (Fig. C-12A). It is a lateral canal that extends south from a point near the outlet of the Virginia Ranch Dam diversion tunnel on Dry Creek to Tennessee Creek in Browns Valley. The diverted waters flow down Tennessee Creek to the District's main irrigation canal. All water flowing in the Harding Canal that is not used for local purposes eventually flows into the Browns Valley system.

Site Characteristics. Harding Canal is an unlined, dug trench with a maximum capacity of about 1.7 cms (60 cfs). By extending the canal about 0.8 km (0.5 mi) along the 335 m (1100 ft) elevation contour, a penstock and powerhouse could be constructed to develop about a 91 m (300 ft) head for hydroelectric generation. Water flowing through the new powerhouse could be carried by natural channels to the District's Main Canal. The canal extension and powerhouse would be located on an undeveloped grass-oak woodland site with access available only by foot travel. Since transmission facilities are not available at the site, a 13 kV transmission line, about 1.6 km (1 mi) long, would have to be built across undeveloped lands in order to use the power produced.

Potential Generation. The potential generation capacity would be 1000 kW based on the average usable canal capacity of 1.4 cms (50 cfs). Using both the irrigation releases between April and October and the part of the spillway discharge that is now passed down Dry Creek from Virginia Ranch Dam, power could be generated for about 9 months; the average annual output would be about 6 550 000 kWh.

New Power Plant Structures. A turbine-generator could be installed at the site to use the 91 m (300 ft) available head. The proposed generating facility would require extending the existing Harding Canal and installing a penstock 533 mm (21 in) in diameter and about 300 m (984 ft) long, a powerhouse, and a short tailrace channel (Fig. C-12B). A horizontal, Francis turbine at the powerhouse would develop 1340 hp under the available head and would be connected directly to a horizontal, air-cooled synchronous generator with a rated output of 1000 kW. A butterfly valve installed upstream from the turbine would separate the generation and irrigation activities.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $1,256,600, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $2,077,300 (Table C-12A).

Figure C-12B

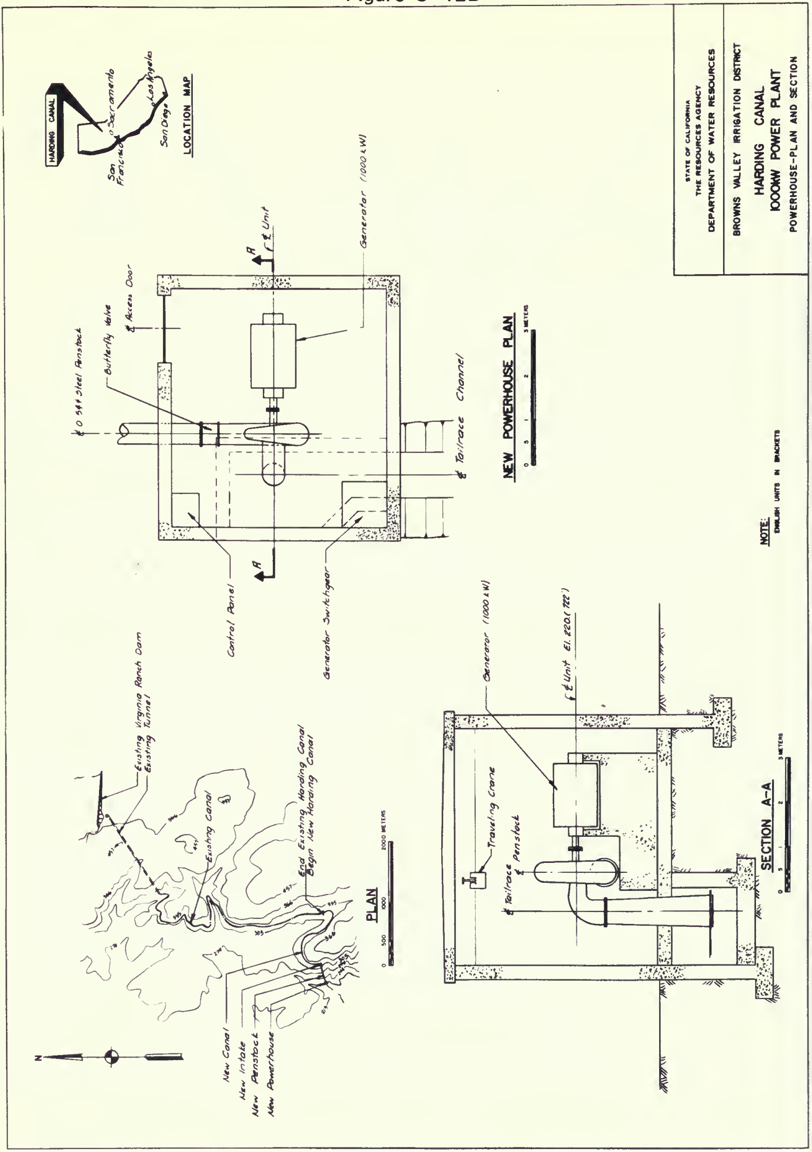

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
BROWNS VALLEY IRRIGATION DISTRICT
HARDING CANAL
1000KW POWER PLANT
POWERHOUSE-PLAN AND SECTION
LOCATION MAP
HARDING CANAL
Sacramento
San Francisco
Los Angeles
San Diego
NEW POWERHOUSE PLAN
Generator (1000 kW)
Access Door
Butterfly Valve
0.54 m Steel Penstock
Tailrace Channel
Control Panel
Generator Switchgear
SECTION A-A
Generator (1000 kW)
Unit El. 220.(722')
Traveling Crane
Tailrace
Penstock
PLAN
Existing Virginia Ranch Dam
Existing Tunnel
Existing Canal
End Existing Harding Canal
Begin New Harding Canal
New Canal
New Intake
New Penstock
New Powerhouse
NOTE: ENGLISH UNITS IN BRACKETS

Table C-12A. Project Cost for Harding Canal Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 890,000
Transmission Facilities	45,000
Subtotal	$ 935,000
Contingencies (20%)	187,000
Total	$1,122,000
Engineering and Administration (12%)	134,600
Total Construction Cost (January 1980 Prices)	$1,256,600
Escalation (4 yrs. at 12% per year)	720,700
Total Construction Cost (January 1984 Prices)	$1,977,300
Studies, Licensing, Permits, and Approvals	100,000
Total	$2,077,300
Cost per kW (1 000 kW)	$ 2,077

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-12B). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-12B. Annual Cost for Harding Canal Project

Cost Item	Amount
Operation and Maintenance	$ 45,000
Insurance	25,500
Interim Replacements	4,500
Total	$ 75,000

The annual costs of owning and operating the project would range between 14 and 21 percent of the direct project cost of $2,077,300, depending on financing. The estimated cost of generation ranges between 4.5 cents and 6.8 cents per kWh (Table C-12C).

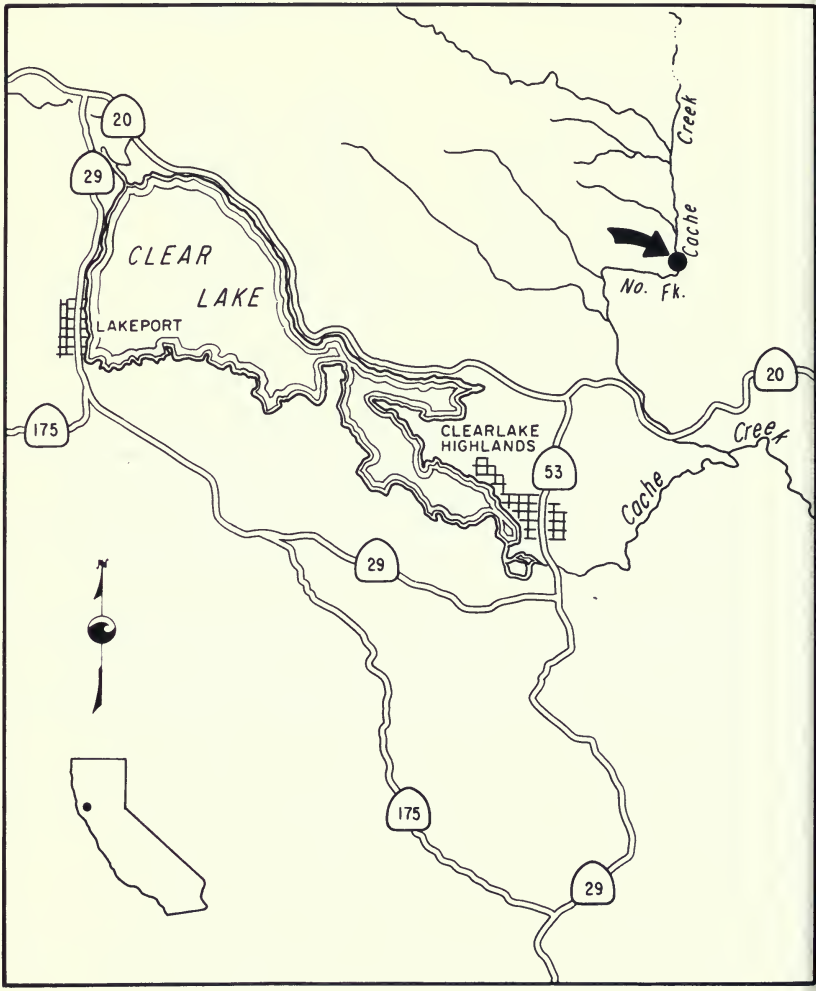
Table C-12C. Average Cost of Energy for Harding Diversion Project

Cost Item	Amount — Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$259,700	$332,400	$369,800
Operating Cost	75,000	75,000	75,000
Total Annual Cost	$334,700	$407,400	$444,800
Average Cost (per kWh)	5.1¢	6.2¢	6.8¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$220,200	$ 299,100	$336,500
Operating Cost	75,000	75,000	75,000
Total Annual Cost	$295,200	$374,100	$411,500
Average Cost (per kWh)	4.5¢	5.7¢	6.3¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations study acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Harding Canal generation exceeds the estimated cost of generation (4.5 to 6.8 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of generation would change little from year to year because only the cost of maintaining the facility is subject to inflation.

Figure C-13A Indian Valley Dam Powerplant



13. Indian Valley Dam

Indian Valley Dam is a rock and earthfill structure owned and operated by the Yolo County Flood Control and Water Conservation District. It is located on Cache Creek, near Clear Lake in Lake County (Fig. C-13A). The dam is used for flood control, water conservation, and recreation.

The District provides irrigation water to an area of Yolo County approximately defined as the rectangular area with corners near Woodland, Davis, Winters, and Capay. The projected irrigated acreage is about 51 400 hectares (127,000 acres), and the estimated annual agricultural water demand is about 481 000 cubic dekametres (390,000 ac-ft). The estimated annual urban water requirement is 61 675 cubic dekametres (50,000 ac-ft).

The dam was completed in 1976, but the reservoir has never filled. A feasibility report, prepared in support of a Public Law 984 Loan, lists the expected firm yield of the reservoir at 59 200 cubic dekametres (48,000 ac-ft). Flood control storage space is 49 300 cubic dekametres (40,000 ac-ft) with the full amount required between December 1 and March 15. Storage in the gross pool at an elevation of 452.6 m (1,485 ft) is 370 790 cubic dekametres (300,600 ac-ft). The bottom of the flood control pool is 197 360 cubic dekametres (160,000 ac-ft) at an elevation of 449.6 m (1,475 ft).

It is expected that once the reservoir fills, it will operate between elevations of 448.7 m (1,472 ft) and 452.6 m (1,485 ft) for flood control and reservoir yield. Under these conditions, the average net head available for power generation would be about 53.3 m (175 ft).

Site Characteristics. Indian Valley Dam has a maximum height of 63 m (207 ft) above the stream bed and a crest 294 m (965 ft) long. Controlled releases from the reservoir are made through the dam's lower outlet located at about in middle of the dam. The outlet works consist of a vertical tower and trash rack; 168 m (550 ft) of 1524 mm (60 in) pipe extending to the butterfly valve in the valve chamber; 174 m (570 ft) of 1.5 m (5 ft) saddle-supported steel pipe inside a 2.9 m (9.5 ft) diameter concrete arch tunnel; and a 1.5 m (5 ft) hollow jet valve. A separate 356 mm (14 in) piping and valving arrangement would meet fish-release requirements with flows up to 0.57 cms (20 cfs); the pipe would start just ahead of the butterfly valve and end with a 305 mm (12 in) hollow jet valve located near the hollow existing jet valve in the outlet terminal building. Both valves would discharge water directly into the spillway stilling basin.

Potential Generation. A vertical Francis turbine with an electric generator rated at 3200 kW is considered for installation at the facility. The potential annual output is estimated at 7.2 million kWh (Table C-13A).

Figure C-13B

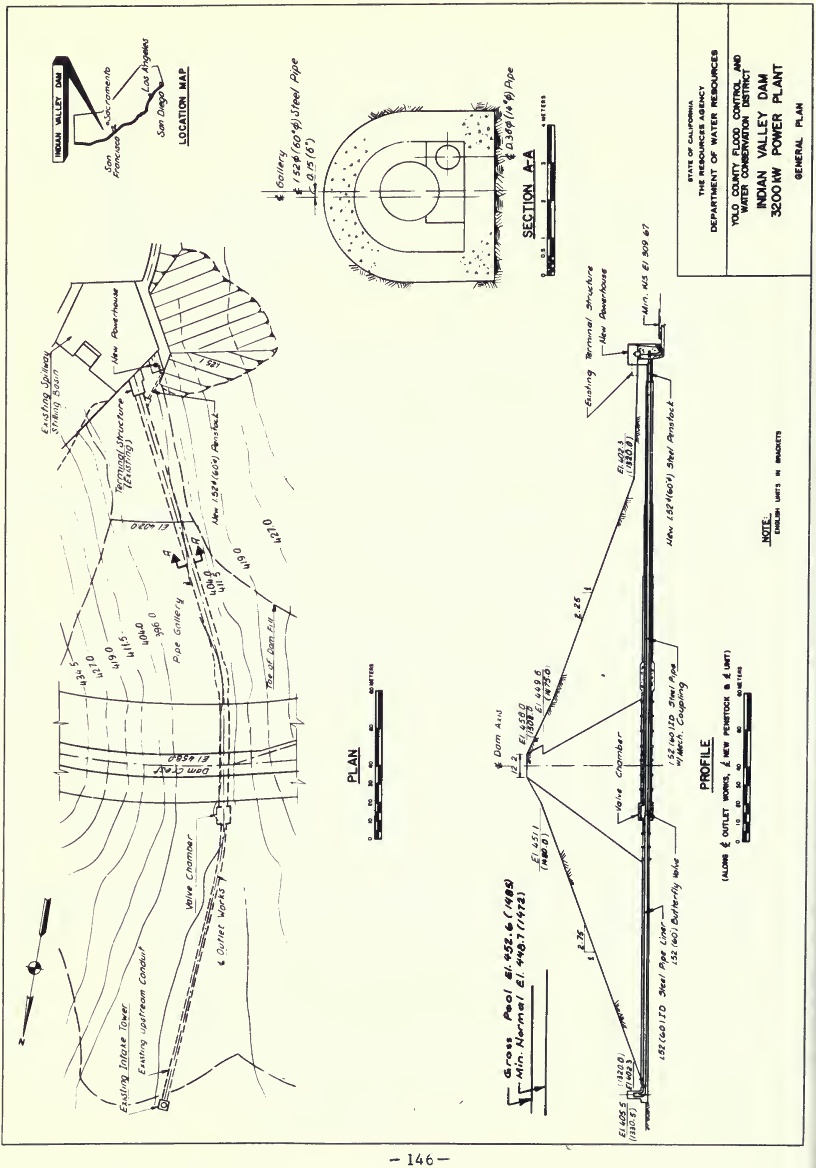

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
YOLO COUNTY FLOOD CONTROL AND WATER CONSERVATION DISTRICT
INDIAN VALLEY DAM
3200 kW POWER PLANT
GENERAL PLAN
LOCATION MAP
INDIAN VALLEY DAM
Sacramento
San Francisco
Los Angeles
San Diego
SECTION A-A
PLAN
PROFILE
(ALONG ℄ OUTLET WORKS, ℄ NEW PENSTOCK & ℄ UNIT)
NOTE: ENGLISH UNITS IN BRACKETS
Existing Spillway Stilling Basin
New Powerhouse
Terminal Structure (Existing)
New 1.52φ (60"φ) Penstock
Pipe Gallery
Toe of Dam Fill
Dam Crest El 458.0
Valve Chamber
℄ Outlet Works
Existing Intake Tower
Existing upstream Conduit
℄ Gallery
℄ 1.52φ (60"φ) Steel Pipe
℄ 0.35φ (14"φ) Pipe
Gross Pool El. 452.6 (1485)
Min. Normal El. 448.7 (1472)
℄ Dam Axis
Existing Terminal Structure
New Powerhouse
Min. W.S. El 309.67
New 1.52φ (60"φ) Steel Penstock
1.52 (60) ID Steel Pipe w/ Mech. Coupling
1.52 (60") Butterfly Valve
1.52 (60) ID Steel Pipe
Steel Pipe Liner
El 405.5 (1330.5)
El 402.3 (1320.0)

Table C-13A. Energy Generation for Indian Valley Dam Project

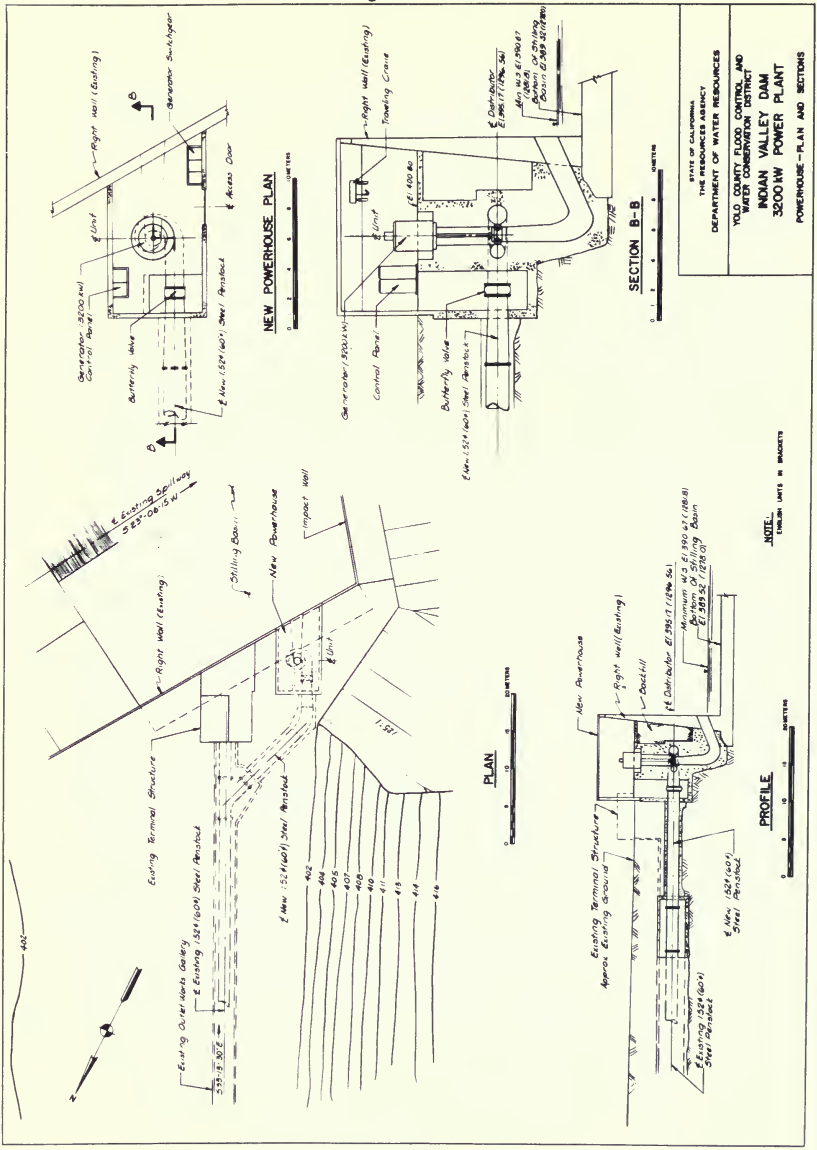
Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	56.4	185	0.3	10	--	--	--
February	56.4	185	0.3	10	--	--	--
March	56.4	185	0.3	10	--	--	--
April	56.4	185	1.0	34	--	--	--
May	56.4	185	5.1	179	75	2213	1 647 000
June	56.4	185	5.7	202	80	2530	1 821 000
July	56.4	185	6.9	244	84	3200	2 381 000
August	56.4	185	4.6	163	72	1837	1 367 000
September	56.4	185	1.4	50	--	--	--
October	56.4	185	0.3	10	--	--	--
November	56.4	185	0.3	10	--	--	--
December	56.4	185	0.3	10	--	--	--
Total							7 216 000

New Power Plant Structures. A turbine-generator installed at the downstream end of the existing lower outlet could use the 52.4 m to 56.4 m (172 ft to 185 ft) available head at Indian Valley Dam. The proposed generating facility includes a 1.5 m (5 ft) steel pipe by-pass, starting about 8 m (26 ft) upstream from the existing outlet control structure, which would carry water to a vertical Francis turbine (Figs. C-13B and C-13C). The turbine could develop 4295 hp under a 46.7 m (185 ft) head and would be connected directly to a vertical, 600 rpm air- cooled synchronous generator with a rated output of 3200 kW. Since the new powerhouse would be adjacent to the existing outlet control structure (Fig. C-13C), the turbine draft tube would discharge the water directly into the existing stilling basin. The operation of the hydroelectric plant and of the existing installation would be kept separate by a 1.3 m (4.3 ft) butterfly valve installed upstream from the turbine. The existing access road is adequate.

Transmission Facilities. Electric transmission facilities are not available at the Indian Valley site. The nearest transmission line which could carry project power is about 14.5 km (9 mi) away along the existing access road. An alternate routing would be about 16 km (10 mi) cross-country to the vicinity of Clear Lake Oaks. A 13 kV transmission line would be adequate to carry project generation.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $3,287,600, based on January 1980 prices. If the project were initiated in 1981, and about 24 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $5,273,100 (Table C-13B).

Figure C-13C



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
YOLO COUNTY FLOOD CONTROL AND WATER CONSERVATION DISTRICT
INDIAN VALLEY DAM
3200 kW POWER PLANT
POWERHOUSE—PLAN AND SECTIONS
NEW POWERHOUSE PLAN
SECTION B-B
PLAN
PROFILE
NOTE: ENGLISH UNITS IN BRACKETS
Right wall (Existing)
Generator Switchgear
Access Door
Unit
Generator (3200 kW)
Control Panel
Butterfly Valve
New 1.524 (60") Steel Penstock
Traveling Crane
El 400.80
Distributor El 395.17 (1296.56)
Min W.S. El 390.67 (1281.8)
Bottom Of Stilling Basin El 389.52 (1278.0)
Existing Spillway S 23°-06'-15" W
Stilling Basin
New Powerhouse
Impact Wall
Existing Terminal Structure
Existing Outlet Works Gallery
Existing 1.524 (60") Steel Penstock
S 33°-19'-30" E
1:521
402
404
405
407
408
410
411
413
414
416
Backfill
Approx Existing Ground
Existing 1.524 (60") Steel Penstock
New 1.524 (60") Steel Penstock
N

Table C-13B. Project Cost of Indian Valley Dam Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 2,046,200
Transmission Facilities	400,000
Subtotal	$ 2,446,200
Contingencies (20%)	489,200
Total	$ 2,935,400
Engineering and Administration (12%)	352,200
Total Construction Cost (January 1980 Prices)	$ 3,287,600
Escalation (4 yrs. at 12% per year)	1,885,500
Total Construction Cost (January 1984 Prices)	$ 5,173,100
Studies, Licensing, Permits, and Approvals	100,000
Total	$ 5,273,100
Cost per kW (3 200 kW)	$ 1,648

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-13C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-13C. Annual Operating Cost of Indian Valley Dam Project

Cost Item	Amount
Operation and Maintenance	$126,000
Insurance	59,500
Interim Replacements	10,700
Total	$196,200

The annual cost of owning and operating the project would range between 14 and 22 percent of the direct project cost of $5,273,100, depending on financing. The estimated cost of generation ranges between 10.5 and 15.7 cents per kWh (Table C-13D).

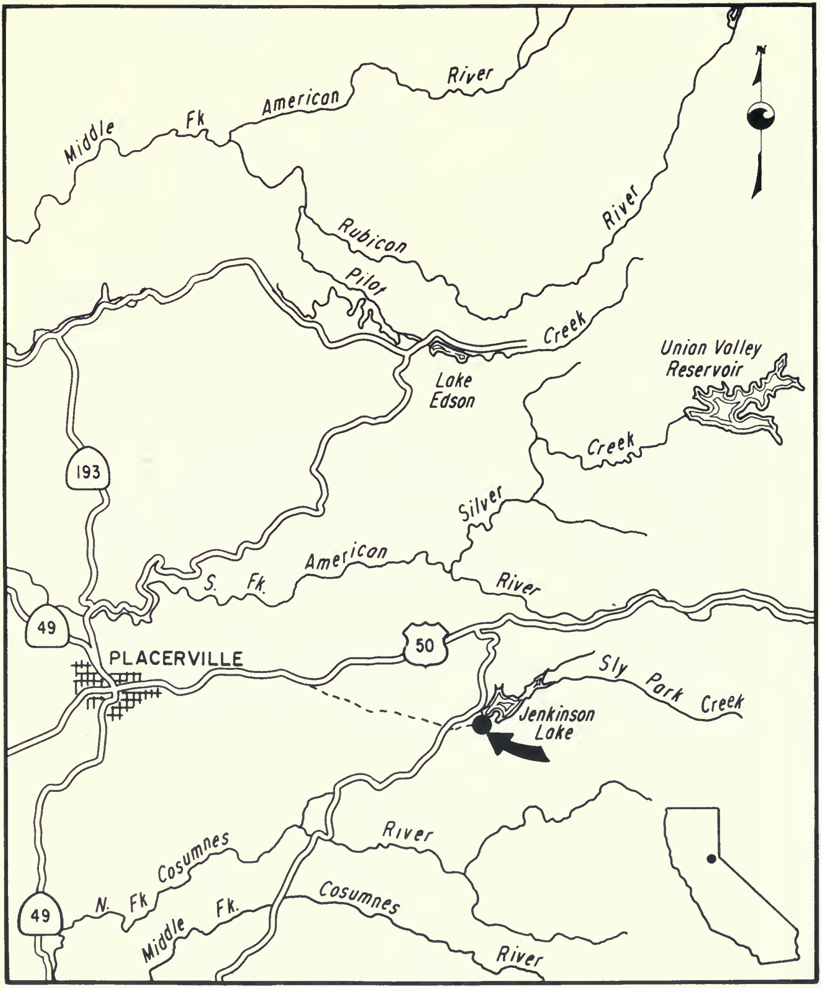
Table C-13D. Average Cost of Energy for Indian Valley Dam Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$659,100	$ 843,700	$ 938,600
Operating Cost	196,200	196,200	196,200
Total Annual Cost	$855,300	$1,039,900	$1,134,800
Average Cost (per kWh)	11.8¢	14.4¢	15.7¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$559,000	$ 759,300	$ 854,200
Operating Cost	196,200	196,200	196,200
Total Annual Cost	$755,200	$ 955,500	$1,050,400
Average Cost (per kWh)	10.5¢	13.2¢	14.6¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of Indian Valley generation is within the estimated generation cost (10.5 to 15.7 cents per kWh). Assuming that a theoretical water and power operations study showed no capacity value, the project cost would equal or exceed revenues from the sale of project generation for the first year of operation. Thus, the project would probably be cost effective.

Figure C-14A Sly Park Dam Powerplant



14. Jenkinson Lake (Sly Park Dam)

Sly Park Dam is owned by WPRS and is operated by the El Dorado Irrigation District. It is located on Sly Park Creek near Pollock Pines in El Dorado County (Fig. C-14A). Sly Park Creek joins Camp Creek downstream from the dam and flows into the Consumnes River. The dam creates Jenkinson Lake which has a total storage capacity of 50 600 cubic dekametres (41,000 ac-ft). Controlled releases are made from the reservoir, and the water is diverted by pipeline throughout El Dorado County for irrigation and domestic use.

Site Characteristics. Sly Park Dam is an earthfill structure 58 m (190 ft) high with a crest about 247 m (810 ft) long. The outlet works consist of a concrete conduit, 1219 mm (48 in) in diameter, extending from the reservoir intake for a distance of about 104 m (340 ft) to a gate chamber located at about the mid-point of the dam; a 0.9 m (3 ft) steel pipe within a 2.0 m (6.5 ft) diameter horseshoe-shaped concrete conduit extends from the gate chamber for a distance of about 128 m (420 ft) to the outlet control structure at the foot of the dam. Just upstream from the outlet control structure the steel pipe changes, by a Y-transition, to two 813 mm (32 in) steel pipes, each controlled by a 686 sq mm (27 sq in) high- pressure slide gate. Downstream from the slide gates, the energy in the water is dissipated in a concrete box about 6 m (20 ft) long. From this energy dissipater, the water enters a 1.2 m (4 ft) concrete pipe operating under pressure created by the water level in the energy dissipater. A by-pass valve and a 203 mm (8 in) pipe located upstream from the dissipater provide a minimum release of 0.03 cms (1 cfs) to enhance streamflow.

Potential Generation. A vertical Francis turbine is considered for installation at Sly Park Dam, because the 39 m to 51 m (128 ft to 167 ft) net operating head exceeds the range of a tube-type turbine. Although a Kaplan turbine could be installed, the limited water available for generation during the nonirrigation season does not justify the Kaplan unit's 50 to 70 percent higher cost.

The potential installed capacity would be 650 kW, and the estimated annual generation is about 1.8 million kWh (Table C-14A).

Figure C-14B

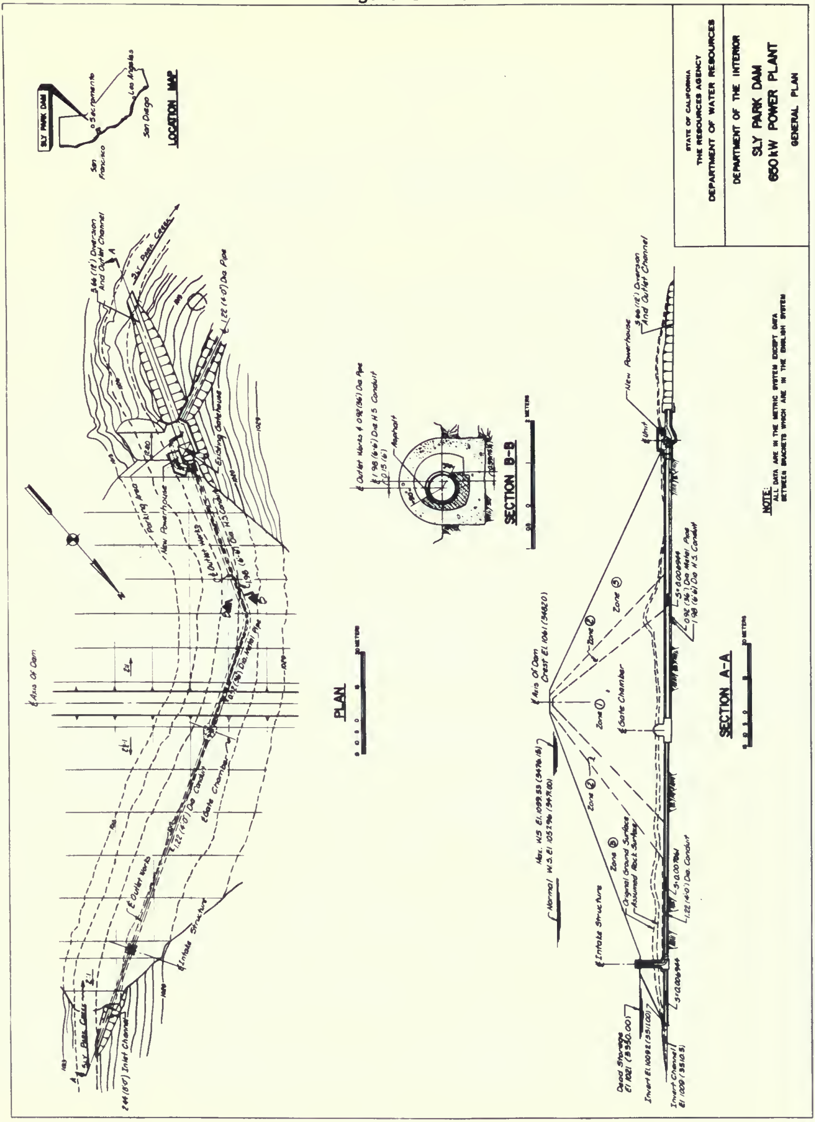

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
DEPARTMENT OF THE INTERIOR
SLY PARK DAM
650kW POWER PLANT
GENERAL PLAN
LOCATION MAP
SLY PARK DAM
Sacramento
San Francisco
Los Angeles
San Diego
PLAN
SECTION B-B
SECTION A-A
New Powerhouse
Parking Area
Existing Gatehouse
Intake Structure
Gate Chamber
Axis Of Dam
Zone 1
Zone 2
Zone 3
Original Ground Surface
Assumed Rock Surface
NOTE:
ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM

Table C-14A. Energy Generation for Jenkinson Lake Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	40.2	132	0.26	9	--	--	--
February	45.7	150	0.26	9	--	--	--
March	50.9	167	0.28	10	--	--	--
April	50.9	167	0.31	11	--	--	--
May	50.9	167	0.88	31	55	240	179 000
June	46.9	154	1.53	54	79	554	400 000
July	44.5	146	1.90	67	84	693	517 000
August	42.0	138	1.87	66	84	646	482 000
September	40.2	132	1.30	46	73	374	270 000
October	39.0	128	0.68	24	--	--	--
November	39.0	128	0.31	11	--	--	--
December	37.2	122	0.23	8	--	--	--
Total							1 848 000

New Power Plant Structures. A turbine and generator could be installed at the downstream end of the existing lower outlet pipe to use the 39 m to 51 m (128 ft to 167 ft) available head. The proposed generating facility includes a 0.9 m (3 ft) steel pipe by-pass starting about 4 m (13 ft) upstream from the existing outlet control structure, a vertical Francis turbine adjacent to the existing outlet gate building, and a tailrace conduit, about 7 m (23 ft) long, discharging into the existing energy dissipater box (Figs. C-14B and C-14C). The turbine could develop 870 hp under a 45 m (147 ft) head and would be connected directly to a vertical, air-cooled synchronous generator with a rated output of 650 kW.

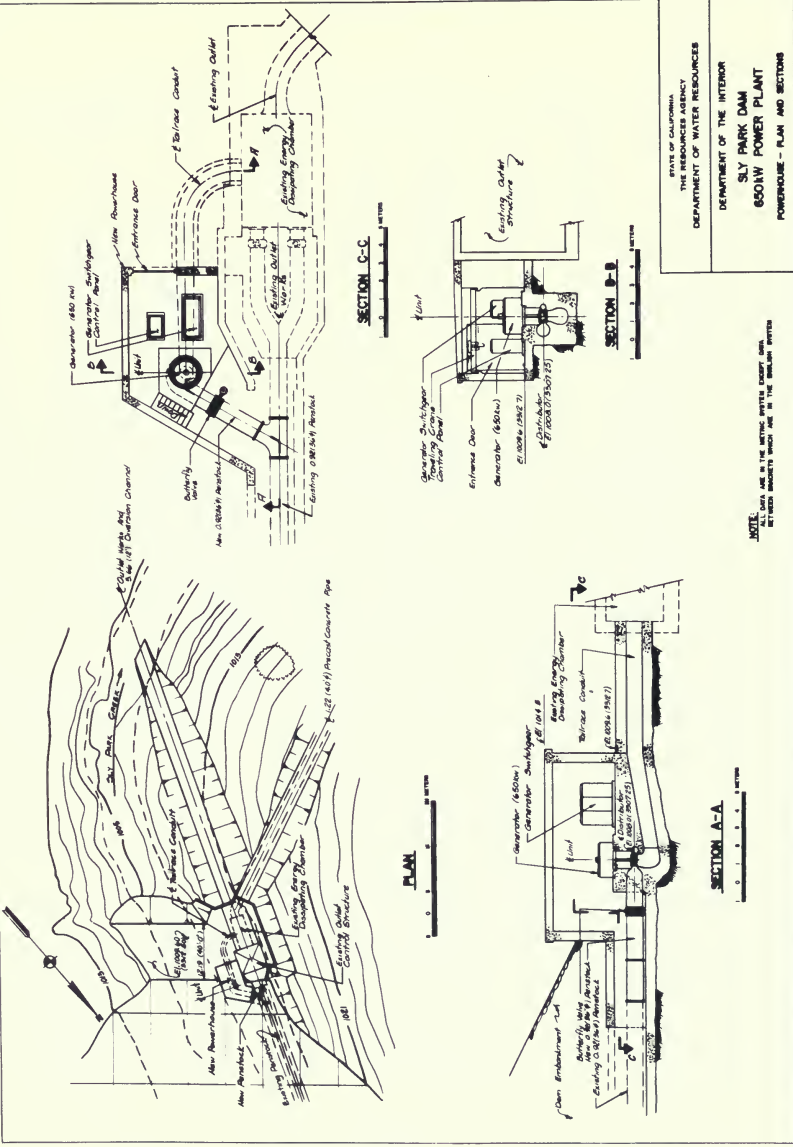
The operation of the hydroelectric plant and that of existing installation would be kept separate by a butterfly valve installed upstream from the turbine. The turbine could be dewatered for maintenance by closing the butterfly valve and placing a cover at the entrance of the tailrace conduit into the energy dissipater.

Transmission Facilities. A 13 kV transmission line is located at the site. The only electric facilities needed are a transformer, protective equipment, and a short connecting line.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $880,300, based on January 1980 prices. Since the generating facility would be located on a manmade conduit operated primarily for purposes other than power generation, it is expected that the site would be exempt from federal licensing requirements. (The exemption provision is discussed in detail in Appendix F.) However, the District would have to comply with the CEQA requirements and determine if the other state approvals are necessary.

If the project were initiated in 1981 and about 30 months were required to complete the feasibility study, obtain approvals, arrange

Figure C-14C



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
DEPARTMENT OF THE INTERIOR
SLY PARK DAM
650kW POWER PLANT
POWERHOUSE - PLAN AND SECTIONS
NOTE: ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
SECTION C-C
SECTION B-B
SECTION A-A
PLAN
Generator (650 kW)
Generator Switchgear Control Panel
New Powerhouse
Entrance Door
Tailrace Conduit
Existing Outlet
Existing Energy Dissipating Chamber
Existing Outlet Works
Butterfly Valve
New 0.92(3'6") Penstock
Existing 0.92(3'6") Penstock
Existing Outlet Structure
Traveling Crane
Distributor
Outlet Works And Diversion Channel
Sly Park Creek
Precast Concrete Pipe
Existing Outlet Control Structure
New Penstock
Existing Penstock
Dam Embankment

financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $1,435,200 (Table C-14B).

Table C-14B. Project Cost for Jenkinson Lake Project

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 643,300
Transmission Facilities	11,700
Subtotal	$ 655,000
Contingencies (20%)	131,000
Total	$ 786,000
Engineering and Administration (12%)	94,300
Total Construction Cost (January 1980 Prices)	$ 880,300
Escalation (4 yrs. at 12% per year)	504,900
Total Construction Cost (January 1984 Prices)	$1,385,200
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,435,200
Cost per kW (650 kW)	$ 2,208

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-14C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-14C. Annual Operating Cost for Jenkinson Lake Project

Cost Item	Amount
Operation and Maintenance	$ 20,400
Insurance	25,500
Interim Replacements	3,800
Total	$ 49,700

The annual cost of owning and operating the project would range between 14 and 21 percent of the direct project cost of $1,435,200, depending on financing. The estimated cost of generation ranges between 10.9 cents and 16.5 cents per kWh (Table C-14D).

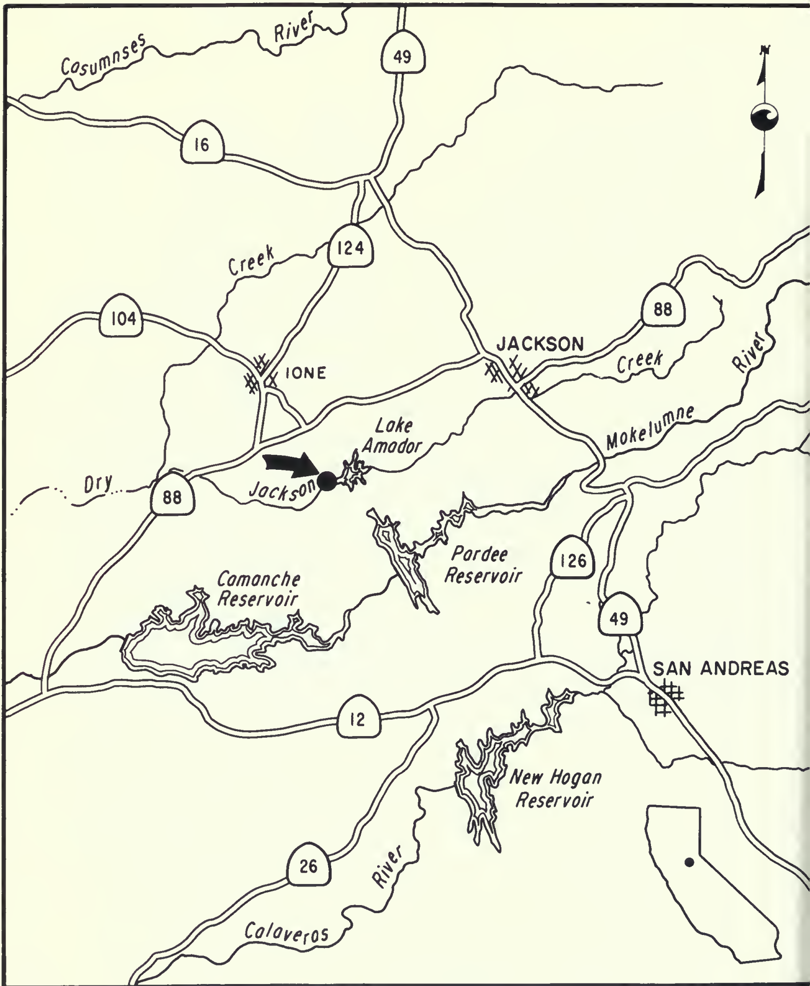
Table C-14D. Average Cost of Energy for Jenkinson Lake Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$179,400	$229,600	$255,500
Operating Cost	49,700	49,700	49,700
Total Annual Cost	$229,100	$279,300	$305,200
Average Cost (per kWh)	12.4¢	15.1¢	16.5¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$152,100	$172,200	$232,500
Operating Cost	49,700	49,700	49,700
Total Annual Cost	$201,800	$221,900	$282,200
Average Cost (per kWh)	10.9¢	12.0¢	15.3¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The value of Jenkinson Lake generation estimated at is within the estimated cost of generation (10.9 to 16.5 cents per kWh). Assuming that a theoretical water and power operations study showed no capacity value, the project cost would about equal revenues from sales of project generation. Thus, the project would probably be cost effective during its first year of operation.

Figure C-15A Jackson Creek Dam Powerplant



15. Lake Amador (Jackson Creek Dam)

lake Amador and Jackson Creek Dam, owned and operated by the Jackson Valley Irrigation District, are about 1.6 km (1 mi) east of Ione in Amador County (Fig. C-15A). Water is stored in the reservoir for irrigation and municipal use in the District's service area. Lake Amador also provides recreational opportunities. In an average-water year, the reservoir yield could maintain a discharge rate of 0.8 cms (30 cfs) between January and October. The effective head would vary from 51.2 m (168 ft) during the winter months to about 45.7 m (150 ft) in October.

Site Characteristics. Jackson Creek Dam is an earthfill structure approximately 55 m (180 ft) high. Controlled releases from the reservoir are made through the dam's lower outlet approximately 270 m (886 ft) long. The first 108 m (354 ft) of the lower outlet, from the reservoir intake to a gate chamber, consist of a 0.9 m (3 ft) steel pipe embedded in concrete. Downstream from the gate chamber for about 160 m (520 ft) to the valve house, the lower outlet consists of a 0.8 m (2.5 ft) steel pipe within a horseshoe concrete conduit having a 1.8 m (6 ft) inside diameter. The main valve is a 0.6 m (2 ft) hollow-cone type valve. About 7.6 m (25 ft) upstream from the outlet structure, the 0.8 m (2.5 ft) steel pipe is provided with a stub of the same diameter, which diverts water into a pipeline.

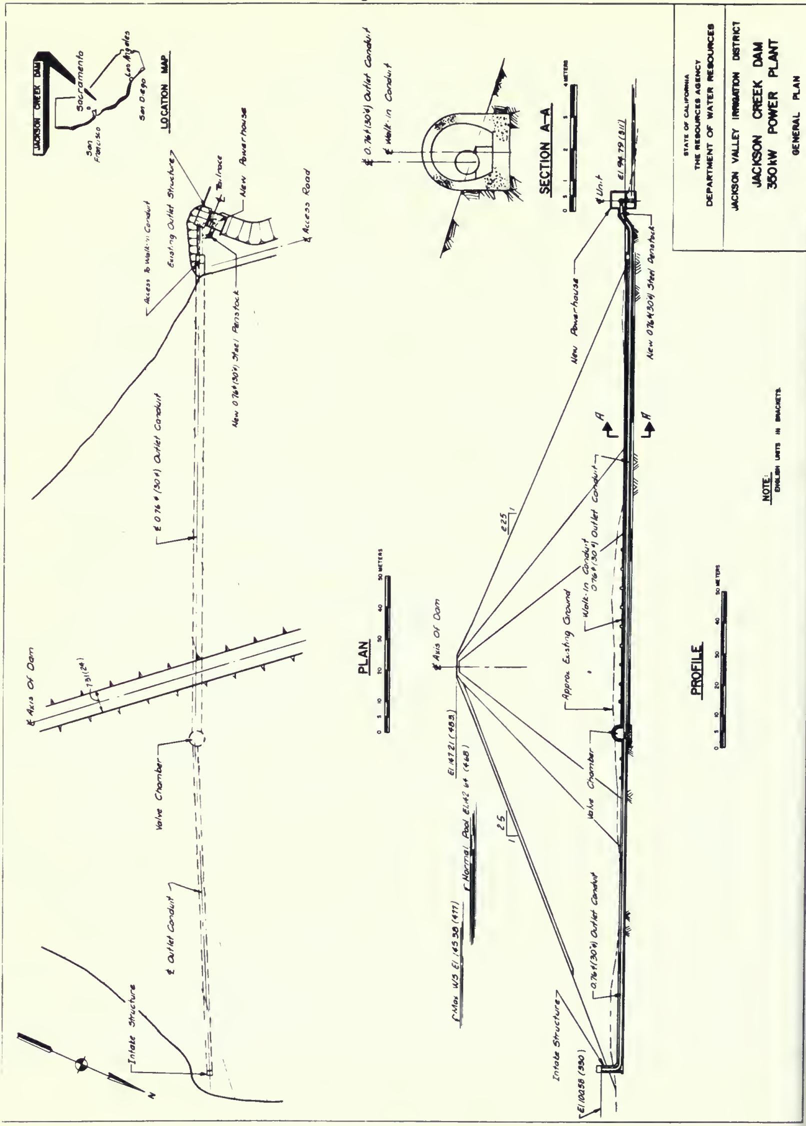
Potential Generation. A horizontal Francis turbine with a generator rated at 350 kW is considered for installation at Lake Amador. The estimated annual generation is about 2.5 million kWh (Table C-15A).

Table C-15A. Energy Generation for Lake Amador Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	51.2	168	0.8	30	85	361	269 000
February	51.2	168	0.8	30	85	361	243 000
March	51.2	168	0.8	30	85	361	269 000
April	50.6	166	0.8	30	85	361	260 000
May	50.6	166	0.8	30	85	357	266 000
June	50.0	164	0.8	30	85	353	254 000
July	49.7	163	0.8	30	85	351	261 000
August	48.2	158	0.8	30	85	340	253 000
September	46.0	151	0.8	30	85	325	234 000
October	45.7	150	0.8	30	85	323	233 000
November	46.0	151	--	--	--	--	--
December	47.9	157	--	--	--	--	--
Total							2 542 000

New Power Plant Structures. A turbine and generator installed at the downstream end of the lower outlet pipe could use the 46 m to 51 m (150 ft to 168 ft) available head. The proposed generating facility includes a 762 mm (30 in) steel pipe by-pass, starting about 4 m (13 ft) upstream from the existing outlet control structure, which carries the water to a horizontal

Figure C-15B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
JACKSON VALLEY IRRIGATION DISTRICT
JACKSON CREEK DAM
350kW POWER PLANT
GENERAL PLAN
JACKSON CREEK DAM
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
SECTION A-A
PLAN
PROFILE
NOTE: ENGLISH UNITS IN BRACKETS
Access To Walk-in Conduit
Existing Outlet Structure
Tailrace
New Powerhouse
Access Road
New 0.76ϕ(30ϕ) Steel Penstock
℄ 0.76ϕ(30ϕ) Outlet Conduit
℄ Axis Of Dam
Valve Chamber
℄ Outlet Conduit
Intake Structure
℄ 0.76ϕ(30ϕ) Outlet Conduit
℄ Walk-in Conduit
℄ Unit
El 94.79 (311)
New Powerhouse
New 0.76ϕ(30ϕ) Steel Penstock
Walk-in Conduit
0.76ϕ(30ϕ) Outlet Conduit
Walk-in Conduit 0.76ϕ(30ϕ) Outlet Conduit
Approx. Existing Ground
El 147.21 (483)
℄ Max WS El 145.38 (477)
℄ Normal Pool El 142.64 (468)
Valve Chamber
0.76ϕ(30ϕ) Outlet Conduit
Intake Structure
El 100.58 (330)
2.25
2.5
N

Francis turbine (Figs. C-15B and C-15C). The turbine could develop 470 hp under a 51 m (168 ft) head and would be connected directly to a horizontal, air-cooled synchronous generator with a rated output of 350 kW. The operation of the hydroelectric plant and of the existing installation would be kept separate with a butterfly valve.

The new powerhouse would be located adjacent to the existing outlet control structure, at approximately the same elevation. An access road to the site exists.

Transmission Facilities. A 13 kV transmission line owned by PGandE is located at the site. No additional transmission facilities are required.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $538,900, based on January 1980 prices. If the project were initiated in 1981 and about 30 months were needed to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. The estimated capital cost in late 1983, with 12 percent inflation, is $898,000 (Table C-15B).

Table C-15B. Project Cost for Lake Amador Project

Cost Item		Amount
Direct Cost		
Hydroelectric Plant Facilities	$	389,000
Transmission Facilities		12,000
Subtotal	$	401,000
Contingencies (20%)		80,200
Total	$	481,200
Engineering and Administration (12%)		57,700
Total Construction Cost (January 1980 Prices)	$	538,900
Escalation (4 yrs. at 12% per year)		309,100
Total Construction Cost (January 1984 Prices)	$	848,000
Studies, Licensing, Permits, and Approvals		50,000
Total	$	898,000
Cost per kW (350 kW)	$	2,566

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-15C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Figure C-15C

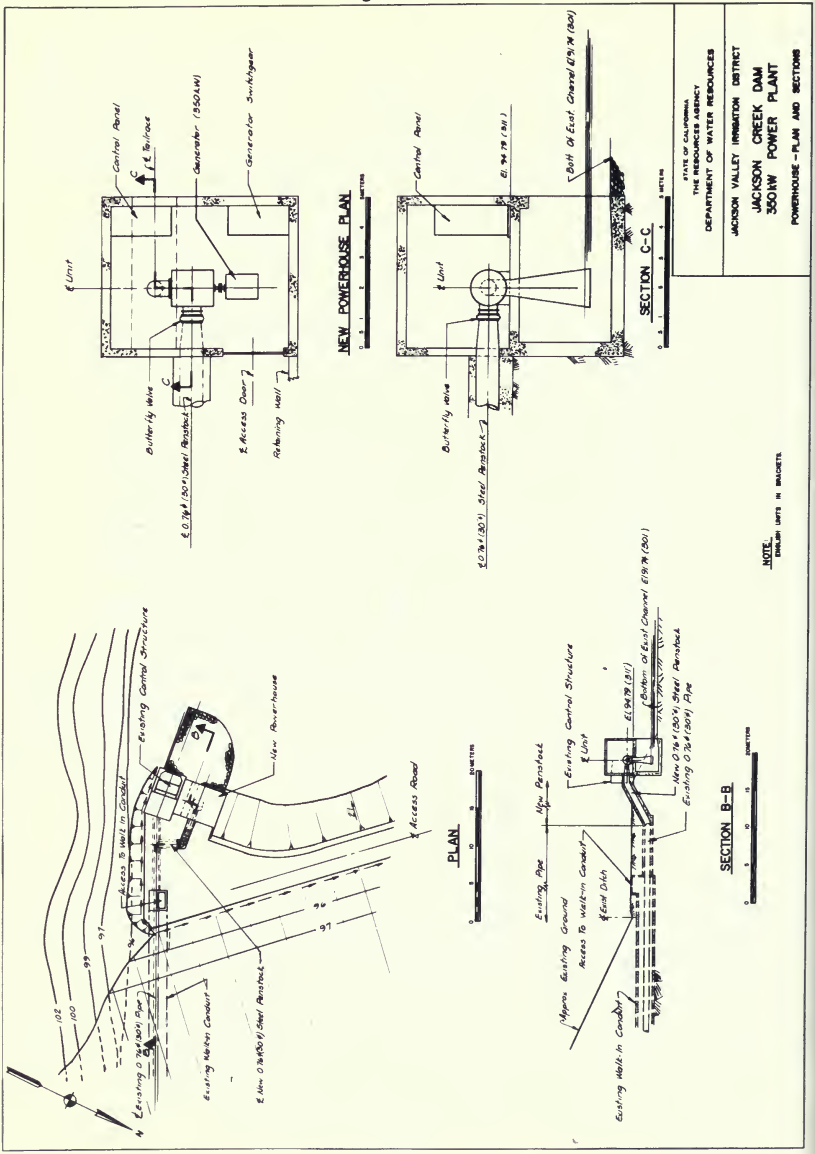

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
JACKSON VALLEY IRRIGATION DISTRICT
JACKSON CREEK DAM
350kW POWER PLANT
POWERHOUSE - PLAN AND SECTIONS
NOTE:
ENGLISH UNITS IN BRACKETS
NEW POWERHOUSE PLAN
Control Panel
℄ Tailrace
Generator (350kW)
Generator Switchgear
℄ Unit
Butterfly Valve
℄ 0.76ϕ (30"ϕ) Steel Penstock
℄ Access Door
Retaining Wall
SECTION C-C
Bott. Of Exist. Channel El. 91.74 (301)
El. 94.79 (311)
℄ 0.76ϕ (30"ϕ) Steel Penstock
PLAN
Access To Walk In Conduit
Existing Control Structure
New Powerhouse
℄ Access Road
Existing 0.76ϕ (30"ϕ) Pipe
Existing Walk-in Conduit
℄ New 0.76ϕ (30"ϕ) Steel Penstock
SECTION B-B
New Penstock
Existing Pipe
Existing Control Structure
℄ Unit
El. 94.79 (311)
Bottom Of Exist Channel El. 91.74 (301)
New 0.76ϕ (30"ϕ) Steel Penstock
Existing 0.76ϕ (30"ϕ) Pipe
Approx. Existing Ground
Access To Walk-in Conduit
℄ Exist Ditch
Existing Walk-In Conduit

Table C-15C. Annual Operating Cost for Lake Amador Project

Cost Item	Amount
Operation and Maintenance	$ 13,600
Insurance	16,000
Interim Replacements	2,400
Total	$ 32,000

The annual cost of owning and operating the project would range between 14 to 21 percent of the direct project cost of $898,000, depending on financing. The estimated cost of generation ranges between 5.0 cents and 7.5 cents per kWh (Table C-15D).

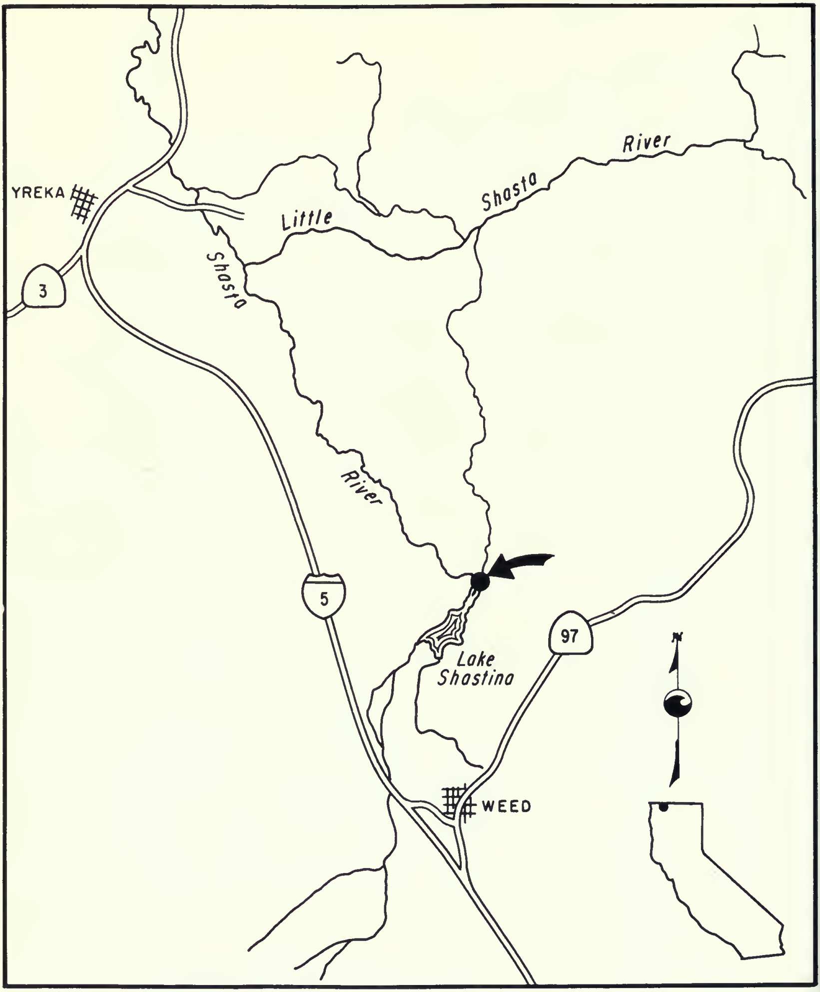
Table C-15D. Average Cost of Energy for Lake Amador Project

Cost Item	Amount Interest Rate		
	9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$112,300	$143,700	$159,800
Operating Cost	32,000	32,000	32,000
Total Annual Cost	$144,300	$175,700	$191,800
Average Cost (per kWh)	5.7¢	6.9¢	7.5¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 95,200	$129,300	$145,500
Operating Cost	32,000	32,000	32,000
Total Annual Cost	$127,200	$161,300	$177,500
Average Cost (per kWh)	5.0¢	6.3¢	7.0¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Lake Amador hydroelectric generation exceeds the estimated cost of generation (5.0 to 7.5 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Lake Amador generation would change little from year to year since only the maintenance cost of the facility is subject to inflation.

Figure C-16A Lake Shastina Powerplant



16. Lake Shastina (Shasta River Dam)

Shasta River Dam, owned and operated by the Montague Water Conservation District, is located about 16 km (10 mi) southeast of Grenada in Siskiyou County (Fig. C-16A). The dam's reservoir, Lake Shastina, provides water for irrigation in the Shasta Valley and for municipal purposes in the city of Montague.

Site Characteristics. The dam is a hydraulic earthfill structure about 30.5 m (100 ft) high. Water is released through the dam's lower outlet which is a concrete pipe 2.6 m (8.5 ft) in diameter and about 150 m (492 ft) long. Releases are controlled by four 0.9 m by 1.3 m (2.8 ft by 4.3 ft) cast iron slide gates located in a tower at the dam and about 45 m (148 ft) from the reservoir's intake structure. The outlet discharges water directly into a canal. Under normal conditions only one of the four gates is used to release water. A 13 kV transmission line is located about 300 m (1,000 ft) from the site.

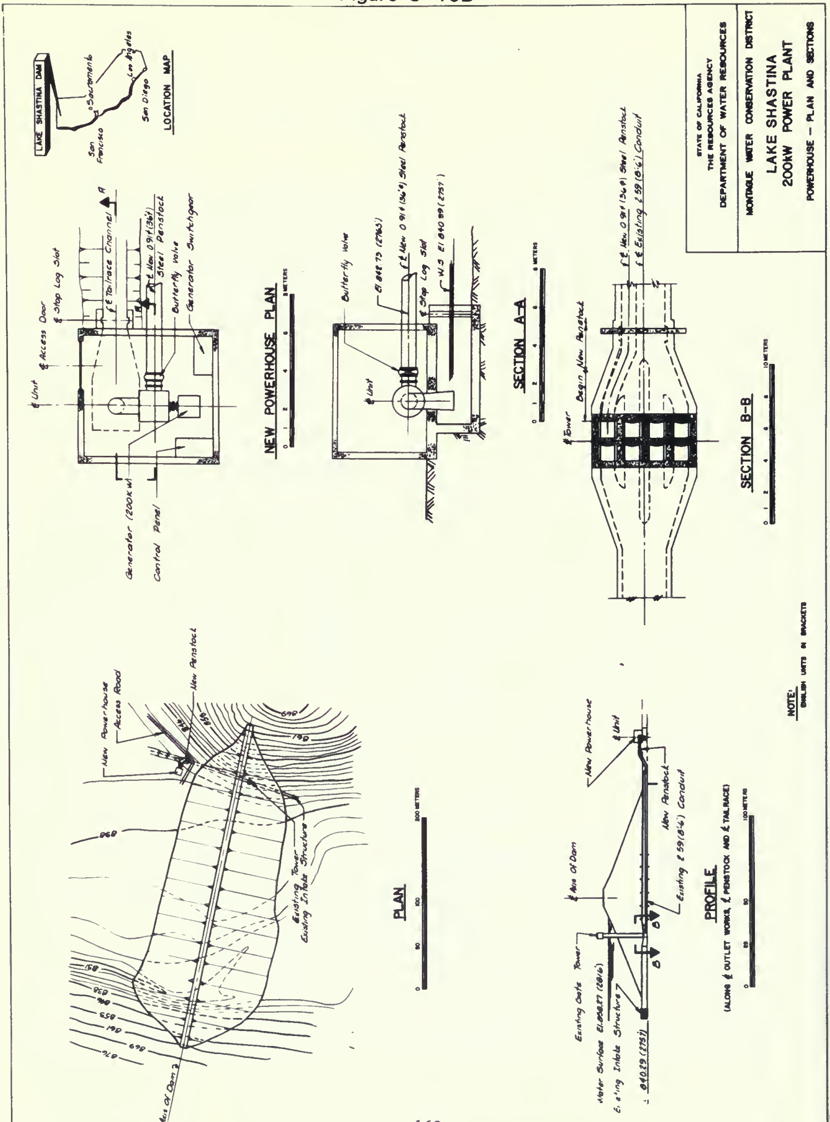
Potential Generation. The potential capacity is 200 kW, and the estimated average annual output is 741 000 kWh (Table C-16A).

Table C-16A. Energy Generation for Lake Shastina Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	--	--	--	--	--	--	--
February	--	--	--	--	--	--	--
March	--	--	--	--	--	--	--
April	15.2	50	1.5	52	65	143	103 000
May	14.6	48	1.8	64	78	203	151 000
June	14.0	46	2.0	69	78	209	150 000
July	12.2	40	2.2	78	78	206	153 000
August	10.4	34	2.1	75	78	168	125 000
September	9.8	32	1.4	48	63	82	59 000
October	9.1	30	0.8	28	--	--	--
November	--	--	--	--	--	--	--
December	--	--	--	--	--	--	--
Total							741 000

New Power Plant Structures. A turbine and generator installed near the downstream end of the existing lower outlet conduit could use the 9 m to 15 m (30 ft to 50 ft) available head at the dam. The proposed generating facility includes a 0.9 m (3 ft) steel penstock installed inside the outlet conduit starting from the existing gate structure (Fig. C-16B). The penstock would use one of the four existing slide-gate openings. The slide gate would be left open, and releases to the generating unit would be controlled by a butterfly valve. The penstock would carry water to a horizontal Francis turbine that could develop 270 hp under a 15 m (50 ft) head. The turbine would be connected directly to a horizontal, air-cooled synchronous generator with a rated output of 200 kW. Operation of the

Figure C-16B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
MONTAGUE WATER CONSERVATION DISTRICT
LAKE SHASTINA
200kW POWER PLANT
POWERHOUSE – PLAN AND SECTIONS
LAKE SHASTINA DAM
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Generator (200kW)
Control Panel
Generator Switchgear
Butterfly Valve
Access Door
Stop Log Slot
Tailrace Channel
Steel Penstock
NEW POWERHOUSE PLAN
SECTION A-A
Begin New Penstock
Tower
SECTION B-B
New Powerhouse
Access Road
New Penstock
Existing Tower
Existing Intake Structure
Axis Of Dam
PLAN
Existing Gate Tower
Existing Intake Structure
New Powerhouse
New Penstock
Existing Conduit
PROFILE
(ALONG ℄ OUTLET WORKS, ℄ PENSTOCK AND ℄ TAILRACE)
NOTE:
ENGLISH UNITS IN BRACKETS

hydroelectric plant and of the existing facility would be kept separate by a butterfly valve upstream from the turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $426,800, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $721,600 (Table C-16B).

Table C-16B. Project Cost for Lake Shastina Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$302,600
Transmission Facilities	15,000
Subtotal	$317,600
Contingencies (20%)	63,500
Total	$381,100
Engineering and Administration (12%)	45,700
Total Construction Cost (January 1980 prices)	$426,800
Escalation (4 yrs. at 12% per year)	244,800
Total Construction Cost (January 1984 prices)	$671,600
Studies, Licensing, Permits, and Approvals	50,000
Total	$721,600
Cost per kW (200 kW)	$ 3,608

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-16C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-16C. Annual Operating Cost for Lake Shastina Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	8,500
Interim Replacements	1,300
Total	$ 22,800

The annual cost of owning and operating the project would range from 14 to 21 percent of the direct project cost of $721,600, depending on

financing. The estimated cost of generation ranges between 13.4 cents and 18.9 cents per kWh (Table C-16D).

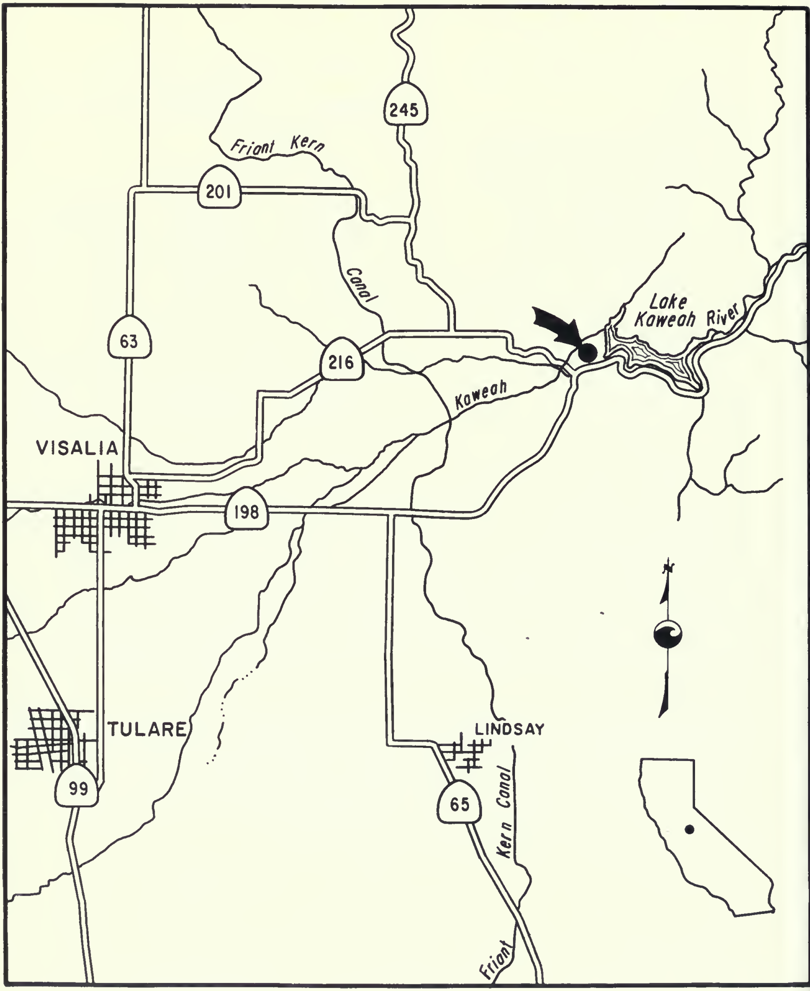
Table C-16D. Average Cost of Energy for Lake Shastina Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 90,200	$115,500	$128,400
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$113,000	$138,300	$151,200
Average Cost (per kWh)	15.2¢	18.7¢	20.4¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 76,500	$103,900	$116,900
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$ 99,300	$126,700	$139,700
Average Cost (per kWh)	13.4¢	17.1¢	18.9¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of Lake Shastina generation is less than the estimated cost of generation (13.4 to 20.4 cents per kWh). The project cost would probably exceed revenues from sales of project generation for the first year of operation. Thus, the project would probably be cost effective after the first year of generation. Benefits would accrue during subsequent years as the price of oil increases, since only the cost of maintaining the facility is subject to inflation.

Figure C-17A Lemoncove Ditch Powerplant



17. Lemoncove Ditch (At Terminus Dam)

The Lemoncove Ditch site is an alternative partial development of the Terminus Dam for hydroelectric generation. Terminus Dam, a flood control facility operated by the U.S. Army Corps of Engineers, is about 32 km (20 mi) upstream from Visalia on the Kaweah River in Tulare County (Fig. C-17A). Terminus Dam creates a reservoir known as Lake Kaweah.

The outlet works of the facility contains a separate conduit used exclusively for delivering water to Lemoncove Ditch. The conduit can carry flows considerably higher than the water requirements of Lemoncove Ditch and, by minor redevelopment, could be used both to deliver water to Lemoncove and to carry partial releases from Lake Kaweah for electrical generation.

Site Characteristics. The outlet works of Terminus Dam include a 0.9 m (3 ft) concrete-encased steel pipe through the dam used for delivering irrigation water into the Lemoncove and Hawkeye Ditches. The pipe passes through the intake gate chamber where flows are controlled by standard service and emergency gate valves. The pipe is under the outlet tunnel invert between the intake gate chamber and the outlet tunnel portal and is about 370 m (1200 ft) long (Sec. A-A of Fig. C-17B). From the outlet tunnel portal, the pipe passes under the outlet channel for about 9 m (30 ft) then turns left to discharge water into a stilling well at the headworks of Lemoncove Ditch.

Potential Generation. Water deliveries to Lemoncove Ditch amount to 0.23 cms (8 cfs) during the irrigation season and 0.03 cms (1 cfs) or less at other times of the year. The 0.3 m (1 ft) pipe from the stilling well to Hawkeye Ditch can deliver up to 0.09 cms (3 cfs) of water. The capacity of the 0.9 m (3 ft) pipe through the dam is about 1.84 cms (65 cfs). All water releases up to the capacity of the pipe could be used for electrical generation.

A vertical Francis turbine is being considered for installation at the site, because the head, which normally varies between 21 m and 49 m (70 ft and 160 ft), is greater than the range that can be used with tube turbines. During most years the pipe could be operated continuously at full capacity.

The potential installed capacity would be 650 kW, and the estimated annual generation is about 3.5 million kWh (Table C-17A).

Table C-17A. Energy Generation for Lemoncove Ditch Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	25.3	83	1.8	65	84	382	285 000
February	24.1	79	1.8	65	84	364	245 000
March	28.7	94	1.8	65	84	433	323 000
April	37.2	122	1.6	57	84	493	356 000
May	49.1	161	1.6	57	84	651	485 000
June	46.9	154	1.6	57	84	622	448 000
July	35.7	117	1.6	57	84	473	353 000
August	24.4	80	1.6	57	84	323	241 000
September	21.6	71	1.6	57	84	287	207 000
October	21.6	71	1.6	58	84	292	218 000
November	21.3	70	1.7	60	84	298	215 000
December	20.7	68	1.8	65	84	313	234 000
Available Generation							3 610 000
Less Scheduled Maintenance (336 hours in December)							128 000
Total							3 482 000

New Power Plant Structures. A turbine and generator installed outside the lower outlet tunnel portal on an extension of the existing 914 mm (36 in) diameter pipe could use the 21 m to 49 m (70 ft to 160 ft) available head. This arrangement would result in a "Y" in the outlet pipe with one leg leading to the existing Lemoncove stilling well and the other leg to the new powerhouse (Figs. C-17B and C-17C).

The proposed power plant arrangement would include a 34 m (112 ft) extension of the 0.9 m (3 ft) pipe which would convey water to a vertical Francis turbine, and a tailrace channel about 20 m (66 ft) long that would discharge into the river. The turbine could develop 870 hp under a 31 m (102 ft) head and would be connected directly to a vertical, air-cooled synchronous generator with a rated output of 650 kW.

The operation of the power plant would be separated from the operation of the existing installation used to release water to Lemoncove Ditch by a butterfly valve installed upstream from the turbine. A second butterfly valve would be installed on the Lemoncove pipe about 6 m (20 ft) upstream of the stilling well. These valves would be used to regulate flows between Lemoncove Ditch and the new power plant.

A 13 kV transmission line, owned by PGandE, is located at the site. The only other transmission facilities required would be a transformer, protective equipment, and a short connecting line.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $1,074,300, based on January 1980 prices. About

Figure C-17B

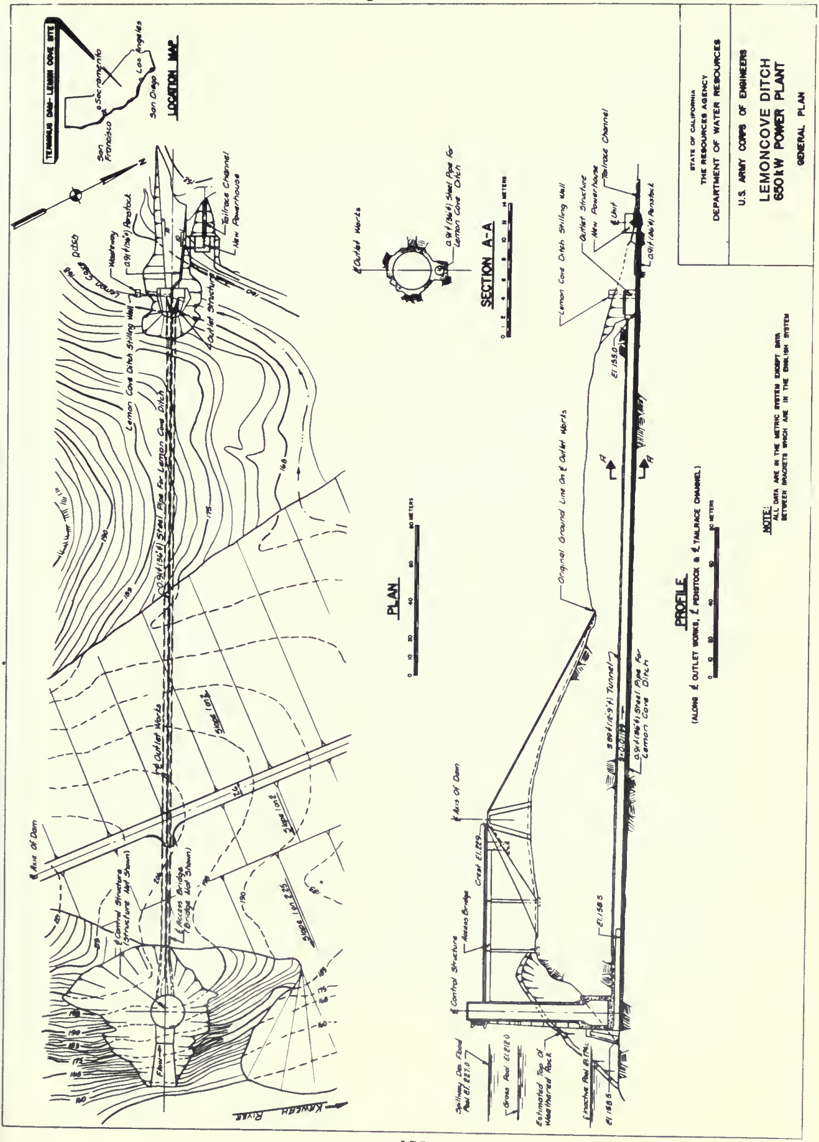
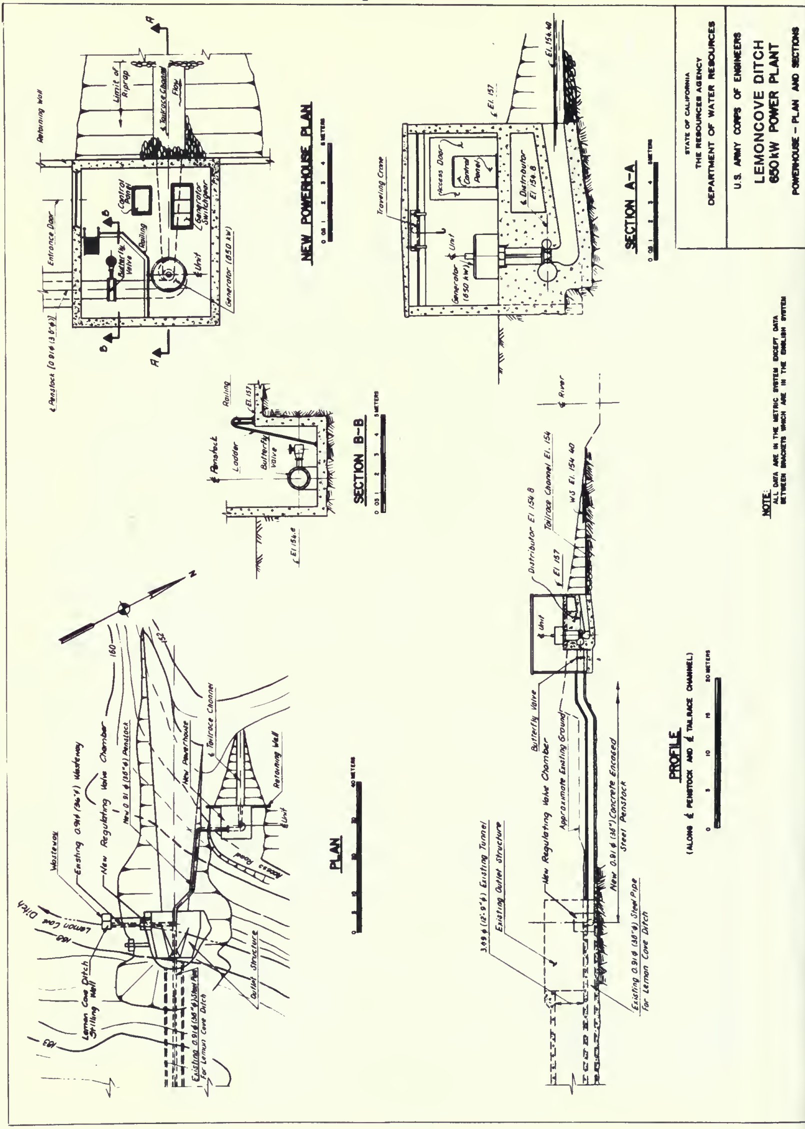

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
U.S. ARMY CORPS OF ENGINEERS
LEMONCOVE DITCH
650kW POWER PLANT
GENERAL PLAN
TERMINUS DAM-LEMON COVE SITE
LOCATION MAP
San Francisco
Sacramento
Los Angeles
San Diego
PLAN
SECTION A-A
PROFILE
(ALONG ℄ OUTLET WORKS, ℄ PENSTOCK & ℄ TAILRACE CHANNEL)
NOTE:
ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
Kaweah River
℄ Axis Of Dam
℄ Outlet Works
Lemon Cove Ditch
Lemon Cove Ditch Stilling Well
Wasteway
0.91 (36") Penstock
Tailrace Channel
New Powerhouse
Outlet Structure
0.91 (36") Steel Pipe For Lemon Cove Ditch
Original Ground Line On ℄ Outlet Works
Crest El. 229
Spillway Des. Flood Pool El. 227.0
Gross Pool El. 212.0
Estimated Top Of Weathered Rock
Inactive Pool El. 174
El. 158.5
El. 155.0
℄ Control Structure
Access Bridge

Figure C-17C



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
U.S. ARMY CORPS OF ENGINEERS
LEMONCOVE DITCH
650kW POWER PLANT
POWERHOUSE - PLAN AND SECTIONS
NEW POWERHOUSE PLAN
SECTION A-A
SECTION B-B
PLAN
PROFILE
(ALONG ℄ PENSTOCK AND ℄ TAILRACE CHANNEL)
NOTE:
ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
Retaining Wall
Limit of Riprap
℄ Tailrace Channel
Flow
Entrance Door
Control Panel
Generator Switchgear
Railing
Butterfly Valve
℄ Unit
Generator (650 kW)
℄ Penstock [0.91 ɸ (3'-0"ɸ)]
Traveling Crane
Access Door
℄ Distributor El 154.8
El. 157
El. 154.40
Ladder
El 154.8
Wasteway
Existing 0.91ɸ (36"ɸ) Wasteway
New Regulating Valve Chamber
New 0.91 ɸ (36"ɸ) Penstock
New Powerhouse
℄ Tailrace Channel
Retaining Wall
Access Road
Lemon Cove Ditch
Lemon Cove Ditch Stilling Well
Outlet Structure
Existing 0.91ɸ (36"ɸ) Steel Pipe For Lemon Cove Ditch
3.9 ɸ (12'-9"ɸ) Existing Tunnel
Existing Outlet Structure
New Regulating Valve Chamber
Approximate Existing Ground
Butterfly Valve
New 0.91 ɸ (36") Concrete Encased Steel Penstock
Existing 0.91ɸ (36"ɸ) Steel Pipe For Lemon Cove Ditch
Distributor El 154.8
Tailrace Channel El. 154
WS El. 154.40
℄ River

36 months will be required for completing the feasibility study, obtaining approvals, design, and building. If the project were initiated in 1981, the work could be completed for first-year operation in 1984. The estimated capital cost in 1984, with 12 percent inflation, is $1,790,400 (Table C-17B).

Table C-17B. Project Cost for Lemoncove Ditch Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 784,300
Transmission Facilities	15,000
Subtotal	$ 799,300
Contingencies (20%)	159,900
Total	$ 959,200
Engineering and Administration (12%)	115,100
Total Construction Cost (January 1980 Prices)	$1,074,300
Escalation (4 yrs. at 12% per year)	616,100
Total Construction Cost (January 1984 Prices)	$1,690,400
Studies, Licensing, Permits, and Approvals	100,000
Total	$1,790,400
Cost per kW (650 kW)	$ 2,754

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-17C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-17C. Annual Operating Cost for Lemoncove Ditch Project

Cost Item	Amount
Operation and Maintenance	$ 47,600
Insurance	25,500
Interim Replacements	4,000
Total	$ 77,100

The annual cost of owning and operating the project would range between 15 and 22 percent of the direct project cost of $1,790,400, depending on financing. The estimated cost of generation ranges between 7.7 cents and 11.4 cents per kWh (Table C-17D).

Table C-17D. Average Cost of Energy for Lemoncove Ditch Project

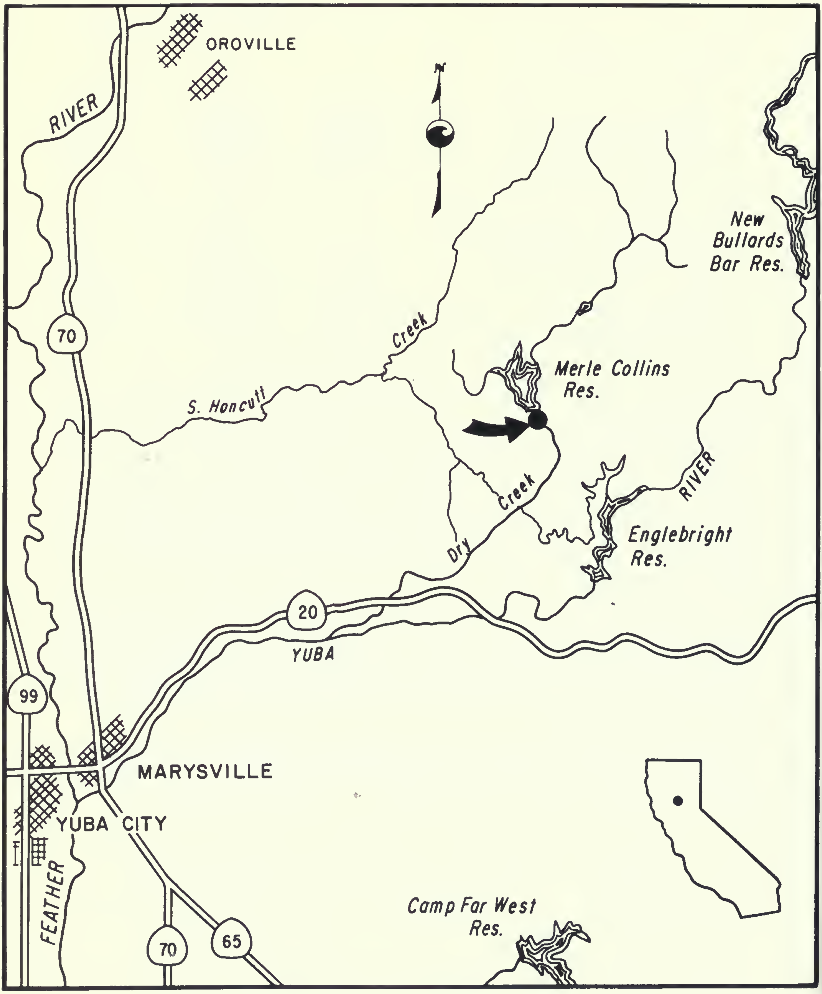
Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	\$223,800	\$286,500	\$318,600
Operating Cost	77,100	77,100	77,100
Total Annual Cost	\$300,900	\$363,600	\$395,800
Average Cost (per kWh)	8.6¢	10.4¢	11.4¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	\$189,800	\$257,800	\$290,000
Operating Cost	77,100	77,100	77,100
Total Annual Cost	\$266,900	\$334,900	\$367,100
Average Cost (per kWh)	7.7¢	9.6¢	10.5¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Since the water used by the Lemoncove project could be composed--in full or in part--of minimum reservoir releases, it is possible that the project would have a capacity value in addition to the 11.1 cents per kWh of energy value. The theoretical study of water and power operations required by PGandE's proposed policy would determine if the project will have a capacity value.

Conclusions. For tax-exempt bond financing at 9 percent interest, the estimated minimum value of Lemoncove generation exceeds the estimated generation cost (7.7 to 11.4 cents per kWh). Thus, the project would be cost effective.

Figure C-18A Virginia Ranch Dam Powerplant



18. Merle Collins Reservoir (Virginia Ranch Dam)

Merle Collins Reservoir and Virginia Ranch Dam are owned and operated by the Browns Valley Irrigation District. It is located on Dry Creek near the community of Browns Valley in Yuba County (Fig. C-18A). In addition to providing part of the water supply for the District, stored water is carried by tunnel and open channel to Browns Valley where it is used for irrigation. The reservoir is also used for boating, fishing, picnicking, and camping. The project was constructed in 1963.

At present, water in the reservoir provides more head than is needed for irrigation releases to the District. However, head is dissipated and wasted by a discharge valve since the District's system is not under pressure. This study investigated the possibility of using hydroelectric facilities to generate energy using the reservoir releases now being wasted, and the spillway discharges that presently by-pass the irrigation tunnel and canal system.

Site Characteristics Water is released to the Browns Valley irrigation system through a manually operated valve. A 0.2 cms (6 cfs) release is made through a second valve to Dry Creek to enhance streamflow. An access road, available for operation and maintenance of the valves and outlet works, would be available for construction and operation of the hydroelectric facility.

A 13 kV single-phase transmission line, owned and operated by PGandE, is located about 1.6 km (1 mi) from the site. Energy generated at this site could be delivered to PGandE by building a 13 kV transmission line for a distance of 4.8 km (3 mi) to connect the existing PGandE line to the site and by installing a third conductor on the existing line.

Irrigation water is released between April and October with the largest releases occuring during July and August, the maximum discharge is about 4.5 cms (160 cfs). Most of the spillway discharge that now flows down Dry Creek could be carried through the District's tunnel and canals during winter months to produce electric power. Power can be generated for about 9 months during an average-water year. This would require that water be released for power production early in the year, when storage in the reservoir reaches 56 740 cubic dekametres (46,000 ac-ft).

Potential Generation. A vertical Francis turbine is being considered for use at this site, because the net operating head of 27.4 m to 37.8 m (90 ft to 124 ft) exceeds that which is usable for a tube-type turbine.

The potential generation capacity would be 900 kW, and the estimated annual generation is about 5.6 million kWh (Table C-18A).

Table C-18A. Energy Generation for Merle Collins Reservoir Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	--	--	0.1	3	--	--	--
February	35.4	116	2.9	104	85	865	581 000
March	38.7	127	2.9	104	85	947	705 000
April	38.7	127	3.1	108	85	984	708 000
May	37.5	125	3.1	108	85	968	720 000
June	35.7	118	3.1	108	85	914	658 000
July	32.0	108	3.3	118	85	914	680 000
August	29.9	100	3.3	118	85	846	629 000
September	28.0	90	3.1	108	85	697	502 000
October	27.4	80	3.1	108	85	620	461 000
November	--	--	0.1	3	--	--	--
December	--	--	0.1	3	--	--	--
Total							5 644 000

Existing Structures. Virginia Ranch Dam is a 46 m high (150 ft) earth and rockfill dam with a crest 580 m (1900 ft) long. The reservoir has a total storage capacity of 70 310 cubic dekametres (57,000 ac-ft).

Controlled releases from the reservoir are made through an outlet low on the west side of the dam. This outlet consists of a concrete conduit, 1.2 m (4 ft) in diameter, for the first 82.3 m (270 ft) from the reservoir outlet to a gate chamber near the mid-point of the dam. Downstream from the gate chamber, for about 107 m (350 ft) to the valve house, the outlet consists of a 1.1 m (3.5 ft) diameter steel pipe inside a 2.1 m (7 ft) diameter horseshoe concrete conduit.

The main valve is a standard Howell-Bunger valve, which discharges the water into a stilling basin then through about 30.5 m (100 ft) of open channel into a tunnel 1158 m (3800 ft) long.

Upstream from the Howell-Bunger valve, a 381 mm (15 in) by-pass outlet pipe discharges water into the natural stream channel for fish and vegetation. The minimum flow to the channel is 0.2 cms (6 cfs).

New Power Plant Structures. A turbine-generator installed at the downstream end of the existing, lower-level conduit could use the 27.4 m to 37.8 m (90 ft to 124 ft) available head. The proposed generating facility would include a 1067 m (42 in) steel pipe by-pass which would carry water from about 3.1 m (10 ft) upstream of the existing valve building to a vertical Francis turbine (Figs. C-17B and C-17C). The turbine could develop 1160 hp at 720 rpm under a 32 m (105 ft) head and would be connected directly to a vertical, air-cooled synchronous generator with a rated output of 900 kW.

Figure C-18B

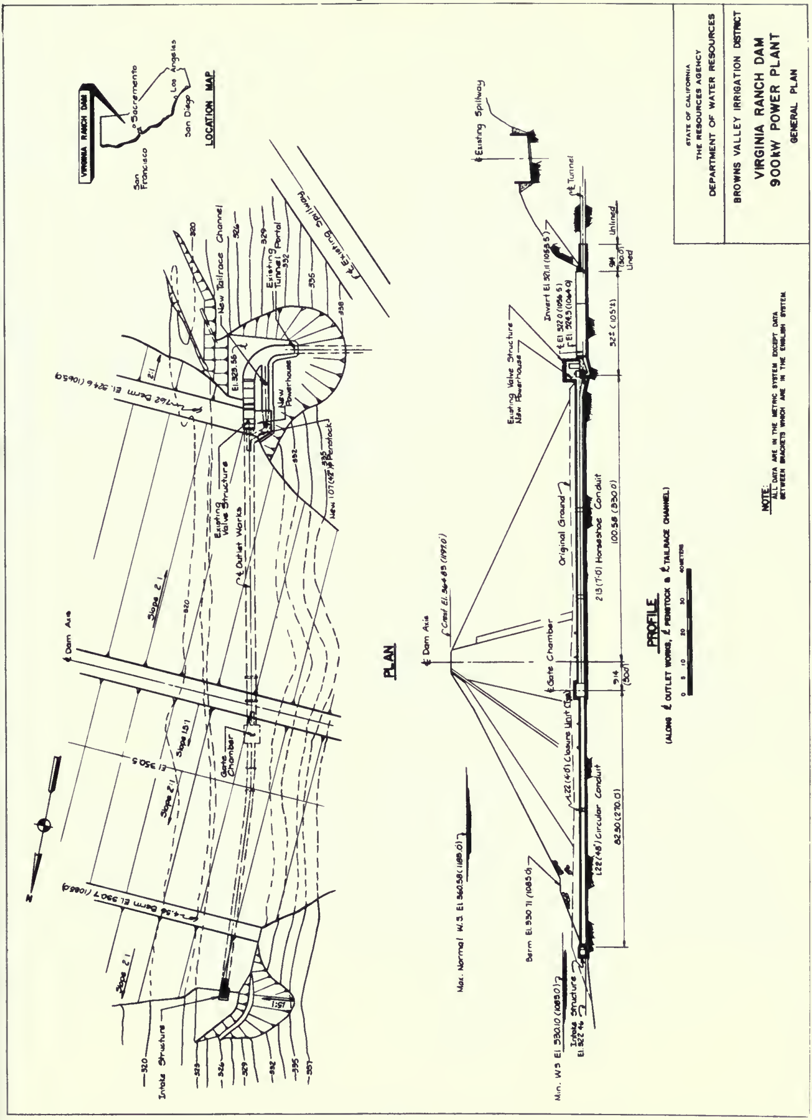
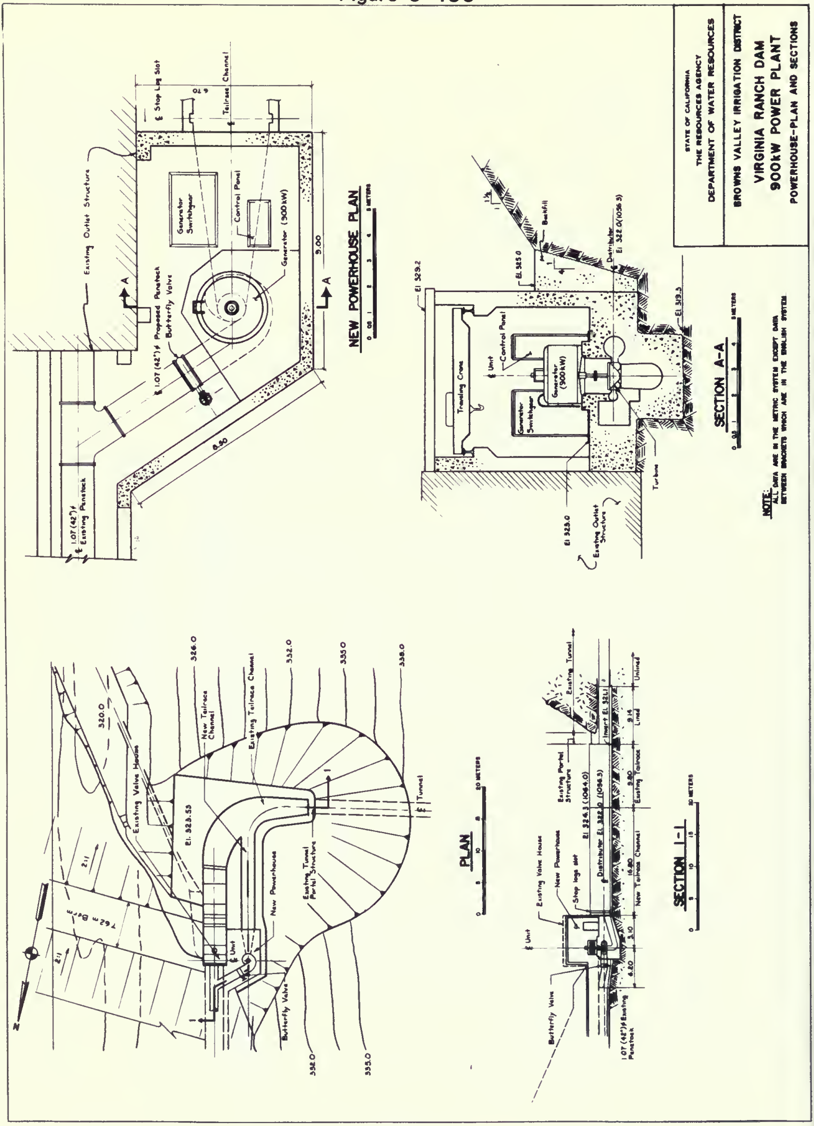

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
BROWNS VALLEY IRRIGATION DISTRICT
VIRGINIA RANCH DAM
900kW POWER PLANT
GENERAL PLAN
LOCATION MAP
VIRGINIA RANCH DAM
Sacramento
San Francisco
Los Angeles
San Diego
PLAN
PROFILE
(ALONG ℄ OUTLET WORKS, ℄ PENSTOCK & ℄ TAILRACE CHANNEL)
NOTE: ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
New Tailrace Channel
Existing Tunnel Portal
Existing Spillway
New Powerhouse
Existing Valve Structure
℄ Outlet Works
Gate Chamber
℄ Dam Axis
Intake Structure
Original Ground
213 (7'-0) Horseshoe Conduit
1.22 (4'-0) Circular Conduit
℄ Gate Chamber
Unlined
Lined

Figure C-18C


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
BROWNS VALLEY IRRIGATION DISTRICT
VIRGINIA RANCH DAM
900kW POWER PLANT
POWERHOUSE-PLAN AND SECTIONS
NEW POWERHOUSE PLAN
SECTION A-A
PLAN
SECTION 1-1
NOTE:
ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM
Existing Outlet Structure
Generator Switchgear
Control Panel
Generator (900 kW)
1.07 (42")⌀ Proposed Penstock Butterfly Valve
1.07 (42")⌀ Existing Penstock
Tailrace Channel
Stop Log Slot
Traveling Crane
Turbine
Distributor
Backfill
Existing Valve House
New Tailrace Channel
Existing Tailrace Channel
New Powerhouse
Existing Tunnel Portal Structure
Butterfly Valve
Existing Tunnel
Existing Portal Structure

Downstream, the waterway would consist of a tailrace channel, about 16.8 m (55 ft) long, which would connect to the existing main channel that carries the water into the downstream tunnel.

The operation of the hydroelectric plant would be separated from that of the existing irrigation installation by a butterfly valve installed upstream from the turbine. Stop logs at the beginning of the new tailrace channel would separate it from the existing main channel so the turbine could be dewatered for maintenance.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $1,260,000, based on January 1980 prices. About 36 months will be required for completing the feasibility study, obtaining approvals, design, and building. Assuming that the project will be initiated early in 1981 and completed early in 1984, the estimated total project cost (with 12 percent annual inflation) is $2,082,600 (Table C-18B).

Table C-18B. Project Cost for Merle Collins Reservoir Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 878,950
Transmission Facilities	58,550
Subtotal	$ 937,500
Contingencies (20%)	187,500
Total	$1,125,000
Engineering and Administration (12%)	135,000
Total Construction Cost (January 1980 Prices)	$1,260,000
Escalation (4 yrs. at 12% per year)	722,600
Total Construction Cost (January 1984 Prices)	$1,982,600
Studies, Licensing, Permits, and Approvals	100,000
Total	$2,082,600
Cost per kW (900 kW)	$ 2,314

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-18C). The cost of operation would be insignificant since an operator must always be available to set the discharge valve for irrigation releases. Regular maintenance could be scheduled during the nonirrigation season when there would be no water for generation.

Table C-18C. Annual Operating Cost for Merle Collins Reservoir Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	34,000
Interim Replacements	5,400
Total	$ 52,400

The annual cost of owning and operating the project would range between 13 and 20 percent of the direct project cost of $2,082,600, depending on financing. The estimated cost of generation ranges between 4.8 cents and 7.5 cents per kWh (Table C-18D).

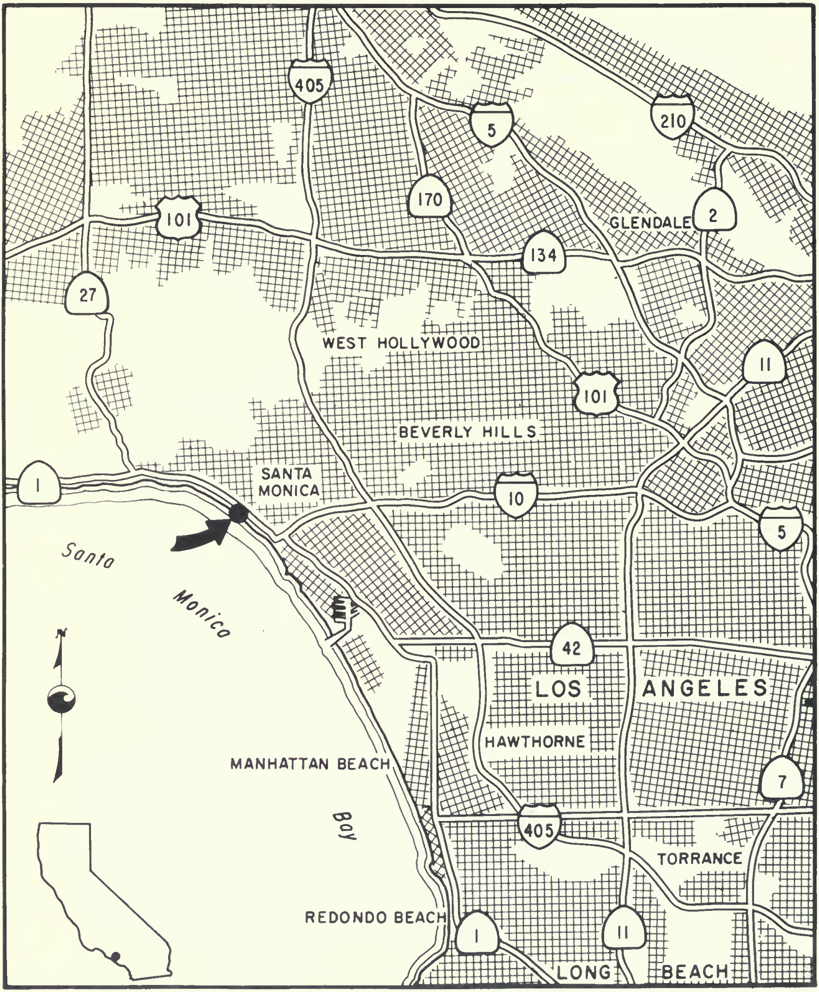
Table C-18D. Average Energy Cost of Merle Collins Reservoir Project

Cost Item	Amount		
	Interest Rate		
	9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$260,300	$333,200	$370,700
Operating Cost	52,400	52,400	52,400
Total Annual Cost	$312,700	$385,600	$423,100
Average Cost (per kWh)	5.5¢	6.8¢	7.5¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$220,800	$299,900	$337,400
Operating Cost	52,400	52,400	52,400
Total Annual Cost	$273,200	$352,300	$389,900
Average Cost (per kWh)	4.8¢	6.2¢	6.9¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed for the purpose of this study that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of Virgina Ranch generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Virgina Ranch hydroelectric generation exceeds the estimated cost of generation (4.8 to 7.5 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The generation cost would change little from year to year, since only maintenance cost is subject to escalation.

Figure C-19A Mount Olivette Powerplant



19. Mount Olivette

The Mount Olivette site is a pipeline pressure break owned and operated by the city of Santa Monica in Los Angeles County (Fig. C-19A). Water is delivered to the site through a cast iron pipeline which is 457 mm (18 in) in diameter and 1067 m (3500 ft) long. The water is pressurized at the source of supply by the Metropolitan Water District of Southern California.

Site Characteristics. The Santa Monica water distribution system is divided into pressure zones for 150, 100, and 80 metres (500, 350, and 250 feet). About 20 percent of the water received at Mount Olivette by-passes the pressure break for distribution in the 150 m (500 ft) pressure zone. The remaining 80 percent passes through the pressure break valve to the Mount Olivette reservoir which, in turn, pressurizes the 100 m (350 ft) pressure zone. Water for the 80 m (250 ft) pressure zone is pumped from wells. The 4 kV transmission line located at the site is owned and operated by the Southern California Edison (SCE). The flow characteristics of the site are such that energy could be generated during all months of the year except February; the greatest flows occur during June, July, and August.

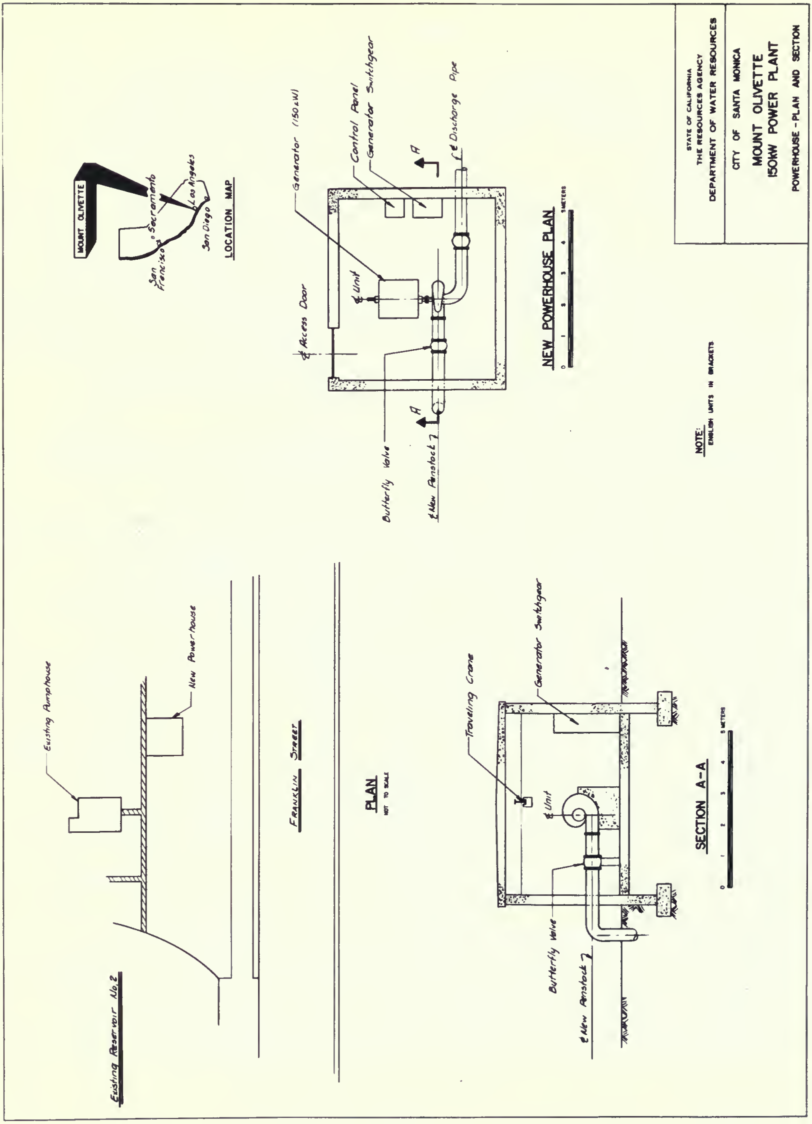
Potential Generation. The potential generation capacity of the Mount Olivette site would be about 150 kW; the estimated average annual output is 1.1 million kWh (Table C-19A).

Table C-19A. Energy Generation for Mount Olivette Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	59.1	194	0.3	9.7	79	126	94 000
February	66.2	217	0.2	6.9	--	--	--
March	61.9	203	0.2	8.7	76	114	84 000
April	61.0	200	0.3	9.0	77	117	84 000
May	50.9	167	0.4	12.5	84	148	110 000
June	47.0	154	0.4	13.7	84	150	108 000
July	48.8	160	0.4	13.1	84	149	111 000
August	48.8	160	0.4	13.1	84	149	111 000
September	57.6	189	0.3	10.3	80	132	95 000
October	58.2	191	0.3	10.0	78	126	94 000
November	55.8	183	0.3	10.9	82	138	100 000
December	57.0	187	0.3	10.6	81	168	125 000
Total							1 116 000

New Power Plant Structures. A turbine-generator installed at the site could use the 47 m to 66 m (154 ft to 217 ft) available head. The proposed generating facility would include a steel by-pass penstock to a horizontal Francis turbine which could develop 200 hp at 0.4 cms (13 cfs) under a 49 m (160 ft) head (Fig. C-19B). The turbine would be connected directly to a horizontal electric generator having a rated capacity of 150 kW. The operation of the hydroelectric facility would be separated from that of the

Figure C-19B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CITY OF SANTA MONICA
MOUNT OLIVETTE
150KW POWER PLANT
POWERHOUSE - PLAN AND SECTION
MOUNT OLIVETTE
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Generator (150 kW)
Control Panel
Generator Switchgear
℄ Discharge Pipe
A
℄ Access Door
℄ Unit
Butterfly Valve
℄ New Penstock
A
NEW POWERHOUSE PLAN
0 1 2 3 4 5 METERS
NOTE: ENGLISH UNITS IN BRACKETS
Existing Pumphouse
New Powerhouse
Existing Reservoir No. 2
Franklin Street
PLAN
NOT TO SCALE
Traveling Crane
Generator Switchgear
℄ Unit
Butterfly Valve
℄ New Penstock
SECTION A-A
0 1 2 3 4 5 METERS

existing operation by butterfly valves installed upstream and downstream from the turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $315,800, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $546,900 (Table C-19B).

Table C-19B. Project Cost for Mount Olivette Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$220,000
Transmission Facilities	15,000
Subtotal	$235,000
Contingencies (20%)	47,000
Total	$282,000
Engineering and Administration (12%)	33,800
Total Construction Cost (January 1980 Prices)	$315,800
Escalation (4 yrs. at 12% per year)	181,100
Total Construction Cost (January 1984 Prices)	$496,900
Studies, Licensing, Permits, and Approvals	50,000
Total	$546,900
Cost per kW (150 kW)	$ 3,646

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-19C). Regular maintenance could be scheduled during the winter months when water flow is at a minimum.

Table C-19C. Annual Operating Cost for Mount Olivette Project

Cost Item	Amount
Operation and Maintenance	$ 20,400
Insurance	8,500
Interim Replacements	1,500
Total	$ 30,400

The annual cost of owning and operating the project would range between 16 and 23 percent of the direct project cost of $546,900, depending

on financing. The estimated cost of generation ranges between 7.9 cents and 11.4 cents per kWh (Table C-19D).

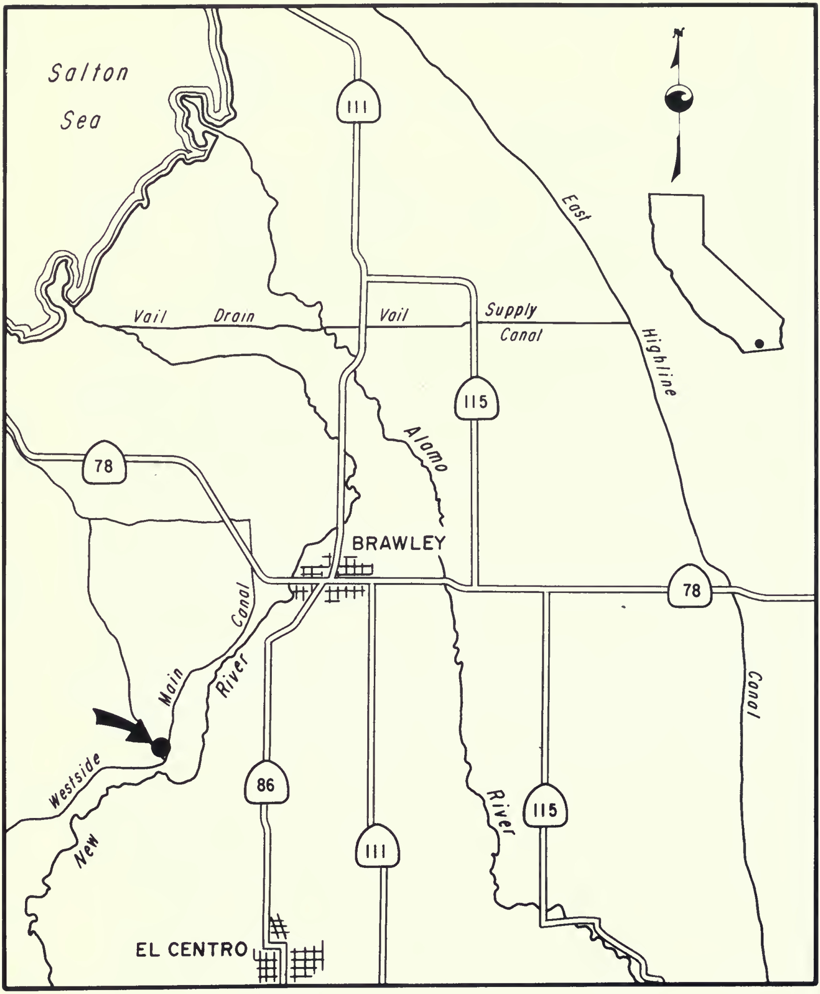
Table C-19D. Average Cost of Energy of Mount Olivette Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 68,400	$ 87,500	$ 97,300
Operating Cost	30,400	30,400	30,400
Total Annual Cost	$ 98,800	$117,900	$127,700
Average Cost (per kWh)	8.8¢	10.6¢	11.4¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 58,000	$ 78,800	$ 88,600
Operating Cost	30,400	30,400	30,400
Total Annual Cost	$ 88,400	$109,200	$119,000
Average Cost (per kWh)	7.9¢	9.8¢	10.7¢

Value of Generation. It is assumed that project generation would be sold to SCE under Section 210 of PURPA. The project would have a capacity value because flows would be available during on-peak hours in all months except February, when there is insufficient water for power generation. On this basis, the estimated value of project generation in 1984 is 13.3 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Mount Olivette generation exceeds the estimated generation cost (7.9 to 11.4 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue in subsequent years as the price of oil increases. The generation cost would change little from year to year, since only maintenance costs are subject to escalation.

Figure C-20A No. 8 Heading Powerplant



20. No. 8 Heading

The No. 8 Heading site, a check structure on the Westside Main Canal, is owned and operated by the Imperial Irrigation District. The site is about 8 km (5 mi) northwest of Imperial City in Imperial County (Fig. C-20A).

Site Characteristics. The existing concrete structure is about 25 m (82 ft) long, and discharges the streamflow into the canal over a 4.2 m (13.8 ft) drop. The structure has three separate bays, each 2.1 m (7 ft) wide and 3.7 m (12 ft) high. The water is discharged downstream through three 1.5 m (5 ft) diameter pipes approximately 15 m (50 ft) long. The installation also includes an automatic spillway about 6 m (20 ft) east of the main check structure. The spillway consists of a radial entrance gate 1.8 m (6 ft) wide by 2.2 m (7.3 ft) high and a 1.5 m (5 ft) diameter pipe about 30 m (100 ft) long.

Potential Generation. A horizontal tube-type turbine is considered for installation at No. 8 Heading because of the constantly low head which ranges between 4.0 m (13.2 ft) and 4.3 m (14.2 ft). Since the flows range between 14 cms and 22 cms (500 cfs and 775 cfs) for eight months of the year, a fixed propeller runner would generate about 87 percent of the potential energy of the site.

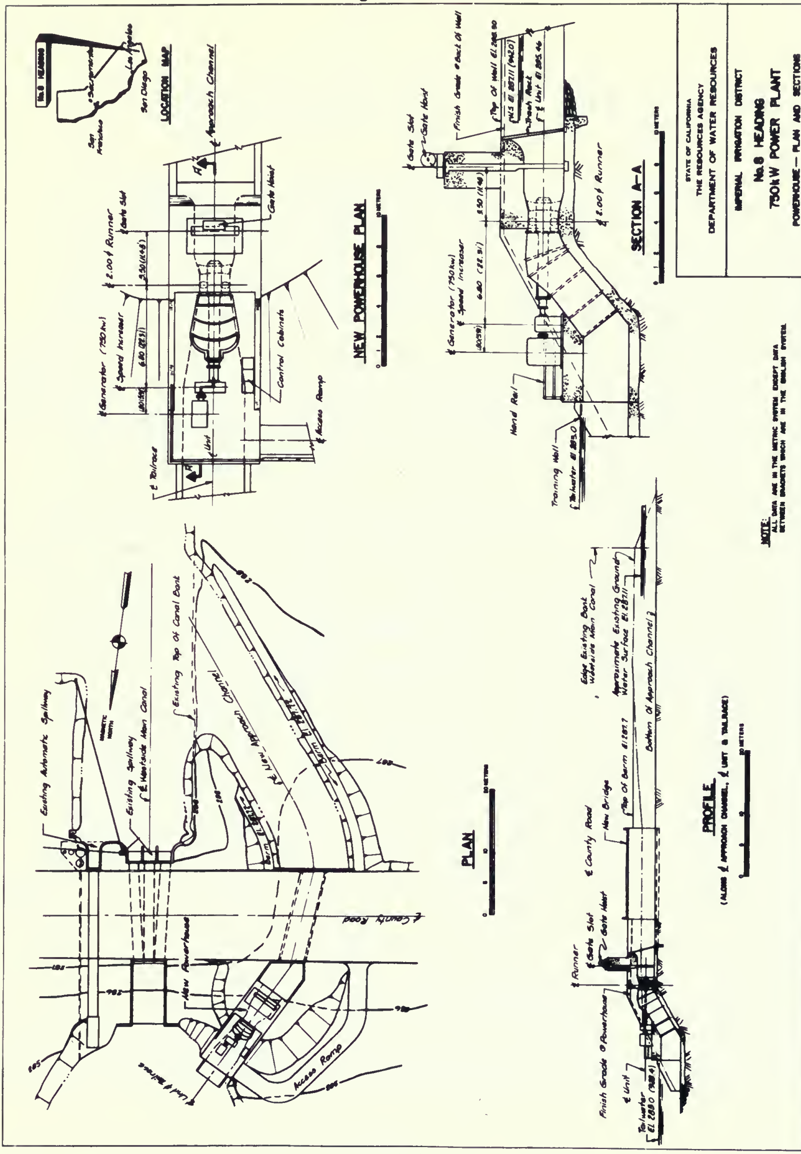
The potential installed capacity would be 750 kW; the estimated annual generation is about 3.9 million kWh (Table C-20A).

Table C-20A. Energy Generation of No. 8 Heading Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	4.4	14.5	3.54	125	--	--	--
February	4.3	14.1	10.62	375	60	268	180 000
March	4.2	13.7	15.57	550	67	427	318 000
April	4.0	13.2	21.95	775	84	727	523 000
May	4.0	13.2	19.82	700	84	657	489 000
June	4.0	13.2	21.95	775	84	727	523 000
July	4.0	13.2	21.95	750	84	704	524 000
August	4.0	13.2	19.82	700	84	657	489 000
September	4.1	13.5	18.41	650	78	579	417 000
October	4.2	13.8	14.61	500	65	379	282 000
November	4.3	14.2	9.91	350	55	231	166 000
December	4.4	14.4	7.08	250	--	--	--
Total							3 911 000

New Power Plant Structures. A turbine and generator installed at No. 8 Heading could use the 4.2 m (13.8 ft) available head. The proposed generating facility includes an approach channel--3.5 m (11.5 ft) wide and 41 m (134.5 ft) long--on the left side of the canal, a horizontal tube-type turbine, and a short tailrace to return stream flows to the canal downstream from the check structure (Fig. C-20B). The turbine could develop 1000 hp under the available head and would be connected, through a speed increaser,

Figure C-20B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
IMPERIAL IRRIGATION DISTRICT
No.8 HEADING
750kW POWER PLANT
POWERHOUSE — PLAN AND SECTIONS
LOCATION MAP
San Francisco
Sacramento
Los Angeles
San Diego
No.8 HEADING
NEW POWERHOUSE PLAN
SECTION A-A
PLAN
PROFILE
(ALONG ℄ APPROACH CHANNEL, ℄ UNIT & TAILRACE)
NOTE: ALL DATA ARE IN THE METRIC SYSTEM EXCEPT DATA BETWEEN BRACKETS WHICH ARE IN THE ENGLISH SYSTEM.
℄ Approach Channel
Gate Hoist
Gate Slot
℄ 2.00 ℄ Runner
℄ Generator (750 kw)
℄ Speed Increaser
Control Cabinets
Access Ramp
℄ Tailrace
℄ Unit
Finish Grade @ Back Of Wall
Top Of Wall El. 288.90
Trash Rack
Hand Rail
Training Wall
Tailwater El. 285.0
Existing Automatic Spillway
Existing Spillway
℄ Westside Main Canal
Existing Top Of Canal Bank
℄ New Approach Channel
New Powerhouse
℄ County Road
℄ Unit ℄ Tailrace
MAGNETIC NORTH
Edge Existing Bank Westside Main Canal
Approximate Existing Ground
Water Surface El. 287.11
Bottom Of Approach Channel
Top Of Berm El. 287.7
New Bridge
Finish Grade @ Powerhouse

to a horizontal air-cooled synchronous generator with a rated output of 750 kW. An inlet gate would be installed in front of the turbine so that the turbine can be dewatered for maintenance.

The proposed arrangement of the power facility would by-pass the existing check structure, and the power plant could be built without affecting the existing water conveyance facilities.

A 13 kV transmission line is located at the site; the only other transmission facilities required are a transformer, protective equipment, and a short, connecting transmission line.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $1,570,600, based on January 1980 prices. Since the generating facility would be located on an installed conduit which is operated primarily for purposes other than power generation, the site would probably be exempt from federal licensing requirements. (The exemption provision is discussed in detail in Appendix C.) However, the District would have to comply with CEQA requirements and obtain other state approvals, if necessary.

If the project were initiated in 1981, and about 30 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. At a 12 percent inflation rate, the estimated project cost in late 1983 is $2,521,400 (Table C-20B).

Table C-20B. Project Cost of No. 8 Heading Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$1,156,100
Transmission Facilities	12,500
Subtotal	$1,168,600
Contingencies (20%)	233,700
Total	$1,402,300
Engineering and Administration (12%)	168,300
Total Construction Cost (January 1980 Prices)	$1,570,600
Escalation (4 yrs. at 12% per year)	900,800
Total Construction Cost (January 1984 Prices)	$2,471,400
Studies, Licensing, Permits, and Approvals	50,000
Total	$2,521,400
Cost per kW (750 kW)	$ 3,362

Cost of Generation. Since the facility and an electric transmission and distribution system are owned and operated by the Imperial Irrigation District, it is assumed that the District would develop and use the power in its own system. The annual costs of owning and operating the project would include debt repayment, the costs of operation and maintenance, insurance, replacements, administration, and overhead.

It is assumed that the District would finance construction by issuing tax-exempt revenue bonds, and that the bonds could be issued for a 35-year term at 9 percent interest. The actual interest rate would depend on financial conditions when the bonds were issued. It is expected that initial development would be financed from electric system revenues or short-term loans and that the bonds would not be issued until about 12 months before the project is completed. The additional cost of operating the plant would be insignificant, since the District already has a full staff of operating personnel. Regular maintenance could be scheduled during the nonirrigation season when there is insufficient water for power generation.

If the project were scheduled to be on-line late in 1983, the bond issue would be about $3,050,000 based on January 1980 bid prices, with a 12 percent annual interest rate and a one-year construction period.

The estimated average generation cost, assuming 35-year bonds, is $389,200 or 10 cents per kWh. For 20-year bonds, the estimated average generation cost would increase to 11.3 cents per kWh (Table C-20C).

Table C-20C. Average Energy Cost of No. 8 Heading Project

Cost Item	Amount	
	20-year Bonds	35-year Bonds
Project Cost	$2,521,400	$2,521,400
Capitalized Interest	226,900	226,900
Interest Earnings	(113,500)	(113,500)
Total Capital Cost	$2,634,800	$2,634,800
Bond Reserve Fund	339,600	288,600
Financing Cost	125,600	126,600
Bond Issue	$3,100,000	$3,050,000
Debt Service (9% interest)	$339,600	$288,600
Operation and Maintenance	20,400	20,400
Insurance	100,200	100,200
Interim Replacements	6,000	6,000
Interest Earnings	(26,000)	(26,000)
Total Annual Cost	$ 440,200	$ 389,200
Annual Cost (% of Project Cost)	17.4	15.4
Average Cost (per kWh)	11.3¢	10.0¢

Since the District has experience with small hydroelectric facilities, it might elect to be self-insured--in full or in part--to reduce the annual insurance premium it would pay on mechanical and electrical equipment. This would substantially reduce its annual generation cost.

Value of Generation. Since the District would probably use the energy produced in its own electric system, the value of such hydroelectric generation to the District would be equal to the cost of the fuel-generated energy it would replace. In addition to the District-owned and operated El Centro steam- electric plant, gas turbines, diesel units, and hydroelectric facilities, the District purchases power under contract from the WPRS and the Colorado River Storage Project.

Natural gas and oil are used for the El Centro steam-electric plant and for the gas turbines. The amount of natural gas burned to produce electricity has declined over the past few years, while the amount of oil burned has increased; this trend is expected to continue. Thus, the new hydroelectric generation would offset the use of oil and its true value would be equal to the cost of oil avoided.

A detailed computation of the avoided energy cost to the District is beyond the scope of this study. However, the average annual avoided energy cost can be estimated based on an average incremental heat rate for the District's generation and the projected price of oil. Assuming an average incremental heat rate of 10,000 Btu per kWh, system losses of 10 percent, and a 1980 oil price of $26.30 per barrel (about $4 per million Btu), the estimated avoided energy cost would be 4.5 cents per kWh. This cost is nearly the same as the SCE rate for mid-peak energy, and thus the projected value of avoided energy for the District can be taken from the partial-peak projection shown in Appendix G.

The District's cost of avoided capacity will depend on its long-range power supply program and the cost of adding generating capacity to its electric system. For the purpose of estimating the capacity value of new hydroelectric generation such as No. 8 Heading, an estimated value of $100 per kW-year is considered appropriate for new capacity with a 35-year life and an initial year of operation in 1984, based on the cost of capacity to other electric utilities in California Volume I, Chapter 2, Table 9.

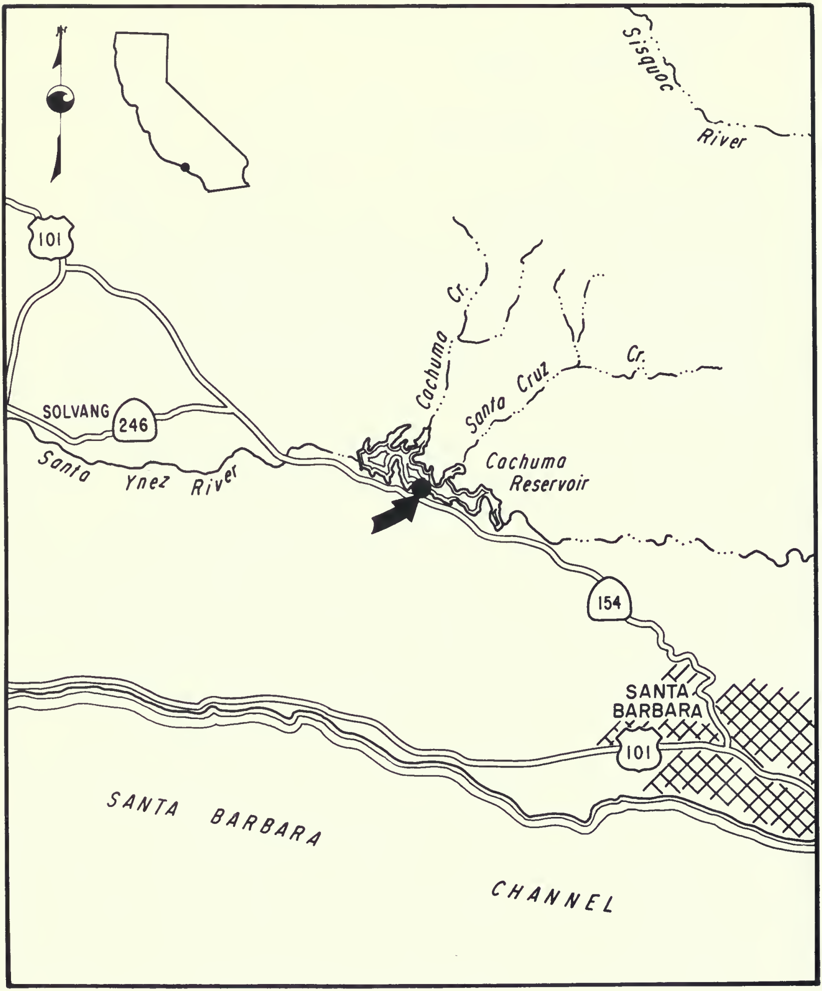
The estimated value of No. 8 Heading generation in 1984 is 11.7 cents per kWh (Table C-20D).

Table C-20D. Generation Value of No. 8 Heading Project

Cost Item	Amount
Capacity (August Capacity)	
657 kW x $100 per kW	$ 65,700
Energy	
3 910 000 kWh at 10¢ per kWh	391,100
Total	$456,800
Average Value (per kWh)	11.7¢

Conclusions. Since the estimated value of No. 8 Heading generation exceeds the estimated cost of generation (10 to 11 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of No. 8 Heading generation would change little from year to year, since only the cost of maintaining the facility is subject to escalation.

Figure C-21A North Portal Tecolote Powerplant



21. North Portal Tecolote

The North Portal Tecolote site is located at the intake structure for the Tecolote Tunnel that diverts water from Lake Cachuma to the south coast area of Santa Barbara County (Fig. C-21A). The Cachuma Project, of which the Tecolote Tunnel is a part, was designed and constructed by the WPRS for the Santa Barbara County Water Agency. The Cachuma Operation and Maintenance Board operates the Cachuma facility for four county water districts and the city of Santa Barbara.

Lake Cachuma is formed by Bradbury Dam on the Santa Ynez River northeast of Santa Barbara. The Tecolote Tunnel from Lake Cachuma to its South Portal turnout is 10.3 km (6.4 mi) long and is presently experiencing groundwater infiltration at an average rate of 0.2 cms (5.5 cfs).

Site Characteristics. The hydraulic facility at the North Portal Tecolote site consists of an intake structure in Lake Cachuma and a reinforced-concrete tunnel 2.4 m (8 ft) in diameter and 244 m (800 ft) long. The tunnel carries water to an underground chamber containing a 914 mm (36 in) regulating valve, baffled energy dissipater, and clorination equipment. The underground chamber can be reached by an elevator from the surface.

Potential Generation. The potential generation capacity of the site would be about 175 kW, and the estimated average annual output is about 720 000 kWh (Table C-21A).

Table C-21A. Energy Generation of North Portal Tecolote Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	19.2	63	0.3	10.0	--	--	--
February	22.6	74	0.2	7.0	--	--	--
March	26.2	86	0.3	10.6	--	--	--
April	26.5	87	0.4	15.4	70	79	57 000
May	26.2	86	0.7	24.9	84	152	113 000
June	25.9	85	0.8	27.0	84	163	117 000
July	24.4	80	0.9	32.4	84	159	118 000
August	22.9	75	0.9	32.4	84	149	111 000
September	21.0	69	0.7	26.1	84	128	92 000
October	19.8	65	0.6	22.8	77	97	72 000
November	19.2	63	0.4	14.8	71	56	40 000
December	18.9	62	0.3	8.8	--	--	--
Total							720 000

New Power Plant Structures. A turbine-generator installed in an extension of the existing underground gate chamber could use the 19.2 m to 26.5 m (63 ft to 87 ft) available head at the Tecolote Intake site. The proposed generating facility would include a steel penstock, 457 mm (18 in) in diameter, connected through a T-connection to the existing water conduit to carry water to an inclined propeller turbine, a speed increaser, a generator, a 660 mm (26 in) diameter steel discharge pipe, and two butterfly valves (Fig. C-21B). The turbine could develop 234 hp under a 26.5 m (87 ft) head and would be connected, through the gearbox speed increaser, to a generator rated at 175 kW. The operation of the hydroelectric facility would be separated from that of the existing facility by two butterfly valves installed upstream and downstream from the turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $745,900, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $1,223,700 (Table C-21B).

Table C-21B. Project Cost of North Portal Tecolote Plant

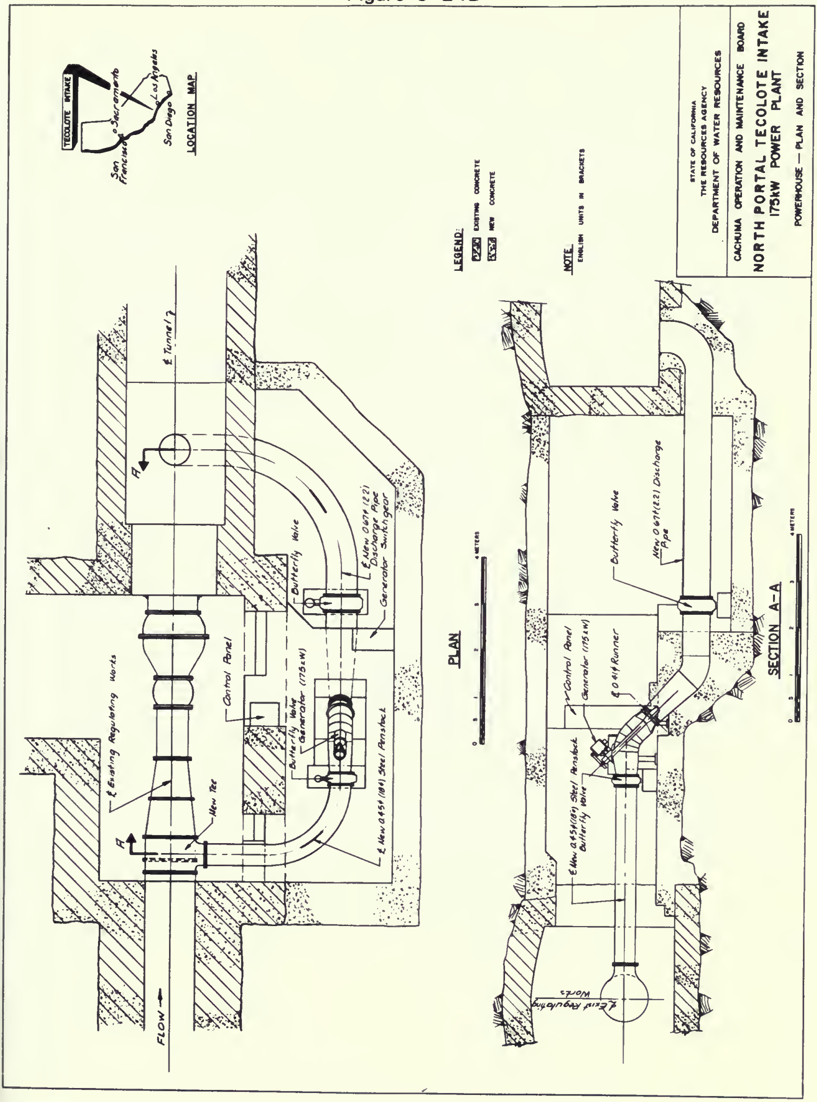
Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 545,000
Transmission Facilities	10,000
Subtotal	$ 555,000
Contingencies (20%)	111,000
Total	$ 666,000
Engineering and Administration (12%)	79,900
Total Construction Cost (January 1980 prices)	$ 745,900
Escalation (4 yrs. at 12% per year)	427,800
Total Construction Cost (January 1984 prices)	$1,173,700
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,223,700
Cost per kW (175 kW)	$ 6,993

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-21C). Regular maintenance could be scheduled during the winter months.

Table C-21C. Annual Operating Cost of North Portal Tecolote Project

Cost Item	Amount
Operation and Maintenance	$ 20,400
Insurance	8,500
Interim Replacements	3,000
Total	$ 31,900

Figure C-21B


TECOLOTE INTAKE
San Francisco
Sacramento
Los Angeles
San Diego
LOCATION MAP
LEGEND:
EXISTING CONCRETE
NEW CONCRETE
NOTE
ENGLISH UNITS IN BRACKETS
STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CACHUMA OPERATION AND MAINTENANCE BOARD
NORTH PORTAL TECOLOTE INTAKE
175kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
℄ Tunnel 7
A
Butterfly Valve
℄ New 0.67ϕ (2.2) Discharge Pipe
Generator Switchgear
Control Panel
Butterfly Valve
Generator (175kW)
℄ New 0.45ϕ (1.8ϕ) Steel Penstock
℄ Existing Regulating Works
New Tee
FLOW
PLAN
4 METERS
SECTION A-A
Butterfly Valve
New 0.67ϕ (2.2) Discharge Pipe
Control Panel
Generator (175kW)
℄ 0.41ϕ Runner
℄ New 0.45ϕ (1.8ϕ) Steel Penstock
Butterfly Valve
℄ Exist Regulating Works

The annual cost of owning and operating the project would range between 13 and 20 percent of the direct project cost of $1,223,700, depending on financing. The estimated cost of generation ranges between 22.4 cents and 34.7 cents per kWh (Table C-21D).

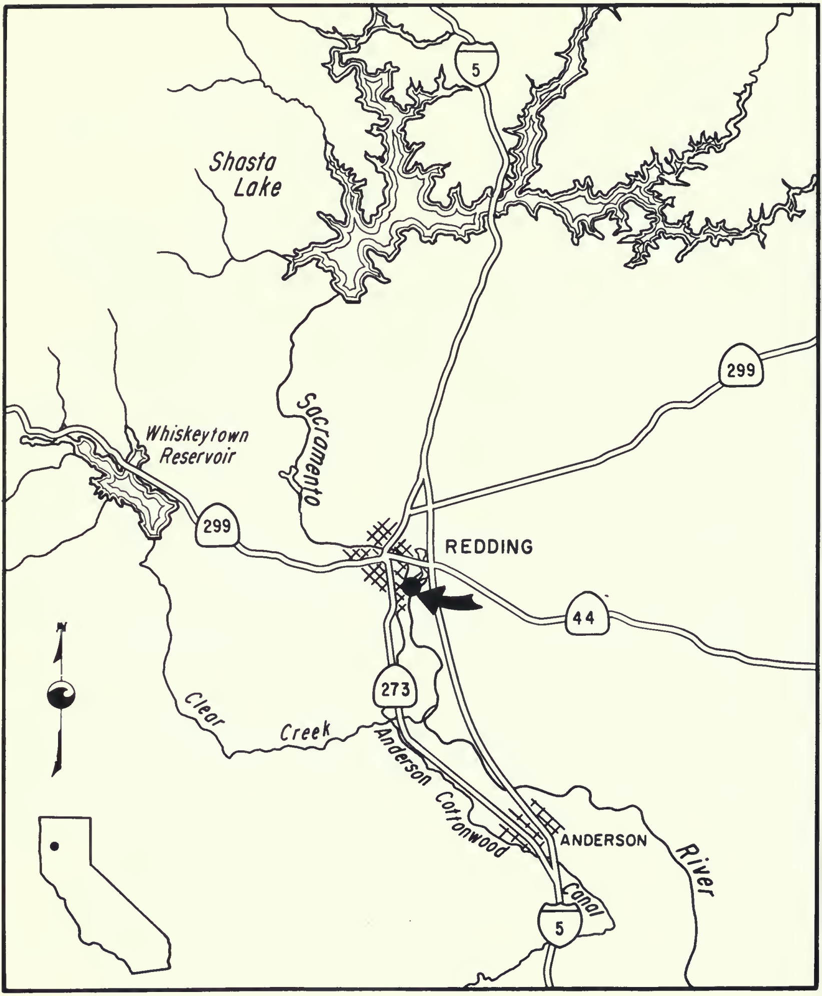
Table C-21D. Average Energy Cost of North Portal Tecolote Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$153,000	$195,800	$217,800
Operating Cost	31,900	31,900	31,900
Total Annual Cost	$184,900	$227,700	$249,700
Average Cost (per kWh)	25.7¢	31.6¢	34.7¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$129,700	$176,200	$198,200
Operating Cost	31,900	31,900	31,900
Total Annual Cost	$161,600	$208,100	$230,100
Average Cost (per kWh)	22.4¢	28.9¢	32.0¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of North Portal Tecolote generation is significantly less than the estimated cost of generation (22.4 to 34.7 cents per kWh), the project if constructed by 1984 would probably not be cost effective until 1990. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-22A Parkview Station Powerplant



22. Parkview Station

Parkview Station is a spillway on the Anderson Canal in Redding in Shasta County (Fig. C-22A). The canal and the spillway are owned and operated by the Anderson-Cottonwood Irrigation District. At this point on the canal, the flow can be stopped by installing stoplogs and diverting all canal flow through the spillway into a ditch connected to the Sacramento River. In this way, the irrigation canal can serve as a forebay for a hydroelectric plant which can operate during the nonirrigation season between November and March.

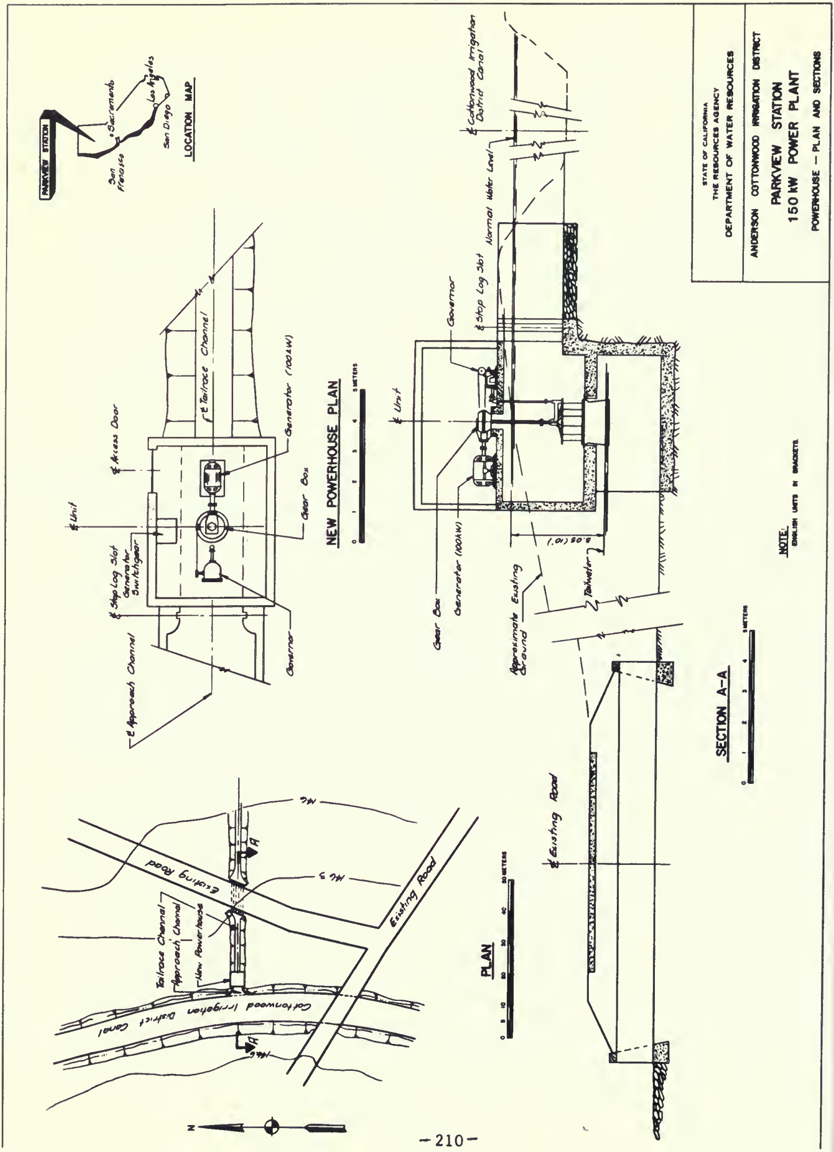
Site Characteristics. The spillway outlet consists of a gate in the irrigation canal and a corrugated metal pipe, about 33.6 m (110 ft) long, which discharges into the lower ditch. Water taken from the Sacramento River for irrigation is returned to the river through this lower ditch. A 13 kV transmission line is located at the site.

Potential Generation. A flow of 4.3 cms (150 cfs) can be diverted through the Anderson Cottonwood Canal to the Parkview Station facility where a drop of 4.6 m (15 ft) is available. Based on this head and flow, the potential capacity during the five-month nonirrigation season would be 150 kW, and the estimated annual generation is 548 000 kWh.

New Power Plant Structures. A turbine-generator could be installed at this site. The proposed generating facility includes an improved intake, power house, and tailrace channel discharging into the existing lower ditch (Fig. C-22B). Stoplogs could be used to shut off flow through the turbine during the irrigation season. The powerhouse would contain a vertical turbine which could develop 200 hp under the 4.6 m (15 ft) head. It would be connected, through a gear box speed increaser, to a horizontal generator with a rated output of 150 kW. The turbine would be provided with wicket gates, making an intake shutoff valve unnecessary.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $368,300, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $604,500 (Table C-22A).

Figure C-22B



PARKVIEW STATION
San Francisco
Sacramento
Los Angeles
San Diego
LOCATION MAP
STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
ANDERSON COTTONWOOD IRRIGATION DISTRICT
PARKVIEW STATION
150 kW POWER PLANT
POWERHOUSE — PLAN AND SECTIONS
℄ Access Door
℄ Unit
℄ Stop Log Slot
Generator Switchgear
℄ Approach Channel
℄ Tailrace Channel
Generator (100kW)
Gear Box
Governor
NEW POWERHOUSE PLAN
5 METERS
℄ Cottonwood Irrigation District Canal
Normal Water Level
℄ Stop Log Slot
Governor
℄ Unit
Gear Box
Generator (100kW)
Approximate Existing Ground
Tailwater
SECTION A-A
NOTE: ENGLISH UNITS IN BRACKETS
Existing Road
℄ Existing Road
Tailrace Channel
Approach Channel
New Powerhouse
Cottonwood Irrigation District Canal
146
146.3
A
N
PLAN
50 METERS

Table C-22A. Project Cost of Parkview Station Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$267,000
Transmission Facilities	7,000
Subtotal	$274,000
Contingencies (20%)	54,800
Total	$328,800
Engineering and Administration (12%)	39,500
Total Construction Cost (January 1980 prices)	$368,300
Escalation (4 yrs. at 12% per year)	211,200
Total Construction Cost (January 1984 prices)	$579,500
Studies, Licensing, Permits, and Approvals	25,000
Total	$604,500
Cost per kW (150 kW)	$ 4,030

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-22B). Regular maintenance could be scheduled during the summer months when water would not be available for generation.

Table C-22B. Annual Operating Cost of Parkview Station Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	8,500
Interim Replacements	1,300
Total	$ 22,800

The annual cost of owning and operating the project would range between 14 and to 22 percent of the direct project cost of $604,500, depending on financing. The estimated cost of generation ranges between 15.8 cents and 23.8 cents per kWh (Table C-22C).

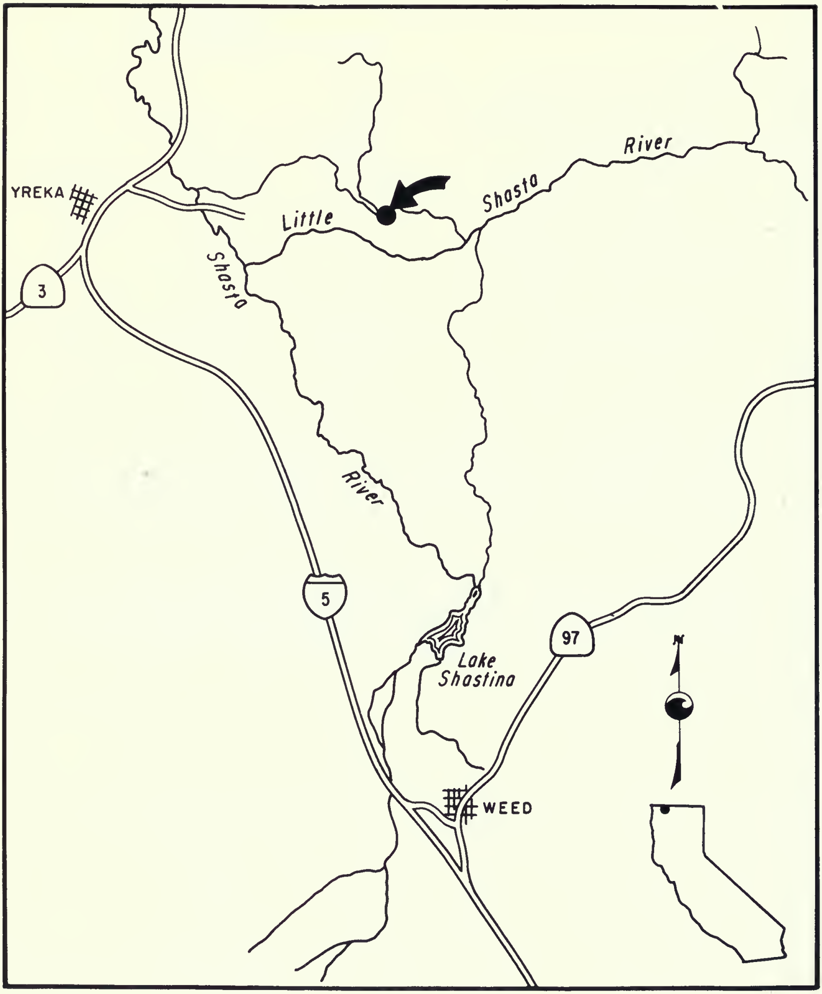
Table C-22C. Average Energy Cost of Parkview Station Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 75,600	$ 96,700	$107,600
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$ 98,400	$119,500	$130,400
Average Cost (per kWh)	18.0¢	21.8¢	23.8¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 64,100	$ 87,000	$ 97,900
Operating Cost	22,800	22,800	22,800
Total Annual Cost	$ 86,900	$109,800	$120,700
Average Cost (per kWh)	15.8¢	20.0¢	22.0¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Parkview Station generation is less than the estimated cost of generation (15.8 to 23.8 cents per kWh), the project would probably not be cost effective in the first three years of operation starting from 1984. This is based on the projected energy rate to be paid by PGandE under Section 210 of PURPA.

Figure C-23A Pumping Plant Lower Powerplant



23. Pumping Plant Lower

Pumping Plant Lower is a drop between two canals that are owned and operated by the Montague Water Conservation District. It is located about 6.4 km (4 mi) east of Montague in Siskiyou County (Fig. C-23A). The plant was constructed in the 1920s to harness the mechanical energy developed by water falling between the two canals and use it to pump part of the water to a higher elevation. However, the plant has not been used for that purpose, and the existing facility is in a deteriorated condition.

Site Characteristics. The original facility at the site consists of a 1219 mm (48 in) diameter riveted steel pipe that carried water from the upper canal to a horizontal turbine connected directly to a pump. The lower canal served as the tailrace for the turbine and as the source of water that was to be pumped to a higher elevation. The original facility was later modified by removing a section of the riveted-steel pipe and disconnecting the turbine. The pipe was capped and a 457 mm (18 in) diameter steel pipe by-pass was installed to carry the water directly to the lower canal. No energy dissipater was used. The gross head at the site is 12.6 m (41.5 ft). A 13 kV transmission line is adjacent to the site.

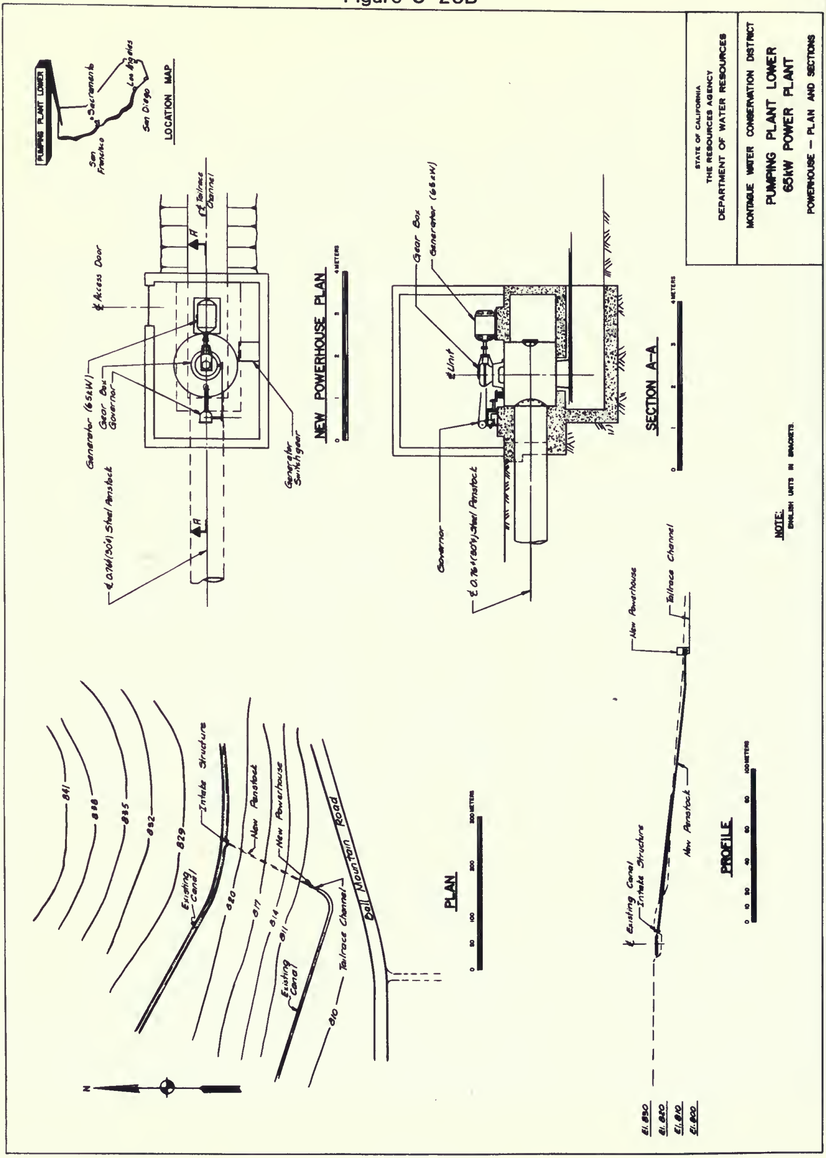
Potentital Generation. The potential capacity would be 65 kW, and the estimated average annual output is 172 000 kWh (Table C-23A).

Table C-23A. Energy Generation of Pumping Plant Lower Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	12.2	40	--	--	--	--	--
February	12.2	40	--	--	--	--	--
March	12.2	40	0.1	5	--	--	--
April	12.2	40	0.3	9	--	--	--
May	12.2	40	0.5	17	65	37	27 500
June	12.2	40	0.7	24	78	63	45 400
July	12.2	40	0.6	22	76	57	42 400
August	12.2	40	0.6	20	72	49	36 500
September	12.2	40	0.4	14	60	28	20 200
October	12.2	40	--	--	--	--	--
November	12.2	40	--	--	--	--	--
December	12.2	40	--	--	--	--	--
Total							172 000

New Power Plant Structures. A turbine and generator installed at the Pumping Plant Lower site could use the 12.6 m (41.5 ft) available head. The proposed facility includes an intake structure on the upper canal to divert water into a new penstock, 762 mm (30 in) in diameter and about 180 m (590 ft) long, which would carry water to a vertical turbine (Fig. C-23B). The water would be discharged into the Lower Canal through a short tailrace channel. The turbine could develop 93 hp under the available head and would be connected, through a speed increaser, to a horizontal generator with a rated output of 65 kW.

Figure C-23B


STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
MONTAGUE WATER CONSERVATION DISTRICT
PUMPING PLANT LOWER
65kW POWER PLANT
POWERHOUSE — PLAN AND SECTIONS
PUMPING PLANT LOWER
San Francisco
Sacramento
Los Angeles
San Diego
LOCATION MAP
Access Door
Tailrace Channel
Generator (65kW)
Gear Box
Governor
Generator Switchgear
0.76 (30") Steel Penstock
NEW POWERHOUSE PLAN
Gear Box
Generator (65kW)
Unit
Governor
0.76 (30") Steel Penstock
SECTION A-A
NOTE:
ENGLISH UNITS IN BRACKETS.
841
838
835
832
829
Intake Structure
New Penstock
New Powerhouse
Ball Mountain Road
Existing Canal
820
817
814
811
Tailrace Channel
Existing Canal
810
PLAN
New Powerhouse
Tailrace Channel
New Penstock
Existing Canal
Intake Structure
PROFILE
El. 830
El. 820
El. 810
El. 800

Cost of the New Power Plant. The estimated cost of building the new generating facility is $204,300, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build it, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent annual inflation, is $346,500 (Table C-23B).

Table C-23B. Project Cost of Pumping Plant Lower Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$145,000
Transmission Facilities	7,000
Subtotal	$152,000
Contingencies (20%)	30,400
Total	$182,400
Engineering and Administration (12%)	21,900
Total Construction Cost (January 1980 prices)	$204,300
Escalation (4 yrs. at 12% per year)	117,200
Total Construction Cost (January 1984 prices)	$321,500
Studies, Licensing, Permits, and Approvals	25,000
Total	$346,500
Cost per kW (65 kW)	$ 5,331

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-23C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-23C. Annual Operating Cost of Pumping Plant Lower Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	8,500
Interim Replacements	1,000
Total	$ 22,500

The annual cost of owning and operating the project would range between 17 and 24 percent of the direct project cost of $346,500, depending on financing. The estimated cost of generation ranges between 34.4 and 48.9 cents per kWh (Table C-23D).

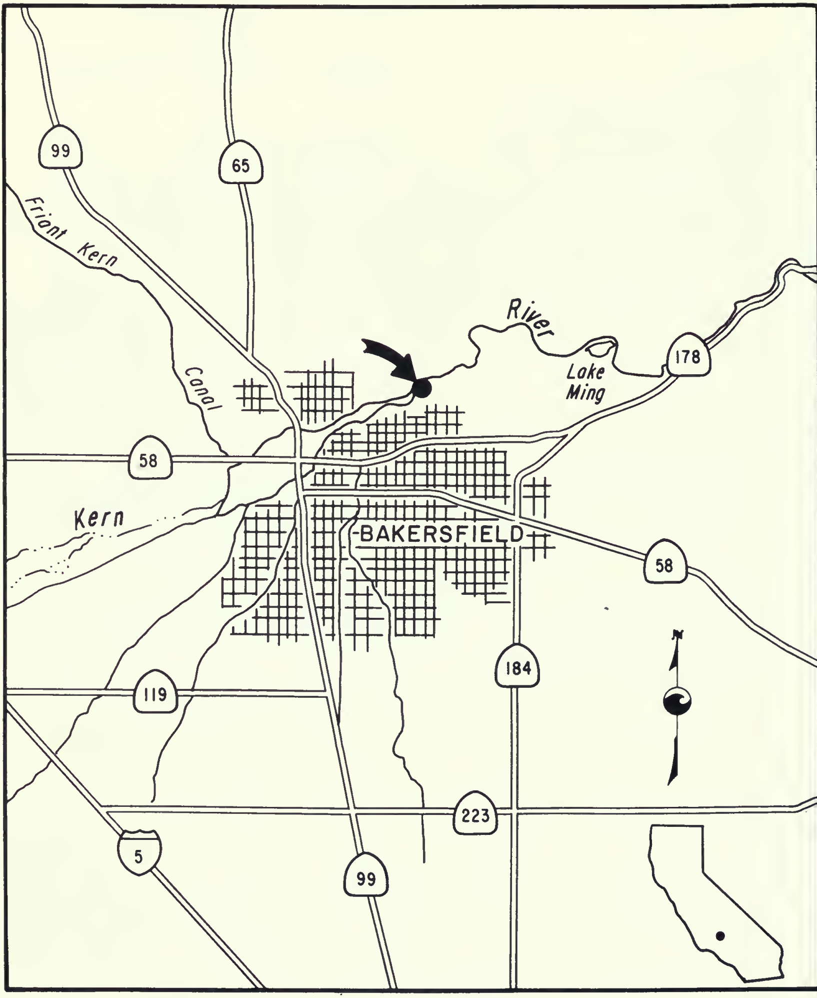
Table C-23D. Average Energy Cost of Pumping Plant Lower Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 43,300	$ 55,400	$ 61,700
Operating Cost	22,500	22,500	22,500
Total Annual Cost	$ 65,800	$ 77,900	$ 84,200
Average Cost (per kWh)	38.3¢	45.3¢	48.9¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 36,700	$ 49,900	$ 56,100
Operating Cost	22,500	22,500	22,500
Total Annual Cost	$ 59,200	$ 72,400	$ 78,600
Average Cost (per kWh)	34.4¢	42.1¢	45.7¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE at its published price for small hydroelectric facilities of 100 kW or less. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh, using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of Pumping Plant Lower generation is considerably less than the estimated cost of generation (34.4 to 48.9 cents per kWh), the project if constructed by 1984 would probably not be cost effective until 1995. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-24A Rocky Point Diversion Dam Powerplant



24. Rocky Point Diversion Dam

Rocky Point Dam is a diversion structure on the Kern River in Bakersfield in Kern County (Fig. C-24A). It is owned and operated by the City of Bakersfield, Kern Delta Water District, and North Kern Water District. The dam diverts water into a canal paralleling the south side of the Kern River. The site is characterized by a low head and relatively large flows during the summer months.

Site Characteristics. The dam is a wood timber structure about 120 m (394 ft) long and 4.5 m (14.8 ft) high. Timber was used for construction because of the sandy stream bed. A 13 kV transmission line is located near the site.

Potential Generation. The potential generation capacity of the facility would be about 300 kW; the estimated average annual output is about 663 000 kWh (Table 24A).

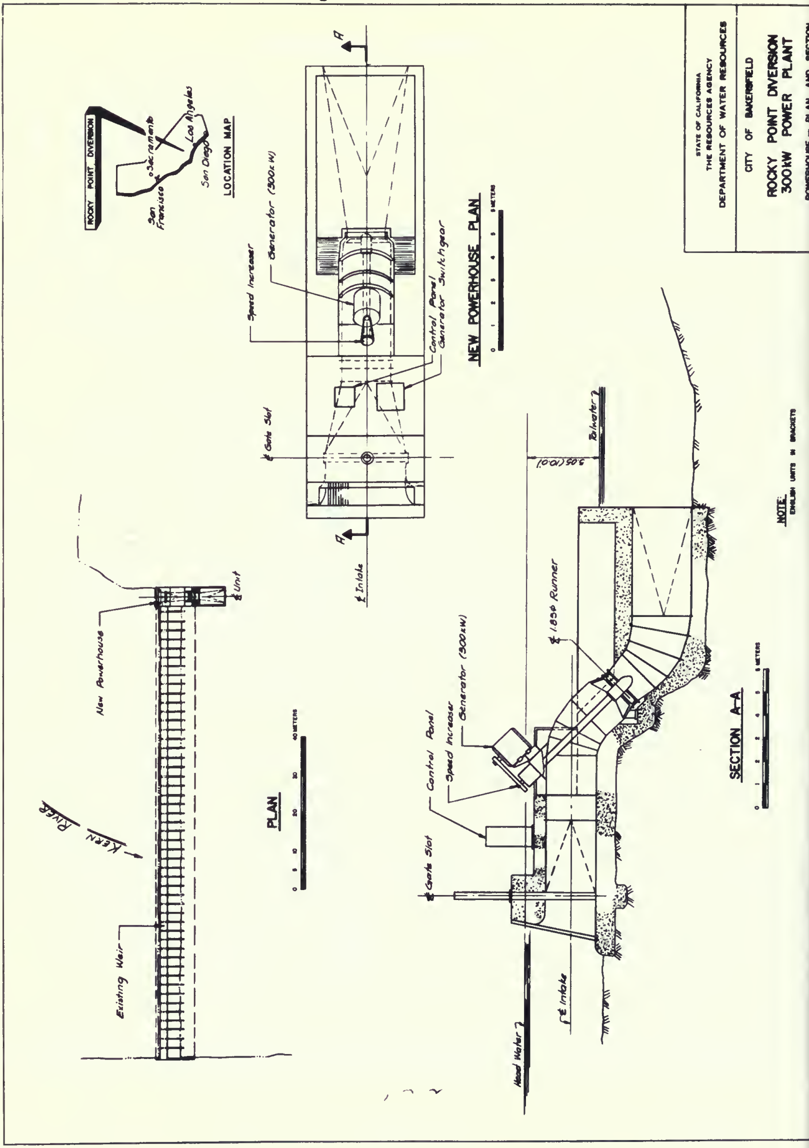
Table 24A. Energy Generation of Rocky Point Diversion Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	3	10	6.3	221	61	114	85 000
February	3	10	1.4	48	--	--	--
March	3	10	--	--	--	--	--
April	3	10	--	--	--	--	--
May	3	10	--	--	--	--	--
June	3	10	8.0	284	72	173	125 000
July	3	10	14.2	501	84	300	233 000
August	3	10	11.8	417	84	296	220 000
September	3	10	--	--	--	--	--
October	3	10	--	--	--	--	--
November	3	10	--	--	--	--	--
December	3	10	--	--	--	--	--
Total							663 000

New Power Plant Structures. A hydraulic turbine and electric generator installed near the left abutment of the existing dam could use the 3 m (10 ft) head available at the site. The proposed generating facility would include an intake structure, a short 5.5 m (18 ft) concrete conduit, a turbine/generator, and a short tailrace channel to return the water to the river (Fig. C-24B). The turbine would be a standard, propeller-type with a runner of 1.8 m (6 ft) in diameter; it could develop 403 hp under the available head. The turbine would be connected, through a speed increaser, to a generator with a rated output of 300 kW. An inlet gate installed upstream from the turbine could be used to partially dewater the unit for inspection and maintenance. An outdoors powerhouse would be used.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $759,400, based on January 1980 prices. If the project were initiated in 1981 and about 30 to 36 months were required to complete

Figure C-24B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
CITY OF BAKERSFIELD
ROCKY POINT DIVERSION
300kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
ROCKY POINT DIVERSION
San Francisco
Sacramento
Los Angeles
San Diego
LOCATION MAP
Speed Increaser
Generator (300kW)
Control Panel
Generator Switchgear
Gate Slot
Intake
A
NEW POWERHOUSE PLAN
Tailwater
3.05 (10.0)
1.85φ Runner
Control Panel
Speed Increaser
Generator (300kW)
Gate Slot
Intake
Head Water
SECTION A-A
NOTE: ENGLISH UNITS IN BRACKETS
Kern River
New Powerhouse
Unit
Existing Weir
PLAN

the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983 (with 12 percent annual inflation) is $1,244,900 (Table C-24B).

Table C-24B. Project Cost of Rocky Point Diversion Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 540,000
Transmission Facilities	25,000
Subtotal	$ 565,000
Contingencies (20%)	113,000
Total	$ 678,000
Engineering and Administration (12%)	81,400
Total Construction Cost (January 1980 Prices)	$ 759,400
Escalation (4 yrs. at 12% per year)	435,500
Total Construction Cost (January 1984 Prices)	$1,194,900
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,244,900
Cost per kW (300 kW)	$ 4,150

Cost of Generation. The generation cost includes the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-24C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-24C. Annual Cost of Rocky Point Diversion Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	17,000
Interim Replacements	2,700
Total	$ 32,700

The annual cost of owning and operating the project would range between 13 and 20 percent of the direct project cost of $1,244,900, depending on financing. The estimated cost of generation ranges between 24.8 cents and 38.4 cents per kWh (Table C-24D).

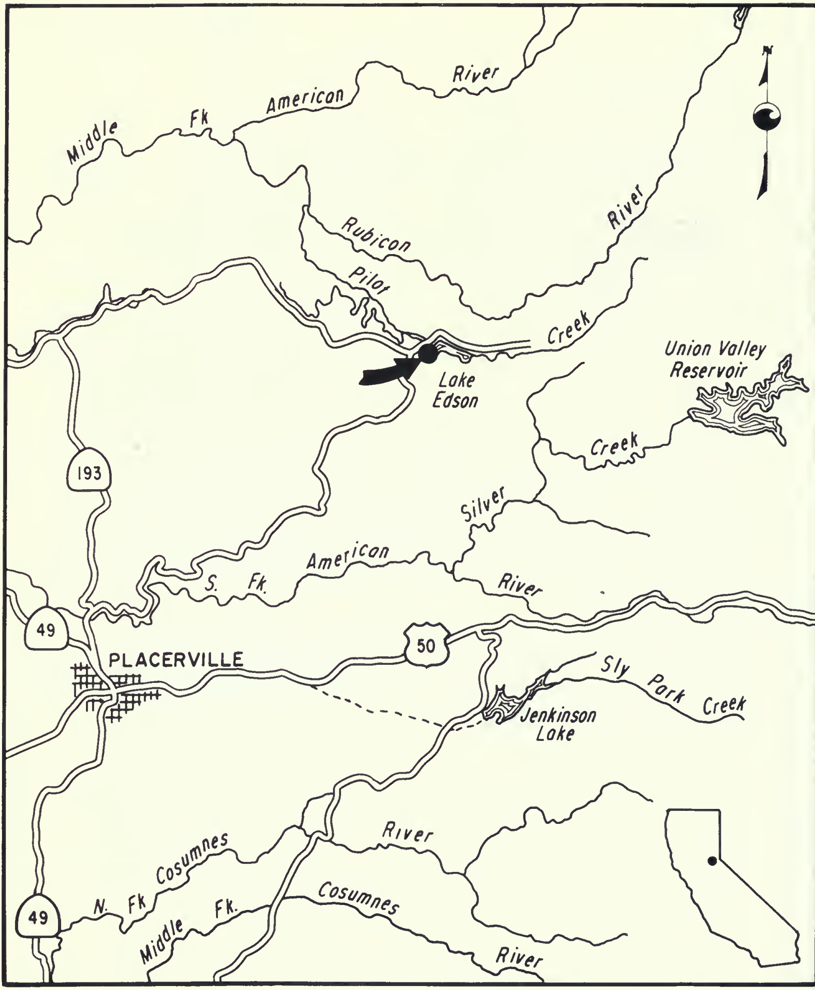
Table C-24D. Average Energy Cost of Rocky Point Diversion Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$155,600	$199,200	$221,600
Operating Cost	32,700	32,700	32,700
Total Annual Cost	$188,300	$231,900	$254,300
Average Cost (per kWh)	28.4¢	35.0¢	38.4¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$132,000	$179,300	$201,700
Operating Cost	32,700	32,700	32,700
Total Annual Cost	$164,700	$212,000	$234,400
Average Cost (per kWh)	24.8¢	32.0¢	35.4¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is also assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of energy generated at Rocky Point Diversion is significantly less than the estimated cost of generation (24.8 to 38.4 cents per kWh). The project if constructed by 1984 would probably not be cost effective until 1991. This is based on the projected energy rates shown in Table 8, Chapter II.

Figure C-25A Stumpy Meadows Powerplant



25. Stumpy Meadows Reservoir (Mark Edson Dam)

Stumpy Meadows Reservoir, formed by the Mark Edson Dam on Pilot Creek, is located about 8 km (5 mi) east of Quintette in El Dorado County (Fig. C-25A). The facility is owned and operated by the Georgetown Divide Public Utility District and is used to conserve water for domestic purposes and irrigation.

Site Characteristics. The reservoir capacity is 24 670 cubic dekametres (20,000 ac-ft) at the maximum water surface elevation of 1300 m (4,268 ft). In an average-water year, a constant flow of 0.8 cms (30 cfs) is available for power generation for about 9.5 months.

The dam is an earth structure approximately 50 m (164 ft) high. Controlled releases from the reservoir are made through the dam's lower outlet which is about 232 m (761 ft) long. The lower outlet consists of a concrete conduit, 0.9 m (36 in) in diameter, between the reservoir intake and a valve chamber, a distance of about 136 m (446 ft). Downstream from the valve chamber, for a distance of about 96 m (315 ft) to the control structure, the lower outlet consists of a 0.8 m (2.5 ft) steel pipe located within a horseshoe-shaped concrete tunnel having an inside diameter of 2 m (6.5 ft). A manually operated 0.8 m (2.5 ft) Howell-Bunger valve at the control structure controls discharges into a reinforced- concrete energy dissipater.

The nearest transmission line is a single-phase 35 kV line located about 6.4 km (4 mi) from the site.

Potential Generation. The potential capacity at Stumpy Meadows Reservoir would be 325 kW, and the estimated average annual output is 2.2 million kWh (Table C-25A).

Table C-25A. Energy Generation of Stumpy Meadows Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	45.7	150	0.9	30	85	323	120 000
February	46.0	151	0.9	30	85	325	218 000
March	46.9	154	0.9	30	85	331	246 000
April	46.9	154	0.9	30	85	331	238 000
May	46.9	154	0.9	30	85	331	246 000
June	46.0	151	0.9	30	85	325	234 000
July	44.2	145	0.9	30	85	312	232 000
August	42.0	138	0.9	30	85	297	221 000
September	40.2	132	0.9	30	85	284	204 000
October	38.7	127	0.9	30	85	273	203 000
November	39.6	130	--	--	--	--	--
December	40.8	134	--	--	--	--	--
Total							2 160 000

New Power Plant Structures. A turbine and generator installed at the downstream end of the existing lower outlet pipe could use the 38.7 m to 46 m (127 ft to 151 ft) available head at the site. The proposed generating facility includes a 0.8 m (2.5 ft) steel pipe by-pass starting about 5 m (16.5 ft) upstream from the existing outlet structure which carries water to a horizontal Francis turbine (Figs. C-25B and C-25C). The turbine could develop 437 hp under a 46 m (151 ft) head and would be connected directly to an air-cooled, synchronous generator with a rated output of 325 kW. The operation of the hydroelectric plant would be separated from that of the existing installation by a butterfly valve installed upstream from the turbine.

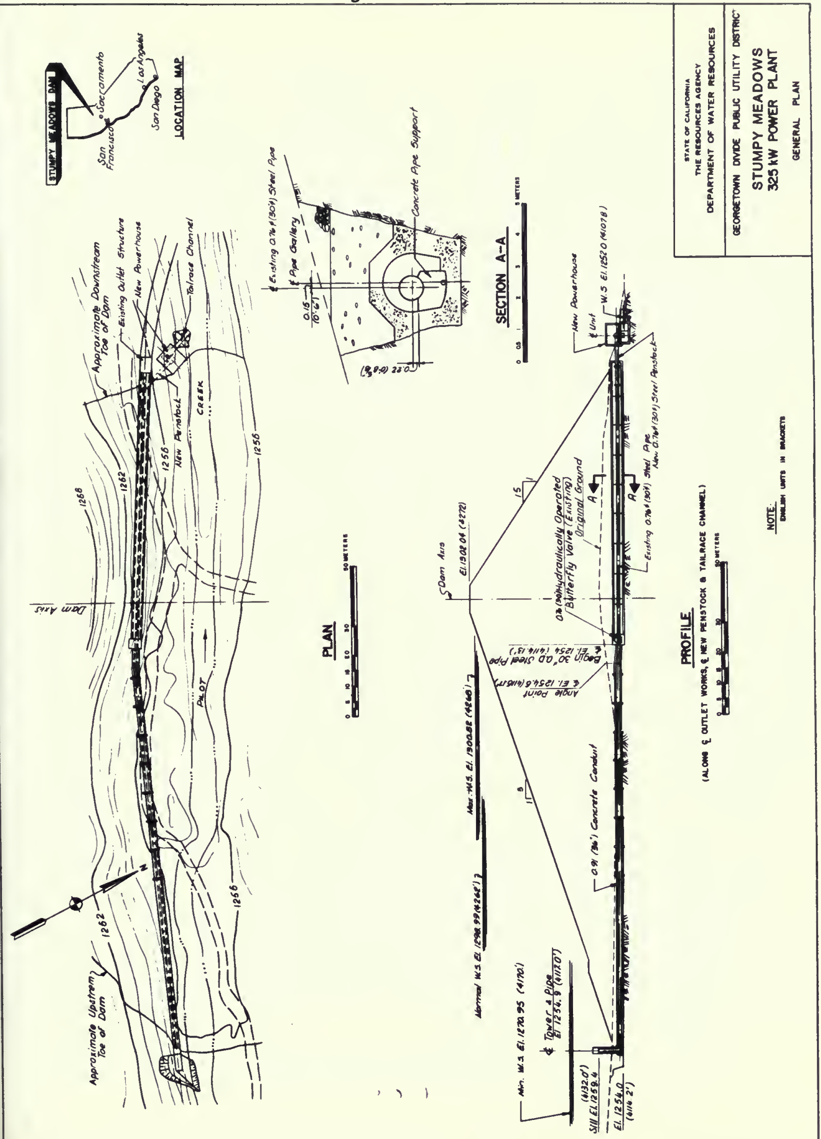
Cost of the New Power Plant. The estimated cost of building the new generating facility is $897,200, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with a 12 percent annual inflation, is $1,511,800 (Table C-25B).

Table C-25B. Project Cost of Stumpy Meadows Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 417,600
Transmission Facilities	250,000
Subtotal	$ 667,600
Contingencies (20%)	133,500
Total	$ 801,100
Engineering and Administration (12%)	96,100
Total Construction Cost (January 1980 prices)	$ 897,200
Escalation (4 yrs. at 12% per year)	514,600
Total Construction Cost (January 1984 prices)	$1,411,800
Studies, Licensing, Permits, and Approvals	100,000
Total	$1,511,800
Cost per kW (325 kW)	$ 4,652

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-25C). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Figure C-25B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
GEORGETOWN DIVIDE PUBLIC UTILITY DISTRICT
STUMPY MEADOWS
325 kW POWER PLANT
GENERAL PLAN
STUMPY MEADOWS DAM
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Approximate Downstream Toe of Dam
Existing Outlet Structure
New Powerhouse
Tailrace Channel
New Penstock
CREEK
PILOT
Dam Axis
Approximate Upstream Toe of Dam
PLAN
Existing 0.76 (30") Steel Pipe
Pipe Gallery
Concrete Pipe Support
SECTION A-A
El. 1302.04 (4272)
Max. W.S. El. 1300.88 (4268)
Normal W.S. El. 1298.99 (4262')
Min. W.S. El. 1270.95 (4170)
Tower & Pipe El. 1254.9 (4117.0')
Sill El. 1259.4 (4132.0')
El. 1254.0 (4114.2')
0.91 (36") Concrete Conduit
Angle Point El. 1254.6 (4116.17)
Begin 30" O.D. Steel Pipe El. 1254 (4114.13')
0.76 (30") Hydraulically Operated Butterfly Valve (Existing)
Original Ground
Existing 0.76 (30") Steel Pipe
New 0.76 (30") Steel Penstock
W.S. El. 1252.0 (4107.8)
Unit
New Powerhouse
PROFILE
(ALONG OUTLET WORKS, NEW PENSTOCK & TAILRACE CHANNEL)
NOTE:
ENGLISH UNITS IN BRACKETS

Figure C-25C

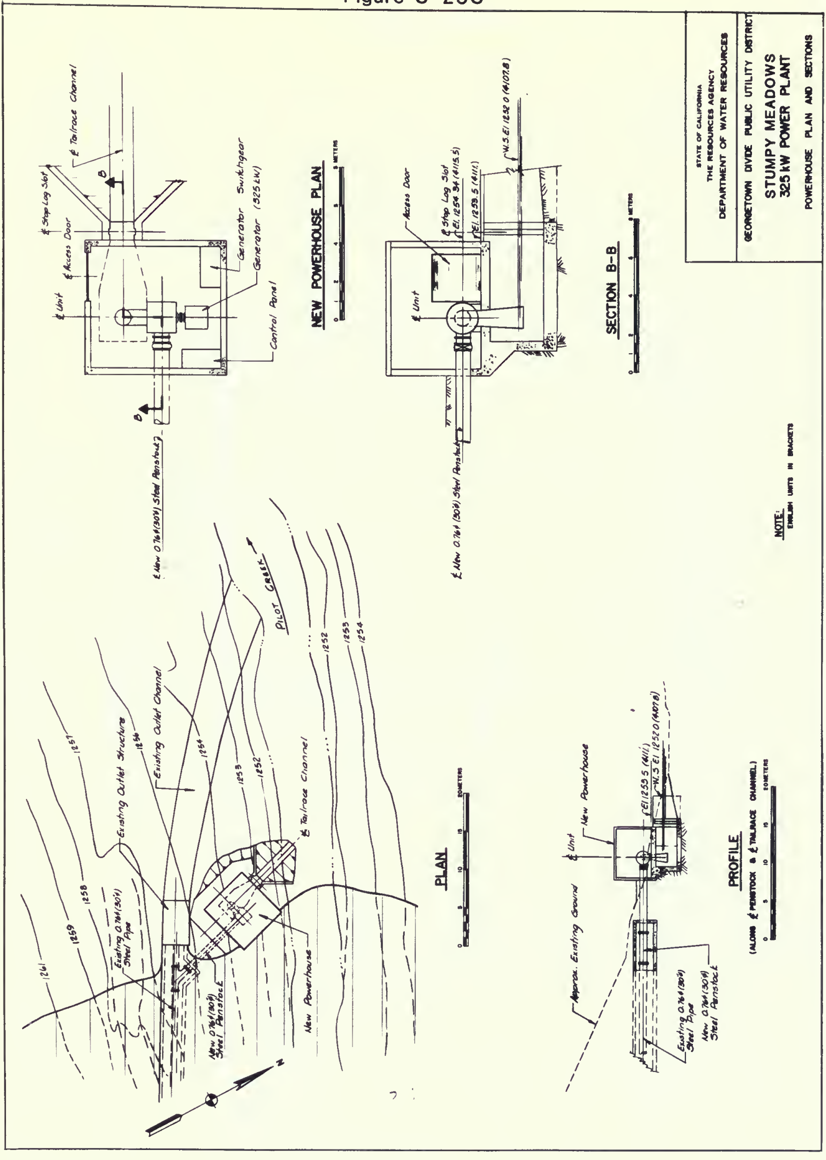

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
GEORGETOWN DIVIDE PUBLIC UTILITY DISTRICT
STUMPY MEADOWS
325 kW POWER PLANT
POWERHOUSE PLAN AND SECTIONS
NEW POWERHOUSE PLAN
SECTION B-B
PLAN
PROFILE
(ALONG ℄ PENSTOCK & ℄ TAILRACE CHANNEL)
NOTE:
ENGLISH UNITS IN BRACKETS
℄ Tailrace Channel
℄ Stop Log Slot
℄ Access Door
℄ Unit
Generator Switchgear
Generator (325 kW)
Control Panel
℄ New 0.76Ø (30Ø) Steel Penstock
Access Door
℄ Stop Log Slot
El. 1254.34 (4115.5)
El. 1253.5 (4111)
W.S. El 1252.0 (4107.8)
Existing Outlet Structure
Existing Outlet Channel
Existing 0.76Ø (30Ø) Steel Pipe
New 0.76Ø (30Ø) Steel Penstock
℄ Tailrace Channel
New Powerhouse
PILOT CREEK
Approx. Existing Ground
New Powerhouse
El 1253.5 (4111)
W.S. El 1252.0 (4107.8)
N
1261
1259
1258
1257
1256
1254
1253
1252

Table C-25C. Annual Operating Cost of Stumpy Meadows Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	8,500
Interim Replacements	2,400
Total	$ 23,900

The annual cost of owning and operating the project would range between 12 and 19 percent of the direct project cost of $1,511,800, depending on financing. The estimated cost of generation ranges between 8.5 cents and 13.6 cents per kWh (Table C-25D).

Table C-25D. Average Energy Cost of Stumpy Meadows Project

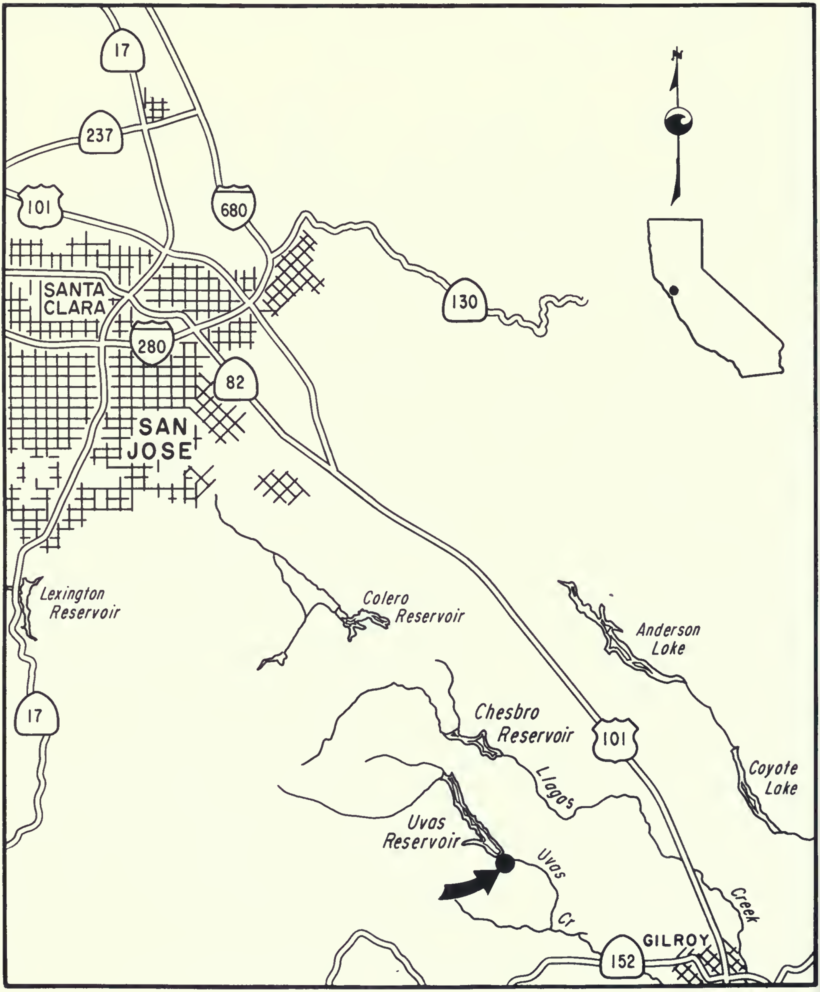
Cost Item	Amount		
	Interest Rate		
	9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$189,000	$241,900	$269,100
Operating Cost	23,900	23,900	23,900
Total Annual Cost	$212,900	$265,800	$293,000
Average Cost (per kWh)	9.9¢	12.3¢	13.6¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$160,300	$217,700	$244,900
Operating Cost	23,900	23,900	23,900
Total Annual Cost	$184,200	$241,600	$268,800
Average Cost (per kWh)	8.5¢	11.2¢	12.4¢

Value of Generation. It is assumed that project generation would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. Since the estimated minimum value of Stumpy Meadows generation is within the range of estimated cost of generation (8.5 to

13.6 cents per kWh), the project would probably be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The cost of Stumpy Meadows generation would change little from year to year since only the maintenance cost of the facility is subject to inflation.

Figure C-26A Uvas Dam Powerplant



26. Uvas Dam

Uvas Dam, owned and operated by the South Santa Clara Valley Water Conservation District, is located about 10 km (6 mi) northwest of Gilroy in Santa Clara County (Fig. C-26A). The dam and reservoir are used for water conservation. Water released during the irrigation season percolates into the ground water basin from where it is pumped through wells and used for irrigation.

Site Characteristics. The Dam is an earth structure about 47 m (155 ft) high with a crest about 314 m (1030 ft) long. Controlled releases are made from the reservoir through the dam's lower outlet, which is about 158 m (518 ft) long and consists of a 0.9 m (3 ft) diameter steel pipe encased in a concrete jacket. The control valve, a 0.8 m (2.5 ft) butterfly valve, is in an outlet control house.

A short distance upstream from the butterfly valve, a T-connection to a 0.9 m (3 ft) pipe with a gate valve diverts water via a 6.4 km (4 mi) concrete pipeline to Uvas Creek. A 13 kV transmission line is located about 152 m (500 ft) from the site.

Potential Generation. A horizontal Francis turbine installed at Uvas Dam could use water that is presently discharged into Uvas Creek. The potential installed capacity would be 300 kW, and the estimated average annual output is 1 million kWh (Table C-26A).

Table C-26A. Energy Generation of Uvas Dam Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	17.7	58	1.7	59	84	243	181 000
February	23.2	76	2.0	72	84	300	202 000
March	24.7	81	2.1	74	84	300	223 000
April	25.0	82	0.7	26	66	119	86 000
May	25.0	82	0.9	31	79	170	126 000
June	23.2	76	0.9	33	79	168	121 000
July	19.8	65	0.9	32	79	139	103 000
August	15.2	50	0.6	20	--	--	--
September	10.4	34	--	--	--	--	--
October	10.4	34	--	--	--	--	--
November	10.4	34	--	--	--	--	--
December	--	--	--	--	--	--	--
Total							1 042 000

New Power Plant Structures. A turbine and generator installed at the downstream end of the existing lower outlet pipe adjacent to the existing control house could use the 20 m to 26 m (65 ft to 85 ft) available head. The proposed generating facility includes a 0.9 m (3 ft) steel pipe by-pass, installed about 4 m (13 ft) upstream from the existing outlet control house, which carries water to a horizontal Francis turbine (Figs C-26B and C-26C). The turbine could develop 402 hp under a 26 m (85 ft) of head and

Figure C-26B

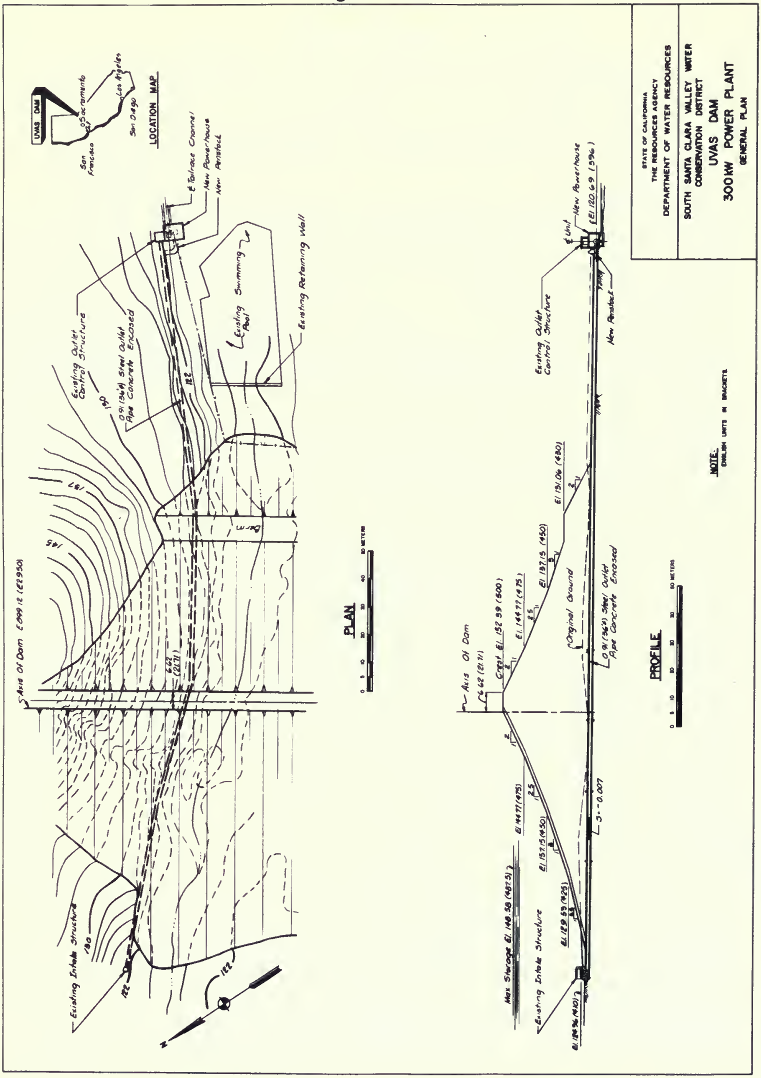
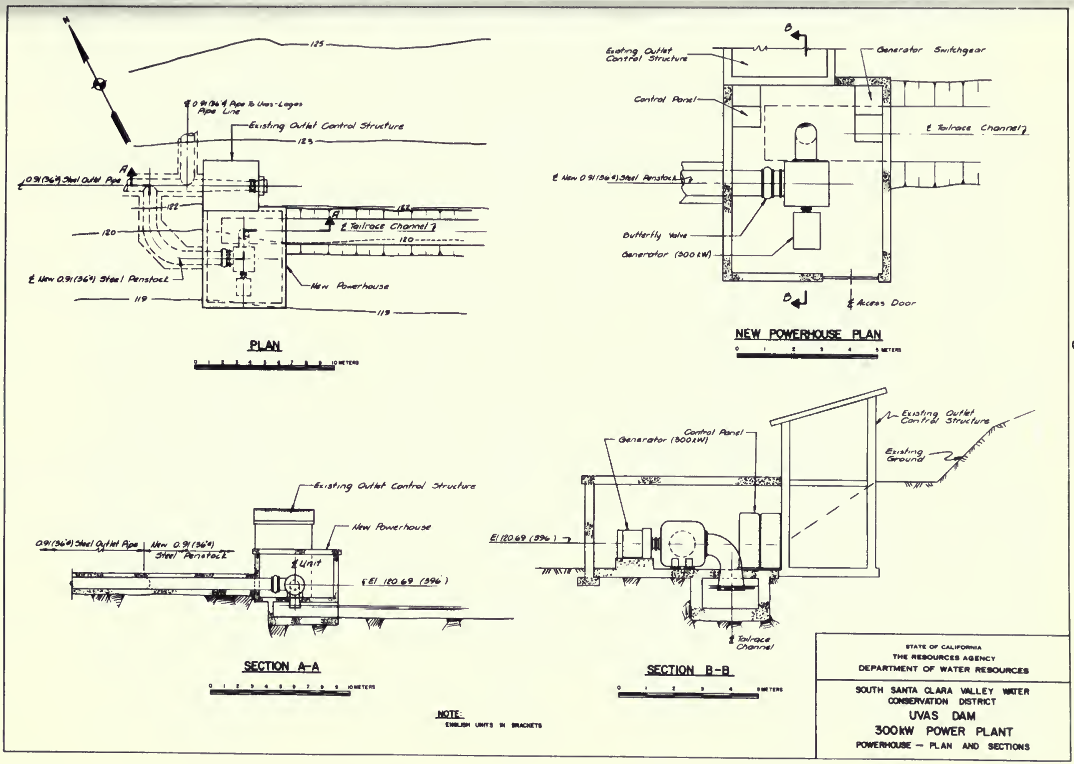

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
SOUTH SANTA CLARA VALLEY WATER CONSERVATION DISTRICT
UVAS DAM
300KW POWER PLANT
GENERAL PLAN
NOTE:
ENGLISH UNITS IN BRACKETS
LOCATION MAP
UVAS DAM
San Francisco
Sacramento
Los Angeles
San Diego
PLAN
PROFILE
Existing Intake Structure
Axis Of Dam
Berm
Existing Outlet Control Structure
0.91 (36") Steel Outlet Pipe Concrete Encased
Existing Swimming Pool
Existing Retaining Wall
℄ Tailrace Channel
New Powerhouse
New Penstock
Crest El. 152.39 (500)
Max Storage El. 148.58 (487.5)
Original Ground
El. 120.69 (396)
S = 0.007

Figure C-26C


125
123
122
120
119
℄ 0.91(36") Pipe to Uvas-Llagas Pipe Line
Existing Outlet Control Structure
0.91(36") Steel Outlet Pipe
A
℄ Tailrace Channel
℄ New 0.91(36") Steel Penstock
New Powerhouse
PLAN
0 1 2 3 4 5 6 7 8 9 10 METERS
Existing Outlet Control Structure
Generator Switchgear
Control Panel
℄ Tailrace Channel
℄ New 0.91(36") Steel Penstock
Butterfly Valve
Generator (300 kW)
B
℄ Access Door
NEW POWERHOUSE PLAN
0 1 2 3 4 5 METERS
Existing Outlet Control Structure
New Powerhouse
0.91(36") Steel Outlet Pipe
New 0.91(36") Steel Penstock
℄ Unit
℄ El 120.69 (396)
SECTION A-A
0 1 2 3 4 5 6 7 8 9 10 METERS
Existing Outlet Control Structure
Existing Ground
Control Panel
Generator (300 kW)
El 120.69 (396)
℄ Tailrace Channel
SECTION B-B
0 1 2 3 4 5 METERS
NOTE:
ENGLISH UNITS IN BRACKETS
STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
SOUTH SANTA CLARA VALLEY WATER CONSERVATION DISTRICT
UVAS DAM
300 kW POWER PLANT
POWERHOUSE — PLAN AND SECTIONS

would be connected directly to a horizontal, air-cooled synchronous generator having a rated output of 300 kW.

The operation of the hydroelectric plant and of the existing installation would be kept separate by a butterfly valve installed upstream from the turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $591,100, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work would be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $980,100 (Table C-26B).

Table C-26B. Project Cost of Uvas Dam Plant

Cost Item	Amount
Direct Cost	
Hydroelectric plant facilities	$ 424,800
Transmission Facilities	15,000
Subtotal	$ 439,800
Contingencies (20%)	88,000
Total	$ 527,800
Engineering and Administration (12%)	63,300
Total Construction Cost (January 1980 Prices)	$ 591,100
Escalation (4 yrs. at 12% per year)	339,000
Total Construction Cost (January 1984 Prices)	$ 930,100
Studies, Licensing, Permits, and Approvals	50,000
Total	$ 980,100
Cost per kW (300 kW)	$ 3,267

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-26C). Regular maintenance could be scheduled during the autumn months when there is insufficient water for power generation.

Table C-26C. Annual Operating Cost of Uvas Dam Project

Cost Item	Amount
Operation and Maintenance	$ 13,000
Insurance	17,000
Interim Replacements	2,700
Total	$ 32,700

The annual cost of owning and operating the project would range between 14 and 21 percent of the direct project cost of $980,100, depending on financing. The estimated cost of generation ranges between 13.1 cents and 19.9 cents per kWh (Table C-26D).

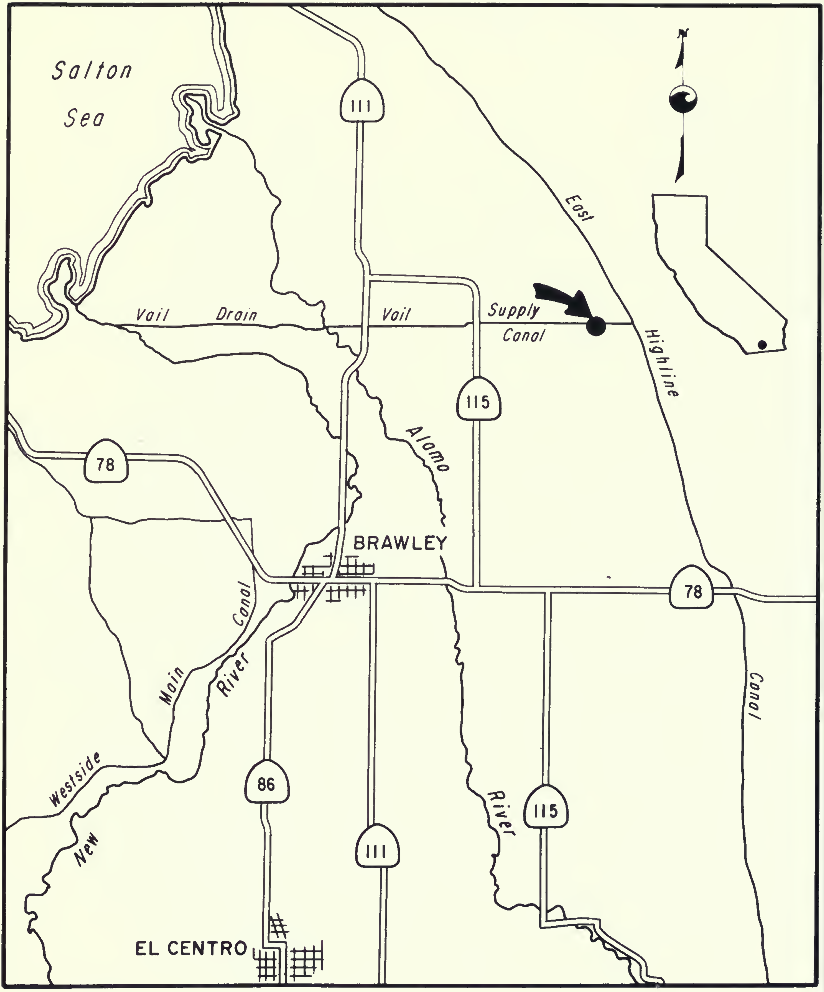
Table C-26D. Average Energy Cost of Uvas Dam Project

Cost Item	Amount Interest Rate 9%	 12%	 15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$122,500	$156,800	$174,500
Operating Cost	32,700	32,700	32,700
Total Annual Cost	$155,200	$189,500	$207,200
Average Cost (per kWh)	14.9¢	18.2¢	19.9¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$103,900	$141,100	$158,800
Operating Cost	32,700	32,700	32,700
Total Annual Cost	$136,600	$173,800	$191,500
Average Cost (per kWh)	13.1¢	16.7¢	18.4¢

Value of Generation. It is assumed that the energy produced would be sold to PGandE under Section 210 of PURPA. It is further assumed, for the purpose of this study, that the project would have no capacity value pending the development of PGandE's proposed policy for the purchase of small hydroelectric generation and the outcome of a theoretical study of water and power operations acceptable to PGandE. On this basis, the estimated value of project generation in 1984 is 11.1 cents per kWh using the CEC median oil-cost projection as the basis for estimating the future cost of electrical energy.

Conclusions. The estimated value of Uvas Dam generation is less than the estimated generation cost (13.1 to 19.9 cents per kWh). The project costs would exceed revenues from sales the energy produced during the first year of operation. However, as the price of oil increases, the project would become cost effective in later years since only the cost of maintaining the facility is subject to inflation.

Figure C-27A Vail Heading Powerplant



27. Vail Heading

Vail Heading is a series of low check structures closely spaced in staircase fashion along the Vail Supply Canal and located about 6 miles east of Calipatria in Imperial County (Fig. C-27A). The canal is owned and operated by the Imperial Irrigation District and receives water from a turnout on the District's East Highline Canal.

Site Characteristics. The Vail Heading consists of eleven check structures that drop the flow 13.7 m (45 ft). The largest drops occur in the first 0.8 km (0.5 mi) at the rate of about 4.9 m (16 ft) per 305 m (1000 ft) of canal length.

Potential Generation. The potential installed capacity would be 225 kW, and the estimated average annual output is 1 million kWh (Table C-27A).

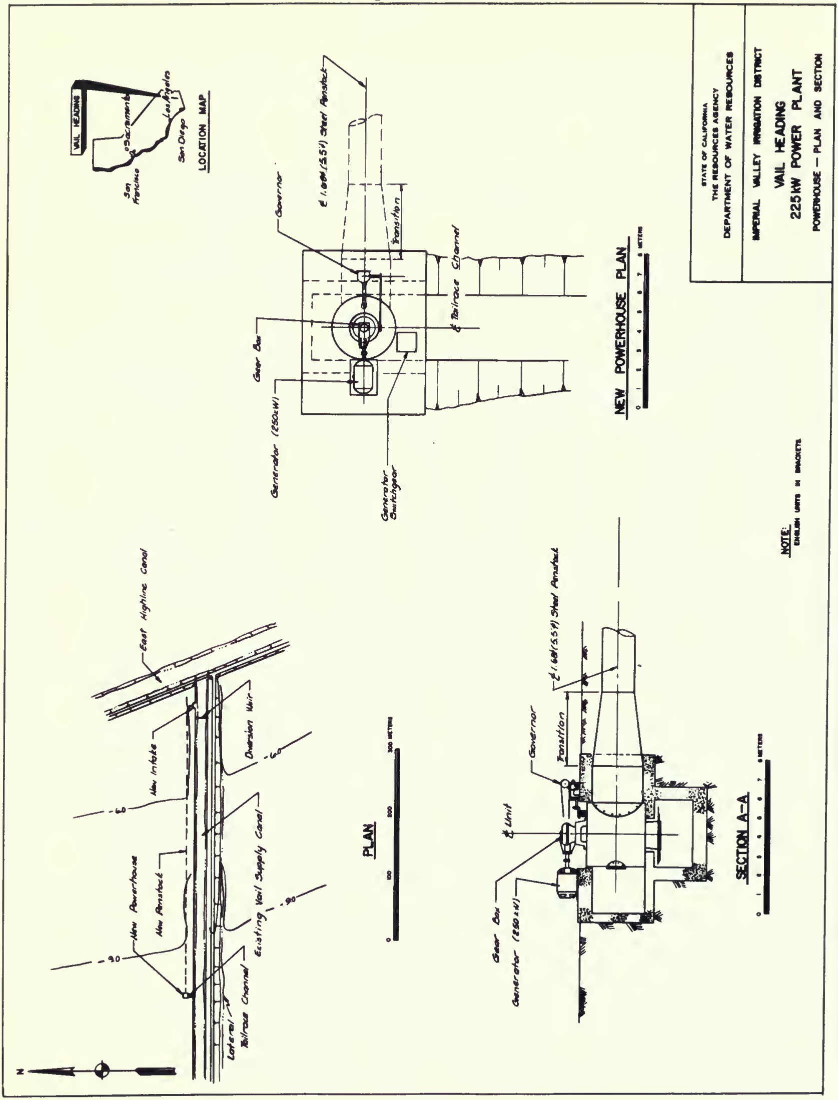
Table C-27A. Energy Generation of Vail Heading Project

Month	Head (m)	Head (ft)	Flow (cms)	Flow (cfs)	Efficiency (%)	Capacity (kW)	Energy (kWh/yr)
January	4.9	16	1.0	34	--	--	--
February	4.9	16	3.2	113	--	--	--
March	4.9	16	4.7	166	80	180	134 000
April	4.9	16	5.4	192	84	218	157 000
May	4.9	16	4.5	160	79	171	127 000
June	4.9	16	4.6	164	80	178	128 000
July	4.9	16	5.6	198	84	225	168 000
August	4.9	16	5.7	201	84	229	170 000
September	4.9	16	4.9	174	83	195	141 000
October	4.9	16	2.9	103	--	--	--
November	4.9	16	2.4	84	--	--	--
December	4.9	16	1.3	45	--	--	--
Total							1 025 000

New Power Plant Structures. A turbine and generator could be installed at the first 4.9 m (16 ft) drop thereby using the shortest distance to develop the available head. The proposed generating facility includes an intake structure to divert water from the canal into a penstock which would then carry the water 450 m (1476 ft) to a hydraulic turbine (Fig. C-27B). The water would be returned to the canal through a short tailrace channel. The turbine could develop 335 hp under a 4.9 m (16 ft) head and would be connected, through a speed increaser, to a horizontal generator with a rated output of 225 kW. A 13 kV transmission line, owned and operated by the District, is located at the site.

Cost of the New Power Plant. The estimated cost of the new generating facility is $850,100, based on January 1980 prices. About 24 to 36 months would be required for completing the feasibility study, obtaining approvals, and building. Since the generating facility would be located on an existing manmade conduit that is now operated primarily for purposes other than power generation, the Vail Heading site would probably be exempt from

Figure C-27B



STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
IMPERIAL VALLEY IRRIGATION DISTRICT
VAIL HEADING
225 kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
VAIL HEADING
Sacramento
San Francisco
Los Angeles
San Diego
LOCATION MAP
Governor
℄ 1.68m (5.5') Steel Penstock
Transition
℄ Tailrace Channel
Gear Box
Generator (250kW)
Generator Switchgear
NEW POWERHOUSE PLAN
0 1 2 3 4 5 6 7 8 METERS
East Highline Canal
New Intake
Diversion Weir
New Powerhouse
New Penstock
Existing Vail Supply Canal
Lateral Tailrace Channel
-60
-90
PLAN
0 100 200 300 METERS
℄ 1.68m (5.5') Steel Penstock
Governor
Transition
℄ Unit
Gear Box
Generator (250kW)
SECTION A-A
0 1 2 3 4 5 6 7 8 METERS
NOTE:
ENGLISH UNITS IN BRACKETS

federal licensing requirements. (The exemption provision is discussed in Appendix F.) However, the District would have to comply with the CEQA process and determine if other state approvals are necessary.

If the project were initiated in 1981, construction could be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $1,387,600 (Table C-27B).

Table C-27B. Project Cost of Vail Heading Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 620,000
Transmission Facilities	12,500
Subtotal	$ 632,500
Contingencies (20%)	126,500
Total	$ 759,000
Engineering and Administration (12%)	91,100
Total Construction Cost (January 1980 Prices)	$ 850,100
Escalation (4 yrs. at 12% per year)	487,500
Total Construction Cost (January 1984 Prices)	$1,337,600
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,387,600
Cost per kW (225 kW)	$ 6,167

Cost of Generation. Since this facility and the electric transmission and distribution system are owned and operated by the Imperial Irrigation District, it is assumed that the District would develop and use the power in its own electric system. The annual cost of owning and operating the project would include the debt repayment, operation and maintenance, insurance, replacements, administration, and overhead.

It is assumed that the District would finance construction by issuing tax-exempt revenue bonds, and that the bonds could be issued for a 35-year term at 9 percent interest. The actual interest rate would depend on financial conditions when the bonds were issued.

It is expected that the initial development would be financed from electric system revenues or short-term loans, and that the bonds would not be issued until about 12 months before the project is completed. The additional cost of operating the plant would be insignificant, since the District already has a full staff of operating personnel. Regular maintenance could be scheduled during the nonirrigation season when there would be no water for power generation.

The estimated average generation cost, assuming 35-year bonds, is \$182,400 or 17.8 cents per kWh (Table C-27C). With 20-year bonds, the estimated average generation cost increases to 20.6 cents per kWh.

Table C-27C. Annual Cost of Vail Heading Project

Cost Item	Amount 20-year Bonds	35-year Bonds
Studies, Approvals, etc.	\$ 50,000	\$ 50,000
Construction Cost	1,387,600	1,387,600
Capitalized Interest	128,800	128,800
Interest Earnings	(62,400)	(62,400)
Total Capital Cost	\$1,504,000	\$1,504,000
Bond Reserve Fund	186,300	163,200
Financing Costs	63,900	61,900
Bond Issue	\$1,754,200	\$1,729,100
Debt Service (9% interest)	\$192,200	\$ 163,600
Operation and Maintenance	13,000	13,000
Insurance	17,000	17,000
Interim Replacements	3,500	3,500
Interest Earnings	(14,700)	(14,700)
Total Annual cost	\$ 211,000	\$ 182,400
Annual Cost (% of Project Cost)	15.2	13.1
Average Cost (per kWh)	20.6¢	17.8¢

Since the District has experience with small hydroelectric facilities, it might elect to be self-insured--in full or in part--to reduce the annual insurance premium on mechanical and electrical equipment. This would substantially reduce its annual generation cost.

Value of Generation. Since the District would probably use the energy produced in its own electric system, the average estimated avoided cost is about 4.5 cents per kWh, at 1980 price levels. This was discussed in the study of the "No. 8 Heading" site which is also owned by the District. The projected value of energy is discussed in Appendix G, and the estimates of partial-peak energy are assumed to be applicable to the Vail Heading output. The assumed value for capacity is \$100 per kW per year.

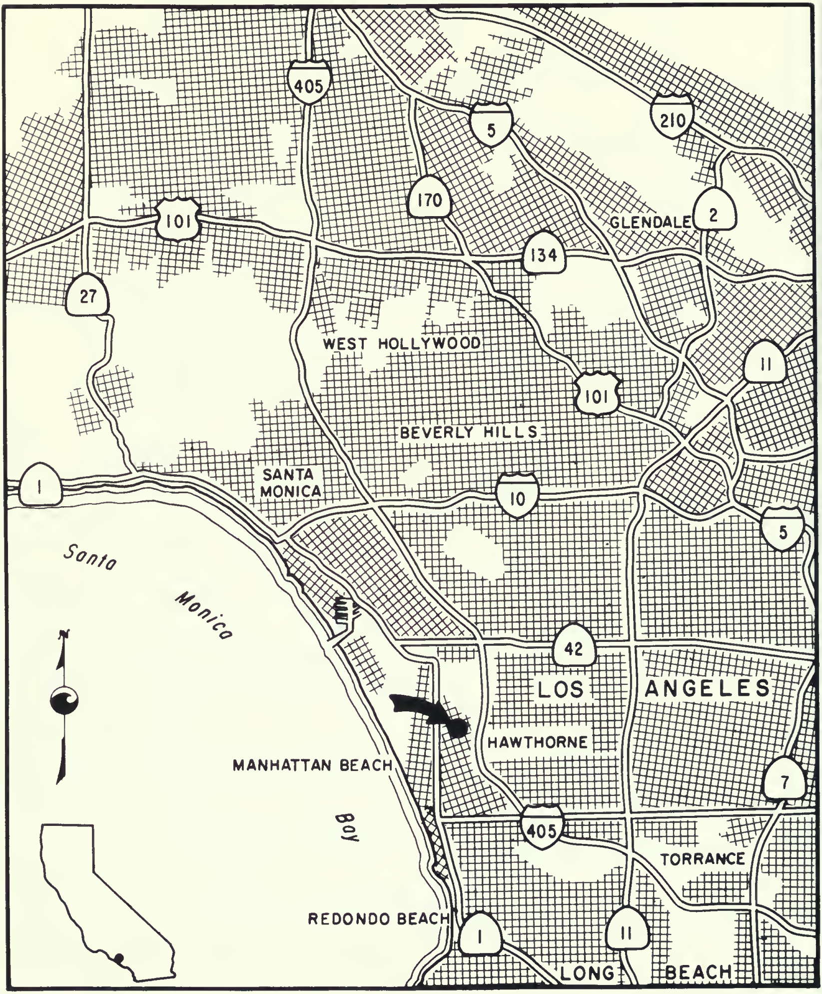
Based on this, the estimated value of Vail Heading generation in 1984 is \$120,300 or 11.7¢ per kWh (Table C-27D).

Table C-27D. Generation Value of Vail Heading Project

Item	Amount
Capacity (June Capacity)	
178 kW at $100 per kW	$ 17,800
Energy	
1 025 000 kWh at 10¢ per kWh	102,500
Total	$120,300
Average Value (per kWh)	11.7¢

Conclusions. Since the estimated value of Vail Heading generation in 1984 is less than the estimated cost of generation (17.8 to 20.6 cents per kWh), the project would not be cost effective during its first year of operation. With the projected increases in the price of oil, the project would be marginally cost effective after the third or fourth year of operation.

Figure C-28A West Coast Basin Barrier Powerplant



28. West Coast Basin Barrier

The West Coast Basin Barrier facility is a pressure-reducing vault owned and operated by the Los Angeles County Flood Control District. It is located under El Segundo Boulevard near Los Angeles International Airport (Fig. C-28A). The facility is part of the West Coast Basin Barrier Project to counteract seawater intrusion into the groundwater basin by injecting fresh water into wells along the coast line from the airport to Long Beach.

Site Characteristics. The hydraulic facility consists of four identical pressure-reducing valves; only two of the valves are in operation at any given time. The valves reduce the pressure of water from the Metropolitan Water District of Southern California distribution system from 1138 kilopascals to 552 kilopascals (165 psi to 80 psi) before injection into the wells. The physical dimensions of the vault were sized for the four valves with extra space allowed only for the maintenance, removal, and installation of equipment. The power distribution line is located adjacent to the site.

Potential Generation. The average flow is 1.1 cms (40 cfs) for 24 hours a day, 365 days a year. The potential capacity would be 500 kW, and the estimated annual output is about 4.2 million kWh, allowing 4 percent outage time for routine maintenance.

New Power Plant Structures. Turbines and generators installed at the facility could use the 56.4 m (185 ft) available head. The proposed generating facility includes a 5 m (16 ft) extension of the existing vault to accommodate two horizontal, modified pump-type turbines, each capable of developing 335 hp under the available head (Fig. C-28B). The turbines would be connected directly to horizontal generators having a rated output of 250 kW each. The operations of the hydroelectric plant and the existing system would be kept separate by two butterfly valves installed upstream and downstream from each turbine.

Cost of the New Power Plant. The estimated cost of building the new generating facility is $689,500, based on January 1980 prices. If the project were initiated in 1981, and about 30 to 36 months were required to complete the feasibility study, obtain approvals, arrange financing, design, and build the project, the work should be completed in late 1983 for operation in 1984. The estimated project cost in late 1983, with 12 percent inflation, is $1,134,900 (Table C-28A).

Figure C-28B

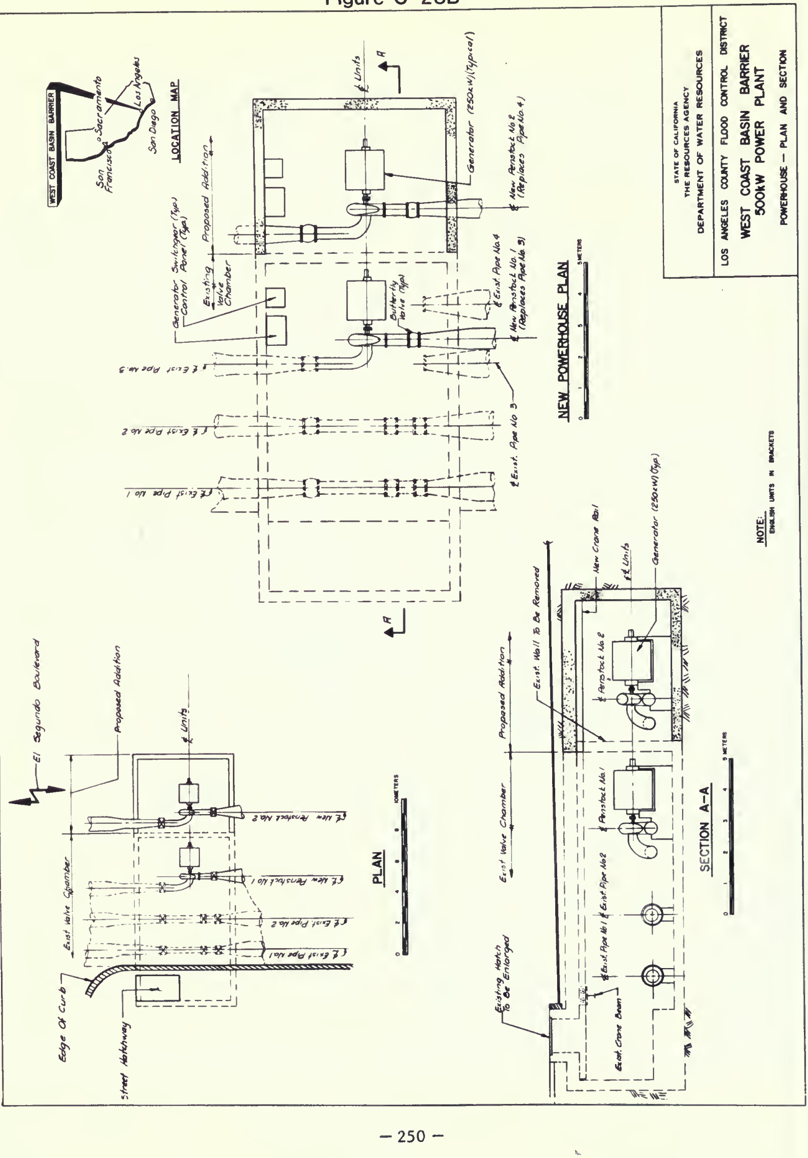

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
LOS ANGELES COUNTY FLOOD CONTROL DISTRICT
WEST COAST BASIN BARRIER
500kW POWER PLANT
POWERHOUSE — PLAN AND SECTION
LOCATION MAP
WEST COAST BASIN BARRIER
Sacramento
San Francisco
Los Angeles
San Diego
NEW POWERHOUSE PLAN
Generator (250kW)(Typical)
Generator Switchgear (Typ.)
Control Panel (Typ.)
Proposed Addition
Existing Valve Chamber
Butterfly Valve (Typ.)
℄ New Penstock No. 2 (Replaces Pipe No. 4)
℄ New Penstock No. 1 (Replaces Pipe No. 5)
℄ Exist. Pipe No. 4
℄ Exist. Pipe No. 3
℄ Exist. Pipe No. 2
℄ Exist. Pipe No. 1
℄ Units
A
PLAN
El Segundo Boulevard
Edge Of Curb
Street Hatchway
Exist. Valve Chamber
℄ New Penstock No. 2
℄ New Penstock No. 1
SECTION A-A
Existing Hatch To Be Enlarged
Exist. Wall To Be Removed
New Crane Rail
Generator (250kW)(Typ.)
℄ Penstock No. 2
℄ Penstock No. 1
℄ Exist. Pipe No. 1
℄ Exist. Pipe No. 2
Exist. Crane Beam
METERS
NOTE:
ENGLISH UNITS IN BRACKETS

Table C-28A. Project Cost of West Coast Basin Barrier Plant

Cost Item	Amount
Direct Cost	
Hydroelectric Plant Facilities	$ 488,000
Transmission Facilities	25,000
Subtotal	$ 513,000
Contingencies (20%)	102,600
Total	$ 615,600
Engineering and Administration (12%)	73,900
Total Construction Cost (January 1980 Prices)	$ 689,500
Escalation (4 yrs. at 12% per year)	395,400
Total Construction Cost (January 1984 Prices)	$1,084,900
Studies, Licensing, Permits, and Approvals	50,000
Total	$1,134,900
Cost per kW (500 kW)	$ 2,270

Cost of Generation. The generation cost would include the fixed annual cost of financing construction, the cost of labor and materials for operation and maintenance, insurance, and replacements (Table C-28B). Regular maintenance could be scheduled during the winter months when there is insufficient water for power generation.

Table C-28B. Annual Operating Cost of West Coast Basin Barrier Project

Cost Item	Amount
Operation and Maintenance	$ 30,600
Insurance	17,000
Interim Replacements	3,000
Total	$ 50,600

The annual cost of owning and operating the project would range between 15 and 22 percent of the direct project cost of $1,134,900, depending on financing. The estimated cost of generation ranges between 4.1 cents and 6.0 cents per kWh (Table C-28C).

Table C-28C. Average Energy Cost of West Coast Basin Barrier Project

Cost Item	Amount Interest Rate 9%	12%	15%
For 20-year term of debt:			
Fixed Annual Cost Rate	12.5%	16.0%	17.8%
Fixed Annual Cost	$ 141,900	$ 181,600	$ 202,000
Operating Cost	50,600	50,600	50,600
Total Annual Cost	$ 192,500	$ 232,200	$ 252,600
Average Cost (per kWh)	4.6¢	5.5¢	6.0¢
For 35-year term of debt:			
Fixed Annual Cost Rate	10.6%	14.4%	16.2%
Fixed Annual Cost	$ 120,300	$ 163,400	$ 183,900
Operating Cost	50,600	50,600	50,600
Total Annual Cost	$ 170,900	$ 214,000	$ 234,500
Average Cost (per kWh)	4.1¢	5.1¢	5.6¢

Value of Generation. It is assumed that project generation would be sold to SCE under Section 210 of PURPA and that the value of generation would be determined by the SCE policy on the purchase of capacity and energy from small power facilities. The West Coast Basin Barrier site would have a capacity value since generation would be available at about a 96 percent capacity factor. On this basis, the estimated value of project generation in 1984 is 10.9 cents per kWh using the CEC median oil-cost projection for estimating the future cost of electrical energy.

Conclusions. Since the estimated value of West Coast Basin Barrier generation exceeds the estimated cost of generation (4.1 to 6.0 cents per kWh), the project would be cost effective during its first year of operation. Additional benefits would accrue during subsequent years as the price of oil increases. The generation cost would change little from year to year, since only the maintenance cost of the facility is subject to inflation.

APPENDIX D

Feasibility Studies for 42 Facilities, Prepared by Others

APPENDIX D

Summary of Feasibility Studies Prepared by Others

The Department did not conduct preliminary studies on sites where feasibility studies were either in progress or had already been completed by others. Copies of 42 such studies were obtained and evaluated. These included several earlier appraisal-level studies prepared by the Department on the State Water Project's facilities. The 42 studies varied in scope from simple preliminary investigations to full-fledged feasibility studies. Since they were conducted by several different engineering firms and site owners, there was no common basis among them, and they had to be evaluated individually to confirm or deny their feasibility. In addition, a 7 percent interest rate was usually used to determine annual cost; this is no longer valid and a much higher cost of raising capital must be used for an accurate economic comparison of projects.

To estimate the economic suitability of the 42 sites, project costs were taken from each of the reports and escalated for inflation to estimate the costs expected for 1984. Project costs include all direct costs such as studies, licensing, permits and approvals, and construction, but do not include financing cost or indirect cost of interest during construction; these are included in the fixed annual cost of owning and operating the project. Annual costs were determined using the fixed annual cost rates obtained in the Department's studies of the 28 representative sites. The computation of fixed annual cost is described in detail in Appendix H.

To determine the cost effectiveness of each proposed facility, the annual cost of energy generation was compared to the price utilities will pay for hydroelectric power based on the avoided cost required by PURPA. An interest rate of 9 percent and a 35-year debt were used for this comparison. Table 8 in Chapter II, shows the estimated rates Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company, will pay for electric generation through the year 2000.

The estimated 1984 project costs for each facility are presented below with a brief summary of the specific characteristics of each site. This information is summarized in Table D.

Table D. Summary of 42 Feasibility Studies Prepared by Others

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	Project Cost ($/kW)	Project Cost (Year)	1984 Project Cost ($/kW)	Annual Cost Rate (%)1/ (Low)	Annual Cost Rate (%)1/ (High)	1984 Energy Cost (¢/kWh) (Low)	1984 Energy Cost (¢/kWh) (High)
1. Anderson Lake	500	2.2	50	1,322	1978	2,610	13.5	20.5	8.0	12.2
2. Antelope Dam	450	1.4	35	2,784	1978	5,200	13.5	20.5	22.8	34.6
3. Bowman Dam	3 000	14.7	56	610	1979	1,080	12.5	19.5	2.7	4.3
4. Canal Creek	940	3.3	40	1,227	1982	1,540	13.0	20.0	5.7	8.8
5. Castaic Dam	275	1.4	58	2,156	1978	4,030	13.5	20.5	10.7	16.2
6. Combie Dam	525	2.9	63	1,737	1979	3,060	13.5	20.5	7.5	11.3
7. Coyote Dam	600	1.3	24	1,006	1978	1,990	13.5	20.5	12.4	18.9
8. Del Valle Dam	400	1.1	31	1,848	1978	3,450	13.5	20.5	16.9	25.7
9. Escaladian Headworks	270	0.8	34	1,494	1982	1,870	13.5	20.5	8.3	12.6
10. Fairfield Drop	970	2.8	33	1,104	1982	1,380	13.0	20.5	6.3	9.8
11. Frankenheimer Drop	4 700	17.0	41	1,056	1982	1,320	12.0	19.0	4.4	7.0
12. Goodwin Dam	970	4.7	55	1,363	1982	1,710	13.0	20.0	4.6	7.1
13. Jackson Meadows Dam	4 000	8.9	25	572	1979	1,010	12.0	19.0	5.4	8.6
14. Lake Berryessa	16 000	43.0	30	330	1975	920	12.0	19.0	4.1	6.5
15. Lake Davis	510	1.5	33	1,807	1978	3,380	13.5	20.5	15.5	23.6
16. Lake Redding	14 500	79.0	62	2,510	1979	4,390	12.0	19.0	9.7	15.3
17. Las Flores Turnout	210	0.7	38	2,541	1978	4,750	14.0	21.0	20.0	29.9
18. Lytle Creek Turnout	1 300	7.8	68	1,079	1978	2,130	13.0	20.0	4.6	7.1
19. Madera Canal 980+65	2 000	5.5	31	535	1980	840	12.5	19.5	3.8	6.0
20. Millerton Lake										
(a) Friant-Kern Canal	15 000	90.3	69	670	1975	1,860	12.0	19.0	3.7	5.8
(b) Madera Canal	5 000	30.6	70	740	1975	2,050	12.0	19.0	4.0	6.4
(c) San Joaquin River	2 700	9.9	42	630	1975	1,750	12.5	19.5	5.9	10.1

1/ Annual cost as percentage of project cost, using Figure 9 in Chapter III.

Table D. Summary of 42 Feasibility Studies Prepared by Others (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	Project Cost ($/kW)	Project Cost (Year)	1984 Project Cost ($/kW)	Annual Cost Rate (%)[1/] (Low)	Annual Cost Rate (%)[1/] (High)	1984 Energy Cost (¢/kWh) (Low)	1984 Energy Cost (¢/kWh) (High)
21. Modesto Reservoir	1 000	3.4	39	1,425	1979	2,510	13.0	20.0	9.6	14.8
22. Mojave Siphon No. 1	6 000	47.0	89	2,868	1981	4,030	12.0	19.0	6.2	9.8
23. Palermo Canal	400	1.5	43	2,863	1981	4,020	13.5	20.5	14.5	22.0
24. Paradise Dam	300	1.2	46	2,007	1980	3,160	13.5	20.5	10.7	16.1
25. Pyramid Dam	1 000	3.2	37	1,568	1981	2,200	13.0	20.0	9.0	13.8
26. Richard B. Parker	2 800	9.2	37	1,113	1982	1,400	12.5	19.5	5.4	8.3
27. San Antonio Dam	6 000	25.6	49	2,126	1978	4,200	12.0	19.0	11.8	18.7
28. Santa Ana Low Turnout	1 400	3.8	31	840	1978	1,660	13.0	20.0	8.0	12.2
29. Sly Creek Dam	13 200	48.2	42	773	1979	1,360	12.0	19.0	4.5	7.1
30. Stampede Dam	3 000	16.0	61	657	1975	1,820	12.5	19.5	4.3	6.7
31. Stone Drop	1 000	4.0	46	1,358	1979	2,390	13.0	20.0	9.6	12.0
32. Sweetwater Turnout	875	2.2	29	934	1978	1,840	13.0	20.0	9.5	14.6
33. Thermalito Afterbay	13 000	42.6	37	1,972	1979	3,290	12.0	19.0	12.1	19.1
34. Thermalito Diversion	3 500	23.0	75	1,616	1979	2,700	12.5	19.5	5.1	8.0
35. Turlock Main Canal Drop No. 1	3 260	12.2	43	930	1982	1,170	12.5	19.5	3.9	6.1
36. Turlock Main Canal Drop No. 2	660	2.1	36	1,437	1982	1,800	13.5	20.5	7.6	11.6
37. Turlock Main Canal Drop No. 6	920	2.9	36	1,292	1982	1,620	13.0	20.0	6.7	10.3
38. Turlock Main Canal Drop No. 7	700	2.1	34	1,408	1982	1,770	13.5	20.5	8.0	12.1

Table D. Summary of 42 Feasibility Studies Prepared by Others (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	Project Cost		1984 Project Cost ($/kW)	Annual Cost Rate (%) 1/		1984 Energy Cost (¢/kWh)	
				($/kW)	(Year)		(Low)	(High)	(Low)	(High)
39. Turlock Main Canal Drop No. 9	1 070	4.7	50	1,670	1982	2,090	13.0	20.0	6.2	9.5
40. Waterman Canyon Turnot	4 000	7.0	20	551	1978	1,090	12.0	19.0	7.5	11.8
41. Whiskeytown Dam	4 000	19.5	56	528	1975	1,460	12.0	19.0	3.6	5.7
42. Woodward Dam	2 300	6.9	34	968	1982	1,210	12.5	19.5	5.0	8.0

1/ Annual cost as percentage of project cost, using Figure 9 in Chapter III.

1. Anderson Lake

Anderson Lake on Coyote Creek in Santa Clara County is owned and operated by the Santa Clara Valley Water District. In the report the "Hydroelectric Power Potential in the Santa Clara Valley," prepared by the Tudor Engineering Company in November 1978, a power plant was considered for installation at this site. It would develop 500 kW of hydroelectric capacity at a design head of 38.1 m (125 ft) and a design flow of 1.4 cms (50 cfs). A new power plant structure to be built would include an Ossberger turbine, a generator, power plant control and monitoring equipment, and a by-pass system. The estimated annual output is 2.2 million kWh.

The estimated cost of the Leroy Anderson power facility is $661,000, at 1978 price levels. Table D-1 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,610 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 8.0 and 12.2 cents per kWh in 1984.

A power plant at Leroy Anderson Reservoir would be cost effective during its first year of operation (1984).

Table D-1
Anderson Lake Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 105,000
Reservoirs, Dams, and Waterways	10,000
Turbine and Generator	186,000
Electrical Equipment	78,000
Miscellaneous Equipment	42,000
Subtotal	421,000
Contingency	105,000
Administration and Management	135,000
TOTAL PROJECT COST	$ 661,000
Average Cost per kW: ($661,000/500 kW)	$1,322

2. Antelope Dam

Antelope Dam on Indian Creek in Plumas County is owned and operated by Department of Water Resources. An earlier study by the Department indicated that a power plant installed at this site would develop 450 kW of hydroelectric capacity at a design head of 23 m (75 ft) and a design flow of 2.4 cms (85 cfs). The estimated annual output is 1.4 million kWh.

The estimated cost of the Antelope Dam power facility is $1,253,000, at 1978 price levels. Table D-2 is a summary of the cost estimate. If construction of the power plant were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $5,200 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 22.8 and 34.6 cents per kWh in 1984.

A power plant at Antelope Dam if operational in 1984, would be cost effective by 1990.

Table D-2
Antelope Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 164,000
Electrical Equipment	119,000
Mechanical Equipment	252,000
Transmission Line	360,000
Subtotal	895,000
Engineering	224,000
Contingency	134,000
TOTAL PROJECT COST	$1,253,000
Average Cost per kW: ($1,253,000/450 kW)	$2,784

3. Bowman Dam

Bowman Dam on Canyon Creek in Nevada County is owned and operated by the Nevada Irrigation District. In a report, "Hydroelectric Power Potential: Nevada Irrigation District," prepared by the Tudor Engineering Company in February 1979, a power plant was considered for installation at this site; it would develop 3 MW of hydroelectric capacity at a design head of 41 m (134 ft) and a design flow of 8.5 cms (300 cfs). A new powerhouse would have to be built to house a vertical Francis turbine and a generator with a rated capacity of 3 MW. The estimated annual project output is 14.7 million kWh.

The estimated cost of the Bowman Dam power facility is $1,831,000, at 1979 price levels. Table D-3 is a summary of the estimated cost. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,080 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 19.0 percent of the project cost depending on financing. The energy cost would range between 2.7 and 4.2 cents per kWh in 1984.

A power plant at Bowman Dam would be cost effective during its first year of operation (1984).

Table D-3
Bowman Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 307,300
Reservoir, Dams, and Waterways	92,700
Turbines and Generators	631,000
Miscellaneous Power Plant Equipment	225,000
Subtotal	1,256,000
Contingency	251,000
Administrative, Engineering, Legal, Management	324,000
TOTAL PROJECT COST	$1,831,000
Average Cost per kW: ($1,831,000/3000 kW)	$610

4. Canal Creek

This site is on Canal Creek in Merced County; it is owned and operated by the Merced Irrigation District. In a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant considered for installation at this site would develop 940 kW of hydroelectric capacity at a design head of 10 m (32.3 ft) and a design flow of 11 cms (380 cfs). A new drop structure would have to be built to house a bulb turbine and a generator; penstock and control gate modifications would also be necessary. The estimated annual output is 3.3 million kWh.

The estimated cost for the Canal Creek power facility is $1,153,152, at 1982 price levels. Table D-4 is a summary of this cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,540 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range from 5.7 and 9.0 cents per kWh in 1984.

A power plant at Canal Creek would be cost effective during its first year of operation (1984).

Table D-4
Canal Creek Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 611,000
Civil Construction and Installation	325,000
Engineering and Management	112,320
Subtotal	1,048,320
Contingency	104,832
TOTAL PROJECT COST	$1,153,152
Average Cost per kW: ($1,153,152/940 kW)	$1,227

5. Castaic Dam (Stream Release)

Castaic Dam, at the confluence of Castaic Creek and Elizabeth Lake Canyon Creek in Los Angeles County, is owned and operated by the Department. An earlier study prepared by the Department indicated that a power plant installed at this site would develop 275 kW of hydroelectric capacity at a design head of 91.4 m (300 ft) and a design flow of 0.4 cms (15 cfs). The estimated annual project output is 1.4 million kWh.

The estimated cost the Castaic Dam power facility is $593,000, at 1978 price levels. Table D-5 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $4,030 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 10.7 and 16.2 cents per kWh in 1984.

A power plant at Castaic Dam would be cost effective during its first year of operation (1984).

Table D-5
Castaic Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 75,600
Electrical Equipment	120,000
Mechanical Equipment	192,000
Transmission Line	36,000
Subtotal	423,600
Engineering	105,900
Contingency	63,500
TOTAL PROJECT COST	$ 593,000
Average Cost per kW: ($593,000/275 kW)	$2,156

6. Combie Dam

Combie Dam on the Combie North Aqueduct in Nevada County is owned and operated by the Nevada Irrigation District. In a report on the "Hydroelectric Power Potential: Nevada Irrigation District," prepared by the Tudor Engineering Company in February 1979, a power plant was considered for installation at this site; it would develop 525 kW of hydroelectric capacity at a design head of 11 m (35 ft) and a design flow of 6 cms (200 cfs). A new power plant would have to be built adjacent to the canal to house a tube-type turbine and a generator. The estimated annual project output is 2.9 million kWh.

The estimated cost of the Combie Dam power facility (canal installation) is $912,000, at 1979 price levels. Table D-6 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $3,060 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 7.5 and 11.3 cents per kWh in 1984.

A power plant at Combie Dam would be cost effective during its first year of operation (1984).

Table D-6
Combie Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 135,000
Reservoir	22,000
Turbines and Generators	289,000
Miscellaneous Power Plant Equipment	180,000
Subtotal	626,000
Contingency	125,000
Administration, Engineering, Legal, Management	161,000
TOTAL PROJECT COST	$ 912,000
Average Cost per kW: ($912,000/525 kW)	$1,737

7. Coyote Dam

Coyote Dam on Coyote Creek in Santa Clara County is owned and operated by the Santa Clara Valley Water District. In the report, the "Hydroelectric Power Potential in the Santa Clara Valley," prepared by the Tudor Engineering Company in November 1978, a power plant was considered for installation at this site; it would develop 600 kW of hydroelectric capacity at a design head of 30.5 m (100 ft) and a design flow of 2.3 cms (80 cfs). The powerhouse would be located on a new penstock extending from the existing outlet conduit between the toe of the dam and the existing energy dissipation structure. About 0.5 km (0.3 mi) of transmission line will be needed to link the powerhouse with an existing PGandE line. The estimated annual project output is 1.3 million kWh.

The estimated cost of the Coyote Dam power facilities is $586,700, at 1978 price levels. Table D-7 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,990 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 12.4 and 18.9 cents per kWh in 1984.

A power plant at Coyote Dam would be cost effective during its first year of operation (1984).

Table D-7
Coyote Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 126,000
Reservoirs, Dams and Waterways	30,000
Turbine and Generator	59,000
Power Plant Equipment	133,500
Poles and Fixtures	15,000
Subtotal	363,500
Contingency	90,900
Administration and Management	132,300
TOTAL PROJECT COST	$ 586,700
Average Cost per kW: ($586,700/600 kW)	$1,006

8. Del Valle Dam (Stream Release)

Del Valle Dam on Arroyo Del Valle in Alameda County is owned and operated by the Department. An earlier study prepared by the Department indicated that a power plant installed at this site would develop 400 kW of hydroelectric capacity at a design head of 36.6 m (120 ft) and a design flow of 1.4 cms (50 cfs). The estimated annual output is 1.1 million kWh.

The estimated cost of the Del Valle power facility is $739,200, at 1978 price levels. Table D-8 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $3,450 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 17.0 and 25.7 cents per kWh in 1984.

A power plant at Del Valle Dam, if operational in 1984, would be cost effective by 1988.

Table D-8
Del Valle Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 153,000
Electrical Equipment	100,000
Mechanical Equipment	239,000
Transmission Line	36,000
Subtotal	528,000
Engineering	132,000
Contingency	79,200
TOTAL PROJECT COST	$ 739,200
Average Cost per kW: ($739,200/400 kW)	$1,848

9. Escaladian Headworks

The Escaladian Headworks, a drop structure on the Main Canal in Merced County, is owned and operated by the Merced Irrigation District. In a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant considered for installation at this site would develop 270 kW of hydroelectric capacity at a design head of 4.6 m (15 ft) and a design flow of 6.5 cms (230 cfs). A structure would have to be built to house a tube-type turbine and a generator. The estimated annual output is 822 000 kWh.

The estimated cost of the Escaladian Headworks power facility is $403,480, at 1982 price levels. Table D-9 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,870 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 8.3 and 12.6 cents per kWh in 1984.

A power plant at Escaladian Headworks would be cost effective during its first year of operation (1984).

Table D-9
Escaladian Headworks Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 202,500
Civil Construction and Installation	125,000
Engineering and Management	39,300
Subtotal	366,800
Contingency	36,680
TOTAL PROJECT COST	$ 403,480
Average Cost per kW: ($403,480/270 kW)	$1,494

10. Fairfield Drop

The Fairfield Drop site on the Fairfield Canal in Merced County is owned and operated by the Merced Irrigation District. In a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site; it would develop 970 kW of hydroelectric capacity at a design head of 9 m (30 ft) and a design flow of 12 cms (420 cfs). A new drop structure would have to be built to house a bulb turbine and a generator. The estimated annual output is 2.8 million kWh.

The estimated cost of the Fairfield Drop power facility is $1,071,224, at 1982 price levels. Table D-10 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,380 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 6.3 and 9.8 cents per kWh in 1984.

A power plant at Fairfield Drop would cost effective during its first year of operation (1984).

Table D-10
Fairfield Drop Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 630,500
Civil Construction and Installation	239,000
Engineering and Management	104,340
Subtotal	973,840
Contingency	97,384
TOTAL PROJECT COST	$1,071,224
Average Cost per kW: ($1,071,224/970 kW)	$1,104

11. Frankenheimer Drop

Frankenheimer Drop on the South San Joaquin Irrigation District's Main Canal in Stanislaus County is owned and operated by the District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 4.7 MW of hydroelectric capacity at a design head of 23.8 m (78 ft) and a design flow of 25.5 cms (900 cfs). The hydroelectric facility would consist of a conventional vertical Francis turbine and an overhead generator. The estimated annual output is 17 million kWh.

The estimated cost of the Frankenheimer Drop power facility is $4,963,728, at 1982 price levels. Table D-11 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,320 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 4.4 and 7.0 cents per kWh in 1984.

A power plant at Frankenheimer Drop would be cost effective during its first year of operation (1984).

Table D-11
Frankenheimer Drop Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$1,410,000
Civil Construction and Installation	2,619,000
Engineering and Management	483,480
Subtotal	4,512,480
Contingency	451,248
TOTAL PROJECT COST	4,963,728
Average Cost per kW: ($4,963,728/4700 kW)	$1,056

12. Goodwin Dam

Goodwin Dam on the Stanislaus River in Calaveras County is owned and operated jointly by the Oakdale Irrigation District and the South San Joaquin Irrigation District. In the report, a "Hydropower Feasibility Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site; it would develop 970 kW of hydroelectric capacity at a design head of 3 m (10 ft) and a design flow of 34 cms (1200 cfs). The existing outlet structure would house a bulb turbine and a generator. The estimated annual output is 4.7 million kWh.

The estimated cost of the Goodwin Dam power facility is $1,322,160, at 1982 price levels. Table D-12 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,710 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 4.6 and 7.3 cents per kWh in 1984.

A power plant at Goodwin Dam would be cost effective during its first year of operation (1984).

Table D-12
Goodwin Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical (including contingencies)	$ 630,500
Civil	550,000
Engineering and Management	141,660
TOTAL PROJECT COST	$1,322,160
Average Cost per kW: ($1,322,160/970 kW)	$1,363

13. Jackson Meadows Dam

Jackson Meadows Reservoir on the Middle Yuba River in Nevada County is owned and operated by the Nevada Irrigation District. In a report, the "Hydroelectric Power Potential: Nevada Irrigation District," prepared by the Tudor Engineering Company in February 1979, a power plant was considered for installation at this site; it would develop 4 MW of hydroelectric capacity at a design head of 59.4 m (195 ft) and a design flow of 8.5 cms (300 cfs). A new powerhouse would have to be built on what is now a streambed to house a vertical Francis turbine and a generator. The estimated annual output is 8.9 million kWh.

The estimated cost of the Jackson Meadows Reservoir power facility is $2,287,000, at 1979 price levels. Table D-13 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,010 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 5.4 and 8.6 cents per kWh in 1984.

A power plant at Jackson Meadows Dam would be cost effective during its first year of operation (1984).

Table D-13
Jackson Meadows Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 332,000
Reservoirs, Dams, and Waterways	303,000
Turbines and Generators	693,000
Miscellaneous Power Plant Equipment	250,000
Subtotal	1,658,000
Contingency	314,000
Administration, Engineering, Legal Management	405,000
TOTAL PROJECT COST	$2,287,000
Average Cost per kW: ($2,287,000/4000 kW)	$572

14. Lake Berryessa (Monticello Dam)

Lake Berryessa on Putah Creek in Napa County is owned and operated by WPRS. In the report, on "Adding Powerplants At Existing Federal Dams: California," prepared by the WPRS in July 1976, a power plant was considered for installation at this site. It would develop 16 MW of hydroelectric capacity at a design head of 60.4 m (198 ft) and a design flow of 31.2 cms (1100 cfs). A Francis turbine and a generator unit would be located at the existing outlet structure; a new electrical station and transmission facilities are also necessary. The estimated annual output is 42.7 million kWh.

The estimated cost of the Lake Berryessa power facility is $5,283,000, at 1975 price levels. Table D-14 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $920 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 4.1 and 6.5 cents per kWh in 1984.

A power plant at Lake Berryessa would be cost effective during its first year of operation (1984).

Table D-14
Lake Berryessa Cost Estimate

Cost Item	Amount
Project Facilities	
Powerplant	$4,880,000
Transmission Line	403,000
TOTAL PROJECT COST	$5,283,000
Average Cost per kW: ($5,283,000/16 000 kW)	$330

15. Lake Davis (Grizzly Valley Dam)

The Lake Davis site, located on Big Grizzly Creek in Plumas County, is owned and operated by the Department. An earlier study by the Department indicated that a power plant installed at this site would develop 510 kW of hydroelectric capacity at a design head of 33.5 m (110 ft) and a design flow of 1.8 cms (65 cfs). The estimated annual output is 1.5 million kWh.

The estimated cost of the Lake Davis power facility is $921,600, at 1978 price levels. Table D-15 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $3,380 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 15.5 and 23.6 cents per kWh in 1984.

A power plant at Lake Davis, if operational by 1984, would be cost effective in 1986.

Table D-15
Lake Davis Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	167,000
Electrical Equipment	175,000
Mechanical Equipment	281,000
Transmission Line	36,000
Subtotal	659,000
Engineering	164,000
Contingency	98,850
TOTAL PROJECT COST	$ 921,600
Average Cost per kW: ($921,600/510 kW)	$1,807

16. Lake Redding

The Lake Redding site, on the Sacramento River in Shasta County, is owned and operated by the Anderson-Cottonwood Irrigation District. In a study entitled "Lake Redding Power Project," prepared by CH2M Hill for the city of Redding in 1979, a power plant at this site was considered. It would develop 14.5 MW of hydroelectric capacity, at a design head of 4.3 m (14 ft) and a design flow of 425 cms (15,000 cfs).

New power plant structures would include a powerhouse and dam; the development would also include channel modification, care of the river, and other miscellaneous items. The new power plant would contain five 2900 kW generators with 4.65 m (15.25 ft) inclined-shaft tube-type turbines. The estimated annual generation is 79 million kWh.

The estimated cost of the Lake Redding power facility is $36.4 million, at 1979 price levels. Table D-16 is a summary of the estimated cost. If construction were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $4,388 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 9.7 and 15.3 cents per kWh in 1984.

A power plant at Lake Redding would be cost effective during its first year of operation (1984).

Table D-16
Lake Redding Cost Estimate

Cost Item	Amount
Powerhouse	
Civil Works	$ 7,000,000
Generating Equipment	11,400,000
Electrical Control and Transmission	700,000
Building and Mechanical Equipment	400,000
Trash Racks	500,000
Upstream Gates	600,000
Subtotal	20,600,000
Diversion Facility	
Bascule Gates	3,200,000
Civil Works	1,200,000
Subtotal	4,400,000
Channel Modification	1,100,000
Care of the River	3,300,000
Miscellaneous	900,000
Administration, Engineering, Legal, etc.	6,100,000
TOTAL PROJECT COST	$36,400,000
Average Cost per kW: ($36,400,000/14 500 kW)	$2,510

17. Las Flores Turnout

The Las Flores Turnout site is in San Bernardino County where the Mojave Siphon crosses the Mojave River; it is owned and operated by the Department. An earlier study prepared by the Department indicated that a power plant installed at this site would develop 210 kW of hydroelectric capacity at a design head of 67 m (220 ft) and a design flow of 0.4 cms (13 cfs). The estimated annual output is 700 000 kWh.

The estimated cost of the Las Flores power facility is $533,700, at 1978 price levels. Table D-17 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $4,750 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 21.0 percent of the project cost, depending on financing. The energy cost would range between 19.2 and 29.9 cents per kWh in 1984.

A power plant at Las Flores Turnout, if operational in 1984, would be cost effective by 1988.

Table D-17
Las Flores Turnout Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 63,500
Electrical Equipment	130,400
Mechanical Equipment	151,300
Transmission Line	36,000
Subtotal	381,200
Engineering	95,300
Contingency	57,200
TOTAL PROJECT COST	$ 533,700
Average Cost per kW: ($533,700/210 kW)	$2,541

18. Lytle Creek Turnout

Lytle Creek Turnout on the Lytle Creek Pipeline in San Bernardino County is owned and operated by the San Bernardino Valley Municipal Water District. In a report, the "Hydroelectric Power Potential on the Foothill and Lytle Creek Pipelines," prepared by the Tudor Engineering Company in August 1978, a power plant was considered for installation at this site. It would develop 1.3 MW of hydroelectric capacity at a design head of 111.3 m (365 ft) and a design flow of 2 cms (70 cfs). New hydroelectric facilities would include a 1300 kW vertical shaft Francis turbine and a generator. The estimated annual output is 7.8 million kWh.

The estimated cost of building the Lytle Creek Turnout power facility is $1,402,000, at 1978 price levels. Table D-18 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,130 per kW.

The estimated annual cost of owning and operating the project would range between 13 and 20 percent of the project cost, depending on financing. The energy cost would range between 4.6 and 7.1 cents per kWh in 1984.

A power plant at Lytle Creek Turnout would be cost effective during its first year of operation (1984).

Table D-18
Lytle Creek Turnout Estimated Cost

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 240,000
Reservoirs, Dams, and Waterways	60,000
Turbine and Generator	513,000
Accessory Electrical Equipment	131,000
Miscellaneous Power Plant Equipment	72,000
Subtotal	1,016,000
Contingency (15%)	152,000
Management	234,000
TOTAL PROJECT COST	$1,402,000
Average Cost per kW: ($1,402,000/1300 kW)	$1,079

19. Madera Canal Station 980+65

The site of Madera Canal Station 980+65, located on the Madera Canal, is owned by the WPRS. In a "Feasibility Report on the Potential Hydroelectric Development at Madera Canal Station 980+65," prepared by Stoddard & Associates and Ed Farmer & Associates, Inc. for the Chowchilla Water District in January 1980, a power plant was considered for installation at this site; it would develop 2 MW of hydroelectric capacity at a design head of 3 m (10 ft) and a design flow of 16.3 cms (575 cfs). Several structural modifications would be required at the site including constructing a new building to house a tube-type turbine and a generator. The estimated annual output is 5.5 million kWh.

The estimated cost of the power facility at Madera Canal Station 980+65 is $1,069,400, at 1980 price levels. Table D-19 is a summary of this cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $840 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 20.0 percent of the project cost, depending on financing. The energy cost would range between 3.8 and 6.1 cents per kWh in 1984.

A power plant at Madera Canal Station 980+65 project would be cost effective during its first year of operation (1984).

Table D-19
Madera Canal Station 980+65 Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 93,100
Turbines and Generators	369,405
Accessory Electrical Equipment	127,381
Miscellaneous Power Plant Equipment	38,214
Transmission Line	80,000
Subtotal	708,100
Contingency	204,422
Engineering and Administration	156,878
TOTAL PROJECT COST	$1,069,400
Average Cost per kW: ($1,069,400/2000 kW)	$535

20. Millerton Lake (Friant Dam)

Millerton Lake on the San Joaquin River in Fresno County is owned and operated by WPRS. In the report, "Adding Powerplants At Existing Federal Dams: California," prepared by WPRS in July 1976, three outlet sites from Millerton Lake were identified as having hydroelectric power potential. These sites are discussed below.

Friant-Kern Canal Plant. This facility would have an estimated capacity of 15 MW. A Francis or adjustable-propeller turbine-generator unit installed here would have an estimated annual output of 90.3 million kWh.

The estimated cost of Friant Kern Canal power facility is $10,030,000, at 1975 price levels. Table D-20A is a summary of the cost estimate. If construction of the project would be completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,860 per kW.

The estimated annual cost of owning and operating the project would range between 12 to 19 percent of the project cost, depending on financing. The energy cost would range between 3.7 and 5.8 cents per kWh in 1984.

Table D-20A
Millerton Lake Cost Estimate
(Friant-Kern Canal Plant)

Cost Item	Amount
Project Facilities	
Powerplant	$ 9,400,000
Transmission Lines and Switchyard	630,000
TOTAL PROJECT COST	$ 10,030,000
Average Cost per kW: ($10,030,000/15 000 kW)	$670

Madera Canal Plant. This plant would have an estimated capacity of 5 MW. A Francis turbine and a generator installed here would have an estimated annual output of 30.6 million kWh.

The estimated cost of the Madera Canal power facility is $3,700,000, at 1975 price levels. Table D-20B is a summary of the cost estimate. If construction of the project would be completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,050 per kW.

The estimated annual cost of owning and operating the project would range between 12 to 19 percent of the project cost, depending on financing. The energy cost would range between 4.0 to 6.4 cents per kWh in 1984.

The three power plants at Millerton Lake would be cost effective during their first year of operation (1984).

Table D-20B
Millerton Lake Cost Estimate
(Madera Canal Plant)

Cost Item	Amount
Project Facilities	
Powerplant	$ 3,100,000
Transmission Lines and Switchyard	600,000
TOTAL PROJECT COST	$ 3,700,000
Average Cost per kW: ($3,700,000/5000 kW)	$740

San Joaquin River Plant. This plant would have an estimated capacity of 2.7 MW. A Francis turbine and a generator unit installed here would have an estimated annual output of 9.9 million kWh.

The estimated cost of the Friant downstream power facility is $1,700,000, at 1975 price levels. Table D-20C is a summary of the cost estimate. If construction of the project would be completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,750 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 19.5 percent of the project cost, depending on financing. The energy cost would range between 5.9 and 10.1 cents per kWh in 1984.

Table D-20C
Millerton Lake Cost Estimate
(San Joaquin River Plant)

Cost Item	Amount
Project Facilities	
Powerplant	$ 1,170,000
Transmission Lines and Switchyard	530,000
TOTAL PROJECT COST	$ 1,700,000
Average Cost per kW: ($1,700,000/2700 kW)	$630

21. Modesto Reservoir

The Modesto Reservoir site is on the Lower Main Canal, an irrigation distribution system in Stanislaus County; it is owned and operated by the Modesto Irrigation District. In a report on the "Lower Main Canal Hydro Stations," prepared by CH2M Hill for the District in November 1978, a power plant was considered for installation at this site; it would develop 1 MW of hydroelectric capacity at a design head of 5.5 m (18 ft) and a design flow of 23 cms (800 cfs). A new powerhouse would have to be built to house a 1000 kW turbine-generator unit. The estimated annual project output is 3.4 million kWh.

It would cost an estimated $1,425,000 to build the Modesto Reservoir power facility, based on 1978 manufacturers' quotations and contractors' bid prices escalated to 1979 price levels. Table D-21 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,510 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 9.6 and 15.2 cents per kWh in 1984.

A power plant at Modesto Reservoir would be cost effective during its first year of operation (1984).

Table D-21
Modesto Reservoir Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 350,000
Turbine and Generator	720,000
Transmission	30,000
Subtotal	1,100,000
Inflation (1 yr at 10%)	110,000
Engineering and Administration	180,000
Legal and Miscellaneous	35,000
TOTAL PROJECT COST	$1,425,000
Average Cost per kW: ($1,425,000/1000 kW)	$1,425

22. Mojave Siphon No. 1

The Mojave Siphon forms a portion of the East Branch of the California Aqueduct in San Bernardino County. It is owned and operated by the Department. In the feasibility report entitled "Mojave Siphon Power Recovery Facility," prepared by the Department, a power plant installed at this site could develop 6 MW of hydroelectric capacity at a design head of 23.8 m (78 ft) and a design flow of 30.3 cms (1070 cfs). A turbine-generator unit rated at 6 MW, was planned for installation at this site. The estimated annual output is 47 million kWh.

The estimated cost of the Mojave Siphon power facility is $17,208,400, at 1981 price levels. Table D-22 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation escalation) would be $4,029 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 6.2 and 9.8 cents per kWh in 1984.

A power plant at Mojave Siphon would be cost effective during its first year of operation (1984).

Table D-22
Mojave Siphon Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 6,627,900
Mechanical Works	2,270,000
Electrical Works	429,000
Turbine and Generator	4,284,000
Transmission Line	45,000
Subtotal	13,655,900
Engineering, Administration, etc.	1,510,800
Contingency	2,041,700
TOTAL PROJECT COST	$17,208,400
Average Cost per kW: ($17,208,400/6000 kW)	$ 2,868

23. Palermo Canal

The Palermo Canal site in Butte County is owned and operated by the Department. An earlier study by the Department indicated that a power plant installed at this site would develop 400 kW of hydroelectric capacity at a design head of 91.4 m (300 ft) and a design flow of 0.5 cms (19 cfs). The estimated annual output is 1.5 million kWh.

The estimated cost of the Palermo Canal power facility is $1,145,000 at 1981 price levels. Table D-23 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $4,020 per kW. The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. This would result in a 1984 energy cost ranging between 14.5 and 22.0 cents per kWh.

A power plant at Palermo Canal would be cost effective during its first year of operation (1984).

Table D-23
Palermo Canal Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 370,000
Electrical Equipment	210,000
Turbine and Generator	160,000
Miscellaneous Mechanical Equipment	70,000
Transmission Line	22,000
Subtotal	832,000
Engineering	230,000
Contingency	83,000
TOTAL PROJECT COST	$1,145,000
Average Cost per kW: ($1,145,000/400 kW)	$2,863

24. Paradise Dam

Paradise Dam on Little Butte Creek in Butte County is owned and operated by the Paradise Irrigation District. In a "Feasibility Report on the Potential Hydroelectric Development at Paradise Reservoir and Dam," prepared by the Tudor Engineering Company in 1980, a power plant was considered for installation at this site. It would develop 300 kW of hydroelectric capacity at a design head of 42.7 m (150 ft) and a design flow of 1.4 cms (50 cfs). A new structure would have to be built at the downstream end of the outlet works to house a Francis turbine and a generator. The estimated annual output is 1.2 million kWh.

The estimated cost of the Paradise Dam power facility is $602,000, at 1980 price levels. Table D-24 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $3,160 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 10.7 and 16.1 cents per kWh in 1984.

A power plant at Paradise Dam would be cost effective during its first year of operation (1984).

Table D-24
Paradise Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 38,000
Reservoir, Dam, and Waterways	12,000
Turbine and Generator	208,000
Station Equipment	130,000
Miscellaneous Power Plant Equipment	30,000
Subtotal	418,000
Contingency	84,000
Indirect Construction Cost	100,000
TOTAL PROJECT COST	$ 602,000
Average Cost per kW: ($602,000/300 kW)	$2,007

25. Pyramid Dam (Stream Release)

The Pyramid Dam on Piru Creek in Los Angeles County is owned and operated by the Department. An earlier study by the Department indicated that a power plant installed at this site would develop 1 MW of hydroelectric capacity at a design head of 91.4 m (300 ft) and a design flow of 1.1 cms (46 cfs). The estimated annual output is 4 million kWh.

The estimated cost of the Pyramid Dam power facility is $1,568,000, at 1981 price levels. Table D-25 is a summary of the estimated cost. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,200 per kW.

The estimated annual cost of owning and operating the project would range between 13 and 20 percent of project cost, depending on financing. The energy cost would range between 7.1 and 11.0 cents per kWh in 1984.

A power plant at Pyramid Dam would be cost effective during its first year of operation (1984).

Table D-25
Pyramid Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$ 495,000
Electrical Equipment	275,000
Turbine and Generator	240,000
Miscellaneous Mechanical Equipment	80,000
Transmission Line	50,000
Subtotal	1,140,000
Engineering	314,000
Contingency	114,000
TOTAL PROJECT COST	$1,568,000
Average Cost per kW: ($1,568,000/1000 kW)	$1,568

26. Richard B. Parker

The Parker site on the Merced Irrigation District's Main Canal in Merced County is owned and operated by the District. In a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site; it would develop 2.8 MW of hydroelectric capacity at a design head of 6 m (20 ft) and design flow of 54 cms (1900 cfs). A new drop structure would have to be built to house two bulb turbines and two generators rated at 1400 kW each. An estimated annual output of 9.2 million kWh could be produced from irrigation releases in the canal.

The estimated cost of the Parker power facility is $3,115,481, at 1982 price levels. Table D-26 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,400 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 19.5 percent of the project cost, depending on financing. The energy cost would range between 5.4 and 8.3 cents per kWh in 1984.

A power plant at the Richard B. Parker site would be cost effective during its first year of operation (1984).

Table D-26
Richard B. Parker Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$1,313,200
Civil Construction and Installation	1,215,600
Engineering and Management	303,456
Subtotal	$2,832,256
Contingency	283,225
TOTAL PROJECT COST	$3,115,481
Average Cost per kW: ($3,115,481/2800 kW)	$1,113

27. San Antonio Dam

The San Antonio Dam site is on the San Antonio River in Monterey County; it is owned and operated by the Monterey County Flood Control and Water Conservation District. In a report, the "San Antonio Power Project," prepared by the Tudor Engineering Company in November 1978, the installation of a power plant at this site was considered. It would develop 6 MW of hydroelectric capacity at a design head of 52 m (170 ft) and a design flow of 15 cms (540 cfs). The new power facility will contain four 2000 hp cross-flow (Ossberger) turbines in a semioutdoor structure. A tunnel would have to be built to connect Nacimiento Reservoir and San Antonio Reservoir. The estimated annual output is 25.6 million kWh.

The estimated cost of the San Antonio Dam power facility and tunnel is $12,758,100, based on 1978 construction costs. Table D-27 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $4,200 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 11.8 and 18.7 cents per kWh in 1984.

A power plant at San Antonio Dam would be cost effective during its first year of operation (1984).

Table D-27
San Antonio Dam Cost Estimate

Cost Item	Amount
Tunnel	
Land and Land Rights	$ 5,000
Tunnel Construction	7,062,000
Contingency	1,413,400
Subtotal	8,480,400
Power Plant	
Structures and Improvements	$ 144,000
Penstock	56,000
Turbines and Generators	1,498,000
Station Equipment	340,000
Miscellaneous Power Plant Equipment	140,000
Contingency	835,600
Subtotal	2,613,600
Total Cost	
Tunnel	$ 8,480,400
Power Plant	2,613,600
Management	1,664,100
TOTAL PROJECT COST	$12,758,100
Average Cost per kW: ($12,758,100/6000 kW)	$2,126

28. Santa Ana Low Turnout

The Santa Ana Low Turnout site is located on the Foothill Pipeline in San Bernardino County and is owned and operated by the San Bernardino Valley Municipal Water District. In the report, the "Hydroelectric Power Potential on the Foothill and Lytle Creek Pipelines," prepared by the Tudor Engineering Company in August 1978, a powerplant was considered for installation at this site. It would develop 1.4 MW of hydroelectric capacity at a design head of 67 m (220 ft) and a design flow of 2.8 cms (100 cfs). The new hydroelectric facility would include a vertical shaft Francis turbine and a generator adjacent to the existing dissipation vault of the turnout structure. The estimated annual output is 3.8 million kWh.

The estimated cost of the Santa Ana Low Turnout power facility is $1,176,000, at 1978 price levels. Table D-28 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,660 per kW.

The estimated annual cost of owning and operating the project would range between 13 and 20 percent of the project cost, depending on financing. The energy cost would range between 8.0 and 12.2 cents per kWh in 1984.

A power plant at Santa Ana Low Turnout would be cost effective during its first year of operation (1984).

Table D-28
Santa Ana Low Turnout Estimated Cost

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 133,000
Reservoirs, Dams and Waterways	86,000
Turbine and Generator	455,000
Accessory Electrical Equipment	131,000
Miscellaneous Power Plant Equipment	47,000
Subtotal	852,000
Contingency	128,000
Management	196,000
TOTAL PROJECT COST	$1,176,000
Average Cost per kW: ($1,176,000/1400 kW)	$840

29. Sly Creek Dam

Sly Creek Dam on Lost Creek in Butte County is owned and operated by the Oroville-Wyandotte Irrigation District. In the report, an "Application for Amendment of License for Project No. 2088: South Fork Project," prepared by the Tudor Engineering Company in November 1979, a power plant was considered for installation at this site. It would develop 13.2 MW of hydroelectric capacity at a design head of 68.6 m (225 ft) and a design flow of 22 cms (777 cfs). A new structure will have to be built to house a refurbished vertical Francis turbine and a generator which will be obtained from the Melones Dam Powerplant. The estimated annual output is 48.2 million kWh.

The estimated cost of the Sly Creek Dam power facility is $10,202,000, at 1979 price levels. Table D-29 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,360 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 4.5 and 7.1 cents per kWh in 1984.

A power plant at Sly Creek Dam would be cost effective during its first year of operation (1984).

Table D-29
Sly Creek Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Construction Contract	$6,557,000
Contingency	658,000
Design and Development	650,000
Construction Management	495,000
Surveys, Testing, Geological Studies	20,000
Administration and Legal Expense	240,000
Financial Consulting and Bond Issue	200,000
Securities Commission	35,000
Allowance for Discount Bid (10%)	1,347,000
TOTAL PROJECT COST	$10,202,000
Average Cost per kW: ($10,202,000/13 200 kW)	$773

30. Stampede Dam

Stampede Dam on the Little Truckee River in Sierra County is owned and operated by WPRS. In the report, "Adding Powerplants At Existing Federal Dams: California," prepared by the WPRS in July 1976, a power plant was considered for installation at this site. It would develop 3 MW of hydroelectric capacity at a design head of 55.8 m (183 ft) and a design flow of 6.8 cms (241 cfs). The new hydroelectric facilities needed would include transmission lines and a Francis turbine and a generator rated at 3000 kW. The estimated annual output is 16 million kWh.

The estimated cost of the Stampede Dam power facility is $1,970,000, at 1975 price levels. Table D-30 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,820 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 4.1 and 6.5 cents per kWh in 1984.

A power plant at Stampede Dam would be cost effective during its first year of operation (1984).

Table D-30
Stampede Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Powerplant	$1,510,000
Transmission Lines	460,000
TOTAL PROJECT COST	$1,970,000
Average Cost per kW: ($1,970,000/3000 kW)	$657

31. Stone Drop

The Stone Drop site on the Lower Main Canal, an irrigation distribution system in Stanislaus County, is owned and operated by the Modesto Irrigation District. In the report, "Lower Main Canal Hydro Stations," prepared by CH2M Hill in November 1978, a power plant was considered for installation at this site. It would develop 1 MW of hydroelectric capacity at a design head of 5.8 m (19 ft) and a design flow of 22.7 cms (800 cfs). A new powerhouse would have to be constructed to house a 1000 kW turbine-generator unit. The estimated annual project output is 4 million kWh.

The estimated cost of the Stone Drop power facility is $1,358,000 based on 1978 manufacturers' quotations and contractors' bid prices escalated to 1979 price levels. Table D-31 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,390 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 9.6 and 12.3 cents per kWh in 1984.

A power plant at Stone Drop would be cost effective during its first year of operation (1984).

Table D-31
Stone Drop Cost Estimate

Cost Item	Amount
Project Facilities	
Civil and Structural	$ 340,000
Turbine and Generator	690,000
Transmission and Miscellaneous	20,000
Subtotal	1,050,000
Escalation (1 yr @ 10%)	105,000
Engineering and Administration	170,000
Legal and Miscellaneous Costs	33,000
TOTAL PROJECT COST	$1,358,000
Average Cost per kW: ($1,358,000/1000 kW)	$1,358

32. Sweetwater Turnout

Sweetwater Turnout on the Foothill Pipeline in San Bernardino County is owned and operated by the San Bernardino Valley Municipal Water District. In the report, the "Hydroelectric Power Potential on the Foothill and Lytle Creek Pipelines," prepared by the Tudor Engineering Company in August 1978, a power plant was considered for installation at this site. It would develop 875 kW of hydroelectric capacity at a design head of 61 m (200 ft) and a design flow of 2.4 cms (85 cfs). New hydroelectric facilities would include a vertical Francis turbine and a generator adjacent to the existing dissipation vault of the turnout structure. The estimated annual output is 2.2 million kWh.

The estimated cost of the Sweetwater Turnout facility is $817,000, at 1978 price levels. Table D-32 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,840 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 9.5 and 15.0 cents per kWh in 1984.

A power plant at Sweetwater Turnout would be cost effective during its first year of operation (1984).

Table D-32
Sweetwater Turnout Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 95,000
Reservoirs, Dams and Waterways	62,000
Turbine and Generator	298,000
Accessory Electrical Equipment	77,500
Miscellaneous Power Plant Equipment	60,000
Subtotal	592,500
Contingency	88,500
Management	136,000
TOTAL PROJECT COST	$ 817,000
Average Cost per kW: ($817,000/875 kW)	$934

33. Thermalito Afterbay River Outlet

The Thermalito Afterbay is adjacent to the Feather River in Butte County; it is owned and operated by the Department. The feasibility study prepared in June 1979 by the International Engineering Company, Inc. and the Aerojet Manufacturing Company indicated that a power plant installed at this site would develop 13 MW of hydroelectric capacity at a design head of 9.1 m (30 ft) and a design flow of 184 cms (6500 cfs). The estimated annual output is 42.6 million kWh.

The estimated cost of the Thermalito Afterbay power facility is $25,630,600, at 1979 price levels. Table D-33 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $3,290 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 12.1 and 19.1 cents per kWh in 1984.

A power plant at Thermalito Afterbay would be cost effective during its first year of operation (1984).

Table D-33
Thermalito Afterbay River Outlet Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$10,214,000
Mechanical Equipment	9,858,000
Electrical Equipment	1,556,000
Subtotal	21,628,000
Labor, Overhead, Travel	4,002,600
TOTAL PROJECT COST	$25,630,600
Average Cost per kW: ($25,630,600/13 000 kW)	$1,972

34. Thermalito Diversion Dam

Thermalito Diversion Dam on the Feather River in Butte County is owned and operated by the Department. An earlier study prepared by the Department indicated that a power plant installed at this site would develop 3.5 MW of hydroelectric capacity at a design head of 21.3 m (70 ft) and a design flow of 20 cms (700 cfs). The estimated annual output is 23 million kWh.

The estimated cost of the Thermalito Diversion Dam power facility is $5,656,000, at 1979 price levels. Table D-34 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $2,700 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 19.0 percent of the project cost, depending on financing. The energy cost would range between 5.1 and 7.9 cents per kWh in 1984. A power plant at Thermalito Diversion Dam would be cost effective during its first year of operation (1984).

Table D-34
Thermalito Diversion Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Civil Works	$1,944,000
Mechanical Equipment	1,140,000
Electrical Equipment	920,000
Transmission Line	36,000
Subtotal	4,040,000
Engineering	1,010,000
Contingency	606,000
TOTAL PROJECT COST	$5,656,000
Average Cost per kW: ($5,656,000/3500 kW)	$1,616

35. Turlock Main Canal Drop No. 1

Canal Drop No. 1 on the Turlock Irrigation District's Main Canal is owned and operated by the District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 3260 kW of hydroelectric capacity, at a design head of 7.9 m (26 ft) and a design flow of 56.6 cms (2000 cfs). The planned power plant development would consist of three generating units next to the existing outlet structure. Each generating unit would be a Leffel turbine in a flume arrangement coupled to a General Electric Company generator and would be rated at 1086 kW. The estimated annual project output is 12.2 million kWh.

The estimated cost of the Canal Drop No. 1 power facility is $3,030,207, at 1982 price levels. Table D-35 is a summary of the estimated cost.

Construction of Canal Drop No. 1 was completed in 1980.

Table D-35
Turlock Main Canal Drop No. 1 Estimated Cost

Cost Item	Amount
Project Facilities	
Electrical and mechanical Equipment	$1,160,000
Civil Construction and Installation	1,252,442
Engineering and Management	342,292
Subtotal	2,754,734
Contingency	275,473
TOTAL PROJECT COST	$3,030,207
Average Cost per kW: ($3,030,207/3260 kW)	$930

36. Turlock Main Canal Drop No. 2

Canal Drop No. 2 on the Main Canal in Stanislaus County is owned and operated by the Turlock Irrigation District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 660 kW of hydroelectric capacity at a design head of 1.8 m (6 ft) and a design flow of 48.1 cms (1700 cfs). A structure would have to be built to house two standard tube-type turbine/generators in a by-pass configuration. The estimated annual output is 2.1 million kWh.

The estimated cost of the Canal Drop No. 2 power facility is $948,640, at 1982 price levels. Table D-36 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,800 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 7.6 and 11.6 cents per kWh in 1984.

A power plant at Canal Drop No. 2 would be cost effective during its first year of operation (1984).

Table D-36
Turlock Main Canal Drop No. 2 Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 495,000
Civil Construction and Installation	275,000
Engineering and Management	92,400
Subtotal	862,400
Contingency	86,240
TOTAL PROJECT COST	$ 948,640
Average Cost per kW: ($948,640/660 kW)	$1,437

37. Turlock Main Canal Drop No. 6

Canal Drop No. 6 on the Main Canal in Stanislaus County is owned and operated by the Turlock Irrigation District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 920 kW of hydroelectric capacity at a design head of 2.4 m (8 ft) and a design flow of 48 cms (1700 cfs). The hydroelectric facility would consist of two turbine-generator units, each rated at 460 kW. The estimated annual output is estimated at 2.9 million kWh.

The estimated cost of the Canal Drop No. 6 power facility is $1,188,880, at 1982 price levels. Table D-37 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,620 per kW.

The estimated annual cost of owning and operating the project would range between 13.0 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 6.7 and 10.5 cents per kWh in 1984.

A power plant at Canal Drop No. 6 would be cost effective during its first year of operation (1984).

Table D-37
Turlock Main Canal Drop No. 6 Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 690,000
Civil Construction and Installation	275,000
Engineering and Management	115,800
Subtotal	1,080,800
Contingency	109,080
TOTAL PROJECT COST	1,188,880
Average Cost per kW: ($1,188,880/920 kW)	$1,292

38. Turlock Main Canal Drop No. 7

Canal Drop No. 7 is located on the Main Canal Drop No. 7 in Stanislaus County and is owned and operated by the Turlock Irrigation District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 700 kW of hydroelectric capacity at a design head of 2.4 m (8 ft) and a design flow of 37 cms (1300 cfs). A new structure would have to be built to house two tube-type turbine-generators. The estimated annual project output is 2.1 million kWh.

The estimated cost of the Canal Drop No. 7 power facility is $985,600, at 1982 price levels. Table D-38 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,770 per kW.

The estimated annual cost of owning and operating the project would range between 13.5 and 20.5 percent of the project cost, depending on financing. The energy cost would range between 8.0 and 12.1 cents per kWh in 1984.

A power plant at Canal Drop No. 7 would be cost effective during its first year of operation (1984).

Table D-38
Turlock Main Canal Drop No. 7 Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 525,000
Civil Construction and Installation	275,000
Engineering and Management	96,000
Subtotal	896,000
Contingency	89,600
TOTAL PROJECT COST	$ 985,600
Average Cost per kW: ($985,600/700 kW)	$1,408

39. Turlock Main Canal Drop No. 9

Canal Drop No. 9 on the Turlock Irrigation District's Main Canal, and is owned and operated by the District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc., in February 1979, a power plant was considered for installation at this site. It would develop 1070 kW of hydroelectric capacity at a design flow of 28.3 cms (1000 cfs). A new drop structure would have to be built to house two Leffel turbines and generators in a flume arrangement. The estimated annual output is 4.7 million kWh.

The estimated cost of the Canal Drop No. 9 power facility is $1,786,400, at 1982 price levels. Table D-39 is a summary of the cost estimate.

Construction of Canal Drop No. 9 was completed in 1979.

Table D-39
Turlock Main Canal Drop No. 9 Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 805,000
Civil Construction and Installation	645,000
Engineering and Management	174,000
Subtotal	1,624,400
Contingency	162,400
TOTAL PROJECT COST	$1,786,400
Average Cost per kW: ($1,786,400/1070 kW)	$1,670

40. Waterman Canyon Turnout

Waterman Canyon Turnout on the Foothill Pipeline in San Bernardino County is owned and operated by the San Bernardino Valley Municipal Water District. In the report, the "Hydroelectric Power Potential on the Foothill and Lytle Creek Pipelines," prepared by the Tudor Engineering Company in August 1978, a power plant was considered for installation at this site. It would develop 4 MW of hydroelectric capacity at a design head of 154 m (505 ft) and a design flow of 3.3 cms (115 cfs). The new hydroelectric facility would include a vertical Francis turbine and a generator adjacent to the existing dissipation vault of the turnout structure. The estimated annual output is 7 million kWh.

The estimated cost of the Waterman Canyon Turnout power facility is $2,202,000, at 1978 price levels. Table D-40 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,090 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 7.5 and 11.8 cents per kWh in 1984.

A power plant at Waterman Canyon Turnout would be cost effective during its first year of operation (1984).

Table D-40
Waterman Canyon Turnout Cost Estimate

Cost Item	Amount
Project Facilities	
Structures and Improvements	$ 105,000
Reservoirs, Dams and Waterways	159,000
Turbine and Generator	1,074,000
Accessory Electrical Equipment	135,000
Miscellaneous Power Plant Equipment	123,000
Subtotal	1,596,000
Contingency	239,000
Management	367,000
TOTAL PROJECT COST	$2,202,000
Average Cost per kW: ($2,202,000/4000 kW)	$551

41. Whiskeytown Dam

Whiskeytown Dam on Clear Creek in Shasta County is owned and operated by WPRS. In the report, "Adding Powerplants At Existing Federal Dams: California," prepared by WPRS in July 1976, a power plant was considered for installation at this site. It would develop 4 MW of hydroelectric capacity at a design head of 68.6 m (225 ft) and a design flow of 7.0 cms (247 cfs). The new hydroelectric facility would include a 4000 kW semi-automatic plant. The present outlet works could be used to deliver down-stream releases to the plant. The estimated annual output is 19.5 million kWh.

The estimated cost of the Whiskeytown Dam power facility is $2,110,000, at 1975 price levels. Table D-41 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,460 per kW.

The estimated annual cost of owning and operating the project would range between 12 and 19 percent of the project cost, depending on financing. The energy cost would range between 3.6 and 5.7 cents per kWh in 1984.

A power plant at Whiskeytown Dam would be cost effective during its first year of operation (1984).

Table D-41
Whiskeytown Dam Cost Estimates

Cost Item	Amount
Project Facilities	
Powerplant	$1,650,000
Transmission Lines	400,000
TOTAL PROJECT COST	$2,110,000
Average Cost per kW: ($2,110,000/4000 kW)	$528

42. Woodward Dam

Woodward Dam on the South San Joaquin Irrigation District's Main Canal is owned and operated by the District. In the report, a "Hydropower Assessment Study," prepared by Fluid Energy Systems, Inc. in February 1979, a power plant was considered for installation at this site. It would develop 2.3 MW of hydroelectric capacity at a design head of 12.2 m (40 ft) and a design flow of 22.7 cms (800 cfs). The hydroelectric facility would consist of either one bulb turbine and a generator, or two tube-type turbines and two generators placed at the existing outlet structure for the Woodward Reservoir. The estimated annual project output is 9 million kWh.

The estimated cost of the Woodward Dam power facility is $2,225,608, at 1982 price levels. Table D-42 is a summary of the cost estimate. If construction of the project were completed for first-year operation in 1984, the estimated project cost (with 12 percent annual inflation) would be $1,210 per kW.

The estimated annual cost of owning and operating the project would range between 12.5 and 19.5 percent of the project cost, depending on financing. The energy cost would range between 5.0 and 8.0 cents per kWh in 1984.

A power plant at Woodward Dam would be cost effective during its first year of operation (1984).

Table D-42
Woodward Dam Cost Estimate

Cost Item	Amount
Project Facilities	
Electrical and Mechanical Equipment	$ 981,500
Civil Construction and Installation	825,000
Engineering and Management	216,780
Subtotal	2,023,280
Contingency	202,328
TOTAL PROJECT COST	$ 2,225,608
Average Cost per kW: ($2,225,608/2300 kW)	$968

APPENDIX E

Capacity, Energy, and Cost Data on Facilities Grouped into Six Categories

APPENDIX E

Capacity, Energy, and Cost Data on Facilities Grouped into Six Categories

Facilities were grouped into six categories based on the type of facility studied (dam, canal, or pipeline) and the estimated installed capacity (greater than 500 kW, or 500 kW or less).

Section E-1

Facilities Studied by the Department of Water Resources

Table E-1.1. Comparison of All Categories

Type of Facility	Number of Facilities	Capacity (kW)	Energy (GWh/yr)
Dams: Greater than 500 kW	7	17 450	61
500 kW or less	6	1 725	8
Subtotal	13	19 175	69
Canals: Greater than 500 kW	3	2 950	17
500 kW or less	6	1 290	4
Subtotal	9	4 240	21
Pipelines: Greater than 500 kW	0	0	0
500 kW or less	6	1 825	12
Subtotal	6	1 825	12
TOTAL	28	25 240	102

Table E-1.2. DAMS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Black Butte	9 200	31.7	39	1,717	12.7	6.4
Clear Lake	2 000	7.5	43	2,469	12.5	8.2
Gould Weir	850	3.5	47	7,499	13.0	23.7
Indian Valley	3 200	7.2	26	1,648	14.3	10.5
Jenkinson Lake (Sly Park Dam)	650	1.8	32	2,208	14.1	10.9
Lemoncove Ditch	650	3.5	61	2,754	14.9	7.7
Merle Collins Reservoir (Virginia Ranch Dam)	900	5.6	71	2,314	13.1	4.9
Subtotal	17 450	60.8				
Capacities of 500 kW or less						
Chesbro	100	0.2	23	5,343	14.9	36.8
Frenchman	450	1.0	25	3,657	13.1	20.0
Lake Amador (Jackson Creek Dam)	350	2.5	82	2,631	14.1	5.1
Lake Shastina (Shasta River Dam)	200	0.7	40	3,608	13.8	13.4
Stumpy Meadows Reservoir (Mark Edson Dam)	325	2.2	77	4,652	12.2	8.5
Uvas	300	1.0	38	3,267	13.1	13.1
Subtotal	1 725	7.6				
TOTAL	19 175	68.4				

1/ For a 35-year term at 9 percent interest rate

Table E-1.3. CANALS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Alamo Drop 3A	1 200	6.7	64	2,312	13.6	6.4
Harding Canal	1 000	6.6	75	2,077	14.2	4.5
No. 8 Heading	750	3.9	59	3,362	15.4	10.0
Subtotal	2 950	17.2				
Capacities of 500 kW or less						
Anderson Flume Division	50	0.2	41	5,518	19.5	28.5
Beardsley Diversion	500	1.7	39	8,062	13.6	31.5
Parkview Station	150	0.5	38	4,030	14.4	15.8
Pumping Plant Lower	65	0.2	35	5,331	17.1	34.4
Rocky Pt. Diversion	300	0.7	27	4,150	13.2	24.8
Vail Heading	225	1.0	51	6,167	13.1	17.8
Subtotal	1 290	4.3				
TOTAL	4 240	21.5				

Table E-1.4. PIPELINES (All have Capacities of 500 kW or less)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Buckeye Conduit	350	2.4	78	2,451	15.3	5.4
Del Loma Tunnel	250	1.9	87	5,130	15.1	10.2
Glendale Dist. System	400	2.0	57	2,558	13.0	6.9
Mount Olivette	150	1.2	84	3,646	16.2	7.9
North Portal Tecolote	175	0.7	46	6,993	13.2	22.4
West Coast Basin Barrier	500	4.2	96	2,270	15.1	4.1
TOTAL	1 825	12.3				

1/ For a 35-year term at 9 percent interest rate

Section E-2

Facilities Studied by Others

Table E-2.1. Comparison of All Categories

Type of Facility	Number of Facilities	Capacity (kW)	Energy (GWh/yr)
Dams: Greater than 500 kW	19	110 405	477
500 kW or less	5	1 825	7
Subtotal	24	112 230	484
Canals: Greater than 500 kW	11	17 950	61
500 kW or less	1	270	1
Subtotal	12	18 220	62
Pipelines: Greater than 500 kW	5	13 575	68
500 kW or less	1	210	1
Subtotal	6	13 785	69
TOTAL	42	144 235	615

Table E-2.2. DAMS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Bowman	3 000	14.7	56	1,080	12.5	2.7
Combie	525	2.9	63	3,060	13.5	7.5
Coyote	600	1.3	24	1,990	13.5	12.4
Goodwin	970	4.7	55	1,710	13.0	4.6
Jackson Meadows	4 000	8.9	25	1,010	12.0	5.4
Lake Berryessa (Monticello Dam)	16 000	43.0	30	920	12.0	4.1
Lake Davis (Grizzly Valley Dam)	510	1.5	34	3,380	13.5	15.5
Lake Redding	14 500	79.0	62	4,390	12.0	9.7
Leroy Anderson	600	1.3	25	2,610	13.5	8.0
Millerton Lake (Friant Dam)						
San Joaquin River	2 700	9.9	42	1,750	12.5	5.9
Friant - Kern Canal	15 000	90.3	69	1,060	12.0	3.7
Madera Canal	5 000	30.6	70	2,050	12.0	4.0
Modesto Reservoir	1 000	3.4	39	2,510	13.0	9.6
Pyramid	1 000	4.0	46	2,208	13.0	9.0
San Antonio	6 000	25.6	49	4,200	12.0	11.8
Sly Creek	13 200	48.2	42	1,360	12.0	4.5
Stampede	3 000	16.0	61	1,820	12.0	4.3
Thermalito Afterbay	13 000	42.6	37	3,290	12.0	12.1
Thermalito Diversion	3 500	23.0	75	2,700	12.5	5.1
Whiskeytown	4 000	19.5	56	1,460	12.0	3.6
Woodward	2 300	6.9	34	1,210	5.0	6.9
Subtotal	110 405	477.3				
Capacities of 500 kW or less						
Antelope	450	1.4	35	5,200	13.5	22.8
Castaic	275	1.4	58	4,030	20.5	10.7
Del Valle	400	1.1	31	3,450	13.5	16.0
Palermo	400	1.5	43	4,023	13.5	14.5
Paradise	300	1.2	46	3,160	13.5	10.7
Subtotal	1 825	6.6				
TOTAL	112 230	483.9				

1/ For a 35-year term at 9 percent interest rate.

Table E-2.3. CANALS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Canal Creek	940	3.3	40	1,540	13.0	5.7
Fairfield Drop	970	2.8	33	1,380	13.0	6.3
Frankenheimer Drop	4,700	17.0	41	1,320	12.0	4.4
Madera Canal Station 980+65	2,000	5.5	31	840	12.5	3.8
Richard B. Parker (Main Canal)	2,800	9.2	38	1,400	12.5	5.4
Stone Drop	1,000	4.0	46	2,390	13.0	9.6
Turlock Main Canal	3,260	12.2	43	1,170	12.0	3.7
Drop No. 2	660	2.1	36	1,800	13.5	7.6
Drop No. 6	920	2.9	36	1,620	13.0	6.7
Drop No. 7	700	2.1	34	1,770	13.5	8.0
Subtotal	17 950	61.1				
Capacities 500 kW or less						
Escaladian Headworks	270	0.8	34	1,870	13.5	8.3
Subtotal	270	0.8				
TOTAL	18 220	61.9				

1/ For a 35-year term at 9 percent interest rate

Table E-2.4. PIPELINES

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Lytle Creek	1 300	7.8	68	2,130	13.0	4.6
Mojave Siphon No. 1	6 000	47.0	89	4,030	12.0	6.2
Santa Ana Low	1 400	3.8	31	1,660	13.0	8.0
Sweetwater Turnout	875	2.2	29	2,350	13.0	12.2
Waterman Canyon	4 000	7.0	20	1,090	12.0	7.5
Subtotal	13 575	67.8				
Capacity of 500 kW or less						
Las Flores Turnout	210	0.7	38	4,750	13.5	20.0
Subtotal	210	0.7				
TOTAL	13 785	68.5				

1/ For a 35-year term at 9 percent interest rate

Section E-3

Facilities With Only Limited Data (Questionnaire Responses)

Table E-3.1. Comparison of All Categories

Type of Facility	Number of Facilities	Capacity (kW)	Energy (GWh/yr)
Dams: Greater than 500 kW	49	176 820	523
500 kW or less	51	8 125	36
Subtotal	100	184 945	559
Canals: Greater than 500 kW	18	65 170	363
500 kW or less	14	3 395	16
Subtotal	32	68 565	379
Pipelines: Greater than 500 kW	42	107 030	597
500 kW or less	41	7 285	36
Subtotal	83	114 315	633
TOTAL	215	367 825	1 571

Table E-3.2. DAMS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Bear Valley Powerplant Rehabilitation	700	3.7	60	2 600	13.5	6.6
Boca	2 000	5.6	32	1,900	12.5	8.5
Bucks Lake (Bucks Storage)	740	3.2	49	2,550	13.5	8.0
Calaveras	700	3.2	52	2,600	13.5	7.7
Camanche	10 680	35.0	37	1,500	12.0	5.5
Camp Far West	6 800	26.9	45	1,550	12.0	4.7
Casitas	700	2.0	33	2,600	13.5	12.3
Cogswell	500	3.0	68	3,100	13.5	7.0
Early Intake	1 300	8.7	76	2,050	13.0	4.0
East Park	900	2.0	25	2,300	13.0	13.5
Farmington	1 400	2.0	21	2,100	13.0	15.0
Gibraltar	1 500	4.0	30	2,000	13.0	9.8
Grant Lake	1 500	3.0	23	2,000	13.0	13.0
Hell Hole Reservoir	550	3.0	62	2,975	13.5	7.4
Hensley Lake (Hidden Dam)	1 300	4.0	35	2,050	13.0	8.7
Hetch Hetchy Reservoir (O'Shaughnessy Dam)	1 600	6.0	43	2,000	13.0	6.9
Hume Lake	1 050	4.6	50	2,150	13.0	6.4
H. V. Eastman Lake (Buchanan Dam)	3 000	9.0	34	1,700	12.5	7.1
Ice House Reservoir	10 000	22.0	25	--	--	--
Isabella	13 000	45.0	39	1,400	12.0	4.6
Lake Clementine (North Fork Dam)	12 000	63.5	60	1,400	12.0	3.1
Lake Fordyce	900	4.0	51	2,300	13.0	6.7
Lake Hennessey (Conn Creek Dam)	500	2.3	53	3,100	13.5	9.1
Lake Kaweah (Terminus Dam)	4 000	20.0	57	1,650	12.0	4.0
Lake Mendocino (Coyote Dam)	4 000	21.0	60	1,650	12.0	3.8
Lake Pillsbury (Scott Dam)	5 000	15.0	34	1,600	12.0	6.4
Lake Piru (Santa Felicia Dam)	3 600	7.8	25	1,650	12.0	9.1
Lake Siskiyou (Box Canyon Dam)	6 000	21.9	42	1,600	12.0	5.3
Lake Thomas A. Edison (Vermillion Valley Dam)	2 000	8.6	49	1,900	12.5	5.5
Lake Yosemite	1 200	2.3	22	2,050	13.0	13.9
Lexington	500	2.9	66	3,100	13.5	7.2
Little Grass Valley	2 600	6.5	29	1,750	12.5	8.8
Los Angeles Reservoir	6 200	37.0	68	1,600	12.0	3.2
Matilija	700	2.0	33	2,600	13.5	12.3

1/ For a 35-year term at 9 percent interest rate

Table E-3.2. DAMS (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW (continued)						
McCloud	1 200	5.4	51	2,050	13.0	5.9
Moccasin Lower	1 600	7.0	50	1,950	13.0	5.8
New Hogan	2 250	9.5	48	1,850	12.5	5.5
Palo Verde Diversion	8 700	65.0	85	1,500	13.0	2.6
Ponderosa Diversion	3 300	14.0	48	1,700	12.5	5.0
Prosser Creek	1 000	3.5	40	2,150	13.0	8.0
Red Bluff Diversion	14 000	70.0	73	1,400	12.0	3.4
Rindge	600	0.9	17	2,850	13.5	25.7
Robert A. Skinner	1 400	6.3	51	2,000	13.0	5.8
Ruth Reservoir (Robert W. Matthews Dam)	4 600	14.2	41	1,650	12.0	5.6
Sand Bar Project	12 000	70.0	67	1,400	12.0	2.9
San Gabriel Dam	500	3.0	68	3,100	13.5	7.0
Scotts Flat Dam	1 300	5.5	48	2,050	13.0	6.3
Spicers Meadows	750	3.3	50	2,550	13.5	7.8
Stony Gorge Dam	6 000	18.0	27	1,600	12.0	6.4
Success	4 000	12.0	34	1,650	12.0	6.6
Tinemaha	1 600	8.3	59	1,950	13.0	4.9
Warm Springs	3 000	15.0	57	1,700	12.5	4.3
West Valley	900	3.8	48	2,300	13.0	7.1
Subtotal	176 820	523.2				
Capacities 500 kW or less						
Alamitos	300	1.0	38	3,900	13.5	15.8
Alisal Creek	50	0.2	46	5,600	19.5	27.3
Anthony House	50	0.2	46	5,600	19.5	27.3
Barrett	60	0.2	38	5,600	19.5	32.8
Big Dalton	50	0.1	23	5,600	19.0	53.2
Big Sage	175	0.7	46	4,700	14.0	16.5
Big Tujunga No. 1	300	1.3	49	3,900	13.5	12.2
Calero	100	0.5	57	5,450	15.0	16.4
Clear Lake	430	1.9	50	3,350	13.5	10.2
Concow	130	0.4	35	5,100	14.5	24.0
Coyote Creek	90	0.4	51	5,450	15.0	18.3
Doris	50	0.1	23	5,600	19.5	54.6
Farmington	400	2.0	57	3,450	13.5	9.3
French Lake	200	0.8	46	4,500	14.0	15.8
Guadalupe	60	0.3	57	5,600	19.5	21.8
Hell Hole Reservoir	550	3.0	86	2,985	13.5	7.4
Henshaw	200	1.0	57	4,500	14.0	12.6
Hour House	100	0.3	34	5,450	15.0	27.3
Indian Creek Dam	50	0.1	23	5,600	19.5	54.6

1/ For a 35-year term at 9 percent interest rate

21—82257

Table E-3.2. DAMS (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities 500 kW or less (continued)						
Jameson Lake (Juncal Dam)	60	0.4	76	5,550	19.0	15.8
Kent Lake (Peters Dam)	150	0.4	30	4,950	14.0	26.0
Lake Arrowhead	75	0.3	46	5,500	17.5	24.1
Lake Eleanor	60	0.3	57	5,550	19.0	21.1
Lake Hemet	75	0.1	15	5,500	17.5	72.2
Lake Hodges	270	1.2	51	4,150	13.5	12.6
Lake Loveland	100	0.5	57	5,450	15.0	16.4
Lake Valley	75	0.3	46	5,500	17.5	24.1
Littlerock Dam	50	0.2	46	5,600	19.5	27.3
Lopez	50	0.4	91	5,600	19.5	13.7
Los Banos Detention	100	0.5	57	5,450	15.0	16.4
Los Padres	75	0.3	46	5,500	17.5	24.1
Lyons	300	1.5	57	3,900	13.5	10.5
Martis Creek	250	1.1	50	4,200	13.5	12.9
McCoy Flat	50	0.2	46	5,600	19.5	27.3
Nicasio	400	1.7	49	3,450	13.5	11.0
Pacheco Lake (North Fork Dam)	60	0.3	57	5,600	19.5	21.8
Pacoima	400	1.0	29	3,450	13.5	18.6
Pilarcitos	200	0.8	46	4,500	14.0	15.8
Rector Creek	100	0.5	57	5,450	15.0	16.4
Round Valley	90	0.4	51	5,450	15.0	18.4
Salt Spring Valley Reservoir	90	0.4	51	5,450	15.0	18.4
San Dimas	100	0.3	34	5,450	15.0	27.3
Santa Anita	300	0.7	27	3,900	13.5	22.6
Schaads Reservoir (Middle Fork Dam)	75	0.4	57	5,500	15.5	16.0
Slab Creek	400	3.0	86	3,450	13.5	6.2
Stevens Creek	75	0.3	46	5,500	17.5	24.1
Stone Canyon	300	2.0	76	3,900	13.5	7.9
Tule Lake	75	0.3	46	5,500	17.5	24.1
Vail	200	0.9	51	4,500	14.0	14.0
Webber	75	0.3	46	5,500	17.5	24.1
White Pines	100	0.4	46	5,450	15.0	20.4
Subtotal	8 125	35.9				
TOTAL	184 945	559.1				

1/ For a 35-year term at 9 percent interest rate

Table E-3.3. CANALS

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
<u>Capacities greater than 500 kW</u>						
All American Canal Drop No. 1	4 700	27.0	66	1,600	12.0	3.3
All American Canal Drop No. 5	5 000	24.0	55	1,600	12.0	4.0
Ceres Spillway	2 100	4.5	24	1,850	12.5	10.8
Cottonwood No. 1	17 000	115.0	77	1,650	12.0	2.9
Cottonwood No. 2	12 000	90.0	86	1,400	12.0	2.2
East Highline Canal	1 800	10.0	63	1,950	12.5	4.4
Fresno Main Canal						
Headworks	650	2.6	46	2,700	13.5	9.1
Boos Check	650	2.6	46	2,700	13.5	9.1
Dresser Check	650	2.6	46	2,700	13.5	9.1
Hickman Spillway	2 100	4.5	24	1,850	12.5	10.8
Kern Island Canal Control Structure	700	3.1	51	2,600	13.5	7.9
Madera Canal						
Station 1064+67	560	1.9	39	2,975	13.5	11.8
Station 1910+60	650	2.6	46	2,700	13.5	9.1
New Siphon Drop	1 410	11.3	92	2,000	13.0	3.2
People's Weir	2 200	3.5	18	1,850	12.5	14.5
South Canal	8 000	37.0	53	1,550	12.0	4.0
Upper Dawson Power Plant	4 000	15.9	45	1,650	12.0	5.0
Volta No. 2 Powerhouse	1 000	5.0	57	2,150	13.0	6.0
Subtotal	65 170	363.1				
<u>Capacities of 500 kW or less</u>						
Ash Main Canal	150	0.7	53	4,950	14.0	14.9
Beardsley Canal Control Structure	260	1.1	48	4,200	13.5	13.4
Buhach Drop	60	0.3	57	5,600	19.5	21.8
Califa	200	0.9	51	4,500	14.0	14.0
Chowchilla Main Canal						
Station 0+00	250	1.1	50	4,200	13.5	12.9
Station 101+80	250	1.1	50	4,200	13.5	12.9
Station 175+00	250	1.1	50	4,200	13.5	12.9
Dahlia Drop	225	1.0	51	4,350	13.5	13.2
Dodge Ave Check	475	2.4	58	3,200	13.5	8.6
Fisher Drop	75	0.3	46	5,500	17.5	24.1
Newside Drop	200	0.9	51	4,500	14.0	14.0
Parker Drop	300	0.8	30	3,900	13.5	19.7

1/ For a 35-year term at 9 percent interest rate

Table E-3.3. CANALS (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities of 500 kW or less (continued)						
Sand Creek Check	200	1.5	86	4,500	14.0	8.4
Tuberose Check	200	1.3	74	4,500	14.5	10.0
Upper Main Canal	200	0.9	51	4,500	14.0	14.0
Youd Drop	100	0.5	57	5,450	15.0	16.4
Subtotal	3 395	15.9				
TOTAL	68 565	379.0				

1/ For a 35-year term at 9 percent interest rate

Table E-3.4. PIPELINES

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW						
Alvarado Treatment Plant	1 700	8.4	56	1,950	13.0	5.1
Azusa Flow Control Structure	740	3.2	49	2,550	13.5	8.0
Balboa	1 200	9.1	87	2,050	13.0	3.5
Big Creek Hydroelectric Plant	800	3.0	43	2,450	13.5	8.8
Cache Slough	600	4.1	50	2,850	13.5	5.6
Carneros Power Project	700	1.6	26	2,600	13.5	15.4
Conejo Pump Station	600	3.0	57	2,850	13.5	7.7
City Creek Turnout	2 000	3.0	17	1,900	12.5	15.8
Corona	2 800	18.0	73	1,700	12.5	3.3
Covina	2 500	16.9	77	1,800	12.5	3.3
Coyote Creek	2 900	19.6	77	1,700	12.5	3.1
Dominguez Gap Barrier	500	2.0	46	3,100	13.5	10.5
Eastside Pipeline	1 000	3.0	34	2,150	13.0	9.3
El Segundo Distribution System	500	3.9	89	3,100	13.5	5.4
Folsom Lake Pipeline	500	2.4	55	3,100	13.5	8.7
Franklin Inlet	800	6.8	97	2,450	13.5	3.9
Highland Avenue Pumping Plant	600	2.6	49	2,850	13.5	8.9
Irvine Lake Pipeline	500	1.0	23	3,100	13.5	20.9
Lateral A	1 600	7.0	50	1,950	13.0	5.8
Lateral B	900	4.0	51	2,300	13.0	6.7
Los Angeles Distribution System						
Location 1	610	3.3	62	2,850	13.5	7.1
Location 15	1 000	8.2	94	2,150	13.0	3.4
Location 16	1 800	9.0	57	1,950	12.5	4.9
Miramar Treatment Plant	1 300	5.7	50	2,050	13.0	6.1
Mojave Siphon No. 2	10 000	78.0	89	1,500	12.0	2.3
Orange County 28	6 300	12.0	22	1,600	12.0	10.1
Orange County 59	5 000	9.4	21	1,600	12.0	10.2
Perris Power Project	7 900	40.3	58	1,550	12.0	3.6
Point Loma Treatment Plant	1 200	8.0	76	2,050	13.0	4.0
Reservoir A	730	3.2	50	2,550	13.5	7.9
Rio Hondo	2 000	12.3	70	1,900	13.0	4.0
San Dieguito Treatment Plant	1 000	4.5	51	2,150	13.0	6.2
San Dimas	9 900	68.2	79	1,500	12.0	2.6
Santiago Creek	3 000	15.6	59	1,700	12.5	4.1
San Vicente Reservoir	850	3.4	46	2,375	13.0	7.7
Sepulveda Canyon	8 600	56.2	75	1,500	12.0	2.8
Sweetwater Treatment Plant	1 400	6.3	51	1,840	13.0	9.5

1/ For a 35-year term at 9 percent interest rate

Table E-3.4. PIPELINES (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate[1/] (%)	1984 Energy Cost (¢/kWh)
Capacities greater than 500 kW (continued)						
Temescal	2 800	18.0	73	1,700	12.5	3.3
Valley View	2 400	14.2	68	1,800	12.5	3.8
Van Owen Regulating Dam	600	5.0	95	2,850	13.5	4.6
Venice	10 100	60.0	68	1,500	12.0	3.0
Yorba Linda Feeder	5 100	33.5	75	1,600	12.0	2.9
Subtotal	107 030	596.9				
Capacities of 500 kW or less						
Big Dalton Station	280	1.2	49	4,150	13.5	13.1
Buffalo Hill Siphon	160	0.5	36	4,950	14.0	22.2
Central Amador Water Project	250	0.7	32	4,200	13.5	20.3
Deer Creek Collection	200	1.0	57	4,500	14.0	12.2
El Dorado Dist. System						
Reservoir 2	50	0.2	46	5,600	19.5	27.3
Reservoir 2A	480	2.1	50	3,200	13.5	9.9
Reservoir 2A-3	360	1.6	51	3,650	13.5	11.1
Reservoir 3	200	0.9	51	4,500	14.0	14.0
Reservoir 5	60	0.3	57	5,600	19.5	21.8
Reservoir 6	80	0.3	43	5,500	16.5	22.7
Reservoir 8	175	0.8	52	4,700	14.0	14.4
Reservoir 9A	175	0.8	52	4,700	14.0	14.4
Reservoir 9B	90	0.4	51	5,450	16.0	18.4
Reservoir 10A	175	0.8	52	4,700	14.0	14.4
Reservoir 10B	60	0.3	57	5,600	19.5	21.8
Emerald Pressure Reducing Station	340	1.5	50	3,700	13.5	11.3
Etiwanda Pressure Reducing Station	250	1.1	50	4,200	13.5	12.9
Jackson-Sutter Creek Outfall Pipeline	60	0.2	38	5,550	19.0	31.6
Kaiser Pipeline	120	0.3	29	5,100	14.5	29.1
Lake Curry	50	0.2	46	5,600	19.5	27.3
Lake Davis-Portola Pipeline	60	0.3	57	5,600	19.5	21.8
Lake Eleanor	60	0.3	57	5,600	19.5	2.18
Lake Mary & Twin Lakes Open Diversion	300	0.8	30	3,900	13.5	19.7
Los Angeles Dist. System						
Location 2	270	2.2	93	4,150	13.5	6.9
Location 3	420	2.1	57	3,400	13.5	9.1
Location 4	270	1.8	76	4,150	13.5	8.4

1/ For a 35-year term at 9 percent interest rate

Table E-3.4. PIPELINES (Continued)

Facility	Capacity (kW)	Energy (GWh/yr)	Capacity Factor (%)	1984 Project Cost ($/kW)	Annual Cost Rate 1/ (%)	1984 Energy Cost (¢/kWh)
Capacities of 500 kW or less (Continued)						
Los Angeles Dist. System (Continued)						
Location 5	140	1.2	98	4,950	14.0	8.1
Location 6	190	1.1	72	4,600	14.0	11.1
Location 7	120	1.0	95	5,150	14.5	9.0
Location 8	130	0.8	70	5,000	14.5	11.8
Location 9	70	0.6	98	5,500	18.0	11.6
Location 10	100	0.6	68	5,450	15.0	13.6
Location 11	70	0.6	98	5,500	18.0	11.6
Location 12	100	0.6	68	5,450	15.0	13.6
Location 13	60	0.5	95	5,550	19.0	12.7
Location 14	60	0.5	95	5,550	19.0	12.7
Mallard Reservoir	200	0.9	51	4,500	14.0	14.0
Redlands Water Treatment Plant	200	0.9	51	4,500	14.0	14.0
Sidney N. Peterson Water Treatment Plant	175	0.4	26	4,700	14.0	28.8
South Portal Doulton Tunnel	200	0.5	29	4,500	14.0	25.2
Terminal Reservoir Inlet	75	0.6	91	5,500	15.5	10.7
Whitewater Canyon	400	2.5	71	3,450	13.5	7.5
Subtotal	7 285	36.0				
TOTAL	114 315	632.9				

1/ For a 35-year term at 9 percent interest rate

APPENDIX F

Permits, Licenses, Certificates, and Other Approvals

Attachments

APPENDIX F

Permits, Licenses, Certificates and Other Approvals

Currently ten or more federal, state, and local agencies have the authority to require and issue permits, licenses, and certificates before a proposed small hydroelectric project can be built and operated. Other federal, state, and local agencies have review privileges over plans for construction and operation and can provide comments to both the site developer and the approving agencies. The site developer must also comply with the provisions of the California Environmental Quality Act of 1970 (CEQA).

If electric generating facilities are to be added to existing dams and other hydraulic structures, some of the authorizing approvals may not be necessary. However, since the approving agency is authorized to decide whether or not its particular permit, license, or certificate is required, the site developer must still provide information to all agencies in each case.

Recent Federal Energy Regulatory Commission (FERC) rules have set alternative licensing procedures for small hydroelectric projects and for installing hydroelectric facilities at existing dams if no significant environmental impact would result from the project. As the lead agency for implementing the National Environmental Policy Act of 1969 (NEPA) with respect to hydroelectric development, FERC also determines if a particular project must have an Environmental Impact Statement (EIS). A project without a significant environmental impact would not need an EIS, and the approval processing period would be shortened significantly.

For similar reasons, building and operating hydroelectric facilities at existing dam or other hydraulic structures in California would usually not require an Environmental Impact Report (EIR). The CEQA process would, however, require an Initial Study to determine whether a Negative Declaration or an EIR should be prepared for the project.

Most approving agencies have rules which determine the type information that an application must contain, and most agencies have forms or formats that must be followed. The permits, licenses, and certificates needed for the construction and operation of a small hydroelectric facility in California and the application procedures for obtaining those approvals are described in this Appendix.

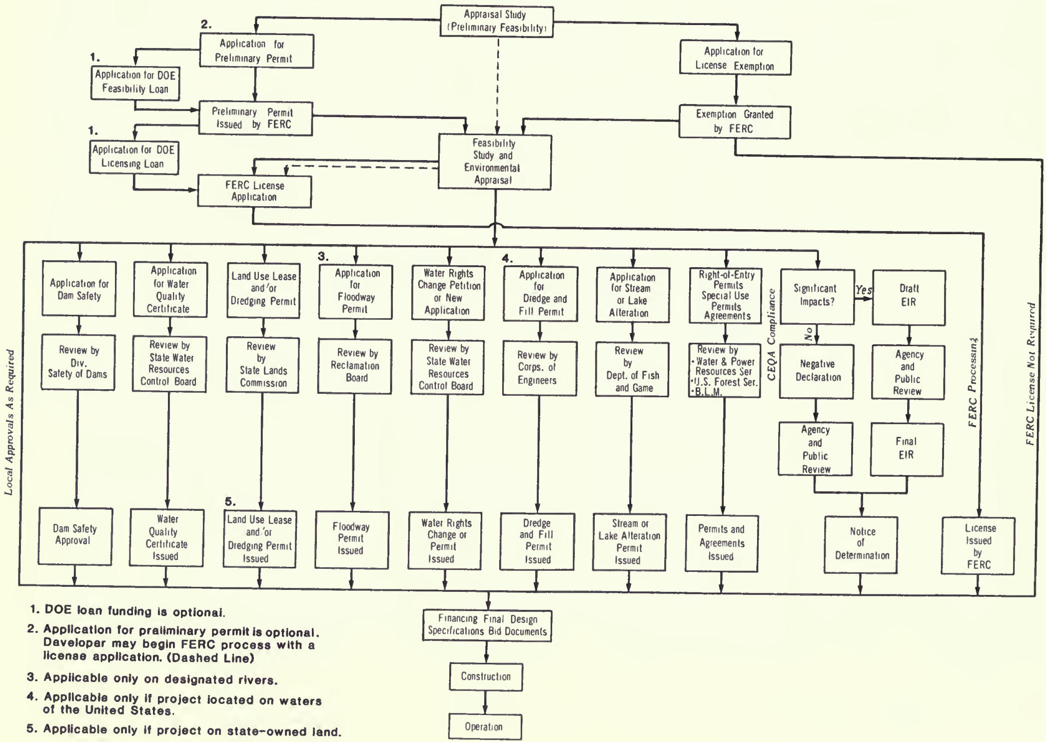
The approving agencies and the subject of their authority are listed in Table F-1, and the general procedures for obtaining the required approvals to develop a site are shown in Figure F.

Table F-1. Agencies Involved in Small Hydroelectric Development

Agency	Authority
Federal Energy Regulatory Commission	- License Exemptions (Conduits below 15 MW) (Projects of 5 MW or less) (Categorical exemptions. Category I, greater than 100 kW but not more than 5 MW. Category II, less than 100 kW.)1/ - Preliminary Permit - Minor License (New or existing - 1.5 MW or less) - Major License (Existing dam above 1.5 MW.
U. S. Army Corps of Engineers	- Dredge and Fill Permit
U. S. Forest Service	- Special Use Permit
U. S. Bureau of Land Management	- Right-of-Way Permit
U. S. Water and Power Resources Service	- Right-of-Entry Permit
Lead Agency (Environmental)	- Environmental Impact Report - Negative Declaration
State Water Resources Control Board	- Water Rights Permit - Water Quality Certificate
Department of Water Resources	- Dam Safety Approval - Floodway Permit
State Lands Commission	- Land Use Lease - Dredging Permit
Department of Fish and Game	- Stream or Lake Alteration Permit
Office of State Treasurer	- Financial Supervision
Counties or Special Districts	- General Plan Amendments, Rezonings, Use Permits and Variances - Grading Permits - Building Permits

1/ FERC proposed rulemaking issued December 22, 1980, Docket No. RM81-7.

Figure F
Approval Process for Small Hydroelectric Projects at Existing Facilities



1. DOE loan funding is optional.
2. Application for preliminary permit is optional. Developer may begin FERC process with a license application. (Dashed Line)
3. Applicable only on designated rivers.
4. Applicable only if project located on waters of the United States.
5. Applicable only if project on state-owned land.

FEDERAL APPROVAL PROCESSES

FERC Licensing Process

The rules and regulations for the FERC licensing process are set forth in Chapter I of Title 18 of the Code of Federal Regulations. A copy of Title 18 is published each April and can be obtained from:

Superintendent of Documents
U. S. Government Printing Office
Washington D.C. 20402.

Since 1978, FERC has thoroughly reformed its requirements and procedures for license applications. These changes resulted from the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA).

The FERC licensing process applies to any proposed hydroelectric project to be located on federal lands or facilities, on a stream that is on or may affect a navigable waterway, or transmission of power across, along, from or in any streams, bodies of water or land under the jurisdiction of United States. The possibility that a project may affect the navigable waterways of the United States, subjects nearly every proposed hydroelectric development to FERC licensing.

The first step in the FERC licensing process may be to obtain a Preliminary Permit. The Preliminary Permit secures for the permittee priority of license application for a project while the permittee obtains data and determines the feasibility of the project and prepares an application for a license. The Preliminary Permit is not a prerequisite to a license. FERC will not accept applications for license from other developers until the permittee has submitted an application for license or has notified FERC that it will not seek a license. The Permit is issued for a period not to exceed three years.

If two or more applications are submitted for a Preliminary Permit, the FERC will favor the applicant with the better adapted plans to develop, conserve, and utilize, in the public interest, the water resources of the region, taking into consideration the ability of each applicant to carry out its plans. If the plans of the applicants are equally well adapted, the FERC will favor the applicant whose application was first accepted for filing. If a municipality or a state is one of the applicants and the others are not, and the municipality or state's plans are at least as well adapted as the others, the FERC will favor the municipality or the state. Also, the municipality or the state will be given the opportunity to make their plans as well adapted as the others.

Public agencies or private developers applying for loans from the U. S. Department of Energy (DOE) under Title IV of PURPA for a feasibility studies or licensing loans must possess or have filed for a License Exemption or a Preliminary Permit with FERC.

Section 213 of PURPA and Title IV of the Energy Security Act of 1980 authorizes FERC to exempt certain small hydroelectric projects from part or all of Part I of the Federal Power Act, including any licensing requirement. In April 1980, FERC published its Final Rule (Docket No. RM79-35) exempting small conduit hydroelectric facilities. In November 1980, FERC published its Final Rule (Docket No. RM80-65) exempting small hydroelectric power projects with an installed capacity of 5 MW or less on a case-by-case basis. In December 1980 FERC issued a proposed rulemaking for a generic exemption for two categories with specified characteristics. The first category applies to projects with an installed capacity of less than 100 kW. The second category applies to projects with an installed capacity of more than 100 kW and less than 5 MW. This generic exemption differs from the case-by-case exemption of projects of less than 5 MW. Only projects with specified characteristics, which will not significantly affect the quality of the human environment, are generically exempted. The case- specific procedures address both exemption from licensing and exemption from provisions of Part I of the Act other than licensing.

Projects that are not exempt require applications for a license. To provide the information required for a license application, the site developer must have completed a feasibility study and an environmental assessment. The feasibility study must be detailed enough to include preliminary layout and design drawings, construction cost estimate using the FERC Uniform System of Accounts, proposed project operation procedures, dependable capacity, and the cost of generation. Projects with an installed capacity of 1500 kW or less are considered as minor projects, and require a simpler application. While making the environmental assessments, the site developer must consult with agencies having jurisdiction over recreation, fish and wildlife, historic sites, archaeology, water quality, water rights, and regional planning.

The FERC staff will review an application for its contents and completeness. The applicant can expect to receive a letter from FERC specifying the deficiencies to be corrected. Few applications are complete when initially filed. However, an important aspect of all this is that the original date of filing establishes priority for receiving the permit or license. Supplemental information or corrections will probably have to be filed within 90 days or on some other schedule established by the applicant and FERC.

The processing time for an FERC application will depend on the complexity of the project, whether construction and operation of the project would result in significant environmental impacts, whether there are competing applications and protests, and how fast they can be satisfied. For small hydroelectric projects proposed for existing hydraulic structures, environmental impacts would probably be minimal, if any, thus speeding up the FERC processing time. If FERC determines that the project would result in significant environmental impact, FERC would prepare an EIS in accordance with NEPA. To prepare the EIS, FERC will use information furnished by the applicant in the permit and license applications, and the FERC staff will make an on-site investigation.

The FERC license, when issued, will contain certain conditions that must be met by the site developer. The extent of the conditions will depend on the complexity of the project, and could include minimum fish releases, water discharge restrictions, reservoir level limitations, and construction constraints.

License Exemptions. Developers may apply to FERC for exemption from licensing. The application requirements are substantially less than those for a license application. The exemption application ensures that FERC can discharge its regulatory obligations under Section 213 of PURPA and under NEPA.

Conduits. A hydroelectric facility is eligible for a conduit exemption if it meets the following criteria:

(1) If it is built, operated, or maintained for the generation of electric power;

(2) If it is used for the generation of electric power, only the hydroelectric potential of a manmade conduit operated primarily for distributing water for purposes other than generation electricity;

(3) If it has an installed capacity no greater than 15 MW; and

(4) If it is located on non-federal lands.

The definition of a "small conduit hydroelectric facility" is a key element in qualifying for an exemption. The facility must discharge the water it uses for power generation:

(1) into a conduit,

(2) directly to a point of agricultural, municipal, or industrial use, or

(3) into a natural water body and an amount of water equal to or greater than the amount discharged from the hydroelectric facility is withdrawn from the water body downstream into a conduit that is part of the same water supply system as the conduit on which the hydroelectric facility is located.

A hydroelectric plant installed at an irrigation dam may or may not be an extemptible facility depending on whether all or a part of the water released for electric generation is also used for agriculture, municipal, and industrial purposes.

An example of an exemptible facility is a hydroelectric plant on a canal where all water flow is used for irrigation, such as the canal owned and operated by the Turlock Irrigation District. A hydroelectric plant installed at a flood control dam would not be an exemptible facility.

After accepting an exemption application, FERC will circulate a notice to responsible parties, including fish and wildlife agencies. Within 90 days after notifying an applicant that his application is acceptable, FERC will grant the exemption as requested, grant an exemption with modifications to the request, deny the exemption, or suspend the 90-day period. If FERC denies the exemption, the applicant can convert the application to a preliminary permit or license application. If FERC does not take any specific action, the application will be considered granted as requested.

The pertinent portions of Code of Federal Regulations governing conduit exemptions (Subpart J) are reproduced in Attachment No. 1.

Projects of 5 MW or Less. Projects meeting the following criteria are eligible to file for a 5 MW exemption from licensing for hydroelectric projects:

(1) If the project is located entirely on federal lands any person may apply for an exemption.

(2) If the project is located on non-federal lands, only a person, or group of persons holding all of the real property interests necessary to develop and operate that project (such as ownership in fee, a leasehold, easement, right-of-way, or an option to obtain such interest) may apply for an exemption from licensing.

FERC will not accept for filing an exemption application for any project that is only part of a licensed water project.

The pertinent portions of Code of Federal Regulations governing 5 MW facility exemptions (Subpart K) are reproduced in Attachment No. 1.

Categorical Exemption, 5 MW or less. If the proposed rulemaking (Docket No. RM81-7) is adopted by FERC the provisions for categorical exemptions will be added to the Code of Federal Regulations, Subpart K. The proposed categorical exemptions are reproduced in Attachment No. 1.

Preliminary Permits. In 1979, FERC revised its regulations for filing and processing preliminary permit applications to simplify the application and to provide FERC with sufficient information to reduce the processing time (Order No. 54, Docket No. RM79-23). In order to prepare an application for a preliminary permit, the site developer will need to make a preliminary assessment of the project and its potential generation.

The pertinent portions of Code of Federal Regulations governing preliminary permits (Subpart I) are reproduced in Attachment No. 2.

Minor Licenses. In 1978, the FERC revised its regulations for filing and processing license applications for small hydroelectric projects where the total generating capacity would be 1500 kW or less (Order No. 11, Docket No. RM78-9). The "Application for Short-Form License (Minor)" was designed to simplify the application and reduce the processing time. To prepare an application for a minor project, the developer will need to make a feasibility study and an environmental assessment for the proposed project.

The pertinent portions of Code of Federal Regulations governing minor licenses (Section 131.6) are reproduced in Attachment No. 3.

Major Licenses at Existing Dams. In 1979, FERC revised its regulations for filing and processing license applications for hydroelectric projects where total generating capacities would be greater than 1500 kW (Order No. 59, Docket No. RM79-36). The developer can use this application form where a new hydroelectric facility is proposed for an existing dam provided that the development will not significantly change the normal maximum surface area of the impoundment and will not make changes in project operation which would result in significant environmental impacts.

The pertinent portions of Code of Federal Regulations governing major licenses (Subpart F) are reproduced in Attachment No. 4.

Inquiries and requests for more information on the various FERC permit and license applications should be directed to

Federal Energy Regulatory Commission
333 Market Street, Sixth Floor
San Francisco, CA 94105
(415) 764-7137

U. S. Army Corps of Engineers

Dredge and Fill Permit. The Corps of Engineers is responsible for protecting navigable waters under Section 10 of the River and Harbor Act of 1889 and under the Dredge/Fill and Discharge Program of Section 404 of the Clean Water Act of 1977. The Dredge and Fill Permits protect the quality of water resources, marshes, swamps, and wetlands, and prevent the alteration or obstruction of navigable waterways. A permit is required if a structure, excavation, or discharge of dredged or fill materials will be located in waters of the United States. Not all potential hydroelectric sites at existing hydraulic structures will require a Dredge and Fill Permit; the decision on the need for the permit is made by the District Engineer.

When a Dredge and Fill Permit is required, the applicant must complete ENG Form 4345 available from the Corps of Engineers office in the district where the proposed project will be located. The Corps of Engineers districts in California are defined by watershed. They are: Central Valley and Northern Sierra Mountains, with offices in Sacramento; Northern and Central Coastal Ranges, with offices in San Francisco; and Southern California with offices in Los Angeles.

The Dredge and Fill Permit application is reproduced in Attachment No. 5.

The Corps of Engineers encourages applicants to contact the District Engineer's Office that has jurisdiction over the specific geographic location of the structure or activity before submitting an application. Correspondence should be addressed to the District Engineer, U. S. Army Engineer District, as follows:

Central Valley and Northern Sierra Mts.	650 Capitol Mall Sacramento, CA 95814 (916) 440-2327
Northern and Central Coastal Ranges	211 Main Street San Francisco, CA 94105 (415) 556-2752

Southern California — P. O. Box 2711
Los Angeles, CA 90053
(213) 688-5607

Other Federal Agencies

U. S. Bureau of Land Management. The bureau is a land management agency responsible for all public lands except withdrawals for National parks, for the Forest Service, for the Military, and for others. Hydroelectric projects located on lands administered by the bureau will require rights-of-way.

Information regarding required permits or agreements for hydroelectric projects can be obtained from:

U. S. Bureau of Land Management
2800 Cottage Way
Sacramento, CA 95825
(916) 484-4515

U. S. Forest Service. The Forest Service is also a land management agency and is responsible for National Forest lands. Hydroelectric projects in the National Forests must have a Special Use Permit. Applications for this permit should be submitted to the Forest Supervisor for the National Forest in which the project is located. The information in the FERC license application is generally sufficient for the Special Use Permit.

Inquiries and information regarding the location of the headquarters of each National Forest Supervisor can be obtained from:

Regional Forester
U. S. Forest Service
630 Sansome Street
San Francisco, CA 94111
(415) 556-0122

U. S. Water and Power Resources Service (WPRS). Non-federal development of WPRS facilities will require Right-of-Entry Permits, and possibly Operational and Reimbursable Agreements with WPRS. These would be in addition to the conditions contained in the FERC license for the project.

Information regarding non-federal development of WPRS facilities can be obtained from:

Northern California

U. S. Water and Power Resources Service
2800 Cottage Way
Sacramento, CA 95825
(916) 484-4228

Southern California

U. S. Water and Power Resources Service
P. O. Box 427
Nevada Highway & Park Street
Boulder City, NV 89005
(702) 293-2161

STATE APPROVAL PROCESS

A developer must comply with the California Environmental Quality Act of 1970 (CEQA) and may be required to obtain certain permits or certificates with respect to water rights, water quality, dam safety, flood plain, and fish and game management. The state agency having jurisdiction will review the developer's plans and determine if a permit is required.

CEQA Compliance

The first steps in obtaining the basic information needed to comply with CEQA are completing the studies of the projects technical and economic feasibility, and an Initial Study, as set forth in the CEQA Guidelines (California Administrative Code, Title 14, Chapter 3). The Initial Study can be prepared from the environmental assessment used to prepare the environmental report for the FERC licensing process. The environmental assessment is based on the construction and operation of the proposed project as determined in the feasibility study. Generally, the information needed for applications to state agencies that have jurisdiction over a project can be taken from both the feasibility study and the environmental assessment.

In the CEQA process, the lead agency is the public agency which has the principal responsibility for carrying out or approving a project. For private development of a small hydroelectric project at an existing facility, the lead agency shall be the public agency with the greatest responsibility for supervising or approving the project as a whole. If the project is to be carried out by a public agency, the lead agency shall be the public agency which proposes to carry out the project. Each state agency and some local agencies have a list of the information required for an acceptable permit application and the criteria used to decide if an application is complete. Within 30 days of receiving a permit application, the state or local agency must inform the applicant, in writing, whether the application is complete and accepted for filing. If incomplete, the agency must specify the deficiencies and the additional information required. If complete, the agency proceeds with the evaluation. If the agency fails to notify the applicant of deficiency or acceptance within 30 days of receipt, the application is deemed sufficient and accepted.

For projects subject to CEQA requirements, the lead agency must conduct an initial study to determine if the project would have a significant adverse effect on the environment unless the lead agency can determine that the project will clearly have a significant effect. The Initial Study provides a written determination of whether a Negative Declaration or an EIR is required for a proposed project. If any aspect(s) of the project, either individually or cumulatively, may significantly effect the environment, an EIR must be prepared.

The Initial Study serves many purposes:

(1) To facilitate environmental assessment early in the design of a project,

(2) To identify environmental impacts, if any

(3) To focus on potentially significant environmental impacts, if any

(4) To enable project modifications to be made to eliminate or mitigate adverse impacts,

(5) To eliminate unnecessary EIRs, and

(6) To provide documentation for the finding in a Negative Declaration, that a project will not have a significant effect on the environment.

The Initial Study would:

(1) describe the project,

(2) identify the environmental setting,

(3) identify environmental effects by using a checklist, matrix, or other method,

(4) discuss ways to mitigate any significant effects which are identified, if any

(5) examine whether the project is compatible with existing zoning and plans, and

(6) name the person(s) who prepared or participated in the Initial Study.

If on the basis of the Initial Study, the lead agency determines that the proposed project will not have a significant effect(s) on the environment, the lead agency will prepare a Negative Declaration which shall include:

(1) a brief description of the project including its commonly-used name, if any;

(2) the location of the project and the name of the project proponent;

(3) a decision that the project will not have significant effect(s) on the environment;

(4) an attached copy of the Initial Study documenting reasons to support finding(s);

(5) mitigation measures, if any, included in the project to avoid potentially significant effects.

The lead agency must make a Negative Declaration available early enough to provide an opportunity for public response before a decision is made to approve the project. The lead agency will file a Notice of Determination which would include:

(1) the agency's decision to approve the project,

(2) the agency's determination of whether the project will significantly effect the environment,

(3) a statement that no EIR has been prepared pursuant to the provisions of CEQA, and

(4) the location where a copy of the Negative Declaration may be examined.

The Resources Agency, State of California is knowledgeable in the CEQA process and will assist hydroelectric developers to understand and meet CEQA requirements. Further information can be obtained from

The Resources Agency
1416 - 9th Street, Room 1311
Sacramento, CA 95814
(916) 445-9134

State Water Resources Control Board

Water Rights Permits. For a new hydroelectric facility at an existing dam or other hydraulic structure, the State Water Resources Control Board may require either an application for new water rights or a petition to change existing water rights. A petition to change existing rights may be filed when the operation of the turbine is strictly incidental to water use under existing permits and licenses. Otherwise, a new application will be required unless the water flowing through the turbine is fully used under riparian claim or pre-1914 appropriate claim, or is groundwater which was not flowing in a known and definite underground channel before extraction. The Board amended its regulations so that incidental power generation can be added, by petition, to existing permits and licenses for consumptive uses.

The application form and supplemental forms for a water rights permit are reproduced in Attachment No. 6.

Inquiries and applications for permits should be directed to:

State Water Resources Control Board
Division of Water Rights
77 Cadillac Drive
Sacramento, CA 95825
(916) 920-6301

Water Quality Certificates. The responsibility for water quality (under Section 401 of the Clean Water Act of 1977) has been delegated to state regulation by the Environmental Protection Agency. In California, a Regional Water Quality Control Board will decide if a proposed hydroelectric project will affect water quality and will respond to the project developer accordingly. If an application for license or exemption has been made to the FERC, they will require either a copy of the water quality certificate or evidence that such a certificate is not required.

The project developer should submit a copy of the FERC license application for the project to the Regional Water Quality Control Board for the region where the project will be located and request a determination on the effect of the project on water quality.

The Regional Water Quality Control Boards are located at:

Northern Coast Region
1000 Coddingtown Center
Santa Rosa, CA 95401
(707) 545-2620

Redding Branch Office
1815 Sacramento Street
Redding, CA 96001
(916) 442-6276

San Francisco Bay Region
1111 Jackson Street, Room 6040
Oakland, CA 94607
(415) 464-1255

Lahontan Region
2092 Lake Tahoe Boulevard
P. O. Box 14367
South Lake Tahoe, CA 95702
(916) 544-3481

Central Coast Region
1122-A Laurel Lane
San Luis Obispo, CA 93401
(805) 549-3147

Victorville Branch Office
15371 Bonanza Road
Victorville, CA 92392
(714) 245-6585

Los Angeles Region
107 South Broadway, Room 4027
Los Angeles, CA 90012
(213) 620-4460

Colorado River Basin Region
73-271 Highway 111, Suite 21
Palm Desert, CA 92260
(714) 346-7497

Central Valley Region
3201 S Street
Sacramento, CA 95816
(916) 445-0270

Santa Ana Region
6833 Indiana Avenue, Suite 1
Riverside, CA 92506
(714) 684-9330

Fresno Branch Office
3374 East Shields Avenue
Fresno, CA 93726
(209) 488-5116

San Diego Region
6154 Mission Gorge Road
Suite 205
San Diego, CA 92120
(714) 286-5114

Department of Water Resources

Dam Safety Approval. If a hydroelectric facility will require the alteration of an existing dam, the Division of Safety of Dams, Department of Water Resources, will require an "Application for Approval of Plans and Specifications for the Repair or Alteration of a Dam and Reservoir". An Alteration Application (Form DWR-4) is reproduced in Attachment No. 7.

If the installation of a hydroelectric facility will increase the water storage elevation of the reservoir, the developer must file an "Application for Approval of Plans and Specifications for the Construction or Enlargement of a Dam and Reservoir" with detailed plans and specifications showing the modifications. A filing fee based on the estimated cost of the modifications is required for construction or enlargement applications. A licensed engineer must prepare the plans and specifications for alterations or modifications to a dam A Construction Application (Form DWR-3) is reproduced in Attachment No. 8.

Project sponsors should direct inquires and applications to

Department of Water Resources
Division of Safety of Dams
P. O. Box 388
Sacramento, CA 95802
(916) 445-1816

Floodway Permit. If the hydroelectric facility is located on a river or waterway that is contained by project levees or is within a designated floodway, The Reclamation Board will require an application for approval of plans and specifications. Application forms for floodway approval are available from The Reclamation Board's Office in Sacramento. The application should contain or be accompanied by information, description, and drawings to permit the Board to make flood control and environmental assessments of the project. The Application for Approval of Plans and/or Encroachment Permit is reproduced in Attachment No. 9.

The waterways that have been designated by The Reclamation Board as requiring a floodway permit are listed in Table F-2.

Table F-2. Streams Requiring Floodway Permit

Stream	County	Location
American River	Sacramento	Mayhew Road to Nimbus Dam
Ash Slough	Madera	Chowchilla to Chowchilla River
Berenda Slough	Madera	Avenue 21-1/2 to Ash Slough
Chowchilla River	Madera Merced Mariposa	Eastside Bypass to Buchanan Dam Site
Clear Creek	Shasta	Sacramento River to Whiskeytown Dam
Colusa Drain	Glenn Colusa Yolo	Knights Landing to Willows

Table F-2. Streams Requiring Floodway Permit (Continued)

Stream	County	Location
Cosumnes River	Sacramento	Mokelumne River to State Highway 99
Cosumnes River	Sacramento	Highway 99 to El Dorado County Line
Cottonwood Creek	Shasta & Tehama	Confluence Sacramento River to the proposed Dutch Gulch Dam site and 7 miles of the South Fork
Cow Creek System	Shasta	Lower reaches of the following creeks: Cow, Little Cow, Dry, Oak Run and Clover
Dry Creek	Sacramento & Placer	Natomas East Drainage Canal to the City of Roseville Sewage Treatment Plant
Dry Creek	Stanislaus	Tuolumne River to AT&SF Railroad
Feather River	Butte	Honcut Creek to Oroville Fish Hatchery Dam
Fresno River	Madera	AT&SF Railroad to Road 22-1/2
Fresno River	Madera	AT&SF Railroad to Hidden Dam Site
Kaweah River	Tulare	Middle Fork: Kaweah Lake to Ash Mountain North Fork: 2.5 miles upstream from Middle Fork South Fork: 1.75 miles upstream from Middle Fork
Kern River	Kern	Tupman to Golden State Highway
Kern River	Kern & Kings	Tupman to Tulare Lake
Kern River	Kern	Golden State Highway to Isabella Dam
Kings River	Fresno	Reedley to Piedra Dutch John Cut Cole Slough Excelsior Road to Layton McMullen Grade Crossing to Parkhurst-Excelsior Avenue
Kings River	Tulare	Highway 99 to Reedley

Table F-2. Streams Requiring Floodway Permit (Continued)

Stream	County	Location
Kings River	Fresno	Mendota Pool to McMullin Grade Crossing
Kings River	Fresno	Piedra to Pine Flat Dam
Kings River	Fresno	Cameron & Byrd Sloughs
Kings River	Kings	Kings River and distributaries within Kings County
Merced River	Merced	San Joaquin River to Merced Falls
Mokelumne River	San Joaquin & Sacramento	Cosumnes River to Highway 99
Porter Slough	Tulare	Road 192 to Tulare River
Sacramento River	Glenn	Ord Ferry Road to Glenn County-Tehama County Line
Sacramento River	Butte	South Parrott Grant Line to Butte County-Tehama County Line
Sacramento River	Tehama	Tehama County
Sacramento River	Shasta	Keswick Dam to Cottonwood Creek
San Joaquin River	Merced	Merced River to Salt Slough
San Joaquin River	Madera & Fresno	Gravelly Ford Area to Friant Dam
San Joaquin River	San Joaquin, Stanislaus, & Merced	Airport Way to Merced River
Tule River	Tulare	Road 192 to Road 224
Tule River	Tulare	Road 224 to Success Dam
Tule River	Tulare	Springville Area
Tuolumne River	Stanislaus	Mitchell Road to Whitmore Road (Extension of Whitmore Avenue)

Table F-2. Streams Requiring Floodway Permit (Continued)

Stream	County	Location
Tuolumne River	Stanislaus	San Joaquin River to extension of Whitmore Avenue
Tuolumne River	Stanislaus	Mitchell Road to LaGrange Dam
Yuba River	Sutter	Highway 70 to Daguerre Point Dam

For more information, contact The Reclamation Board at:

Department of Water Resources
The Reclamation Board
Floodway Permit Section
1416 Ninth Street, Room 335-10
Sacramento, CA 95814
(916) 445-9225

State Lands Commission

Small hydroelectric projects located on state-owned lands or waterways (Except for projects on the State Water Project and the Central Valley Project) will require a land use lease from the State Lands Commission. If the project requires dredging in state-owned swamps, overflows, marshes, tidelands, and/or submerged lands, or in the beds of navigable waters where the state has mineral rights, a Dredging Permit will be required.

The Commission has an "Application Requirements Checklist" (Form 54.1) and a "General Data" (Form 54.1) that serves the Commission in its efforts. Since leases, licenses, permits, land sales, or other entitlements to use state lands under the jurisdiction of the Commission can only be authorized after compliance with the California Environmental Quality Act (CEQA), the Commission also has an "Environmental Data" (Form 54.3) and "Environmental Information Form" (EIF) which specify the format and detail of the data that must be supplied when applying for Commission action.

These forms are reproduced in Attachment No. 10.

Inquiries and application for permits should be directed to:

Dredging Permits

State Lands Commission
1807 - 13th Street
Sacramento, CA 95814
Attention:
Dredging Coordinator
(916) 322-7802

Other Than Dredging Permits

State Lands Commission
Division of Land Management
and Conservation
1807 - 13th Street
Sacramento, CA 95814
(916) 445-7738

Department of Fish and Game

Stream or Lake Alteration Agreements. If a project will change the natural state of any river, stream, or lake, the project's sponsor must enter into a Stream or Lake Alteration Agreement with the Department of Fish and Game. These agreements are often referred to as 1601 or 1603 permits. In general, this requirement applies to any work undertaken within the mean high-water mark of a body of water which contains fish or wildlife resources or where the project sponsor will use material from the stream-bed. The Department of Fish and Game determines the high-water mark by (1) the height of residue deposited by the stream, river, or lake on its bank or beach in the course of a normal year; (2) the yearly fluctuation in flow; (3) personal knowledge of the area involved; and (4) United States Geological Survey charts. The application form for an alteration agreement is reproduced in Attachment No. 11.

All inquiries and applications for Stream or Lake Alteration Agreement should be directed to the Fish and Game office in the area where the project is located as follows:

Department of Fish and Game 627 Cypress Redding, CA 96001 (916) 246-6511	Del Norte, Humboldt, Lassen, Modoc, Shasta, Siskiyou, Tehama and Trinity Counties
Department of Fish and Game 1001 Jedsmith Drive Sacramento, CA 95819 (916) 355-7030	Alpine, Amador, Butte, Calaveras, Colusa, eastern Contra Costa, El Dorado, Glenn, Lake, Napa, Nevada, Placer, Plumas, Sacramento, San Joaquin, Sierra, eastern Solano, Sutter, Yolo, and Yuba Counties
Department of Fish and Game Yountville Veterans Facility P. O. Box 47 Yountville, CA 94599 (707) 944-2443	Alameda, western Contra Costa, Marin, Mendocino, Monterey, San Benito, San Luis Obispo, San Mateo, Santa Clara, Santa Cruz, western Solano, and Sonoma Counties
Department of Fish and Game 1234 East Shaw Avenue Fresno, CA 93710 (209) 222-3761	Fresno, Kern, Kings, Madera, Mariposa, Merced, Stanislaus, Tulare, and Tuolumne Counties
Department of Fish and Game 350 Golden Shore Long Beach, CA 90802 (213) 590-5177	Imperial, Inyo, Los Angeles, Mono, Orange, Riverside, San Bernardino, San Diego, Santa Barbara, and Ventura Counties

Office of State Treasurer

The Districts Securities Division of the State Treasurer's Office has financial supervision over special districts and certain other local agencies for the benefit of their constituents and to help establish and maintain the confidence of the bond-buying public. This protects the credit rating of districts, agencies, and the state. The Division conducts an impartial examination of the overall feasibility and financial soundness of each major debt proposal, and supervises the expenditure of proceeds from the sale of bonds, warrants, or other forms of indebtedness. It also conducts engineering inspections of the projects under construction to assure investors that the project being financed will be completed as planned. Each district with outstanding certified securities must file an annual report of its financial transactions with the State Treasurer.

In general, the Districts Securities Division has financial supervision over all districts that have landowner or assessed-value voting. Districts that have resident voting are subject to financial supervision only as specified in the act under which the district may be formed. Districts subject to financial supervision file an application with the State Treasurer, and after review of the financial and engineering analyses including an open public meeting, the State Treasurer will issue a report or order setting forth his determination and authorizing the district to proceed in a specific manner.

Project sponsors should direct inquiries and applications to:

Office of State Treasurer
Districts Securities Division
120 Montgomery Street, Room 1025
San Francisco, CA 94104
(415) 557-1932

COUNTY OR SPECIAL DISTRICTS

Most small hydroelectric projects will require local approval by the counties or special districts within whose boundaries the facilities will be located. This approval may be in the form of general plan amendments, rezonings, use permits, variances, grading permits, and/or building permits. Since the requirements are site-specific and vary from one county to another, detailed information cannot be provided in this report. Developers should contact the appropriate County Clerk and Planning Department(s) for further information.

ATTACHMENT NO. 1

FEDERAL ENERGY REGULATORY COMMISSION

LICENSE EXEMPTIONS

- Conduits, 15 MW or less
- Projects of 5 MW or less
- Categorical Exemptions
  - Greater than 100 kW but not more than 5 MW
  - Less than 100 kW

Attachment No. 1

License Exemption

The FERC rulemaking under Section 213 of PURPA concerning exemption of small conduit hydroelectric facilities from regulation added Subpart J to Part 4, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations. Sections 4.90, 4.91, and 4.92 of Subpart J are reproduced in the following paragraphs to allow potential site developer to determine if the proposed hydroelectric facility may be exempt from federal regulation and to provide the procedure for making an application for exemption.

Similarily, the FERC rulemaking under Section 408 of the Energy Security Act of 1980 concerning exemption of hydroelectric projects of 5 MW or less from licensing added Subpart K to Part 4, Subchapter B, Chapter 1, of Title 18, Code of Federal Regulations. Sections 4.101 through 4.107 of Subpart K are also reproduced in the following paragraphs.

FERC has issued a proposed rulemaking (Docket No. RM81-7, December 22, 1980) to provide for exemption for two categories of hydroelectric projects of 5 MW or less. This would amend and revise titles and paragaphs of Subpart K and add Sections 4.109 through 4.113. These are reproduced in the following paragraphs.

Subpart J - EXEMPTION OF SMALL CONDUIT HYDROELECTRIC FACILITIES

§4.90 Applicability and purpose.

This subpart implements Section 30 of the Federal Power Act and provides procedures for obtaining an exemption for constructed or unconstructed small conduit hydroelectric facilities, as defined in §4.91, from all or part of the requirements of Part I of the Federal Power Act, including licensing, and the regulations issued under Part I.

§4.91 Definitions.

For the purpose of this subpart:

(a) "Conduit" means any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity. The term "not primarily for the generation of electricity" includes but is not limited to a conduit:

(i) which was built for the distribution of water for agricultural, municipal, or industrial consumption, and is operated for such a purpose, and

(ii) to which a hydroelectric facility has been or is proposed to be added.

(b) "Construction of a dam" means any construction, repair, reconstruction, or modification of a dam that creates a new impoundment or increases the normal maximum surface elevation or the normal maximum surface area of an existing impoundment.

(c) "Dam" means any structure that impounds water.

(d) "Fish and wildlife agencies" means the U.S. Fish and Wildlife Service, the National Marine Fisheries Service if anadromous fish may be affected, and any State agency with administrative authority over fish or wildlife resources of the State in which a particular small conduit hydroelectric facility will be located.

(e) "Non-Federal lands" means any lands except land to which the United States holds fee title.

(f) "Small conduit hydroelectric facility" means an existing or proposed hydroelectric facility, including all structures, fixtures, equipment, and lands used and useful in the operation or maintenance of the hydroelectric facility, but not including the conduit on which the hydroelectric facility is located or the transmission lines associated with the hydroelectric facility, which facility is constructed, operated, or maintained for the generation of electric power and:

(1) utilizes for electric power generation the hydroelectric potential of a conduit;

(2) is located entirely on non-Federal lands;

(3) has an installed generating capacity of 15 megawatts or less;

(4) is not an integral part of a dam;

(5) discharges the water it uses for power generation either:

(i) into a conduit;

(ii) directly to a point of agricultural, municipal, or industrial consumption; or

(iii) into a natural water body, if a quantity of water equal to or greater than the quantity discharged from the hydroelectric facility is withdrawn from that water body downstream into a conduit that is part of the same water supply system as the conduit on which the hydroelectric facility is located; and

(6) does not rely upon construction of a dam which construction will create any portion of the hydrostatic head that the facility uses for power generation, unless that construction would occur for agricultural, municipal, or industrial consumptive purposes even if hydroelectric generating facilities were not installed.

§4.92 Exemption applications.

(a) Who may apply. Any citizen or association of citizens of the United States, municipality, State, or corporation incorporated under the laws of the United States or a State, may apply for exemption of a small conduit hydroelectic facility from all or part of the provisions of Part I of the Federal Power Act.

(b) General requirements. (1) Except as otherwise prescribed in this subpart, an application for exemption of a small conduit hydroelectric facility must conform to the requirements set forth in §§1.5 and 1.14 through 1.17 of this chapter. (2) An original and fourteen copies of the exemption application must be submitted to the Secretary of the Commission. Full-sized prints (but not the originals) of all required maps and drawings must be filed with the original application. The original maps or drawings (microfilm) may be requested pursuant to §4.31(c) of this part.

(c) Contents of Application. (1) An application for exemption under this subpart must include:

(i) an introductory statement, including a declaration that the facility for which application is made meets the requirements of §4.91(f) of this subpart (If the facility qualifies but for the discharge requirement of §4.91(f)(5), the introductory statement must identify that fact and state that the application is accompanied by a petition for waiver of §4.91(f)(5), filed pursuant to §1.7(b) of this chapter.); and

(ii) Exhibits A, B, E, and G.

(2) Introductory Statement. The introductory statement must be set forth in the following format:

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR EXEMPTION FOR SMALL
CONDUIT HYDROELECTRIC FACILITY

[Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for the [name of facility], a small conduit hydroelectric facility that meets the requirements of [insert the following language, as appropriate: "§4.91(f) of this subpart" or "§4.91(f) of this subpart, except paragraph (f)(5)"], from certain provisions of Part I of the Federal Power Act.

The location of the facility is:

State or Territory:
County:
Township or nearby town:

The exact name and business address of each applicant are:

____

____

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

____

____

____

[Name of applicant] is [a citizen of the United States, an association of citizens of the United States, a municipality, State, or a corporation incorporated under the laws of (specify the United States or the State of incorporation, as appropriate), as appropriate].

The provisions of Part I of the Federal Power Act for which exemption is requested are:

[List here all sections or subsections for which exemption is requested.]

[If the facility does not meet the requirement of §4.91(f)(5), add the following sentence: "This application is accompanied by a petition for waiver of §4.91(f)(5), submitted pursuant to 18 C.F.R §1.7(b)."]

(3) <u>Exhibit A</u>. Exhibit A must describe the small conduit hydroelectric facility and proposed mode of operation with appropriate references to Exhibits B and G. To the extent feasible the information in this exhibit may be submitted in tabular form. The following information must be included:

(i) a brief description of any conduits and associated consumptive water supply facilities, intake facilities, powerhouses, and any other structures associated with the facility.

(ii) The proximate natural sources of water that supply the related conduit.

(iii) The purposes for which the conduit is used.

(iv) The number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units.

(v) The type of each hydraulic turbine.

(vi) A description of how the plant is to be operated, manually or automatically, and whether the plant is to be used for peaking.

(vii) Estimations of:

(A) the average annual generation in kilowatt hours;

(B) the average head of the plant;

(C) the hydraulic capacity of the plant (flow through the plant) in cubic feet per second;

(D) the average flow of the conduit at the plant or point of diversion; and

(E) the average amount of the flow described in clause (D) available for power generation.

(viii) The planned date for beginning construction of the facility.

(ix) If the hydroelectric facility discharges directly into a natural body of water and a petition for waiver of §4.91(f)(5) has not be submitted, evidence that a quantity of water equal to or greater than the quantity discharged from the hydroelectric facility is withdrawn from that water body downstream into a conduit that is part of the same water supply system as the conduit on which the hydroelectric facility is located.

(x) If the hydroelectric facility discharges directly to a point of agricultural, municipal, or industrial consumption, a description of the nature and location of that point of consumption.

(xi) A description of the nature and extent of any construction of a dam that would occur in association with construction of the proposed small conduit hydroelectric facility, including a statement of the normal maximum surface area and normal maximum surface elevation of any existing impoundment before and after that construction; and any evidence that the construction would occur for agricultural, municipal, or industrial consumptive purposes even if hydroelectric generating facilities were not installed.

(4) Exhibit B. Exhibit B is a general location map that must show the following information:

(i) the physical structures of the small conduit hydroelectric facility in relation to the conduit and any dam to which any of these structures is attached;

(ii) a proposed boundary for the small conduit hydroelectric facility, by indicating distances from the facility's structures; and

(iii) the ownership of the parcels of the land within the proposed boundary for the small conduit hydroelectric facility.

(5) Exhibit E. This exhibit is an environmental report that must include the following information, commensurate with the scope and environmental impact of the facility's construction and operation:

(i) A description of the environmental setting in the vicinity of the facility, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational use, socio-economic conditions, historical and archeological resources, and visual resources. The report must give special attention to endangered or threatened plant and animal species, critical habitats, and sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from State natural resources agencies, the State historic preservation officer, and from local offices of Federal natural resources agencies.

(ii) A description of the expected environmental impacts resulting from the continued operation of an existing small conduit hydroelectric facility, or from the construction and operation of a proposed small conduit hydroelectric facility, including a discussion of the specific measures proposed by the applicant and others to protect and enhance environmental resources and to mitigate adverse impacts of the facility on them.

(iii) A description of alternative means of obtaining an amount of power equivalent to that provided by the proposed or existing facility.

(iv) Documentary evidence that the applicant consulted with fish and wildlife agencies before filing, including any terms or conditions of exemption that those agencies have determined are appropriate to prevent loss of, or damage to, fish and wildlife resources or otherwise to carry out the provisions of the Fish and Wildlife Coordination Act. If any fish or wildlife agency fails to provide the applicant with timely documentation of the consultation process, the applicant may submit a summary of the consultation and any determinations of the agency.

(v) Any additional information the applicant considers important.

(6) Exhibit G. Exhibit G is a set of drawings showing the structures and equipment of the small conduit hydroelectric facility. The drawings must include plan, elevation, profile, and section views of the power plant and any other principal facility structure and of any dam to which a facility structure is attached. Each drawing must be an ink drawing or a drawing of similar quality on a sheet no smaller than eight and one-half inches by eleven inches, with a scale no smaller than one inch equals 50 feet for plans and profiles and one inch equals 10 feet for sections. Generating and auxiliary equipment must be clearly and simply depicted and described. For purposes of this subpart, these drawing specifications replace those required in §4.32 of the Commission's regulations.

Subpart K - EXEMPTION OF SMALL HYDROELECTRIC POWER PROJECTS OF 5 MEGAWATTS OR LESS (Case-by-Case Basis)

§4.101 Purpose

This subpart provides a procedure for obtaining exemption on a case-by-case basis from all or part of Part I of the Federal Power Act (Act), including licensing, for certain small hydroelectric power projects.

§4.102 Definitions.

For purposes of this subpart --

(a) "Dam" means any structure for impounding water, including any diversion structure that is designed to obstruct all or substantially all of the flow of a natural body of water.

(b) "Existing dam" means any dam, the construction of which was completed on or before April 20, 1977, and which does not require any construction or enlargement of impoundment structures (other than repairs or reconstruction) in connection with the installation of any small hydroelectric power projects.

(c) "Fish and wildlife agencies" means the U.S. Fish and Wildlife Service, the National Marine Fisheries Service if anadromous or estuarine fish may be affected, and any state agency with administrative authority over fish or wildlife resources of the state or states in which the small hydroelectric power project is or will be located.

(d) "Federal lands" means any lands to which the United States holds fee title.

(e) "Non-Federal lands" means any lands other than Federal lands.

(f) "Real property interests" includes ownership in fee, right-of-way, easement, or leasehold.

(g) "Licensed water power project" means a project, as defined in section 3 (11) of the Act, that is licensed under Part I of the Act.

(h) "Project" means:

(1) the impoundment and any associated dam, intake, water conveyance facility, power plant, primary transmission line, and other appurtenant facility, if a lake or similar natural impoundment or a man-made impoundment is used for power generation; or

(2) any diversion structure other than a dam and any associated water conveyance facility, power plant, primary transmission line, and

other appurtenant facility, if a natural water feature other than a lake or similar natural impoundment is used for power generation.

(i) "Person" means any individual and, as defined in section 3 of the Act, any corporation, municipality, or state.

(j) "Qualified exemption applicant" means any person who meets the requirements specified in § 4.103(b)(2) with respect to a small hydroelectric power project for which exemption from licensing is sought.

(k) "Qualified license applicant" means any person to whom the Commission may issue a license, as specified in section 4(e) of the Act.

(l) "Small hydroelectric power project" means any project in which capacity will be installed or increased after the date of application under this subpart and which will have a total installed capacity of not more than 5 megawatts and which:

(1) would utilize for electric power generation the water power potential of an existing dam that is not owned or operated by the United States or by any instrumentality of the Federal Government, including the Tennessee Valley Authority; or

(2) would utilize a natural water feature for the generation of electricity, without the need for any dam or man-made impoundment.

(m) "Install or increase" means to add new generating capacity at a site that has no existing generating units, to replace or rehabilitate an abandoned or unused existing generating unit, or to increase the generating capacity of any existing power plant by installing an additional generating unit or by rehabilitating an operable generating unit in a way that increases its rated electric power output.

§4.103 General provisions.

(a) Exemptible projects. Except as provided in paragraph (c), the Commission may exempt under this subpart any small hydroelectric power project from all or part of Part I of the Act, including licensing.

(b) Who may apply.

(1) Exemption from provisions other than licensing. Any qualified license applicant or licensee seeking amendment of license may apply for exemption of the related project from provisions of Part I of the Act other than licensing.

(2) Exemption from licensing.

(i) Only Federal lands involved. If only rights to use or occupy Federal lands would be necessary to develop and operate the proposed small hydroelectric power project, any person may apply for exemption of that project from licensing.

(ii) Some non-Federal lands involved. If real property interests in any non-Federal lands would be necessary to develop and operate the proposed small hydroelectric power project, any person who has all of the real property interests in non-Federal lands necessary to develop and operate that project, or an option to obtain those interests, may apply for exemption of that project from licensing.

(c) Limitation for licensed water power project. The Commission will not accept for filing an application for exemption from licensing for any project that is only part of a licensed water power project.

(d) Waiver. A qualified exemption applicant may petition under §1.7 of this chapter for waiver of any specific provision of this subpart. The Commission may grant a waiver if consistent with section 408 of the Energy Security Act of 1980.

§4.104 Relationships among applications, exemptions, permits, and licenses.

For purposes of this subpart, the Commission will treat preliminary permit and license applications, preliminary permits, licenses, exemptions from licensing, and applications for exemption from licensing that are related to a small hydroelectric power project as follows:

(a) Limitations on submission and acceptance of exemption applications.

(1) Unexpired permit or license. If there is an unexpired preliminary permit or license in effect for a project, the Commission will accept an application for exemption of that project from licensing only if the exemption applicant is the permittee or licensee.

(2) Pending permit or license application.

(i) Pending permit application. If a preliminary permit application for a project has been accepted for filing, an application for exemption of that project from licensing, or a notice of intent to submit such an application, may be submitted not later than the last date for filing protests or petitions to intervene prescribed in the public notice issued for the permit application under §4.31(c)(2) of this chapter.

(ii) Pending license application.

(A) Submitted by permittee. If an accepted license application for a project was submitted by a permittee before the preliminary permit expired, the Commission will not accept an application for exemption of that project from licensing submitted by a person other than the permittee.

(B) Submitted by non-permittee other than qualified exemption applicant. Except as provided in clause (A), if the first accepted license application for a project was filed by a person other than a qualified exemption applicant, an application for exemption from licensing, or a notice of intent to submit such an application, may be submitted not later than the last date for filing protests or petitions to intervene prescribed in the public notice issued for that license application under §4.31(c)(2) of this chapter.

(C) Submitted by qualified exemption applicant. If the first accepted license application for a project was filed by a qualified exemption applicant, the applicant may request that its license application be treated initially as an application for exemption from licensing by so notifying the Commission in writing and, unless only rights to use or occupy Federal lands would be necessary to develop and operate the project, submitting documentary evidence showing that the applicant holds the real property interests under §4.103(b)(2)(ii). Such notice and documentation must be submitted not later than the last date for filing protests or petitions to invervene prescribed in the public notice issued for the license application under §4.31(c)(2) of this chapter.

(b) Priority of exemption applicant's earlier permit or application. Any accepted preliminary permit or license application submitted by a person who later applies for exemption of the project from licensing under paragraph (a)(2)(i) or (ii)(C) will retain its validity and priority under Subpart D of this part until the preliminary permit or license application is withdrawn or the project is exempted from licensing under this subpart.

(c) Limitations on submission and acceptance of permit or license applications.

(1) General rule. Except as permitted under subparagraph (2) or under §4.106(c) or (e), the Commission will not accept a preliminary permit or license application for any small hydroelectric project if:

(i) that project is exempt from licensing, under this subpart; or

(ii) the Commission has accepted an application for exemption of that project from licensing and the application has not yet been granted or denied.

(2) Exceptions.

(i) If the Commission has accepted an application for exemption of a project from licensing, any qualified license applicant may submit a competing license application that proposes to develop at least 7.5 megawatts in that project, or a notice of intent fo file such a license application, not later than the last date for filing protests or petitions to intervene prescribed in the public notice of the application for exemption from licensing issued under §4.31(c)(2) of this chapter.

(ii) If a project is exempted from licensing and real property interests in any non-Federal lands would be necessary to develop and operate the project, any person who is a qualified license applicant and has any of those real property interests in non-Federal lands may submit a license application for that project.

(iii) If the Commission has accepted an application for exemption of a project from licensing and the application has not yet been granted or denied, the applicant for exemption may submit a license application for that project if it is a qualified license applicant. The pending application for exemption from licensing will be considered withdrawn as of the date that the Commission accepts the license application for filing.

(iv) If a license application submitted under clause (ii) or (iii) has been accepted for filing, any qualified license applicant may submit a competing license application in accordance with §4.33 of this part.

(d) Requirements for notices of intent and competing applications.

(1) Competing exemption applications and notices of intent.

(i) Any notice of intent to file an application for exemption from licensing submitted under paragraph (a)(2)(i) or (ii)(B) must conform to the requirements of §4.33(b) of this chapter.

(ii) If a notice of intent is submitted under paragraph (a)(2)(i) or (ii)(B), the application for exemption from licensing must be submitted not later than 120 days after the last date for filing protests and petitions to intervene prescribed in the public notice issued for the permit or license application under §4.31(c)(2) of this chapter.

(iii) Any notice of intent or application for exemption from licensing submitted under paragraph (a)(2)(i) or (ii)(B) must be accompanied by proof of service of a copy of the notice of intent or exemption application on the permit or license applicant.

(2) Competing license applications and notices of intent.

(i) Any notice of intent to file a license application submitted under paragraph (c)(2)(i) must conform to the requirements of §4.33(b) of this chapter and specify the capacity that the applicant proposes to install in the project.

(ii) If a notice of intent is submitted under paragraph (c)(2)(i), the license application must be submitted not later than 120 days after the last date for filing protests and petitions to intervene prescribed in the public notice issued for the exemption application under §4.31(c)(2) of this chapter.

(iii) Any notice of intent or application for license submitted under paragraph (c)(2)(i) must be accompanied by proof of service of a copy of the notice or application on the exemption applicant.

(e) Disposition of competing applications.

(1) Exemption v. permit. If an accepted application for a preliminary permit and an accepted application for exemption from licensing propose to develop mutually exclusive small hydroelectric power projects, the Commission will favor the application for exemption.

(2) Exemption v. license. If an application for a license and an application for exemption from licensing are each accepted for filing and each propose to develop a mutually exclusive project, the Commission will favor the application first filed, unless the Commission determines the plans of the subsequent applicant would better develop the water power potential of the affected water resources.

§4.105 Action on exemption applications.

(a) Exemption from provisions other than licensing. An application for exemption of a small hydroelectric power project from provisions of Part I of the Act other than the licensing requirement will be processed and considered as part of the related application for license or amendment of license.

(b) Exemption from licensing.

(1) General Procedure. An application for exemption of a small hydroelectric power project from licensing will be processed in accordance with paragraphs (c) through (g) of §4.31 of this part, except that notice will be published only once in a daily or weekly newspaper of general circulation in each county in which the project is or will be located. The additional time that may be allowed under §4.31(d) of this part for correcting deficiencies in an application for exemption may not exceed 45 days.

(2) Hearing. The Commission may order a hearing on an application for exemption from licensing either on its own motion or on the motion of any party in interest. Any hearing shall be limited to the isslues prescribed by order of the Commission.

(3) Consultation. The Commission will circulate a notice of application for exemption from licensing to interested agencies at the time the applicant is notified that the application is accepted for filing. If a particular agency does not comment within 60 days from the date of issuance of the notice, that agency will be presumed to have no comment on or objection to the exemption requested. Any comments submitted by a fish or wildlife agency must include any specific terms or conditions that the agency has determined are necessary to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the provisions of the fish and Wildlife

Coordination Act, except those terms or conditions that may be included in Exhibit E of the application for exemption submitted under §4.107(e). Any fish or wildlife agency that does not comment within the 60-day period will be presumed to have determined that no terms or conditions of exemption are necessary for the above purposes, except the terms and conditions included in Exhibit E of the exemption application.

(4) Automatic exemption. If the Commission has not taken one of the actions set forth in subparagraph (5) within 120 days after notifying the applicant that its application for exemption from licensing is accepted for filing, exemption of the project, as proposed, will be deemed to be found consistent with the public interest and granted, on the standard terms and conditions set forth in §4.106.

(5) Affirmative action on exemption. Within 120 days after notifying an applicant that its application for exemption from licensing is accepted for filing, the Commission may take any of these affirmative actions:

(i) grant the exemption as requested;

(ii) grant an exemption from provisions of Part I of the Federal Power Act (and the regulations issued under those provisions) other than those for which exemption was requested, upon finding that modification of the exemption requested is in the public interest;

(iii) deny exemption if granting the exemption would be inconsistent with the public interest; or

(iv) suspend the 120-day period for action under this paragraph, upon finding that additional time is necessary for gathering additional information, conducting additional proceedings; or deliverating on the issues raised by the application.

(6) Non-standard terms and conditions. In granting an exemption from licensing, the Commission may prescribe terms or conditions in addition to those set forth in §4.106 in order to:

(i) protect the quality or quantity of the related water supply;

(ii) otherwise protect life, health, or property;

(iii) avoid or mitigate adverse environmental impact; or

(iv) better conserve, develop, or utilize in the public interest the water resources of the region.

§4.106 Standard terms and conditions of exemption from licensing.

Any exemption from licensing granted under this subpart for a small hydroelectric power project is subject to the following standard terms and conditions:

(a) Article 1. The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt project. If any terms or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(b) Article 2. The construction, operation, and maintenance of the exempt project must comply with any terms and conditions that any Federal or state fish and wildlife agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the purposes of the Fish and Wildlife Coordination Act, as specified in Exhibit E of the application for exemption from licensing or in the comments submitted in response to the notice of the exemption application.

(c) Article 3. The Commission may accept a license application by any qualified license applicant and revoke this exemption if actual construction or development of any proposed generating facilities has not begun within 18 months, or been completed within four years, from the date on which this exemption was granted. If an exemption is revoked, the Commission will not accept a subsequent application for exemption within two years of the revocation.

(d) Article 4. This exemption is subject to the navigation servitude of the United States if the project is located on navigable waters of the United States.

(e) Article 5. This exemption does not confer any right to use or occupy any Federal lands that may be necessary for the development or operation of the project. Any right to use or occupy any Federal lands for those purposes must be obtained from the administering Federal land agencies. The commission may accept a license application by any qualified license applicant and revoke this exemption, if any necessary right to use or occupy Federal lands for those purposes has not been obtained within one year from the date on which this exemption was granted.

§4.107 Contents of application for exemption from licensing.

(a) General requirements.

(1) An application for exemption from licensing submitted under this subpart must contain the introductory statement and exhibits

described in this section and, if the project structures would use or occupy any lands other than Federal lands, an appendix containing documentary evidence showing that the applicant has the real property interests required under §4.103(b)(2)(ii) of this subpart. An application for exemption from licensing must conform to the requirements set forth in §§1.5 and 1.14 through 1.17 of this chapter.

(2) An original and fourteen copies of the exemption application must be submitted to the Secretary of the Commission, and a copy must be served at the same time on the Commission's regional engineer for the region in which the project is located and on each of the consulted fish and wildlife agencies. Full-sized prints of all required maps and drawings must be filed with the application. Maps and drawings need not conform to the requirements of §4.32 of this part, but must be of sufficient size, scale, and quality to permit easy reading and understanding. The Commission will request original drawings (microfilm) when it notifies the applicant that the application is accepted.

(b) Introductory statement. The application must include an introductory statement that conforms to the following format:

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR EXEMPTION OF
SMALL HYDROELECTRIC POWER PROJECT
FROM LICENSING

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for an exemption for [name of project], a small hydroelectric power project that is proposed to have an installed capacity of 5 megawatts or less, from licensing under the Federal Power Act. [If applicable: The project is currently licensed as FERC Project No. _____.]

(2) The location of the project is:

[State or territory] ____________________

[County] ____________________

[Township or nearby town] ____________________

[Stream or body of water] ____________________

(3) The exact name and business address of each applicant are:

____

____

____

(4) The exact name and business address of each person authorized to act as agent for the applicant in this application are:

____

____

____

(5) [Name of applicant] is [specify, as appropriate: a citizen of the United States or other identified nation; an association of citizens of the United States or other identified nation; a municipality; a state; or a corporation incorporated under the laws of (specify the United States or the state or nation of incorporation, as appropriate)].

(c) Exhibit A. Exhibit A must decribe the small hydroelectric power project and its proposed mode of operation. To the extent feasible, the information in this exhibit may be submitted in tabular form. The applicant must submit the following information:

(1) A brief description of any existing dam and impoundment proposed to be utilized by the small hydroelectric power project and any other existing or proposed project works and appurtenant facilities, including intake facilities, diversion structures, powerhouses, primary transmission lines, penstocks, pipelines, spillways, and other structures, and the sizes, capacities, and construction materials of those structures.

(2) The number of existing and proposed generating units at the project, including auxiliary units, the capacity of each unit, any provisions for future units, and a brief description of any plans for retirement or rehabilitation of existing generating units.

(3) The type of each hydraulic tubine of the small hydroelectric power project.

(4) A description of how the power plant is to be operated, that is, run-of-river or peaking.

(5) A graph showing a flow duration curve for the project or, if flow data are not available from United States Geological Survey records, the estimated average annual stream flow in cubic feet per second.

(6) Estimations of:

(i) the average annual generation in kilowatt-hours;

(ii) the average and design head of the power plant;

(iii) the hydraulic capacity of each turbine of the power plant (flow through the plant) in cubic feet per second;

(iv) the number of surface acres of the man-made or natural impoundment used, if any, at its normal maximum surface elevation and its net and gross storage capacities in acre-feet.

(7) The planned data for beginning and completing the proposed construction or development of generating facilities.

(8) A description of the nature and extent of any repair, reconstruction, or other modification of a dam that would occur in association with construction or development of the proposed small hydroelectric power project, including a statement of the normal maximum surface area and normal maximum surface elevation of any existing impoundment before and after construction.

(d) Exhibit B. Exhibit B is a general location map, which may be prepared on United States Geological Survey topographic quadrangle sheets or similar topographic maps of a state agency, enlarged, if necessary, to show clearly and legibly all of the information required by this paragraph. The map must show the following information:

(1) The location of the existing and proposed physical structures of the small hydroelectric power project, including any dam or diversion structure, reservoir or impoundment, penstocks, pipelines, power plants, access roads, transmission lines, and other important features.

(2) The relationship of the project structures to the stream or other body of water on which the project is located and to the nearest town or other permanent objects that can be readily recognized in the field.

(3) A description of who owns or otherwise has real property interests in any tract of land occupied by the small hydroelectric power project or the structures to which it is directly connected.

(e) Exhibit E. This exhibit is an environmental report that must include the following information, commensurate with the scope and environmental impact of the construction and operation of the small hydroelectric power project:

(1) A description of the environmental setting of the project, including vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational uses, historical and archeological resources, and scenic and aesthetic resources. The report must list any endangered or threatened plant and animal species, any critical habitats, and any sites eligible for or included on the National Register of Historic Places. The applicant may obtain assistance in the preparation of this information from state natural resources agencies, the state historic preservation officer, and from local offices of Federal natural resources agencies.

(2) A description of the expected environmental impacts from the proposed construction or development and the proposed operation of the small hydroelectric power project, including any impacts from any

proposed changes in the capacity and mode of operation of the project if it is already generating electric power, and an explanation of the specific measures proposed by the applicant, the agencies consulted, and others to protect and enhance environmental resources and values and to mitigate adverse impacts of the project on such resources.

(3) Letters or other documentation showing that the applicant consulted or attempted to consult with each of the relevant fish and wildlife agencies (specify each agency) before filing the application, including any terms or conditions of exemption that those agencies have determined are appropriate to prevent loss of, or damage to, fish or wildlife resources or otherwise to carry out the provisions of the Fish and Wildlife Coordination Act. If any fish or wildlife agency fails to provide the applicant with documentation of the consultation process within a reasonable time, in no case less than 30 days after documentation is requested, the applicant may submit a summary of the consultation and any determinations of the agency. Any exemption application that does not contain the information in this subparagraph will be considered patently deficient and be rejected pursuant to §4.31(d) of this part. The applicant may obtain a list of fish and wildlife agencies from the Director of the Division of Hydropower Licensing or any Regional Engineer.

(4) Any additional information the applicant considers important.

(f) Exhibit G. Exhibit G is a set of drawings showing the structures and equipment, that is, the proposed and existing project works, of the small hydroelectric power project. The drawings must include plan, elevation, and section views of the power plant, any existing dam or diversion structure, and any other principal structure of the project.

§4.108 Contents of Application for exemption from provisions other than licensing.

An application for exemption of a small hydroelectric power project from provisions of Part I of the Act other than the licensing requirement need not be prepared according to any specific format, but must be included as an identified appendix to the related application for license or amendment of license. The application for exemption must list all sections or subsections of Part I of the Act for which exemption is requested.

Subpart K of Part 4 is amended by revising § 4.101 and by revising the title and paragraphs (a) and (d) of § 4.103, and by adding §§ 4.109 though 4.113, to read as follows for certain projects with installed capacity of more than 100 kilowatts.

SUBPART K - EXEMPTION OF SMALL HYDROELECTRIC POWER PROJECTS OF 5 MEGAWATTS OR LESS[1/]

§4.101 Applicability. (a) General. This subpart provides procedures for exemption on a case-specific or categorical basis from all or part of Part I of the Federal Power Act (Act), including licensing, for small hydroelectric power projects as defined in §4.102.

(b) Case-specific exemption. The provisions of §§ 4.103 through 4.108 apply to:

(1) exemption of any small hydroelectric power project from provisions of Part I of the Act other than licensing; and

(2) exemption of any small hydroelectric power project from licensing, except any project that has been exempted as part of a category of exemptible projects under §§4.109 through 4.112.

(c) Categorical exemption of certain projects of more than 100 kilowatts. The provisions of §§4.109 through 4.112 apply to exemption from licensing for any small hydroelectric power project which meets the criteria set forth in § 4.109(a) of this subpart. Such projects may be exempted by filing a notice of exemption from licensing.

(d) Categorical exemption of certain projects of 100 kilowatts or less. The provisions of §4.113 apply to certain small hydroelectric power projects which have a proposed installed capacity of 100 kilowatts or less and which are categorically exempt from licensing by operation of this subpart.

* * * * *

§4.103 General provisions for case-specific exemption.

(a) Exemptible projects. Subject to the provisions of paragraphs (b) and (c) of this section and §§4.104 through 4.106, the Commission may exempt on a case-specific basis any small hydroelectric power project from all or part of Part I of the Act, including licensing. Applications for exemption for specific projects shall conform to the requirements of §§4.107 or 4.108, as applicable.

* * * * *

(d) Waiver. In applying for case-specific exemption from licensing, a qualified exemption applicant may petition under §1.7 of this chapter for waiver of any specific provision of §§4.102 through 4.107. The Commission will grant a waiver only if consistent with section 408 of the Energy Security Act of 1980.

* * * * *

1/ FERC Proposed Rulemaking issued December 22, 1980, Docket No. RM81-7

§4.109 General provisions for categorical exemption from licensing for certain projects with installed capacity of more than 100 kilowatts.

(a) Exempted projects. Subject to the provisions of §§4.110 and 4.111 and effective according to paragraph (b) of this section, the Commission exempts from the licensing requirements of Part I of the Act any small hydroelectric power project which has a proposed installed capacity of more than 100 kilowatts and which:

(1) utilizes for electric power generation only the water power potential of an existing dam;

(2) does not entail any increase in the normal maximum surface elevation of the impoundment pursuant to repair or reconstruction of a dam;

(3) does not entail, for the purpose of generating electric power, any change from the prevailing regime of storage and release of water from the impoundment;

(4) does not entail diversion of water from the waterway for more than 300 feet from the toe of the dam to the point of discharge into the waterway;

(5) does not entail construction of any primary transmission line which:

(i) has a design capacity of more than 69 kilovolts (KV);

or

(ii) is more than one mile long and located on a new right-of-way;

(6) utilizes only a dam at which there is no significant existing upstream or downstream passage of fish;

(7) will not cause violation of applicable water quality standards established by the U.S. Environmental Protection Agency or any state in which the project is located;

(8) does not entail any construction on or alteration of any site included in or eligible for inclusion in the National Register of Historic Places;

(9) does not entail construction in the vicinity of any threatened or endangered species or critical habitat, listed or designated in the regulations of the U.S. Department of the Interior; and

(10) is not only part of a licensed water power project.

(b) Effective date of exemption. Any small hydroelectric power project in the category of projects specified in paragraph (a) is exempted from licensing as of the date that a notice of exemption from licensing for that project, complying with the provisions of §4.112, is deemed accepted for filing.

(c) Who may file a notice of exemption from licensing for Category A projects.

(1) Only Federal lands involved. If only the rights to use or occupy Federal lands would be necessary to develop and operate a proposed small hydroelectric power project that meets the criteria of paragraph (a), any person may file a notice of exemption from licensing for that project under §4.112.

(2) Some non-Federal lands involved. If real property interests in any non-Federal lands would be necessary to develop and operate a proposed small hydroelectric power project that meets the criteria of paragraph (a), any person who has all of the real property interests in non-Federal lands necessary to develop and operate that project, or an option to obtain those interests, may file a notice of exemption from licensing for that project under §4.112.

§4.110 Categorical exemption from licensing for projects of more than 100 kilowatts: relationships among applications, exemptions, permits, licenses, and notices of exemption. For purposes of categorical exemption from licensing under §§4.109 through 4.112, the Commission will treat preliminary permit and license applications, preliminary permits, license, exemptions from licensing, and applications for exemption from licensing that are related to any small hydroelectric power project described in §4.109(a), as follows:

(a) Limitations on submission and acceptance of notices of exemption. (1) Unexpired permit or license. If there is an unexpired preliminary permit or license in effect for a project, the Commission will accept a notice of exemption from licensing for any project meeting the criteria of §4.109(a) only if the person filing the notice is the permittee or licensee. If the notice of exemption is submitted by a permittee, the permit will be deemed cancelled. If the notice of exemption is filed by a licensee, the license will be deemed terminated.

(2) Pending permit, license, or exemption application.

(i) General Rule. Except as permitted under clause (ii), the Commission will not accept a notice of exemption from licensing for any project meeting the criteria of §4.109(a) if a preliminary permit or license application for that project, or an application for exemption of that project from licensing, has been accepted for filing.

(ii) Exceptions. If an application for preliminary permit, license, or exemption from licensing has been accepted for filing for a project meeting the criteria of §4.109(a), the Commission will accept a notice of exemption from licensing for that project, if:

(A) no competing application, whether for preliminary permit, license, or exemption from licensing, has been accepted for filing for that project;

(B) the last date for filing protests or petitions to intervene, prescribed in the public notice issued for the permit or license application under §4.31(c)(2) of this chapter, has passed;

(C) no notice of intent to file a competing preliminary permit or license application for that project has been filed in accordance with §4.33(b) of this chapter; and

(D) the person filing the notice of exemption is the applicant for preliminary permit, license, or exemption from licensing.

(iii) Withdrawal of pending applications. If a notice of exemption from licensing complying with §4.112 is filed under clause (ii), any pending application for preliminary permit, license, or exemption from licensing will be deemed withdrawn.

(b) Limitations on submissions and acceptance of permit or license applications. (1) General rule. Except as permitted under subparagraph (2) or under §4.111(c) or (e), the Commission will not accept a preliminary permit or license application for any small hydroelectric power project that is exempt from licensing pursuant to §4.109.

(2) Exceptions. (i) If a project is exempted from licensing pursuant to §4.109, any qualified license applicant may submit a license application that proposes to develop at least 7.5 megawatts in any exempted project.

(ii) If a project is exempted from licensing pursuant to §4.109 and real property interests in any non-Federal lands would be necessary to develop and operate the project, any person who is both a qualified license applicant and has any of the real property interests in such non-Federal lands may submit a license application for that project. If a license application is submitted under this clause, any other qualified license applicant may submit a competing license application in accordance with §4.33 of this part.

§4.111 Standard terms and conditions of categorical exemption from licensing for projects installed capacity of more than 100 kilowatts. Any small hydroelectric power project exempted from licensing under §4.109 (a) is subject to the following standard terms and conditions:

(a) Article 1. The Commission reserves the right to conduct investigations under sections 4(g), 306, 307, and 311 of the Federal Power Act with respect to any acts, complaints, facts, conditions, practices, or other matters related to the construction, operation, or maintenance of the exempt project. If any term or condition of the exemption is violated, the Commission may revoke the exemption, issue a suitable order under section 4(g) of the Federal Power Act, or take appropriate action for enforcement, forfeiture, or penalties under Part III of the Federal Power Act.

(b) Article 2. The construction, operation, and maintenance of the exempt project must comply with any measures that any fish and wildlife agency may in the future prescribe as part of any migratory fish restoration program.

(c) Article 3. The Commission may accept a license application submitted by any qualified license applicant and revoke this exemption if actual construction or development of any proposed generating facilities has not begun within 18 months, or been completed within four years, from the effective date of this exemption. If an exemption is revoked, the Commission will not accept a subsequent notice of exemption from licensing or application for exemption for the project within two years of the revocation.

(d) Article 4. This exemption is subject to the navigation servitude of the United States if the project is located on navigable waters of the United States.

(e) Article 5. This exemption does not confer any right to use or occupy any Federal lands that may be necessary for the development or operation of the project. Any right to use or occupy any Federal lands for those purposes must be obtained from the administering Federal land agencies. The Commission may accept a license application submitted by any qualified license applicant and revoke this exemption if any necessary right to use or occupy Federal lands for those purposes has not been obtained within one year from the effective date of this exemption.

(f) Article 6. Any exempted small hydroelectric power project that utilizes a dam that is more than 33 feet in height above streambed, as defined in 18 C.F.R. §12.30(b)(3) of this chapter, impounds more than 2,000 acre-feet of water, or has high hazard potential, as defined in 18 C.F.R. §12.30(b)(2), is subject to the following provisions of 18 C.F.R. Part 12:

(1) §12.4(b)(2)(i), (ii), (iii)(B), (iv), and (v);

(2) §12.4(c); and

(3) Subpart D.

For the purposes of applying these provisions of 18 C.F.R. Part 12, the exempted project is deemed to be a licensed project development and the owner of the exempted project is deemed to be a licensee, under the definitions in 18 C.F.R. §13.3.

§4.112 Notice of exemption from licensing for projects with installed capacity of more than 100 kilowatts. (a) General requirement. Any person meeting the requirements specified in §4.109(c) and filing a notice of exemption from licensing for any small hydroelectric power project under §4.109(a) must submit:

(1) the original and 14 copies of the notice of exemption described in paragraph (c) of this section; and

(2) proof of service of a copy of the notice of exemption on:

(i) the U.S. Fish and Wildlife Service and other fish and wildlife agencies;

(ii) the state Historic Preservation Officer for each state in which the project is located; and

(iii) the state water resource agency for each state in which the project is located or, if there are no applicable state water quality standards, the U.S. Environmental Protection Agency.

(b) Certifications or surveys. As a basis for certifying to the nature and effects of a small hydroelectric power project under paragraph (c)(4) of this section, a person filing a notice of exemption must:

(1) obtain certification from the state water resource agency for each state in which the project is located or, if there are no applicable state water quality standards, from the U.S. Environmental Protection Agency, that the project will not cause a violation of any applicable water quality standards.

(2) obtain certification from the U.S. Fish and Wildlife Service or the fish and wildlife agency for each state in which the project is located that there is no significant existing upstream or downstream passage of fish at any project dam;

(3) either obtain certification from the state Historic Preservation Officer of each state in which the project is located or obtain an independent field survey and survey of the applicable literature, conducted by an archeologist approved by each applicable state Historic Preservation Officer, with respect to whether the project will entail construction on or alteration of sites included in or eligible for inclusion in the National History Register of Historic Places;

(4) either obtain certification from the U.S. Fish and Wildlife Service or the state fish and wildlife agency for each state in which the project is located or obtain an independent field survey and survey of the applicable literature, conducted by a biologist approved by each applicable state fish and wildlife agency, with respect to whether the project entails any construction in the vicinity of any endangered or threatened species or critical habitat listed or designated in the regulations of the U.S. Department of the Interior.

(c) Contents. The notice of exemption from licensing required by this section must conform to the following format:

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Notice of Exemption of
Small Hydroelectric Power Project
From Licensing

(1) [Name of filing party or parties] notifies [notify] the Federal Energy Regulatory Commission that the [name of the project], a small hydroelectric power project as defined in 18 C.F.R. §4.102, is exempt from licensing under the terms of 18 C.F.R. §4.109 through §4.111. [If applicable: The project is currently licensed as FERC Project No. _____.]

(2) The location of the project is:

[State or territory] ______________________________

[County] ______________________________

[Township or nearby town] ______________________________

[River or stream] ______________________________

[River basin] ______________________________

(3) The exact name, business address, and telephone number of the filing party or parties are:

____

____

(4) The project includes the following features:

(a) Dams: [For each existing dam, identify the dam; state the date on which construction was completed and state both the dam's height above streambed and the gross storage capacity of the related impoundment as defined in 18 C.F.R. §12.30].

(b) Powerplants: [For each powerplant: identify the powerplant; state whether it is existing or proposed; state the hydraulic head; state the installed capacity in kilowatts and average annual generation in kilowatt-hours for any existing electric generating capacity; and state the proposed total installed capacity in kilowatts and the estimated average annual generation in kilowatt-hours for the proposed total installed capacity].

(c) Average stream flow: The average annual streamflow is [ ] cubic feet per second.

(5) It is certified that [name of filing party or parties] has [have] complied with §4.112(c) of the Commission's regulations and that the small hydroelectric power project conforms to the specifications set forth in §4.109(a) of the Commission's regulations, including the following:

(i) The [each applicable state water resource agencies or U.S. Environmental Protection Agency] has [have] certified that the construction, operation, and maintenance of the project will not cause a violation of any applicable water quality standards.

(ii) The [U.S. Fish and Wildlife Service or each applicable state fish and wildlife agency] has [have] certified that there is no significant existing upstream or downstream migration of fish at any project dam.

(iii) The proposed small hydroelectric power project does not entail any construction on or alteration of any site that is included in or is eligible for inclusion in the National Register of Historic Places.

(iv) The proposed small hydroelectric power project does not entail construction in the vicinity of any threatened or endangered species or critical habitat listed or designated in the regulations of the U.S. Department of the Interior.

(6) [Signature of filing party or parties under §1.15 of this chapter; subscription and verification under §1.16 of this chapter]

§4.113 General provisions for categorical exemption from licensing for certain projects with installed capacity of 100 kilowatts or less.

(a) Exemption. (1) The Commission categorically exempts from the licensing requirements of Part I of the Act, effective according to paragraph (b) any small hydroelectric power project that:

(i) utilizes for electric power generation only the water power potential of an existing dam;

(ii) has total proposed installed capacity of not more than 100 kilowatts; and

(iii) is not only part of a licensed water project.

(b) Effective dates. (1) Exemption. Any small hydroelectric power project meeting the criteria in paragraph (a) is exempted from licensing as of the effective date of this section.

(2) Proposed capacity. For purposes of installing or increasing capacity in any project meeting the criteria in paragraph (a), under the definition of small hydroelectric power project in §4.102(1), the effective date of this section is deemed to be the date of notice of exemption or application under this subpart.

(c) Limitation on submissions and acceptance of permit or license applications. For purposes of categorical exemption under this section, the Commission will treat preliminary permit and license applications, preliminary permits, licenses, and applications for exemptions from licensing that are related to a small hydroelectric power project described in §4.113(a), as follows:

(1) General rule. Except as permitted under subparagraph (2), the Commission will not accept a preliminary permit or license application for any small hydroelectric power project that is exempted from licensing pursuant to §4.113.

(2) Exceptions. (i) If a project is exempted from licensing pursuant to §4.113, any qualified license applicant may submit a license application that proposes to develop at least 7.5 megawatts in any exempted project.

(ii) If a project is exempted from licensing pursuant to §4.113 and real property interests in any non-Federal lands would be necessary to develop and operate the project, any person who is both a qualified license applicant and has any of those real property interests in non-Federal lands may submit a license application for that project. If a license application is submitted under this clause, any other qualified license applicant may submit a competing license application in accordance with §4.33 of this part.

4. Section 4.102(l) is amended by inserting after the words "after the date of" the words "notice of exemption or."

5. Section 4.104 is amended by revising the title to read "Case-specific exemption from licensing: relationships among applications, exemptions, permits and licenses." and by deleting from the first sentence the words "this subpart" and substituting in lieu thereof the words "case-specific exemption under §§4.103 through 4.107".

6. Section 4.105 is amended in the first sentence of paragraph (b)(6) be deleting the words "In granting an exemption from licensing," and substituting in lieu thereof the words "In approving any application for exemption from licensing,".

7. Section 4.106 is amended by revising the title of the section, by revising the first sentence, and by revising the second sentence of paragraph (c) to read:

§4.106 Standard terms and conditions of case-specific exemption from licensing. Any case-specific exemption from licensing granted for small hydroelectric power project is subject to the following standard terms and conditions:

* * * * *

(c) Article 3.

* * * * *

If an exemption is revoked, the Commission will not accept a subsequent application for exemption or a notice of exemption from licensing within two years of the revocation.

* * * * *

7. Section 375.308 is amended in paragraph (n) and (o) to read as follows:

§375.308 Delegations to the Director of the Office of Electric Power Regulation.

* * * * *

(n) Issue deficiency letters regarding electric rate schedule filings, refund reports, corporate applications for the sale of facilities with respect to interlocking directorates, exemption applications a notices of exemption filed under Subparts J or K of Part 4 of this chapter, and applications filed under Part I of the Federal Power Act.

(o) Reject a rate filing, an application filed under Part I of the Federal Power Act, an application or other filing under section 405 of the Public Utility Regulatory Policy Act of 1978, or a non-complying notice of exemption from licensing filed under §§4.109 through 4.112 of this chapter, unless accompanied by a request for waiver in conformity with §1.14(a)(2) of this chapter, if it fails patently to comply with applicable statutory requirements or Commission rules, regulations and orders.

* * * * *

ATTACHMENT NO. 2

FEDERAL ENERGY REGULATORY COMMISSION

PRELIMINARY PERMIT

Attachment No. 2

Preliminary Permit

The application for preliminary permit is set forth in Subpart I of Part 4, Subchapter B, Chapter 1 of Title 18, Code of Federal Regulations. Section 4.81 is reproduced in the following paragraphs to assist a potential site developer in making an application to FERC for a Preliminary Permit to determine the feasibility of a project and to support an application for license.

4.81 Contents of application.

Each application for a preliminary permit must include the following initial statement and numbered exhibits containing the information and documents specified:

(a) Initial statement:

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
APPLICATION FOR PRELIMINARY PERMIT

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for a preliminary permit for the proposed [name of project] water power project, as described in the attached exhibits. This application is made in order that the applicant may secure and maintain priority of application for a license for the project under Part I of the Federal Power Act while obtaining the data and performing the acts required to determine the feasibility of the project and to support an application for a license.

(2) The location of the proposed project is:

State or territory : ______________________

County : ______________________

Township or nearby town : ______________________

Stream or other body of water: ______________________

(3) The exact name and business address of each applicant are:

____

____

____

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

____

____

____

(4) [Name of applicant] is a [citizen, association of citizens, domestic corporation, municipality, or state, as appropriate].

(5) The proposed term of the requested permit is [period not to exceed 36 months].

(b) Exhibit 1 must contain a description of the proposed project, specifying and including, to the extent possible:

(1) the number, physical composition, dimensions, general configuration and, where applicable, age and condition, of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, that would be part of the project;

(2) the estimated number, surface area, storage capacity, and normal maximum surface elevation (mean sea level) of any reservoirs, whether existing or proposed that would be part of the project;

(3) the estimated number, length, voltage, interconnections, and, where applicable, age and condition, of any primary transmission lines, whether existing or proposed, that would be part of the project [see 16 U.S.C. §796(11)];

(4) the total estimated average annual energy production and the estimated number, rated capacity, and, where applicable, age and condition, of any turbines or generators, whether existing or proposed, that would be part of the project;

(5) all lands of the United States that are enclosed within the proposed project boundary described under paragraph (e)(3) of this section, identified and tabulated on a separate sheet by legal subdivisions of a public land survey of the affected area, if available; and

(6) any other information demonstrating in what manner the proposed project would develop, conserve, and utilize in the public interest the water resources of the region.

(c) Exhibit 2 is a description of studies conducted or to be conducted with respect to the proposed project, including field studies. Exhibit 2 must supply the following information:

(1) General requirement. For any proposed project, a study plan containing a description of:

(i) any studies, investigations, tests, or surveys that are proposed to be carried out, and any that have already taken place, for the purpose of determining the technical, economic, and financial feasibility of the proposed project, taking into consideration its environmental impacts, and of preparing an application for a license for the project; and

(ii) the approximate locations and nature of any new roads that would be built for the purpose of conducting the studies; and

(2) Work plan for new dam construction. For any development within the project that would entail new dam construction, a work plan and schedule containing:

(i) a description, including the approximate location, of any field study, test, or other activity that may alter or disturb lands or waters in the vicinity of the proposed project, including floodplains and wetlands; measures that would be taken to minimize any such disturbance; and measures that would be taken to restore the altered or disturbed areas; and

(ii) a proposed schedule (a chart or graph may be used), the total duration of which does not exceed the proposed term of the permit, showing the intervals at which the studies, investigations, tests, and surveys, identified under this paragraph are proposed to be completed.

(iii) For purposes of this paragraph, "new dam construction" means any dam construction the studies for which would require test pits, borings, or other foundation exploration in the field.

(3) Waiver. The Commission may waive the requirements of paragraph (c)(2) pursuant to §1.14(a)(2) of this chapter, upon a showing by the applicant that the field studies, tests, and other activities to be conducted under the permit would not adversely affect cultural resources or endangered species and would cause only minor alterations or disturbances of lands and waters, and that any land altered or disturbed would be adequately restored.

(d) Exhibit 3 must contain a statement of costs and financing, specifying and including, to the extent possible:

(1) the estimated costs of carrying out or preparing the studies, investigations, tests, surveys, maps, plans or specifications identified under paragraph (c) of this section;

(2) the expected sources and extent of financing available to the applicant to carry out or prepare the studies, investigations, tests, surveys, maps, plans, or specifications identified under paragraph (c) of this section; and

(3) a description of the proposed market for the power generated at the project, including the identity of the proposed purchaser or

purchasers of the power, and any information that is available concerning the revenues to be derived from sale of the power.

(e) Exhibit 4 must include a map or series of maps, to be prepared on United States Geological Survey topographic quadrangle sheets or similar topographic maps of a state agency, if available. The maps need not conform to the precise specifications of §4.32(a) and (b). If the scale of any base map is not sufficient to show clearly and legibly all of the information required by this paragraph, the maps submitted must be enlarged to a scale that is adequate for that purpose. (If Exhibit 4 comprises a series of maps, it must also include an index sheet showing, by outline, the parts of the entire project covered by each map of the series.) The maps must show:

(1) the location of the project as a whole with reference to the affected stream or other body of water and, if possible, to a nearby town or any permanent monuments or objects that can be noted on the maps and recognized in the field;

(2) the relative locations and physical interrelationships of the principal project features identified under paragraph (b) of this section;

(3) a proposed boundary for the project, enclosing:

(i) all of the principal project features identified under paragraph (b) of this section;

(ii) any non-Federal lands and any public lands or reservations of the United States [see 16 U.S.C. §796(1) and (2)] necessary for the purposes of the project. To the extent that those public lands or reservations are covered by a public land survey, the project boundary must enclose each of and only the smallest legal subdivisions (quarter-quarter section, lots, or other subdivisions, identified on the map by subdivision) that may be occupied in whole or in part by the project.

(4) areas within the vicinity of the proposed project boundary which are included in or have been designated for study for inclusion in the National Wild and Scenic River System; and

(5) areas within the project boundary that, under the provisions of the Wilderness Act, have been:

(i) designated as wilderness area;

(ii) recommended for designation as wilderness area; or

(iii) designated as wilderness study area.

ATTACHMENT NO. 3

FEDERAL ENERGY REGULATORY COMMISSION

MINOR LICENSE

Attachment No. 3

Minor License

The application for a short-form license is provided for in Section 4.60 and set forth in Section 131.6 of Chapter 1 of Title 18, Code of Federal Regulations. The application form and instructions for completing it, prepared by FERC, are reproduced in the following paragraphs to assist a potential site developer in making an application to the FERC for a minor license for a small hydroelectric project of not more than 1500 kW capacity.

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR SHORT-FORM LICENSE (MINOR)

1. Applicant's full name and address: ______________________________

____
(Zip Code)

2. Location of Project:

State: ____________________ County: ________________

Nearest town: ______________ Water body: ____________

3. Project description and proposed mode of operation (reference to Exhibits K and L, as appropriate):

(continue on separate sheet, if necessary)

4. Land of the United States affected (shown on Exhibit K)

	(Name)	(Acres)
a. National Forest	______________	________________
b. Indian Reservation	___________	_________________

	(Name)	(Acres)
c. Public Lands Under Jurisdiction of	___________	___________
d. Other	___________	___________

e. Total U.S. Lands ____________________________________

f. Check appropriate box:

☐ Surveyed ☐ Unsurveyed land in public-land state:

(1) If surveyed land in public-land state provide the following:

Sections and subdivisions: ____________________

Range __________________ Township: ____________

Principal base and meridian: _________________

(2) If unsurveyed or not in public-land state, see Item 8 of instructions: ____

5. Purposes of project (use of power output, etc.)

____

6. Construction of the project is planned to start _______ it will be completed within ____ months from date of the issuance of license.

7. List here and attach copies of State water permits or other permits obtained authorizing the use or diversion of water, or authorizing (check appropriate box):

☐ the construction, operation, and maintenance

☐ the operation and maintenance of the proposed project.

8. Attach an environmental report prepared in accordance with the requirments set forth in the Instructions for Completing Application for Short-Form License (Minor), below.

9. Attach Exhibits K and L drawings.

10. State of ____

County of ______________________________________ ss:

____

____

____,

being duly sworn, depose(s) and say(s) that the contents of this application are true to the best of _____ knowledge or belief and that (check appropriate box)

☐ ____ is (are) a citizen(s) of the United States

☐ all members of the association are citizens of the United States

☐ ____ is (are) the duly appointed agent(s) of the state (municipality) (corporation) (association) and has (have) signed this application this __ day of _____, 19__.

____
(Applicant(s))

By ____

Subscribed and sworn to before me, a Notary Public of the State of ____________________________, this ___ day of _____,

/SEAL/

____
(Notary Public)

INSTRUCTIONS FOR COMPLETING APPLICATION FOR SHORT-FORM LICENSE (MINOR)

GENERAL

1. This application may be used if the proposed or existing project will have or has a total generating capacity of not more than 1,500 kW (2,000 horsepower). Advice regarding the proper procedure for filing should be requested from the Federal Energy Regulatory Commission in Washington, D.C.; or from one of the Commission's Regional Offices in Atlanta, Chicago, Forth Worth, New York, or San Francisco.

2. This application is to be completed and filed in an original and nine copies with the Federal Energy Regulatory Commission, 825 N. Capitol Street, N.E., Washington, D.C., 20426. Each of the original and the nine copies of the application is to be accompanied by:

a. One copy each of Exhibits K and L described below.

b. One copy each of a state water quality certificate pursuant to Section 401 of the Federal Water Pollution Control Act (or evidence that this certificate is not needed), and any water rights certificate or similar evidence required by state law relating to use or diversion of water. In lieu of submitting a copy of a Section 401 certificate (or other certificate), evidence that applications for these certificates have been filed with appropriate agencies, or that such certificates are not necessary, will be adequate to begin FERC processing of the application.

c. One copy each of any other state approvals necessary. (Applicant should contact the state natural resources department or equivalent to ascertain whether any such approvals are necessary.)

d. One copy of Applicant's environmental report, described below.

3. Applicant is required to consult with appropriate Federal, State, and local resources agencies during the preparation of the application and provide interested agencies with the opportunity to comment on the proposal prior to its filing with the Commission. The comments of such agencies must be attached to the application when filed. A list of agencies to be consulted can be obtained from the Commission's main office or the appropriate regional office.

4. No work may be started on the project until receipt of a signed license from the Commission. The application itself does not authorize entry upon Federal land for any purpose. If the project is located in part or in whole upon Federal land, the Applicant should contact the appropriate land management agency regarding the need to obtain a right-of-way permit. As noted above, other state or Federal permits may be required.

5. An applicant must be: a citizen or association of citizens of the United States; a corporation organized under the laws of the United States or a State; a State; or a municipality.

(a) If the applicant is a natural person, include an affidavit of United States citizenship.

(b) If the applicant is an association, include one verified copy of its articles of association. If there are no articles of association, that fact shall be stated over the signature of each member of the association. Also include a complete list include a complete list of members and a statement of the citizenship of each in an affidavit by one of them.

(c) If the applicant is a corporation, include one copy of the charter or certificate and articles of incorporation, with all the amendments, duly certified by the secretary of state of the State where organized, and one copy of the by-laws. If the project is located in a state other than that in which the corporation is organized, include a certificate from the secretary of state of the State in which the project is located showing compliance with the laws relating to foreign corporations.

(d) If the applicant is a state, include a copy of the laws under the authority of which the application is made.

(e) If the applicant is a municipality as defined in the Federal Power Act, include one copy of its charter or other organization papers, duly certified by the secretary of state of the State in which it is located, or other proper authority. Also include a copy of the State laws authorizing the operations contemplated by the application.

Include a copy of all minutes, resolutions of stockholders or directors, or other representatives of the applicant, properly attested, authorizing the filing of the application. This information can be provided by a letter attached to the application.

6. If the stream or water body is unnamed, give the name of the nearest named stream or water body to which it is tributary.

7. The project description (application item 3) shall include, as appropriate: the number of generating units, including auxiliary units, the capacity of each unit, and provisions, if any, for future units; type of hydraulic turbine(s); a description of how the plant is to be operated, manual or automatic, and whether the plant is to be used for peaking; estimated average annual generation in kilowatthours or mechanical energy equivalent; estimated average head on the plant; reservoir surface area in acres and, if known, the net and gross storage capacity; estimated hydraulic capacity of the plant (flow through the plant) in cubic feet per second; estimated average flow of the stream or water body at the plant or point of diversion; sizes, capacities, and construction materials, as appropriate, of pipelines, ditches, flumes, canals, intake facilities, powerhouses, dams, transmission lines, etc.; and estimated cost of the project.

8. In the case of unsurveyed public land, or land not in a public-lands state, give the best legal description available. Include the

distance and general direction from the nearest city or town, fixed monument, physical features, etc.

9. Exhibits K and L shall be submitted on separate drawings. Drawings for Exhibits K and L shall have identifying title blocks and bear the following certification:

"This drawing is a part of the application for license made by the undersigned this ___ day of ________, 19__.

____________________________"
(Name of Applicant)

10. The Commission reserves the right to require additional information, or another filing procedure, if data provided indicate such action to be appropriate.

EXHIBIT K- PROJECT LANDS AND BOUNDARIES

1. The Exhibit K is a planimetric map showing the portion of the stream developed, the location of all project works, and other important features, such as: the dam or diversion structure, reservoir, pipeline, powerplant, access roads, transmission lines, project boundary, private land ownerships (clearly differentiate between fee ownership and land over which applicant only owns an easement), and Federal land boundaries and identifications.

2. The map shall be an ink drawing or drawing of similar quality on a sheet not smaller than 8 inches by 10-1/2 inches, drawn to a scale no smaller than one inch equals 1,000 feet. Ten legible prints shall be submitted with the application. Upon request after review of the application, the tracing must be submitted.

3. The project boundary shall be drawn on the map so that the relationship of each project facility and reservoir to other property lines can be determined. The boundary shall enclose all project works, such as the dam, reservoir, pipelines, roads, powerhouse, and transmission lines. The boundary shall be set at the minimum feasible distance from project works necessary to allow operation and maintenance of the project and control of the shoreline and reservoir. The distance in feet from each principle facility to the boundary shall be shown. The project boundary should be a surveyed line with stated courses and distances. A tape-compass survey is acceptable. True north shall be indicated on the map. The area of Federal land in acres within the project boundary shall be shown. The appropriate Federal agency should be contacted for assistance in determining the Federal land acreage. For clarity, use inset sketches to a larger scale than used for the overall map to show relationships of project works, natural features, and property lines.

4. Show one or more ties by distance and bearing from a definite, identifiable point or points on project works or the project boundary to established corners of the public land survey or other survey monuments, if available.

5. If the project affects unsurveyed Federal lands, the protraction of township and section lines shall be shown. Such protractions, whenever available, shall be those recognized by the agency of the United States having jurisdiction over the lands. On unsurveyed lands, show ties by distance and bearing to fixed recognizable objects.

6. If the project uses both Federal and private lands, the detailed survey descriptions discussed above for the project boundary apply only to Federal lands. General location data and an approximate project boundary will normally suffice for project works on private lands.

EXHIBIT L-PROJECT STRUCTURES AND EQUIPMENT

1. The exhibit shall be a simple ink drawing or drawing of similar quality on a sheet no smaller than 8 inches by 10-1/2 inches, drawn to a scale no smaller than one inch equals 50 feet for plans and profiles, and one inch equals 10 feet for sections. Ten legible prints shall be submitted with the application. Upon request after initial review of the application, tracings must be submitted.

2. The drawing shall show a plan, elevation, and section of the diversion structure and powerplant. Generating and auxiliary equipment proposed should be clearly and simply depicted and described. Include a north arrow on the plan view.

ENVIRONMENTAL REPORT

The environmental report should be consistent with the scope of the project and the environmental impacts of the proposed action; e.g., authorization to operate and maintain an existing project, or a project using an existing dam or other facility, would require less detailed information than authorization to construct a new project. The environmental report shall set forth in a clear and concise manner:

(1) A brief description of the project and the mode of operation, i.e., run-of-river, peaking or other specific mode.

(2) A description of the environmental setting in and near the project area, to include vegetative cover, fish and wildlife resources, water quality and quantity, land and water uses, recreational use, socio-economic aspects, historical and archeological resources, and visual resources. Special attention shall be provided endangered and threatened plant and animal species, critical habitats, and sites eligible for or included on the National Register of Historic Places. Assistance in the preparation of this information may be obtained from state natural resources departments and from local offices of Federal natural resources agencies.

(3) A description of the expected environmental impacts resulting from the continued operation of an existing project, or from the construction and operation of a new project or a project using an existing dam or other existing facility. Include a discussion of specific measures proposed by the Applicant and others to protect

and enhance environmental resources and to mitigate adverse impacts of the project on the environmental resources and values, the cost of those measures, and the party undertaking to implement those measures if other than the Applicant.

(4) A description of alternative means of obtaining an amount of power equivalent to that provided by the project in the event that construction or continued operation of the project is not authorized.

(5) A description of the steps taken by the Applicant in consulting with Federal, state, and local agencies during the preparation of the environmental report. Indicate which agencies have received the final report and provide copies of letters containing the comments of those agencies.

ATTACHMENT NO. 4

FEDERAL ENERGY REGULATORY COMMISSION

MAJOR PROJECT - EXISTING DAM

Attachment No. 4

Major Project - Existing Dam

The regulations governing applications for a license for Major Projects - Existing Dams are contained in Sections 4.50 and 4.51 of Subpart F of Part 4, Chapter 1 of Title 18, Code of Federal Regulations. These regulations are reproduced in the following paragraphs to assist a potential site developer in making an application for a major project at an existing dam.

SUBPART F - APPLICATION FOR LICENSE
FOR MAJOR PROJECT - EXISTING DAM

§4.50 Applicability and definitions.

(a) Applicability. The provisions of §§4.50 and 4.51 apply to any application for either an initial license or a new license for a major project - existing dam.

(b) Definitions. For the purposes of this subpart:

(1) "Dam" means any structure for impounding or diverting water;

(2) "Existing dam" means any dam that has been completely constructed;

(3) "Existing impoundment" means any body of water that an existing dam impounds;

(4) "Initial license" means the first license issued for a water power project under either the Federal Water Power Act of 1920 or the Federal Power Act;

(5) "Major project - existing dam" means a licensed or unlicensed, existing or proposed water power project that, as proposed to be licensed:

(i) would have a total installed generating capacity of more than 2,000 hp (1.5 MW);

(ii) would not use the water power potential provided by any dam except an existing dam;

(iii) does not include any proposed repair or reconstruction of an existing dam that would result in a significant change in the normal maximum surface area or the normal maximum surface elevation of an existing impoundment; and

(iv) does not include any proposed new development or change in project operation that would result in a significant environmental impact;

(6) "New development" means any construction, installation, repair, reconstruction, or other change in the existing state of project works or appurtenant facilities, including any dredging and filling in project waters; and

(7) "New license" means any license for a water power project that is issued under the Federal Power Act after the initial license for that project, except an annual license issued under Section 15 of the Federal Power Act.

(c) Guidance from Commission staff. A prospective applicant for a major license - existing dam may seek advice from the Commission staff regarding the applicability of these sections to its project [see 4.31(g)], including the determinations whether any proposed repair or reconstruction of an existing dam would result in a significant change in the normal maximum surface area or the normal maximum surface elevation of an existing impoundment, or whether any proposed new development or change in project operation would result in a significant environmental impact.

§4.51 Contents of application.

Each application for a license for a major project - existing dam must be prepared after consultation with the appropriate state public service commission or board and the other Federal, state, and local agencies specified in this section. The applicant may obtain a list of agencies to be consulted from the Director of the Commission's Division of Licensed Projects. Each application must include an initial statement and lettered exhibits containing the following information and documents:

(c) Initial statement.

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR
PROJECT -- EXISTING DAM

(1) [Name of applicant] applies to the Federal Energy Regulatory Commission for a [license or new license, as appropriate] for the [name of project] water power project, as described in the attached exhibits. [Specify any previous FERC project number designation.]

(2) The location of the project is:

State or territory : ______________________________

County : ______________________________

Township or nearby town: ______________________________

Stream or other body of Water: ______________________________

(3) The exact name and business address of the applicant are:

____

____

____

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

____

____

____

(4) The applicant is a [citizen of the United States, association of citizens of the United States, domestic corporation, municipality or state, as appropriate, see 16 U.S.C. §796].

(5)(i) The statutory or regulatory requirements of the state(s) in which the project would be located and that affect the project as proposed with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act are: [provide citation and brief identification of the nature of each requirement.]

(ii) The steps which the applicant has taken or plans to take to comply with each of the laws cited above are: [provide brief description for each law.]

(b) Exhibit A is a description of the project. This exhibit need not include information on project works maintained and operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, or any other department or agency of the United States, except for any project works that are proposed to be altered or modified. If the project includes more than one dam with associated facilities, each dam and the associated component parts must be described together as a discrete development. The description for each development must contain:

(1) the physical composition, dimensions, and general configuration of any dams, spillways, penstocks, powerhouses, tailraces, or other structures, whether existing or proposed, to be included as part of the project;

(2) the normal maximum surface area and normal maximum surface elevation (mean sea level), gross storage capacity, and usable storage capacity of any impoundments to be included as part of the project;

(3) the number, type, and rated capacity of any turbines or generators, whether existing or proposed, to be included as part of the project;

(4) the number, length, voltage, and interconnections of any primary transmission lines, whether existing or proposed, to be included as part of the project [see 16 U.S.C. §796(11)];

(5) the specifications of any additional mechanical, electrical, and transmission equipment appurtenant to the project; and

(6) all lands of the United States that are enclosed within the project boundary described under paragraph (h) of this section (Exhibit G), identified and tabulated by legal subdivisions of a public land survey of the affected area or, in the absence of a public land survey, by the best available legal description. The tabulation must show the total acreage of the lands of the United States within the project boundary.

(c) Exhibit B is a statement of project operation and resource utilization. If the project includes more than one dam with associated facilities, the information must be provided separately for each such discrete development. The exhibit must contain:

(1) a statement whether operation of the power plant will be manual or automatic, an estimate of the annual plant factor, and a statement of how the project will be operated during adverse, mean, and high water years;

(2) an estimate of the dependable capacity and average annual energy production in kilowatthours (or a mechanical equivalent), supported by the following data:

(i) the minimum, mean, and maximum recorded flows in cubic feet per second of the stream or other body of water at the powerplant intake or point of diversion, with a specification of any adjustments made for evaporation, leakage, minimum flow releases (including duration of releases), or other reductions in available flow; a flow duration curve indicating the period of record and the gauging stations used in deriving the curve; and a specification of the period of critical streamflow used to determine the dependable capacity;

(ii) an area-capacity curve showing the gross storage capacity and usable storage capacity of the impoundment, with a rule curve showing the proposed operation of the impoundment and how the usable storage capacity is to be utilized;

(iii) the estimated hydraulic capacity of the powerplant (maximum flow through the powerplant) in cubic feet per second;

(iv) a tailwater rating curve; and

(v) a curve showing powerplant capability versus head and specifying maximum, normal, and minimum heads;

(3) a statement, with load curves and tabular data, if necessary, of the manner in which the power generated at the project is to be utilized, including the amount of power to be used on-site, if any, the amount of power to be sold, and the identity of any proposed purchasers; and

(4) a statement of the applicant's plans, if any, for future development of the project or of any other existing or proposed water power project on the stream or other body of water, indicating the approximate location and estimated installed capacity of the proposed developments.

(d) Exhibit C is a construction history and proposed construction schedule for the project. The construction history and schedule must contain:

(1) if the application is for an initial license, a tabulated chronology of construction for the existing project structures and facilities described under paragraph (b) of this section (Exhibit A), specifying for each structure or facility, to the extent possible, the actual or approximate dates (approximate dates must be identified as such) of:

(i) commencement and completion of construction or installation

(ii) commencement of commercial operation; and

(iii) any additions or modifications other than routine maintenance; and

(2) if any new development is proposed, a proposed schedule describing the necessary work and specifying the intervals following issuance of a license when the work would be commenced and completed.

(e) Exhibit D is a statement of costs and financing. The statement must contain:

(1) If the application is for an initial license, a tabulated statement providing the actual or approximate original cost (approximate cost must be identified as such) of:

(i) any land or water right necessary to the existing project; and

(ii) each existing structure and facility described under paragraph (b) of this section (Exhibit A).

(2) If the applicant is a licensee applying for a new license, and is not a municipality or a state, an estimate of the amount which would be payable if the project were to be taken over pursuant to section 14 of the Federal Power Act upon expiration of the license in effect [see 16 U.S.C. §807], including:

(i) fair value;

(ii) net investment; and

(iii) severance damages.

(3) If the application includes proposals for any new development, a statement of estimated costs, including:

(i) the cost of any land or water rights necessary to the new development; and

(ii) the cost of the new development work, with a specification of:

(A) total cost of each major item;

(B) indirect construction costs such as costs of construction equipment, camps, and commissaries;

(C) interest during construction; and

(D) overhead, construction, legal expenses, taxes, administrative and general expenses, and contingencies.

(4) A statement of the estimated average annual cost of the total project as proposed, specifying any projected changes in the costs over the estimated financing or licensing period if the applicant takes such changes into account, including:

(i) cost of capital (equity and debt);

(ii) local, state, and Federal taxes;

(iii) depreciation or amortization, and

(iv) operation and maintenance expenses, including interim replacements, insurance, administrative and general expenses, and contingencies.

(5) A statement of the estimated annual value of project power, based on a showing of the contract price for sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source, specifying any projected changes in the cost of power from that source over the estimated financing or licensing period if the applicant takes such changes into account.

(6) A statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e)(3) and (4) of this section.

(f) Exhibit E is an environmental report. The report must be prepared in consultation with local, state, and Federal agencies with expertise in environmental matters. The names and addresses of these agencies may be obtained from the Director, Division of Licensed

Projects. If any agency that an applicant is required to consult fails to provide to the applicant timely documentation of the consultation process as set forth in this paragraph, the applicant may submit a summary of the consultation and the recommendations of the agency. Information provided in the report must be organized and referenced according to the provisions of this paragraph. If a request for information is not applicable, the application must explain briefly why it does not apply. The environmental report must contain the following elements:

(1) General description of the locale. The applicant must provide a general description of the environment of the project and its immediate vicinity. The description must include general information concerning climate, topography, wetlands, vegetative cover, land development, population size and density, the presence of any floodplain and the occurrence of flood events in the vicinity of the project, and any other factors important to an understanding of the setting.

(2) Report on water use and quality. The report must discuss the consumptive use of project waters and the impact of the project on water quality. The report must be prepared in consultation with the state and federal agencies with responsibility for management of water quality in the affected stream or other body of water. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent, and results of the consultation. The report must include:

(i) a description (including specified volume over time) of existing and proposed uses of project waters for irrigation, domestic water supply, steam-electric plant, industrial, and other consumptive purposes;

(ii) a description of existing water quality in the project impoundment and downstream water affected by the project and the applicable water quality standards and stream segment classification;

(iii) a description of any minimum flow releases specifying the rate of flow in cubic feet per second (cfs) and duration, changes in the design of project works or in project operation, or other measures recommended by the agencies consulted for the purposes of protecting or improving water quality, including measures to minimize the short-term impacts on water quality of any proposed new development of project works [for any dredging or filling, refer to 40 C.F.R. Part 230 and 33 C.F.R. §§320.3(f) and 323.3(e)];

(iv) a statement of the existing measures to be continued and new measures proposed by the applicant for the purpose of protecting or improving water quality, including an explanation of why the applicant has rejected any measures recommended by an agency and described under paragraph (f)(2)(iii) of this section.

(v) a description of the continuing impact on water quality of continued operation of the project and the incremental impact of proposed new development of project works or changes in project operation; and

(vi) as an appendix, either:

(A) a copy of a water quality certificate (or agency statement that such certification is waived) as described in section 401 of the Federal Water Pollution Control Act (also known as the Clean Water Act) [see 33 U.S.C. §1341]; or

(B) a copy of a dated letter from the applicant to the appropriate agency requesting that certification.

(3) Report on fish, wildlife, and botanical resources. The report must discuss fish, wildlife, and botanical resources in the vicinity of the project and the impact of the project on those resources. The report must be prepared in consultation with any state agency with responsibility for fish, wildlife, and botanical resources, the U.S. Fish and Wildlife Service, the National Marine Fisheries Service (if the project may affect anadromous fish resources subject to that agency's jurisdiction), and any other state or Federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent, and results of the consultation. The report must include:

(i) a description of the fish, wildlife, and botanical resources of the project and its vicinity, and of downstream areas affected by the project, including identification of any species listed as threatened or endangered by the U.S. Fish and Wildlife Service [see 50 C.F.R. §§17.11 and 17.12];

(ii) a description of any measures or facilities recommended by the agencies consulted for the mitigation of impacts on fish, wildlife, and botanical resources, or for the protection or improvement of those resources;

(iii) a statement of any existing measures or facilities to be continued or maintained and any measures or facilities proposed by the applicant for mitigation of impacts on fish, wildlife, and botanical resources, or for the protection or improvement of such resources, including an explanation of why the applicant has rejected any measures or facilities recommended by an agency and described under paragraph (f)(3)(ii) of this section.

(iv) a description of any anticipated continuing impact on fish, wildlife, and botanical resources of continued operation of the project, and the incremental impact of proposed new development of project works or changes in project operation; and

(v) the following materials and information regarding the measures and facilities identified under paragraph (f)(3)(iii) of this section:

(A) functional design drawings of any fish passage and collection facilities, indicating whether the facilities depicted are existing or proposed (these drawings must conform to the specifications of §4.32 regarding dimensions of full-sized prints, scale, and legibility);

(B) description of operation and maintenance procedures for any existing or proposed measures or facilities;

(C) an implementation or construction schedule for any proposed measures or facilities, showing the intervals following issuance of a license when implementation of the measures or construction of the facilities would be commenced and completed;

(D) an estimate of the costs of construction, operation, and maintenance of any proposed facilities, and of implementation of any proposed measures, including a statement of the sources and extent of financing; and

(E) a map or drawing that conforms to the size, scale, and legibility requirements of §4.32 showing by the use of shading, cross-hatching, or other symbols the identity and location of any measures or facilities, and indicating whether each measure or facility is existing or proposed (the map or drawings in this exhibit may be consolidated).

(4) Report on historical and archeological resources. The report must discuss the historical and archeological resources in the project area and the impact of the project on those resources. The report must be prepared in consultation with the State Historic Preservation Officer and the U.S. Heritage Conservation and Recreation Service. Consultation must be documented by appending to the report a letter from each agency consulted that indicates the nature, extent, and results of the consultation. The report must contain:

(i) identification of any sites either listed or determined to be eligible for inclusion in the National Register of Historic Places that are located in the project area, or that would be affected by operation of the project or by new development of project facilities (including facilities proposed in this exhibit);

(ii) a description of any measures recommended by the agencies consulted for the purpose of locating, identifying, and salvaging historical or archaeological resources that would be affected by operation of the project, or by new development of project facilities (including facilities proposed in this exhibit), together with a statement of what measures the applicant proposes to implement and an explanation of why the applicant rejects any measures recommended by an agency.

(iii) the following materials and information regarding the survey and salvage activities described under paragraph (f)(4)(ii) of this section:

(A) a schedule for the activities, showing the intervals following issuance of a license when the activities would be commenced and completed; and

(B) an estimate of the costs of the activities, including a statement of the sources and extent of financing.

(5) Report on recreational resources. The report must discuss existing and proposed recreational facilities and opportunities at the project. The report must be prepared in consultation with local, state, and regional recreation agencies and planning commissions, the U.S. Heritage Conservation and Recreation Service, and any other state or Federal agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report a letter from each agency consulted indicating the nature, extent, and results of the consultation. The report must contain:

(i) a description of any existing recreational facilities at the project, indicating whether the facilities are available for public use;

(ii) an estimate of existing and potential recreational use of the project area, in daytime and overnight visits;

(iii) a description of any measures or facilities recommended by the agencies consulted for the purpose of creating, preserving, or enhancing recreational opportunities at the project and in its vicinity (including opportunities for the handicapped), and for the purpose of ensuring the safety of the public in its use of project lands and waters;

(iv) a statement of the existing measures or facilities to be continued or maintained and the new measures or facilities proposed by the applicant for the purpose of creating, preserving, or enhancing recreational opportunities at the project and in its vicinity, and for the purpose of ensuring the safety of the public in its use of project lands and waters, including an explanation of why the applicant has rejected any measures or facilities recommended by an agency and described by an agency and described under paragraph (f)(5)(iii) of this section; and

(v) the following materials and information regarding the measures and facilities identified under paragraphs (f)(5)(i) and (iv) of this section:

(A) identification of the entities responsible for implementing, constructing, operating, or maintaining any existing or proposed measures or facilities;

(B) a schedule showing the intervals following issuance of a license at which implementation of the measures or construction of the facilities would be commenced and completed;

(C) an estimate of the costs of construction, operation, and maintenance of any proposed facilities, including a statement of the sources and extent of financing;

(D) a map or drawing that conforms to the size, scale, and legibility requirements of §4.32 showing by the use of shading, cross-hatching, or other symbols the identity and location of any facilities, and indicating whether each facility is existing or proposed (the maps or drawings in this exhibit may be consolidated); and

(vi) a description of any areas within or in the vicinity of the proposed project boundary that are included in, or have been designated for study for inclusion in, the National Wild and Scenic Rivers System, or that have been designated as wilderness area, recommended for such designation, or designated as a wilderness study area under the Wilderness Act.

(6) Report on land management and aesthetics. The report must discuss the management of land within the proposed project boundary, including wetlands and floodplains, and the protection of the recreation and scenic values of the project. The report must be prepared following consultation with local and state zoning and land management authorities and any Federal or state agency with managerial authority over any part of the project lands. Consultation must be documented by appending to the report a letter from each agency consulted indicating the nature, extent, and results of the consultation. The report must contain:

(i) a description of existing development and use of project lands and all other lands abutting the project impoundment;

(ii) a description of the measures proposed by the applicant to ensure that any proposed project works, rights-of-way, access roads, and other topographic alterations blend, to the extent possible, with the surrounding environment; (see, e.g., 44 C.F.R. 1496, et seq.);

(iii) a description of wetlands or floodplains within, or adjacent to, the project boundary, any short-term or long-term impacts of the project on those wetlands or floodplains, and any mitigative measures in the construction or operation of the project that minimize any adverse impacts on the wetlands or floodplains;

(iv) a statement, including an analysis of costs and other constraints, of the applicant's ability to provide a buffer zone around all or any part of the impoundment, for the purpose of ensuring public access to project lands and waters and protecting the recreational and aesthetic values of the impoundment and its shoreline;

(v) a description of the applicant's policy, if any, with regard to permitting development of piers, docks, boat landings, bulkheads, and other shoreline facilities on project lands and waters; and

(vi) maps or drawings that conform to the size, scale and legibility requirements of §4.32, or photographs, sufficient to show the location and nature of the measures proposed under paragraph (f)(6)(ii) of this section (maps or drawings in this exhibit may be consolidated).

(7) List of literature. The report must include a list of all publications, reports, and other literature which were cited or otherwise utilized in the preparation of any part of the environmental report.

(g) Exhibit F consists of general design drawings of the principal project works described under paragraph (b) of this section (Exhibit A).

(1) The drawings must conform to the specifications of §4.32 and must indicate whether each structure depicted is existing or proposed.

(2) Detailed working drawings that show the precise plans and specifications for proposed structures should not be filed with the application, but must be prepared for the purposes of construction and, if a license is issued and construction ensues, retained as permanent project records.

(3) The general design drawings required under this paragraph must show plans (overhead view), elevations (front view), profiles (side view), and sections for each principal project work. The drawings must be accompanied by a description of the physical condition or state of maintenance and repair of any structures or equipment and by sufficient information relating to composition and competency of foundations and other structures, gradation of filter and riprap material, design strength and ultimate strength of concrete and steel, stress and stability analyses, the project design flood (and Standard Project Flood or Probable Maximum Flood, if different from the design flood) used for stability analysis, spillway rating curves, water levels, and other controlling factors to demonstrate that the structures are safe and adequate to fulfill their stated functions.

(h) Exhibit G is a map of the project. The map must conform to the specifications of §4.32. If more than one sheet is used, the sheets must be numbered consecutively and each sheet must bear a small inset sketch showing the entire project (or development) and indicating the portion depicted on the sheet. The map must show:

(1) Location of the project and principal features. The map must show the location of the project as a whole with reference to the affected stream or other body of water and, if possible, to a nearby town or any permanent monuments or objects, such as roads, transmission lines or other structures, that can be noted on the map and recognized in the field. The map must also show the relative locations and physical interrelationships of the principal project works and other features described under paragraph (b) of this section (Exhibit A).

(2) Project boundary. The map must show a project boundary enclosing all of the principal project works and other features described under paragraph (b) of this section (Exhibit A). The boundary must enclose only those lands necessary for operation and maintenance of the project and for other project purposes, such as recreation, shoreline control, or protection of environmental resources (see paragraph (f) of this section (Exhibit E)). Existing residential, commercial, or other structures may be included within the boundary only to the extent that underlying lands are needed for project purposes (e.g., for flowage, public recreation, shoreline control, or protection of environmental resources). If the boundary is on land covered by a public land survey, ties must be shown on the map at sufficient points to permit accurate plotting of the position of the boundary relative to the lines of the public land survey. If the lands are not covered by a public land survey the best available legal description of the position of the boundary must be provided, including distances and directions from fixed monuments or physical features. The boundary must be described as follows:

(i) Impoundments. (A) The boundary around a project impoundment may be described by any of the following:

(1) contour lines, including the contour elevation (preferred method);

(2) specified courses and distances (metes and bounds);

(3) if the project lands are covered by a public land survey, lines upon or parallel to the lines of the survey; or

(4) any combination of the above methods.

(B) The boundary must be located no more than 200 feet (horizontal measurement) from the exterior margin of the reservoir, defined by the normal maximum surface elevation, except where deviations may be necessary in describing the boundary according to the above methods, or where additional lands are necessary for project purposes, such as public recreation, shoreline control, or protection of environmental resources.

(ii) Continuous features. The boundary around linear ("continuous") project features such as access roads, transmission lines, and conduits may be described by specified distances from center lines or offset lines of survey. The width of such corridors must not exceed 200 feet, unless good cause is shown for a greater width. Several sections of a continuous feature may be shown on a single sheet, with information showing the sequence of contiguous sections.

(iii) Noncontinuous features. (A) The boundary around noncontinuous project works such as dams, spillways, and powerhouses may be described by:

(1) contour lines;

(2) specified courses and distances;

(3) if the project lands are covered by a public land survey, lines upon or parallel to the lines of the survey; or

(4) any combination of the above methods.

(B) The boundary must enclose only those lands that are necessary for safe and efficient operation and maintenance of the project, or for other specified project purposes, such as public recreation or protection of environmental resources.

(3) Federal lands. Any public lands and reservations of the United States [see 16 U.S.C. §796(1) and (2)] ("Federal lands") that are within the project boundary e.g., lands administered by the U.S. Forest Service, Bureau of Land Management, National Park Service, or Indian tribal lands, and the boundaries of those Federal lands, must be identified on the map:

(i) by legal subdivisions of a public land survey of the affected area (a protraction of identified township and section lines is sufficient for this purpose);

(ii) by the Federal agency, identified by symbol or legend if desired, that maintains or manages each identified subdivision of the public land survey within the project boundary; and

(iii) in the absence of a public land survey, by the location of the Federal lands according to the distances and directions from fixed monuments or physical features. When a Federal survey monument or a Federal bench mark will be destroyed or rendered unusable by the construction of project works, at least two permanent, marked, witness monuments or bench marks must be established at accessible points. The maps must show the location (and elevation, for bench marks) of the survey monument or bench mark which will be destroyed or rendered unusable, as well as of the witness monuments or bench marks. Connecting courses and distances from the witness monuments or bench marks to the original must also be shown.

(4) Non-Federal lands. For those lands within the project boundary not identified under paragraph (b)(3) of this section, the map must identify by legal subdivision:

(i) lands owned in fee by the applicant and lands that the applicant plans to acquire in fee; and

(ii) lands over which the applicant has acquired or plans to acquire rights to occupancy and use other than fee title, including rights acquired or to be required by easement or lease.

ATTACHMENT NO. 5

U.S. ARMY CORPS OF ENGINEERS

DREDGE AND FILL PERMIT

APPLICATION FOR A DEPARTMENT OF THE ARMY PERMIT

For use of this form, see EP 1145–2–1

The Department of the Army permit program is authorized by Section 10 of the River and Harbor Act of 1899, Section 404 of P. L. 92–500 and Section 103 of P. L. 92–532. These laws require permits authorizing structures and work in or affecting navigable waters of the United States, the discharge of dredged or fill material into waters of the United States, and the transportation of dredged material for the purpose of dumping it into ocean waters. Information provided in ENG Form 4345 will be used in evaluating the application for a permit. Information in the application is made a matter of public record through issuance of a public notice. Disclosure of the information requested is voluntary; however, the data requested are necessary in order to communicate with the applicant and to evaluate the permit application. If necessary information is not provided, the permit application cannot be processed nor can a permit be issued.

One set of original drawings or good reproducible copies which show the location and character of the proposed activity must be attached to this application (see sample drawings and checklist) and be submitted to the District Engineer having jurisdiction over the location of the proposed activity. An application that is not completed in full will be returned.

1. Application number (To be assigned by Corps)

2. Date

Day Mo. Yr.

3. For Corps use only.

4. Name and address of applicant.

Telephone no. during business hours

A/C ( ) ____________

A/C ( ) ____________

5. Name, address and title of authorized agent.

Telephone no. during business hours

A/C ( ) ____________

A/C ( ) ____________

6. Describe in detail the proposed activity, its purpose and intended use (private, public, commercial or other) including description of the type of structures, if any to be erected on fills, or pile or float–supported platforms, the type, composition and quantity of materials to be discharged or dumped and means of conveyance, and the source of discharge or fill material. If additional space is needed, use Block 14.

7. Names, addresses and telephone numbers of adjoining property owners, lessees, etc., whose property also adjoins the waterway.

8. Location where proposed activity exists or will occur.

Address:

____

Street, road or other descriptive location

____

In or near city or town

____

County State Zip Code

Tax Assessors Description: (if known)

Map No. Subdiv. No. Lot No.

Sec. Twp. Rge.

9. Name of waterway at location of the activity.

ENG Form 4345, 1 OCT 77 Edition of 1 Apr 74 is obsolete.

10. Date activity is proposed to commence. ______________________________

Date activity is expected to be completed ______________________________

11. Is any portion of the activity for which authorization is sought now complete? ☐ YES ☐ NO
If answer is "Yes" give reasons in the remark section. Month and year the activity was completed ______________________________. Indicate the existing work on the drawings.

12. List all approvals or certifications required by other federal, interstate, state or local agencies for any structures, construction, discharges, deposits or other activities described in this application.

Issuing Agency	Type Approval	Identification No.	Date of Application	Date of Approval

13. Has any agency denied approval for the activity described herein or for any activity directly related to the activity described herein?

☐ Yes ☐ No (If "Yes" explain in remarks)

14. Remarks (Checklist, Appendix H for additional information required for certain activities).

15. Application is hereby made for a permit or permits to authorize the activities described herein. I certify that I am familiar with the information contained in this application, and that to the best of my knowledge and belief such information is true, complete, and accurate. I further certify that I possess the authority to undertake the proposed activities.

____
Signature of Applicant or Authorized Agent

The application must be signed by the applicant; however, it may be signed by a duly authorized agent (named in Item 5) if this form is accompanied by a statement by the applicant designating the agent and agreeing to furnish upon request, supplemental information in support of the application.

18 U. S. C. Section 1001 provides that: Whoever, in any manner within the jurisdiction of any department or agency of The United States knowingly and willfully falsifies, conceals, or covers up by any trick, scheme, or device a material fact or makes any false, fictitious or fraudulent statements or representations or makes or uses any false writing or document knowing same to contain any false fictitious or fraudulent statement or entry, shall be fined not more than $10,000 or imprisoned not more than five years, or both. Do not send a permit processing fee with this application. The appropriate fee will be assessed when a permit is issued.

ATTACHMENT NO. 6

STATE WATER RESOURCES CONTROL BOARD

(DIVISION OF WATER RIGHTS)

- Petition for Change in Purpose of Use
- Petition for Change (1) of Point of Diversion
  (2) by Addition of Point of Rediversion
  (3) of Place of Use
- Application to Appropriate Unappropriated Water
- Supplement to Application
- Environmental Information

PETITION FOR CHANGE IN PURPOSE OF USE

Application________ Permit ________License______

State Water Resources Control Board
Division of Water Rights
77 Cadillac Drive
Sacramento, CA 95825

I request permission to change the purpose of use described in this permit or license as follows:

____
(State all purposes for which water is to be used)

____

Give reason for proposed change: ______________________________________

____

Does this change involve any place of use not described in the permit or license? ________________. If answer is yes, give legal description:
(yes or no)

____

____

____

THIS CHANGE DOES NOT INVOLVE AN INCREASE IN THE AMOUNT OF THE APPROPRIATION OR SEASON OF USE.

Give names and addresses of persons known to you who may be affected by the proposed change:

____

____

____

____

____

____

I declare under penalty of purjury that the above is true and correct to the best of my knowledge and belief.
Dated:____________________, 19___, at ____________________, California.

____

____

Section 1547 of the Water Code requires a $10 filing fee with petitions for changes.

SWRCB 22e (4/75)

27—82257

PETITION FOR CHANGE ☐ OF POINT OF DIVERSION
☐ BY ADDITION OF POINT OF REDIVERSION
☐ OF PLACE OF USE

Application__________________Permit______________License____________

State Water Resources Control Board
Division of Water Rights
77 Cadillac Drive
Sacramento, CA 95825
(916) 920-6151

I hereby petition for changes noted above and shown on the accompanying map and described as follows:

____
(Give tie by bearing and distance or by coordinate distances from some
____
government corner and the 40-acre subdivisions in which the new point
____
of diversion lies or acreage to be irrigated within each 40-acre tract.)

GIVE REASON FOR PROPOSED CHANGE:______________________________________

____

WILL OLD POINT OF DIVERSION OR PLACE OF USE BE ABANDONED?____________
(yes or no)

WATER WILL BE USED FOR ________________________________PURPOSES.

I have access to the proposed new point of diversion or control the place of use proposed by virtue of

____
(ownership, lease, verbal, or written agreement)

____
(If by lease or agreement, state name and address of party or parties from whom access has been obtained.)

Are there any persons taking water from the stream between the old point of diversion and the new point of diversion? _______________
(yes or no)

Give names and addresses, if answered yes, as well as other persons known to you who may be affected by the proposed change.

____

____

____

THIS CHANGE DOES NOT INVOLVE AN INCREASE IN THE AMOUNT OF THE APPROPRIATION OR SEASON OF USE.

I declare under penalty of perjury that the above is true and correct to the best of my knowledge and belief.

Dated:_______________, 19___, at___________________________California.

____

Note: Section 1547 of the Water Code requires a $10 filing fee with petitions for changes.

SWRCB 22 (5/75)

STATE OF CALIFORNIA

MINIMUM FILING FEE: $10:00
FILE TWO COPIES
TYPE OR PRINT IN INK

State Water Resources Control Board
DIVISION OF WATER RIGHTS
77 Cadillac Drive, Sacramento, CA 95825

APPLICATION to APPROPRIATE UNAPPROPRIATED WATER

(For explanation of entries required, see booklet "How to File an Application to Appropriate Unappropriated Water in California.")

Application No. ______________ Filed ______________ at ______________ ______ M.

(Do NOT fill in the above blanks)

1. APPLICANT

I, ______________________________
(Name of Applicant)

____
(Telephone Number where you may be reached between 8 a.m. and 5 p.m.—include area code)

____
(Address) (City or Town) (State) (Zip Code)

do hereby make application for a permit to appropriate the following described UNAPPROPRIATED waters of the State of California, SUBJECT TO VESTED RIGHTS

2. SOURCE

a. The name of the source at the point of diversion is ______________________________
(If unnamed, state nature of source and that it IS unnamed)

tributary to ______________________________

b. In a normal year does the stream dry up at any point downstream from your project? YES ☐ NO ☐. If Yes, in what months does it usually dry up? ______________________________

3. POINT of DIVERSION and REDIVERSION

a.

List all points giving coordinate distances from section corner or other tie as allowed by Board regulations	Point is within (40-acre Subdivision)	Section	Township	Range	Base and Meridian
	¼ of ¼				
	¼ of ¼				
	¼ of ¼				

b. The point of diversion will be in the County of ______________

c. Does applicant own the land at the point of diversion? YES ☐ NO ☐.

d. If applicant does not own land at point of diversion, state name and address of owner and state what steps have been taken to obtain right of access: ______________________________

4. PURPOSE of USE, AMOUNT and SEASON

a. State the purpose(s) for which water is to be appropriated, the amounts of water for each purpose and dates between which diversions will be made in the table below.

PURPOSE OF USE	DIRECT DIVERSION				STORAGE		
	AMOUNT		SEASON OF DIVERSION		AMOUNT	COLLECTION SEASON	
	Cubic feet per second or gallons per day	Acre-feet annually	Beginning Date	Ending Date	Acre-feet annually	Beginning Date	Ending Date
Irrigation							
Domestic							
	______ (TOTAL)				______ (TOTAL)		

b. Total combined direct diversion and storage during any one year will be ______________ acre-feet.

c. If water will be stored and the reservoir is not at the diversion point, the maximum rate of diversion to offstream storage will be ______ cfs. Diversion to offstream storage will be made by pumping ☐; gravity ☐.

(Submit "Environmental Information" SWRCB Form 1-2 if project is NOT exempt from CEQA, See Appendix D of the instructions.

5. JUSTIFICATION OF AMOUNT

a. IRRIGATION: Maximum acreage to be irrigated in any one year will be __________ acres.

CROP	ACRES	METHOD OF IRRIGATION (Sprinklers, flooding, etc.)	ACRE-FEET (annually)	NORMAL SEASON	
				Beginning Date	Ending Date

b. DOMESTIC: The number of residences to be served __________. Separately owned: YES ☐ NO ☐

The total number of people to be served __________. Estimated daily use per person __________ (gallons per day).

The total area of domestic lawns and gardens __________ (square feet).

Miscellaneous domestic uses __________ (Dust control area. Number and kind of domestic animals, etc.).

c. STOCKWATERING: Kind of stock __________. Maximum Number ______. Describe type of operation (feedlot, dairy, range, etc.)

____

d. RECREATIONAL: Type of recreation __________.

Private __________. Open to public without charge __________. Open to public admission charged __________.

(Submit "Supplement to Application", form SWRCB 1-1, for justification of amount for uses not listed above.)

6. DIVERSION WORKS

a. Diversion will be by pumping from __________ (sump, offset well, channel, reservoir, etc.). Pump discharge __________. Horsepower __________.

b. Diversion will be by gravity by means of __________ (pipe in unobstructed channel, pipe through dam, siphon, gate, etc.).

c. Main conduit from diversion point to first lateral or offstream storage reservoir:

CONDUIT (Pipe or channel)	MATERIAL (Kind of Pipe or channel lining)	CROSS SECTIONAL DIMENSION (Pipe diameter or ditch depth and top and bottom width)	LENGTH (feet)	TOTAL LIFT OR FALL		CAPACITY (estimated)
				(feet)	(+ or −)	

d. The following applies to storage reservoirs: (For reservoirs having a capacity of 25 acre-feet or more, complete supplemental form SWRCB 1-1).

Name or number of reservoir, if any	DAM				RESERVOIR		
	Height of dam from streambed to spillway level (ft.)	Material of construction	Dam Length (ft.)	Freeboard Dam height above spillway crest (ft.)	Approximate surface area when full (acres)	Approximate capacity (acre-feet)	Max. water depth

e. Estimated total cost of the diversion works proposed is __________ (Give only cost of intake, or headworks, pumps, storage reservoirs, and main conduits.)

7. PLACE OF USE

a. Applicant owns the land where the water will be used: YES ☐ NO ☐. Land is in joint ownership: YES ☐ NO ☐.

All joint owners should include their names as applicants and sign the application. If applicant does not own land where the water will be used, give name and address of owner and state what arrangements have been made with the owner.

____

____

b.

USE IS WITHIN (40-acre Subdivision)	SECTION	TOWNSHIP	RANGE	BASE AND MERIDIAN	IF IRRIGATION	
					State Number of Acres	Presently cultivated (Yes or No)
¼ of ¼						
¼ of ¼						
¼ of ¼						
¼ of ¼						
¼ of ¼						
¼ of ¼						

If area is unsurveyed, state the location as if lines of the public land survey were projected. If space does not permit listing all 40-acre tracts, include on another sheet or state sections, townships and ranges, and show detail on map. For public districts or other extremely large areas, see page 16 of instruction booklet "How to File an Application to Appropriate Unappropriated Water in California".

8. COMPLETION SCHEDULE

a. Proposed date of project commencement: __________. b. Estimated date of Project completion: __________.

c. Estimated date of complete application of water to proposed use: __________. d. If complete, date of completion: __________.

(ATTACH SUPPLEMENTAL SHEETS HERE)

9. GENERAL

a. What is the name of the post office most used by those living near the proposed point of diversion? ______

b. Does any part of the place of use comprise a subdivision on file with the State Department of Real Estate? YES ☐ NO ☐. If Yes, state name of subdivision ______ If No, is subdivision of these lands contemplated? YES ☐ NO ☐.

Is it planned to individually meter each service connection? YES ☐ NO ☐. If Yes, when? ______

c. Have you consulted the California Department of Fish and Game concerning this proposed project? YES ☐ NO ☐. If Yes, state the Department's opinion concerning the potential effects of your proposed project on fish and other wildlife and state measures required for mitigation ______

If No, state the effects on fish and other wildlife you foresee as potentially arising from your proposed project. ______

d. Please name other public agencies, if any, from which you have obtained or are required to obtain approvals regarding this project: ______

e. Is reclaimed water available or do you expect such to be available in the near future which could be used in lieu of the water sought under this application? YES ☐ NO ☐ If Yes, explain: ______

f. Is it practical to reduce the amount applied for by reusing or reclaiming a portion of the water appropriated? YES ☐ NO ☐

g. What are the names and addresses of diverters of water from the source of supply downstream from the proposed point of diversion? ______

10. EXISTING WATER RIGHT

Check the appropriate box below:

A. ☐ Applicant does not claim an existing right for the use of water sought by this application.

B. ☐ Applicant claims an existing right for use of water sought by this application but agrees NOT to exercise said right so long as a permit or license for such use remains in effect.

C. ☐ The water sought by this application is for additional water over that claimed under an existing right.

Complete Table below if B or C is checked:

Nature of Rights (riparian, appropriative, purchased water, etc.)	Year of First Use	Use made in recent years including amount, if known	Season of Use	Source	Location of Point of Diversion

11. AUTHORIZED AGENT (Optional)

With respect to: ☐ All matters concerning this water right application, ☐ those matters designated as follows: ______

Name ______ Address ______

______ Zip Code: ______ ______ (Telephone No. of agent between 8 a.m. and 5 p.m.)

is authorized to act on my behalf as my agent.

12. SIGNATURE of APPLICANT

I (we) declare under penalty of perjury that the above is true and correct to the best of my (our) knowledge and belief.

Dated ______ 19 ____ , at ______ , California

Ms. Mr.
Miss, Mrs. ______
(Signature of applicant) (Refer to Section 671 of the Board's regulations)

If applicants are members of the same family (i.e., husband, wife, mother, father, son, brother, sister, etc.) or reside at the same address, please indicate their relationship:

Ms. Mr.
Miss, Mrs. ______
(Signature of applicant) (Refer to Section 671 of the Board's regulations)

Additional information needed for preparation of this application may be found in the leaflet entitled "HOW TO FILE AN APPLICATION TO APPROPRIATE UNAPPROPRIATED WATER IN CALIFORNIA". If there is insufficient space for answers in this form, attach extra sheets. Please cross reference all remarks to the numbered paragraph to which they may refer. Send application in duplicate to the STATE WATER RESOURCES CONTROL BOARD, DIVISION OF WATER RIGHTS, 77 Cadillac Drive, Sacramento, CA 95825, with $10 minimum filing fee.

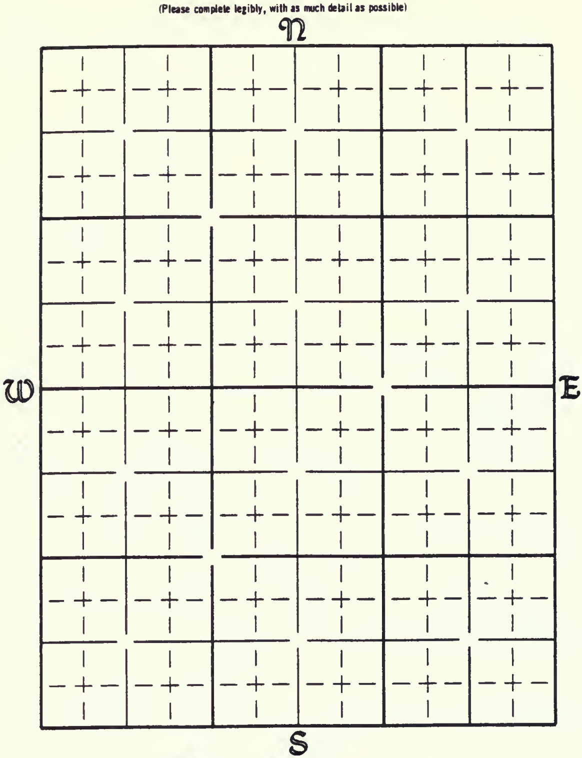
STATE OF CALIFORNIA

State Water Resources Control Board

DIVISION OF WATER RIGHTS

Application Map

(Please complete legibly, with as much detail as possible)



SECTION ____ SECTION(S) ________________

TOWNSHIP ________; RANGE ________; ________ B&M

(1) Show location of the spring or stream, and give name.

(2) Show location of the main ditch or pipe line.

(3) Indicate clearly the proposed place of use of the water.

(4) Locate and describe the point of diversion (i.e., the point at which water is to be taken from the stream or spring) in the following way: Begin at the most convenient known corner of the public land survey, such as a section or quarter section corner (if on unsurveyed land more than two miles from a section corner, begin at a mark or some natural object or permanent monument that can be readily found and recognized) and measure directly north or south until opposite the point which it is desired to locate; then measure directly east or west to the desired point. Show these distances in figures on the map as shown in the Instructions, Page 20.The map scale is 2 inches equals 1 mile. If a different scale is used, please indicate.

APPLICATION NO. ________________

SUPPLEMENT TO APPLICATION

(This supplement is required for uses other than irrigation, domestic, stockwatering, and recreation and for surface storage of 25 acre-feet or more.)

5. JUSTIFICATION of AMOUNT

e. MUNICIPAL: Estimated projected use:

POPULATION 5-year periods until use is completed		MAXIMUM MONTH		ANNUAL USE		
		Average daily use per capita (gal.)	Rate of Diversion (cfs)	Average daily use (gal. per capita)	Acre-foot (per capita)	Total Acre-feet
PERIOD	POP.					
Present						
19						
19						
19						
19						

Month of maximum use during year ________________. Month of minimum use during year ________________.

Is it planned to individually meter each service connection? YES ☐ NO ☐. If so, when? ________________

f. HEAT CONTROL: The total area of heat protection is ________ (net acreage) acres. Type of crop protected ________________

Rate at which water is applied to use: ________ (gpm) (cfs) (circle one)

The heat protection season will begin about ________________ (beginning date) and end about ________________ (ending date).

g. FROST PROTECTION: The total area of frost protection is ________ (net acreage) acres. Type of crop protected ________________.

Rate at which water is applied to use: ________ (gpm) (cfs) (circle one)

The frost protection season will begin about ________________ (beginning date) and end about ________________ (ending date).

h. INDUSTRIAL USE: Type of industry ________________________________

Basis of determination of amount of water needed ________________________________

i. MINING: The name of the mine is ________________________ (name of claim) Patented ☐ or Unpatented ☐.

The nature of the mine is ________________________. Mineral to be mined is ________________.

Type of milling or processing ________________________________.

After use, the water will be discharged into ________________________ (name of stream)

in ________________________ (state 40-acre subdivision) of Sec. ____, T____, R ____, ______ B.&M.

j. POWER USE: The total fall to be utilized is ______ feet. The maximum amount of water to be used through the penstock is ______ cubic feet per second. The maximum theoretical horsepower capable of being generated by the works is ________________ (cubic feet per second x fall ÷ 8.8)

The use to which power is to be applied is ________________________ (for distribution and sale or private use, etc.). The nature of the works by means of which power is to be developed is ________________________ (Turbine, Pelton wheel, etc.). The size of the nozzle to be used is ______ inches.

After use, the water will be discharged into ________________________ (name of stream) in ________________________ (state 40-acre subdivision) of Sec. ____, T____, R ____, ______ B.&M.

k. OTHER: Describe use: ________________________. Basis of determination of amount of water needed: ________________

____

6. DIVERSION WORKS (Storage Reservoirs)

The following applies to storage reservoirs having a capacity of 25 acre-feet or more:

Diameter of outlet pipe (inches)	Length of outlet pipe (feet)	Vertical distance between entrance and exit of outlet pipe (feet) Fall	Vertical distance from spillway to outlet pipe in reservoir (feet) Head	Estimated storage below outlet pipe entrance (Dead storage)

SWRCB 1-1 (10/76)

STATE OF CALIFORNIA

APPLICATION NO. ____________

State Water Resources Control Board

DIVISION OF WATER RIGHTS

ENVIRONMENTAL INFORMATION

COUNTY INFORMATION

1. What is (are) the County Tax Assessor's parcel number(s) for the project site? ____________
2. What is the County zoning designation for the project site? ____________
3. Is the proposed project consistent with the current County zoning designation? ☐ YES ☐ NO
4. Which of the following best describes the type(s) of land use(s) generally occurring on other land adjacent to the project?

   ☐ agricultural ☐ residential ☐ industrial ☐ other (describe): ____________

5. Does the project involve grading or other disturbance of the soil surface? ☐ YES ☐ NO If no, explain: ____________

   If yes, which of the following measures do you intend to use during construction and operation of the project in order to prevent erosion of soil into surface waters?

   ☐ construction only during dry season. ☐ immediate reseeding of disturbed areas. ☐ contour plowing in areas of use

   ☐ other (explain): ____________

   ☐ none (explain): ____________

6. Will the County require issuance of any of the following?

   a. grading permit: ☐ YES ☐ NO
   b. watercourse obstruction permit: ☐ YES ☐ NO
   c. change of zoning or variance: ☐ YES ☐ NO
   d. use permit: ☐ YES ☐ NO
   e. other permit/approval: ☐ YES ☐ NO If yes, explain: ____________

   If the answer to any of the above is yes, will the County prepare an environmental assessment of the project and become lead agency pursuant to the California Environmental Quality Act? ☐ YES ☐ NO

7. Sewage wastes shall be disposed of by which of the following means?

   ☐ County approved septic tank(s) under permit number(s): ____________

   ☐ community sewer

   ☐ other (explain): ____________

   ☐ no sewage will be generated by the project

FISH AND WILDLIFE INFORMATION

8. Which of the following best describes the general vegetative habitat in the project area?

   ☐ grassland ☐ oak woodland ☐ brush/chaparral ☐ pine forest ☐ hardwood forest ☐ marsh

   ☐ cultivated land (describe): ____________

   ☐ other (describe): ____________

9. Does the project involve removal or flooding (such as in a reservoir) of any grassland, brush, trees, or riparian (streamside) vegetation?

   ☐ YES ☐ NO If yes, explain and indicate number of acres involved: ____________

(ATTACH ADDITIONAL SHEETS, IF NEEDED) (OVER)

SWRCB 1-2 (5/79)

10. Which of the following types of fisheries exist in the source? (Note: this information is available from the California Department of Fish and Game – see attached regional office listings.)

MIGRATORY	NONMIGRATORY
☐ salmon	☐ trout
☐ steelhead trout	☐ bluegill
☐ sturgeon	☐ black bass
☐ striped bass	☐ catfish
☐ shad	☐ none
☐ none	

☐ other (explain): ____________________

____

Who is the source of information for the above?

Name: ____________________ Telephone: ( ) ________

11. Does a California Department of Fish and Game representative expect that the proposed project would substantially reduce the habitat of a fish or wildlife species or cause a fish or wildlife population to drop below self-sustaining levels? ☐ YES ☐ NO

Who did you contact regarding the above?

Name: ____________________ Telephone: ( ) ________

WATER QUALITY INFORMATION

12. Will construction or operation of the project involve the discharge of any of the following materials into groundwater or surface waters?
   a. pesticides, herbicides, or fungicides ☐ YES ☐ NO
   b. fertilizers ☐ YES ☐ NO
   c. metallic wastes ☐ YES ☐ NO
   d. industrial chemicals ☐ YES ☐ NO
   e. decomposable organic materials ☐ YES ☐ NO
   f. soil ☐ YES ☐ NO

13. If you answered yes to any of the above in question No. 12, will the appropriate Regional Water Quality Control Board (see attached regional office listings) require issuance of a permit to discharge wastes? ☐ YES ☐ NO Explain: ____________________

____

____

Who is the source of information for the above?

Name: ____________________ Telephone: ( ) ________

14. Will the project divert all of the existing flow in the source at any time? ☐ YES ☐ NO If yes, during what months will this normally occur? ____________________

ARCHAEOLOGICAL AND HISTORICAL INFORMATION

15. Are there any sites of known archaeological or historical value located within the general project area? ☐ YES ☐ NO
If yes, will construction or operation of the project disturb any artifacts or structures of archaeological or historical value? ☐ YES ☐ NO
Explain: ____________________

____

____

____

PHOTOGRAPHS

16. Enclose labeled colored photographs of each point of diversion and each place of use described in this application (Polaroid snapshots will be accepted.)

I (we) declare under penalty of perjury that the above is true and correct to the best of my (our) knowledge and belief.

Dated: ____________ 19____, at ____________________, California.

Ms. Mr. ____________________
Miss, Mrs. ____________________

Ms. Mr. ____________________
Miss, Mrs. ____________________

(ATTACH ADDITIONAL SHEETS, IF NEEDED)

ATTACHMENT NO. 7

DEPARTMENT OF WATER RESOURCES

(DIVISION OF SAFETY OF DAMS)

APPLICATION FOR APPROVAL OF PLANS

AND SPECIFICATIONS FOR THE REPAIR

OR ALTERATION OF A DAM AND RESERVOIR

FILE IN DUPLICATE

[For full information concerning the filling out and filing of this form send for Statutes and Regulations Pertaining to Supervision of Dams and Reservoirs.]

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
DIVISION OF SAFETY OF DAMS

Dam No. .... Application Filed ....
Applicant must not fill in the above blanks.

APPLICATION FOR APPROVAL OF PLANS AND SPECIFICATIONS FOR THE REPAIR OR ALTERATION OF A DAM AND RESERVOIR

[This application involves in no way the right to appropriate water
To secure the right to appropriate water, application should be made to the State Water Resources Control Board on forms which will be furnished upon request.]

I, ... (Name of individual signing application) of .... (Address) ....

County of .... State of ...., hereby make application for the approval of plans and specifications for the repair / alteration (Strike out one) of .... (Name of dam and reservoir) .... dam and reservoir.

The owner of the dam and reservoir is .... (Name of owner) ....

of .... (Address) .... County of .... State of ....

If the owner is a corporation, give name and address of president and secretary—

....

....

The applicant is acting for the owner in the capacity of .... (Agent, Lessee, Trustee, Engineer, etc.)

Location of Dam

1. The dam is in .... County, in the .... ¼, Sec. ...., Tp. ...., R. ...., ... B. & M.

and is located on .... (Creek, river or watershed) .... tributary to .... (Creek or river) ....

Description of Proposed Work

2. Type of dam .... (Concrete arch or gravity, earth, rockfill, etc.) ....

3. Description of work contemplated .... (Use extra sheets or exhibits if necessary) ....

....

....

....

....

....

....

4. Work will result in .... ("No change in" or "lowering") .... the maximum storage level.

....
This form is not to be used if the alteration will increase the water storage elevation of the reservoir as previously operated.

5. Work is to commence by ...., and to be completed by ....

6. Engineer .... 7. Contractor ....

SIGN ALL COPIES [Signed] .... (Applicant)

Form DWR 4

this .... day of .... 19 ....

APPROVAL OF APPLICATION FILED________________,
INCLUDING THE PLANS AND SPECIFICATIONS

This is to certify that the within application, including plans and specifications for the

repair
alteration *of* .... *dam and reservoir, No.*............, *has been examined*
Strike out one

and the same is hereby .... *approved, subject to the following terms and limitations:*

1. *Construction work shall be commenced on or before* ....

2. *Construction work shall be completed on or before* ....

....
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....

Witness my hand and the seal of the Department of Water Resources of the State of California

this..........*day of*....................*19*........

....
Division Engineer

ATTACHMENT NO. 8

DEPARTMENT OF WATER RESOURCES

(DIVISION OF SAFETY OF DAMS)

APPLICATION FOR APPROVAL OF PLANS

AND SPECIFICATIONS FOR THE

CONSTRUCTION OR ENLARGEMENT OF

A DAM AND RESERVOIR

FILE IN DUPLICATE

[For full information concerning the filling out and filing of this form send for Statutes and Regulations Pertaining to Supervision of Dams and Reservoirs.]

STATE OF CALIFORNIA
THE RESOURCES AGENCY
DEPARTMENT OF WATER RESOURCES
DIVISION OF SAFETY OF DAMS

Application No. .... Filed ....
Applicant must not fill in the above blanks

APPLICATION FOR APPROVAL OF PLANS AND SPECIFICATIONS FOR THE CONSTRUCTION OR ENLARGEMENT OF A DAM AND RESERVOIR

[**This application involves in no way the right to appropriate water**
To secure the right to appropriate water, application should be made to the State Water Resources Control Board on forms which will be furnished upon request.]

I, ... (Name of individual signing application) of .... (Address)

County of .... State of ...., hereby make application for the approval of

the plans and specifications for the construction / enlargement (Strike out one) of .... (Name of dam) dam.

The owner of the dam and reservoir is .... (Name of owner)

of .... (Address) County of .... State of ....

Is the owner a Public Utility? .... (Yes or No)

If the owner is a corporation, give name and address of president and secretary

....

....

The applicant is acting for the owner in the legal capacity of .... (Agent, Lessee, Trustee, etc.)

Location of Dam

1. The dam is in .... County, in the ....¼,Sec. ...., Tp. ...., R. ...., ... B. & M.

and is located on .... (Creek, river or watershed) tributary to .... (Creek or river)

Description of Dam and Reservoir

(If for an enlargement, the data given below are for the enlarged dam)

2. Type of dam .... (Concrete arch or gravity, earth, rockfill, etc.) 3. Length of crest ....ft.

4. Height lowest outside limit of barrier to M.S.E.* ....ft.

5. Freeboard ....ft. (MSE* to top) 6. Thickness at top .... ft. 7. Spillway crest elevation ....ft.

8. Slope upstream** .... 9. Slope downstream** ....
**This information to be supplied for earth or rockfill dams.

10. Amount of material in dam .... cu. yds. 11. Estimated cost $ .... (Fee will be based on this figure)

12. Spillway data .... (Type, capacity, etc.)

13. Outlet data .... (Type, capacity, etc.)

14. Elevation of crest of dam .... (Approximate elevation to be given if true elevation not available) above ....datum

15. Area of reservoir at M.S.E.* ....acres. 16. Capacity of reservoir at M.S.E.* .... ac. ft.

17. Drainage, area .... sq. mi.

*Maximum Storage Elevation ....ft.
To spillway crest, top of flashboards or top of spillway gates whichever is greatest

Form DWR 3

28—82257

18. State what provisions will be made to divert flood flows during construction ....

....
If necessary to clarify this feature, drawings showing the temporary diversion works will be required

Precipitation, Flood or Inflow Data

19. **Rainfall.** If records of rainfall other than those published by the U.S. Weather Bureau are available, state the location and names of the stations and the maximum intensity of rainfall for 1, 12, 24 and 48 hours. (Use extra sheets or exhibits if necessary.)

....

20. State the estimated maximum rainfall on watershed ....inches of rain in .... hours.

21. **Flood or inflow data.** If records of flood flow other than those published by the U.S.G.S. are available state: location and dates of measurements; maximum flow in cubic feet per second; duration in hours of crest flow and of the flood. State the estimated maximum flood flow in cubic feet per second and the duration of flood and of crest flow in hours. State maximum inflow if flow data are not applicable. (Use extra sheets or exhibits if necessary.)

....

....

....

General Information

22. State the purpose of the dam and reservoir ....
Diversion only; storage only; storage and diversion; debris storage, etc.

23. State the use that is to be made of water ....
Municipal, domestic, irrigation, power, mining or recreation

24. Engineers ....: ....
Chief Engineer — Resident Engineer

....
Consulting Engineer

25. If the proposed dam and reservoir is to be built under federal license or permit, state what department has jurisdiction ....

26. The maps, plans and specifications and filing fee of $.................. accompanying this application are a part thereof.

[Signed] ....
Applicant

(ORIGINAL SIGNATURE REQUIRED ON ALL COPIES) this .... day of .... 19 ......

APPROVAL OF APPLICATION NO. ...., INCLUDING THE PLANS AND SPECIFICATIONS

This is to certify that Application No. ...., including the plans and specifications for the .... dam and reservoir has been examined and the same is hereby .... approved, subject to the following terms and limitations:

1. *Construction work shall be started within one year from date.*
2. *No foundations or abutments shall be covered by the material of the dam until the department has been given an opportunity to inspect and approve the same.*

....

....

....

Witness my hand and the seal of the Department of Water Resources of the State of California

this ....day of ....19 ......

....
Division Engineer

ATTACHMENT NO. 9

DEPARTMENT OF WATER RESOURCES

(THE RECLAMATION BOARD)

APPLICATION FOR APPROVAL OF PLANS

AND/OR ENCROACHMENT PERMIT

State of California — THE RECLAMATION BOARD — The Resources Agency

For Office Use

Application No.

APPLICATION FOR APPROVAL OF PLANS AND/OR ENCROACHMENT PERMIT

1 Application to the State Reclamation Board for approval to ______________________________

____

____

____

2. Section ________ Township ________ Ⓝ/Ⓢ Range ________ Ⓔ/Ⓦ County ______________________

3. **Please check exhibits accompanying application.**

a. ☐ Location or vicinity map, to scale, showing location of proposed work in relation to known topographic features, to permit visitation and/or inspection of the work.

b. ☐ A complete plan of the proposed work to scale, showing dimensions, materials of construction, and relationship of the proposed work to adjacent or affected project features.

c. ☐ A cross section of the levee, berm and stream area with dimensions and elevations of the levee crown, levee toes, flood plane, low water level, etc., with reference to the U.S. Geological Survey, U.S. Corps of Engineers, or other datum generally used within the locale.

d. ☐ Profiles of existing or proposed levees, fills, or other obstructions in the stream or overflow area with reference to U.S. Geological Survey, U.S. Corps of Engineers, or other datum generally used within the locale.

4. Please Print:

Name of Applicant	Address-Zip Code	Telephone Number

Signature ______________________________________ Date ________________

5. Endorsement:

We, the Trustee of ______________________________________
(DISTRICT NAME AND NUMBER)

hereby approve and give consent to the execution of the above plan subject to the following conditions:

☐ Conditions listed on back of this form

☐ No conditions

Date ________________________

Signatures of Trustees:

______________________ ______________________

______________________ ______________________

______________________ ______________________

DWR 3615 (Rev. 7/77)
SRB 300 (Rev. 7/77)

(Continued back of page)

6. Has any agency made an environmental review of your proposed project under the provisions of the California Environmental Quality Act of 1970? If Yes, check ☐. Please furnish copy. If Pending, check ☐.

Reviewing Agency name: ______________________________

______________________________ State Clearing House SCH. No. ______________

7. Name and address of owners of adjacent land parcels sharing a length or point of common boundary with the land upon which the contents of this application apply.

Name	Address	Zip Code

8. Applicant's Statement of Water Rights:

If the proposed work under this application is for the purpose of diverting water from a public watercourse, submit the following information:

a. Water right permit or license number.

b. Statement of water diversion and use number
*(if riparian or pre-1914, give appropriation number).

c. Will there be a change in point or rate of diversion if Reclamation Board permit is granted, and

d. Has a petition for change of point or rate of diversion been filed with the State Water Resources Control Board?

**NOTE – Application is not complete without this information.*

ATTACHMENT NO. 10

STATE LANDS COMMISSION

APPLICATION FOR DREDGING PERMIT OR LEASE

OF STATE LANDS

Work Order ______

1807 - 13th Street
Sacramento, California 95814
Telephone: (916) 445-7738
Principal Office

APPLICATION REQUIREMENTS CHECKLIST

State of California – State Lands Commission

100 Oceangate, Suite 300
Long Beach, California 90802
Telephone: (213) 590-5201
Extractive Development

The following is the list of requirements for application for State Lands Commission action. The forms and data below are necessary for the projects indicated.

The staff of the Commission has attempted to enclose all of the information requirements necessary for your project application as it has been described to the staff. However, the applicant is advised that any of the information listed below may be required during the processing of the application.

- [ ] General Data, Form 54.2
- [ ] Leases and Permits for Tideland and/or Submerged Lands, Form 54.4
- [ ] Leases and Permits for Non-tide and/or submerged Lands, Form 54.5
- [ ] Environmental Data Form 54.3 [ ] EIF Form 59.2 [ ] EIF Form 69.3
- [ ] Proposed Pipelines–Offshore State Lands, Form 52.1(a)
- [ ] Proposed Pipelines–Inland Waterways, Form 52.1(b)
- [ ] Existing Pipelines–Offshore State Lands, Form 52.1(c)
- [ ] Existing Pipelines–Inland Waterways, Form 52.1(d)
- [ ] Purchase of State school lands, Forms 60.6 and 63.1
- [ ] Recreational Piers (PRC §6503) [ ] Form 51.4(a) [ ] Form 51.4(b)
- [ ] Highway uses, plats required per Commission Form 52.6. Evidence that the reasonable value of the State Lands and/or materials used is deposited in the General Fund and credited to the Resources Protection Account will be required.
- [ ] Railroad Right of Way, plats required per Commission Form 52.7
- [ ] Boundary Determination and/or Exchange Agreement, Commission Form 52.8
- [ ] Salvage Permit, Commission Form 69.5 and the requirements in 2 California Administrative Code, Article 2.5
- [ ] Sublease on Granted Lands, including the information outlined in 2 California Administrative Code, Article 9.
- [ ] Fair market rental – if this application will require the staff of the Commission to determine the fair market rental value of the lands to be leased, the applicant shall be required to submit data sufficient for Commission staff to make such evaluation. The information required may include but is not necessarily limited to, financial statements, option agreements, comparable sales/lease data, and/or other information necessary in order to make the fair rental determination.
- [ ] Oil and Gas Compensatory Agreement, Form 33.32
- [ ] Oil and Gas (Negotiated), Form 33.33
- [ ] Geothermal Prospecting Permit, Form 33.42
- [ ] Geothermal Lease (Preferential), Form 33.39
- [ ] Mineral Prospecting Permit, Form 33.44
- [ ] Mineral Lease (Preferential), Form 33.34
- [ ] Oil and Gas, Geothermal, and Other Mineral Lease Competitive), Form 33.40
- [ ] Dredging Permits (Public Resources Code §6303), Form 33.41
- [ ] Modification of Right of Surface Entry (PRC 6401), Form 33.43
- [ ] Resumption of Drilling Operations, Form 33.36
- [ ] Ocean Floor Well Proposals, Form 33.37
- [ ] Well Proposals (New, redrill, repair, recompletion, abandonment, etc.), Form 33.35
- [ ] Alteration of Facilities, Form 33.38
- [ ] Signature and Certification Page, Form 54.2

Failure of an applicant to provide the information outlined in this form within the time limits prescribed by staff of the State Lands Commission may result in significant delays in determining that an application is complete; or, cancellation of the application.

In those instances where Commission costs and expenses are chargeable to the applicant, the applicant shall deposit with the Commission, the applicable expense deposit. If the deposits are not received within twenty-one (21) days of request, the application may be cancelled. Processing costs and environmental fees are calculated based on actual or estimated costs plus proportional overhead. If the estimated cost or fee is less than the actual cost, the applicant will be required to submit these additional costs within the allowable time period.

The preceding information is necessary in order to process your application for lease of State-owned land. You have the right to review files maintained about you by the State Lands Commission, except as provided for by law. The Commission Records Coordinator, State Lands Commission, 1807 - 13th Street, Sacramento, CA 95814, telephone (916) 445-9742, is responsible for maintenance of the information which is collected by the Commission.

The conduct of the State Lands Commission is governed by Public Resources Code Sections 6000, et seq. and 2 California Administrative Code Sections 1900, et seq. These provisions, by reference, are included herein.

Your application has been assigned the number indicated in the top right corner of this sheet. Please refer to it whenever communicating with this office.

WHITE COPY – APPLICANT YELLOW COPY – FILES

Form 54.1 (4/78)

GENERAL DATA

Work Order ____________________

This information is required of all applicants except as noted below.

A. APPLICATION BY:

[ ] Individual [ ] Partnership [ ] Corporation [ ] Public Agency

Applicant's Name: ____________________

Telephone: ( ) ____________________ ( ) ____________________
RESIDENCE BUSINESS

Applicant's Address: ____________________

____
(CITY AND STATE)

Applicant's Agent (if any): ____________________

Telephone: ( ) ____________________

Agent's Address: ____________________

B. If the applicant is a corporation, partnership or other association:

1. If the applicant is a corporation, attach a Certificate of Incorporation issued by the State of California or a Certificate of Incorporation issued by the State of Incorporation, together with the certificate issued by the State of California authorizing the applicant to transact business in California; and a certified statement of the names of the corporate president, secretary, and/or officer authorized to execute contracts.

2. If the applicant is a partnership, attach a certified copy of the partnership statement. If no partnership statement has been filed in the county in which the partnership does business, so state in your application and further give all particulars of the partnership.

3. If applicant is another form of association, state its nature, membership and other particulars regarding its legal existence.

C. PUBLIC AGENCIES:

Generally, all permits and leases issued by the State Lands Commission require monetary consideration. However, a public agency applicant may qualify for a rent-free lease/permit. In order to so qualify, the applicant must submit in writing a statement of justification for the rent-free status, which status shall be based on a statewide, as compared with a primarily local, public benefit. Such statement shall detail the statewide public benefit derived from the project. The State Lands Commission shall determine whether a statewide public benefit is derived from the project.

D. INDIVIDUAL:

If applicant seeks a lease or permit for an extractive development, individual applicants and members of associations, shall secure a copy of their birth certificate, certificates of naturalization or other evidence of citizenship.

E. LOCATION OF STATE LAND:

County: ____________________ Nearest City: ____________________

Miles: __________ Township, Range, Section, Reference Meridian: ____________________

____

OR Waterway: ____________________

F. USE OF STATE LAND:

[ ] Commercial;
[ ] Right of Way;
[ ] Mineral Lease (preferential);
[ ] Geothermal Lease (preferential);
[ ] Oil & Gas Lease (negotiated);
[ ] Industrial;
[ ] Grazing;
[ ] Mineral Lease (competitive);
[ ] Geothermal Lease(competitive)
[ ] Oil & Gas compensatory Agreement;
[ ] Recreational;
[ ] Mineral Prospecting Permit;
[ ] Geothermal Prospecting Permit;
[ ] Oil & Gas Lease (competitive);
[ ] Dredging;
[ ] Other; ____________________

[ ] EXISTING STRUCTURE/CONTINUED USE [ ] NEW CONSTRUCTION/ADDITIONAL USE

Form 54.2 (11/78)

G. **IDENTIFY, (IF KNOWN), OTHER PUBLIC AGENCIES HAVING APPROVAL AUTHORITY OVER YOUR PROPOSED PROJECT.** (e.g., Corps of Engineers, Local Planning Agency, etc.).

____

____

ANY OF THE ABOVE APPROVALS OBTAINED MUST BE SUBMITTED WITH THE APPLICATION.

H. **PROJECT DESCRIPTION:**

The applicant shall provide a narrative description of the project with references to maps, plot plans, financial analysis, and other graphics as may be appropriate. The project should be defined in sufficient detail so that Commission staff can analyze and evaluate the project. Sufficient data should be supplied which will:

1. Show how the proposed project will be carried out, including initial construction equipment, techniques, time schedules and operational requirements.
2. Show the project's future phases or extensions, if any.
3. Detail other proposed projects that will be dependent upon this project or will be directly influenced by this project.
4. Describe existing development in the vicinity which will directly (or indirectly) influence or be influenced by this project.
5. Enable the Commission to determine if the project:
   a. is in the best interest of the State;
   b. conflicts with the various trusts under which State lands are held;
   c. is a viable use of State lands.

I. **FEES:**

1. A non-refundable filing fee of $25.00 is required of all applicants.
2. An environmental processing fee may be required.
3. Applicants for the following leases or permits which do not provide for monetary consideration, or for any of the following actions which do not result in any increase in monetary consideration, shall submit, in addition to any filing fee required by law, the fees specified below:

	TRANSACTION	MINIMUM NON-REFUNDABLE EXPENSE DEPOSIT
a.	Right of way	$350
b.	Public agency lease or permit	$450
c.	Assignment/sublease of a lease	$300
d.	Amendment of a lease to accommodate lessee and which does not increase the rental	$500
e.	Most other types of transactions not listed herein	$300

4. Extractive Development Fees:

a.	For mineral prospecting permits and leases; competitive bid leases; geothermal prospecting permits and leases; oil and gas leases; compensatory agreements	$100
b.	Dredging permits unless for the public benefit	$300

5. **The above listed fees are necessary to reimburse the Commission for the cost to process typical, uncomplicated transactions. If the amount proves to be insufficient due to unusual complexities or for other reasons, additional funds will be requested.**

Signature and Certification

All statements contained above on the attached application form and related exhibits are true and correct to the best of my knowledge and belief and are submitted under penalty of perjury.

Applicant: ____________________ Applicant: ____________________

BY: ____________________ TITLE: ____________________
(If Agent)

DATE: ____________________

ENVIRONMENTAL DATA

All leases, licenses, permits, land sales or other entitlements for use of State lands under the jurisdiction of the State Lands Commission shall be authorized only after compliance with California Environmental Quality Act (CEQA) has been achieved. Depending upon the nature and size of your project, and its status in the permitting process, the environmental data requirements may vary. Answers to the following questions will dictate the level and quantity of data required.

1. Is there any existing environmental document regarding the proposed project? If so, please attach a copy and your environmental data requirements may be satisfied.

2. If your answer to No. 1 above is negative, has a "lead agency" been designated for the project? If so, please identify, and your environmental data requirements may be satisfied.

3. If your answers to the above questions are negative, and your project is designated below by the Commission as typically requiring an environmental impact report, provide the information on State Lands Commission **E.I.F. Form 59.2** attached. The following projects are those which typically require an environmental impact report: Oil and gas lease; geothermal prospecting permit or lease; mineral prospecting permit or lease; resumption of drilling; major industrial, commercial, or right of way construction; public works projects; salvage lease or permit; or a project which may have a significant impact on Class A significant lands identified in the **Inventory of Unconveyed State School Lands and Tide and Submerged Lands Possessing Significant Environmental Values,** *dated December 1, 1975.*

4. If your project does not fit within the confines of Nos. 1, 2, or 3, provide the information listed in State Lands Commission **E.I.F. Form 69.3.**

5. If it is determined that an environmental document (environmental impact report or negative declaration) need be prepared for the project, the applicant agrees, as a part of the application, to enter into a contract with the State Lands Commission for payment of all costs encountered in the preparation of the appropriate document.

6. Applicant is further advised that the determination of what type of environmental document is necessary is the responsibility of the State Lands Commission.

FORM 54.3 (4/78)

ENVIRONMENTAL INFORMATION FORM (E.I.F.)

This form describes the data that must be furnished the State Lands Commission as part of an application for Commission action.

1. **Project and Its Location.** Give the name of the project and its location. Generally, two maps or drawings should be submitted. One should show the general vicinity of the proposed project; i.e., nearby landmarks, roads and other features that would make clear its relation to the general vicinity. The other, preferably topographic, should show the project in detail; i.e., the location of buildings, fills, dredge areas, dikes, public access areas, etc.

2. **Statement of the Objectives Sought by the Proposed Project.** Briefly describe what the project is intended to achieve (e.g., new piers for shipping, new park for recreation, shoreline development for public health and safety, oil and gas development).

3. **General Description of the Project.** Describe the project's technical, economic and environmental characteristics, considering the principal engineering proposals and supporting public service facilities. Include in this description the principal features of the project (e.g., well locations, exact size of proposed fills, exact scope of proposed dredging, extent of proposed shoreline public access, etc.). The purpose is to provide a clear, concise overall description of the project.

4. (a) **Description of the Environmental Setting.** Describe the environment in the vicinity of the project, as it exists before commencement of the project, from both a local and regional perspective. Knowledge of the regional setting is critical to the assessment of environmental impacts. Special emphasis should be placed on environmental resources that are rare or unique to that region. Specific reference to related projects, both public and private, both existent and planned, in the region should also be included, for purposes of examining the possible cumulative impact of such projects. List the flora and fauna found in the project area (common and scientific names).

   (b) **Water Quality Aspects.** Describe in the environmental setting section, and other sections where applicable, water quality aspects of the proposed project which have been previously certified by the appropriate state or interstate organization as being in substantial compliance with applicable water quality standards.

5. **Assessment of Impact.** All phases of a project must be considered when evaluating its impact on the environment: Planning, acquisition, development and operation. The following subjects shall be discussed, preferably in separate sections or paragraphs. If they are not discussed separately, the E.I.F. should include a table showing where each of the subjects is discussed.

6. **Significant Environmental Effects Project.** Describe the direct and indirect impacts of the project on the environment, giving due consideration to both the short-term and long-term effects. It should include specifics of the area, the resources involved, physical changes, alterations to ecological systems and changes induced in population distribution, population concentration, the human use of the land (including commercial and residential development) and other aspects of the resource base such as water, scenic quality and public services. Cumulative effects shall also be discussed when found to be significant.

7. **Any Significant Environmental Effects Which Cannot Be Avoided If The Proposal Is Implemented.** Describe any significant impacts, including those which can be reduced to an insignificant level but not eliminated. Where there are impacts that cannot be alleviated, without imposing an alternative design, their implications and the reasons why the project is being proposed, notwithstanding their effect, should be described. Describe impacts on any aesthetically valuable surroundings, or on human health.

8. **Mitigation Measures Proposed to Minimize the Significant Environmental Effects.** Describe significant avoidable adverse impacts, including inefficient and unnecessary consumption of energy, and the measures proposed to minimize these impacts. This discussion shall include an

identification of the acceptable levels to which such impacts will be reduced, and the basis upon which such levels were identified. Where alternative measures are available to mitigate an impact, each should be discussed and the basis for selecting one alternative should be identified. Energy conservation measures, as well as other appropriate mitigation measures, shall be discussed. Examples of energy conservation measures are provided in the Appendix.

9. **Alternatives to the Proposed Action.** Describe all reasonable alternatives to the project, or to the location of the project, which could feasibly attain the basic objectives of the project, and why they were rejected in favor of the ultimate choice. The specific alternative of "no project" must also always be evaluated, along with the impact. Describe alternatives capable of substantially reducing or eliminating any environmentally adverse impacts, even if these alternatives substantially impede the attainment of the project objectives, and are more costly.

10. **The Relationship Between Local Short-Term Uses of Man's Environment and the Maintenance and Enhancement of Long-Term Productivity.** Describe the cumulative and long-term effects of the proposed project which adversely affect the state of the environment. Special attention should be given to impacts which narrow the range of beneficial uses of the environment or pose long-term risks to health or safety. In addition, the reasons why the proposed project is believed by the sponsor to be justified now, rather than reserving an option for further alternatives, should be explained (only required if action is adoption of plan, policy or ordinance of the State Lands Commission, or if project will be subject in NEPA).

11. **Any Significant Irreversible Environmental Changes Which Would Be Involved in the Proposed Action Should it be implemented.** Uses of nonrenewable resources during the initial and continued phases of the project may be irreversible since a large commitment of such resources makes removal or nonuse thereafter unlikely. Primary impacts and, particularly, secondary impacts (such as a highway improvement which provides access to a nonaccessible area) generally commit future generations to similar uses. Also, irreversible damage can result from environmental accidents associated with the project. Irretrievable commitments of resources should be evaluated to assure that such current consumption is justified (only required if action is adoption of plan, policy or ordinance of the State Lands Commission, or if project will be subject in NEPA).

12. **The Growth-Inducing Impact of the Proposed Action.** Discuss the ways in which the proposed project could foster economic or population growth, either directly or indirectly, in the surrounding environment. Included in this are projects which would remove obstacles to population growth (a major expansion of a wastewater treatment plant might, for example, allow for more construction in service areas). Increases in the population may further tax existing community service facilities so consideration must be given to this impact. Also discuss the characteristic of some projects which may encourage and facilitate other activities that could significantly affect the environment, either individually or cumulatively. It must not be assumed that growth in any area is necessarily beneficial, detrimental, or of little significance to the environment.

13. **Energy Conservation.** Energy conservation measures including both the available alternatives and those incorporated into the design and operation of the proposed project should be addressed in the E.I.F..

14. **Organizations and Persons Consulted.** The identity of all federal, state or local agencies, other organizations and private individuals consulted in preparing the E.I.F. should be specified.

15. The data and degree of specificity required in your Environmental Information Form must correspond with the data and degree of specificity involved in the underlying activity. Typically, the larger the project, the greater the degree of specificity and data; conversely, the smaller the project, the less specificity and data required.

ATTACHMENT NO. 11

DEPARTMENT OF FISH AND GAME

NOTIFICATION OF REMOVAL OF MATERIALS
AND/OR ALTERATION OF LAKE, RIVER, OR
STREAMBED BOTTOM, OR MARGIN

The department has 30 days from date of receipt in which to make its recommendations.

T.H.P. No.__________

Notification No.__________ Received__________

STATE OF CALIFORNIA

RESOURCES AGENCY

DEPARTMENT OF FISH AND GAME

NOTIFICATION OF REMOVAL OF MATERIALS AND/OR ALTERATION OF LAKE, RIVER, OR STREAMBED BOTTOM, OR MARGIN

A. APPLICANT Pursuant to Sections 1601–1606 of the California Fish and Game Code

I, __________ (Name of Applicant) of __________ (Mailing Address),

Representing __________ (Name of Agency, Company, etc.)

Hereby notify the California Department of Fish and Game of operations to be carried out by me, or the organization I represent, from __________ (Date) to __________ (Date)

__________ (Name of Stream, River, or Lake) of __________ County, tributary to __________ in the __________ (NE, NW, SE, or SW) ¼,

Section__________ Township__________ Range__________ U.S.G.S. Map__________,

Co. Assessor's Parcel No.__________ Property Owner__________,

whose address is__________

__________ (Name of Person to Be Contacted at Site During Operations) is responsible for operations at the site.

He can be reached at__________ (Mailing Address) __________ (Telephone)

B. Description of operation 1. The nature of said operations will be as follows:
Check all squares which apply.

- ☐ Soil, sand, gravel, and/or boulder removal or displacement
- ☐ Water diversion or impoundment
- ☐ Mining—other than aggregate removal
- ☐ Road or bridge construction
- ☐ Levee or channel construction
- ☐ Logging
- ☐ Temporary, recreational or irrigation dam
- ☐ Other—Describe below

2. Type of material removed, displaced or added ☐ Soil ☐ Sand ☐ Gravel ☐ Boulders
Volume__________
3. Equipment to be used in the described site__________
4. Use of water (i.e., domestic, irrigation, gravel, washing, etc.)__________ Quantity__________
5. Describe type and density of vegetation to be affected, and estimate area involved.
____
6. What actions are proposed to protect fish and wildlife resources and/or mitigate for project impacts?__________
____
7. Please attach and send to the Department any available project environmental documents.
8. Briefly describe proposed construction methods. Diagram or sketch below the location of your operation to clearly indicate the stream or other water and access from named public road. Indicate locked gates with an "X". Show existing features with a solid line (————) and proposed features with a broken line (- - - -). Show compass direction. Attach larger scale map if necessary.

NO CARBON NEEDED
FG2023 (REV. 3-80)

__________ Signature of Applicant __________ Date

12735-600 3-80 500 QUAD ①° DSP

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APPENDIX G

Utility Purchase Prices for Hydroelectric Generation

APPENDIX G

Utility Purchase Prices for Hydroelectric Generation

G-1A. Pacific Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators

G-1B. Pacific Gas and Electric Company's Proposed Policy for Power Purchases from Hydroelectric Facilities Greater than 100 kW

G-2. Southern California Edison Company's Proposed Policy for Power Purchases from Hydroelectric Facilities

G-3A. San Diego Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators for Installations of 100 kW or less

G-3B. San Diego Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators for Installation of Greater than 100 kW

SECTION G-1A

Pacific Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators

A power sales agreement was published by Pacific Gas and Electric Company (PGandE) in February 1980. It contains the terms under which the utility will make individual offers to purchase power from qualified facilities using cogeneration, or generation with fuels derived from biomass, wood waste, or refuse. The agreement includes the current schedule of prices for energy and capacity delivered to PGandE, and the conditions pertaining to interconnection, protective devices, metering, and operational procedures.

The PGandE agreement provides for both capacity and energy payments under two options, and for a combined capacity and energy payment under a third option. The owners or operators are free to select whichever option they prefer.

Energy Rate. The energy rate is based on PGandE's average quarterly cost of incremental fuel. It is published by PGandE as required by the California Public Utilities Commission's (CPUC) Order Instituting Investigation No. 26, Decision No. 91109 of December 19, 1979. The energy rate is established for a three-month period following the quarter during which the fuel cost is calculated and is applied as follows:

Cost-Quarter Used	Months to Which Energy Rate Applies
January to March	May to July
April to June	August to October
July to September	November to January
October to December	February to April

The rolling three-month energy rate enables reasonably close-tracking of actual oil prices, which have been changing at unpredictable intervals since 1978. The energy rate is divided into three parts, based on three time-of-day energy generation costs, and on two seasons.

The highest energy payment is during on-peak hours on weekdays. More of these hours occur during the peak-load summer season of May 1 to September 30; they are 6 hours daily on Monday through Friday, from 12:30 pm to 6:30 pm, except on holidays. On-peak hours during the winter season of October 1 to April 30 are 4 hours daily on Monday through Friday, from 4:30 pm to 8:30 pm, except on holidays.

The lowest energy rate is during off-peak hours, which are 10 hours daily from 10:30 pm to 8:30 am Monday through Saturday, except on holidays. Off-peak rates are also in effect 24 hours a day on Sunday and holidays. These off-peak hours are the same all year regardless of the season. The utility specifies eight holidays when off-peak rates would apply: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans' Day, Thanksgiving Day, and Christmas Day as set forth in Public Law 90-363. The intermediate, or partial-peak rate, is in effect during all other hours not designated as either on-peak or off-peak hours.

Based on PGandE's quarterly average energy cost for January through March 1980, the energy rates to be applied to generation purchased by PGandE for May through July 1980 are:

On-peak hours	5.675¢ per kWh
Partial-peak hours	5.459¢ per kWh
Off-peak hours	4.700¢ per kWh

The weighted average energy rate calculated by combining the above rates and hours is about 5.1¢ per kWh. This mid-1980 weighted average is used to estimate future energy rates based on projected oil prices.

Capacity Rate. In addition to the energy rate, PGandE will pay a capacity rate if the seller has made contract capacity available to PGandE and meets certain minimum requirements:

(1) The maximum amount of capacity used for making a capacity payment is the minimum amount the power facility can produce during the peak months of June, July, and August.

(2) The minimum amount of capacity during the peak months of June, July, and August must be available for all on-peak hours subject to an allowance of 20 percent of those hours for forced outages. (Being available means either actually delivered to PGandE or callable for operation at PGandE's request.)

(3) Scheduled outages must be performed between November and April unless otherwise agreed upon.

The seller has three options for calculating of capacity payments. Option 1 is payment in twelve equal monthly installments. To qualify for this option, the seller must have the minimum capacity (discussed above) to deliver power as requested by PGandE's dispatcher.

Option 2 payments vary each month according to the capacity actually delivered to PGandE. The payment in any month cannot exceed the capacity rate times the minimum capacity available during June, July, and August (contract capacity), and is calculated by a formula related to hours of generation:

Monthly delivered capacity = Monthly Factor x Seasonal Factor
where:

$$\text{Monthly Factor} = \frac{A}{C \times (B-S) \times (1-F)} \times \left(1 - \frac{M}{D}\right)$$

Seasonal Factor = 0.1172 for May through September; and
0.0588 for October through April.

where:

A = Energy delivered on-peak and partial-peak hours in kWh;

B = Number of on-peak and partial peak hours during the month;

C = Contract capacity in kW;

D = Number of days in the month;

F = The fraction of on-peak and partial-peak hours allowed for forced outage (amounting to 20%);

M = The number of days during the month that the facility is out of service on scheduled maintenance; and

S = On-peak and partial-peak hours that the facility is out of service on scheduled maintenance.

The seasonal allocation factors are subject to change by PGandE based on PGandE's marginal-capacity cost allocation.

Option 3 offers payment based on energy deliveries to PGandE during on-peak, partial-peak, and off-peak hours with the payment varying each month according to those energy deliveries and the seasonal value of power. The payment in any month cannot exceed the maximum payment under Option 2, assuming delivery of the full contract capacity. The payment is calculated by multiplying the capacity rate by the following energy allocation factors:

Time-of-day Period	May through September	October through April
On-peak hours	0.03357	0.02022
Partial-peak hours	0.02323	0.00893
Off-peak hours	0.00553	0.00476

The option selected by the owner or operator of a small power facility will depend on the size of the facility and its generation characteristics.

The capacity rate that would apply to Options 1 and 2 will be adjusted upward to the highest capacity price for the scheduled operation date. The power sales agreement will also be adjusted to the date that the small power facility begins operation. The capacity rate is in terms of dollars per kilowatt of capacity per year which are levelized for the term of the agreed-upon sale to PGandE. The capacity rate varies from \$60 to \$103 per kilowatt depending on the initial year of operation and the term of the power sales contract. The published capacity rate, dated February 4, 1980, is shown in Table 9, Chapter II.

Sample Computation. For a 20-year power sales contract with PGandE starting in the second quarter of 1980, the prices that PGandE would pay for cogeneration capacity and energy delivered to it can be shown by the following example:

> Assume 1 kW of capacity is sold under a 20-year contract (Option 1 selected for capacity payment) with delivery starting in May 1980, and that the generation in May was 595 kWh.
>
> Capacity payment = 1 kW x \$73 per kW x 1/12
> = \$6.08 per 595 kWh
> = 1.0¢ per kWh
>
> (The assumed capacity factor is 595/744 or 0.80. The price in cents per kWh will vary by a capacity factor.)

The combined capacity and energy prices for this sample computation for cogeneration capacity and energy delivered to PGandE at mid-1980 is estimated as follows:

Capacity	= 1.0¢
Energy (weighted average)	= 5.1¢
Total per kWh	= 6.1¢

Policy For Power Installations of 100 kW or less

In July 1980, PGandE made a form of power sales agreement available for cogeneration, renewable resources (including water, wind, and solar energy), and waste or biomass for installations of 100 kW or less. The energy rate is the same as the prices for the cogeneration agreement discussed above, but the capacity rate is significantly less than for the cogeneration agreement.

The capacity rate is proposed as an installation incentive and a performance incentive. The installation incentive amounts to 75¢ per kW per month (\$9 per kW annually) and will be paid for any month in which the generating facility produces sufficient energy to equal at least the product of 5 percent of the total hours in the month times the kilowatt output rating of the facility. An additional 75¢ per kW per month will be paid for any month that the generating facility produces sufficient energy to equal at least the product of 35 percent of the hours in the month times the kilowatt output rating of the facility. The hours in the month used for these incentive calculations is actually based on the meter-reading schedule which varies from 27 to 33 days.

While the time-of-delivery prices (on-peak, partial-peak, and off-peak) are the same as for the cogeneration agreement, an optional standard weighted-average price is available. For the period May 1 through July 31, 1980, the standard weighted-average price was 4.994¢ per kWh.

The combined capacity and energy price for a small hydroelectric installation operating at an 80 percent capacity factor with the output delivered to PGandE is estimated as

Capacity = \$1.50/kW x 1 kW/595 kWh	= 0.2¢
Energy (weighted average)	= 5.0¢
Total per kWh	= 5.2¢

SECTION G-1B

Pacific Gas and Electric Company's Proposed Policy for Power Purchases from Hydroelectric Facilities Greater than 100 kW

In August 1980, PGandE filed a proposed form of agreement with the CPUC for the purchase of hydroelectric generation from installations with capacities greater than 100 kW. This proposed agreement is significantly different from PGandE's cogeneration agreement in terms of the amount of capacity that would be paid for, and the addition of discount factors for potential recurring dry water years and for transformer and transmission losses to the "load center." The discount factors are applied to the capacity and energy rates established by PGandE for the cogeneration agreement.

The amount of capacity paid for would be the calculated theoretical monthly capacity for the hydroelectric plant assuming the driest water year of record. The driest year was 1977 which was the second year of the 1976-77 drought. The amounts of capacity and energy that could be produced under theoretical 1977 water conditions must be documented by a theoretical study of water and power operations acceptable to PGandE.

Two discount factors are applied to the energy rate. The first discount factor (F1) accounts for year-to-year swings in power production that cause PGandE to experience changes in its thermal costs and in its fuel inventory. It is necessary to prepare a long-term theoretical study of water and power operations in order to calculate factor F1. A typical period of time for the operation study would be 50 years. Factor F1 can be approximated using the formula:

$$F1 = \frac{0.25\ (\text{average energy of 28\% of the driest years}) + 0.75}{(\text{long-term average energy})}$$

A long-term study of water and power operations would cover a period of 50 years or more and would estimate the average generation for each year. The long-term average energy is the sum of the annual energy for all the years of the operations study divided by the number of years of the study. The average energy of the 28 percent of the driest years for a 50-year study would include the "dust bowl" years of 1929 through 1934, plus 1937, 1944, 1947, 1949, 1960, 1961, and the most severe drought years of 1976 and 1977.

The second energy discount factor (F2) accounts for the remote location of potential hydroelectric projects, whereas no discount is applied to cogeneration facilities regardless of location. The transmission loss factor for energy (part of factor F2) varies from 0.91 to 0.93 in very remote areas like Shasta County to 1.0 in the Bay Area plus 1 percent to 3 percent for transformer losses (the remaining part of factor F2). The total potential discount is about 10 percent on energy output from small hydroelectric projects located in remote areas.

Similarly, the total potential discount on capacity (factor F3) is 13 to 15 percent for hydroelectric projects located in areas remote from the Bay Area or the San Joaquin Valley. Again, no capacity discount is applied to cogeneration facilities regardless of location.

For many irrigation districts, the 1977 driest-year criterion means that a potential hydroelectric project would receive no capacity credit, and the transmission and transformer discount would reduce the value of hydroelectric energy generation by an average of about 12 percent compared with equivalent cogeneration installations. In addition, the water year factor (F1) could further reduce the payments for hydroelectric energy generation compared with equivalent cogeneration installations.

The calculation of payments for hydroelectric generation under PGandE's proposed form of purchase agreement will be subject to the historical water conditions and location of a particular hydroelectric site. However, a range of values can be estimated as in the following example:

Assume 1 kW of capacity is installed and sold to PGandE under a 20-year contract starting in May 1980, and that the generation in May was 595 kWh.

Discount Factors:

F1 = (0.25 x 1.0) + 0.75 = 1.00 (best)

= (0.25 x 0) + 0.75 = 0.75 (worst)

F2 = 0.93 x 0.97 = 0.90

F3 = 0.90 x 0.97 = 0.87

Depending on theoretical 1977 water conditions, the amount of the 1 kW of installed capacity that would be considered available could vary from zero to 1 kW.

Maximum capacity payment	= 0.87 x 1 kW x $73 per kW x 1/12x1/595 = 0.89¢/kWh
Minimum capacity payment	= none
Maximum energy payment	= 1.0 x 0.90 x 5.1¢ per kWh = 4.59¢ per kWh
Minimum energy payment	= 0.75 x 0.90 x 5.1¢ per kWh = 3.44¢ per kWh

The combined capacity and energy prices for this sample computation for hydroelectric capacity and energy delivered to PGandE at mid-1980 can be estimated:

	Maximum	Minimum
Capacity	0.9¢	0.0¢
Energy (Weighted average)	4.6¢	3.4¢
Total per kWh	5.5¢	3.4¢

It is unlikely that a theoretical water and power operation study will result in either the maximum or minimum payment for hydroelectric generation at a particular site. For the purposes of making a preliminary feasibility study of a potential hydroelectric site, unless specific site conditions are known to be different, a reasonable anticipated price for an average-water year can be estimated

Capacity	= 0.89¢ per kWh x 0.25	= 0.2¢
Fl	= (0.25 x 0.50) + 0.75	= 0.88
Energy	= 0.88 x 0.90 x 5.1¢ per kWh	= 4.0¢
Total per kWh		= 4.2¢

SECTION G-2

Southern California Edison Company's Proposed Policy for Power Purchases from Hydroelectric Facilities

On May 15, 1980, the Southern California Edison Company (SCE) published its avoided-cost information entitled "Interim Proposed Policy for Cogeneration and Small Power Production." The pricing schedules attached to SCE's policy statement are provided to form the basis for an offer to purchase all energy and capacity from cogeneration and small power producers who meet minimum qualifications.

Energy Rate. The energy rate is based on SCE's recorded fuel purchase costs and will be revised quarterly to reflect the avoided cost of generated energy. The rate is divided into six parts, relating to time-of-day generation costs and winter and summer seasons. The highest energy value occurs during on-peak hours on weekdays. Although the same number of on-peak hours are specified during both winter and summer seasons, the time-of-day is different, and the energy rate is different for the two seasons. On-peak hours during the summer season (May 1 to October 31) are 6 hours daily on Monday through Friday, from Noon to 6 pm, except on holidays. On-peak hours during the winter season (November 1 through April 30) are 5 hours daily on Monday through Friday, from 5 pm to 10 pm, except on holidays.

The lowest energy rate is during off-peak hours, which are 10 hours daily from 10 pm to 8 am Monday through Friday, and 24 hours daily on Saturday, Sunday, and holidays. The nine holidays when off-peak rates would apply are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans' Day, Thanksgiving Day, and Christmas.

The intermediate or mid-peak rate is in effect during all hours that are not designated as either on-peak or off-peak hours.

The SCE energy rate for the quarter ending July 31, 1980 was 4.7¢ per kWh for on-peak and mid-peak hours, and 4.6¢ per kWh for off-peak hours.

Capacity Rate. In addition to the energy rate for generation delivered to SCE, the utility will make a capacity payment based on contracted kilowatts, capacity factor (CF), a factor related to time-of-day and season (termed "Factor 1" by SCE), and the ability to meet minimum emergency availability criteria. The capacity factor, which cannot exceed 1.0, is calculated as the kilowatthours delivered to SCE divided by the product of contracted kilowatts times the hours in the period during which the energy was produced. The capacity payments will vary each month according to the amount of energy delivered to SCE during on-peak, mid-peak, and off-peak hours. The amount of capacity delivered to SCE can be expressed as:

Monthly capacity delivered = Contracted kW x CF x Factor 1
where:

$$CF = \frac{\text{kWh delivered}}{\text{Contract kW x hours in month}}$$

(Note: CF cannot exceed 1.0)

and

Summer May 1 to Oct. 31	Factor 1	Average Hours	Time(PST)
On-peak	0.07333	129.00	Noon to 6 pm
Mid-peak	0.01000	172.00	8 am to Noon & 6 pm to 10 pm
Off-peak	0.00833	435.00	All other hours

Winter Nov. 1 to Apr. 30	Factor 1	Average Hours	Time(PST)
On-peak	0.05500	104.17	5 pm to 10 pm
Mid-peak	0.01000	187.50	8 am to 5 pm
Off-peak	0.01000	436.33	All other hours

The policy proposed by SCE describes the minimum criteria to be addressed in the contract agreement concerning emergency availability and monthly availability. Full capacity payments will be made for those qualifying facilities that meet the minimum criteria. A qualifying facility not meeting the minimum criteria may still be eligible for a payment proportionate to the value of its capacity to SCE. However, the payments for total output should be at least equal to the avoided cost of energy. (SCE does not propose to apply energy discount factors for water-year conditions or transmission, as proposed by PGandE. See the discussion of PGandE's proposed policy for hydroelectric installations greater than 100 kW in the preceeding section.)

The utility does not specifically address capacity payments for run-of-the-stream hydroelectric installations in its proposed policy, but suggests that a 50 percent reduction of the capacity value is a reasonable approximation in lieu of a case-by-case determination. There would be an additional 50 percent reduction for a hydroelectric installation that could not attain a monthly capacity factor of 51 percent or greater by time period.

The payment for capacity in any particular month is equal to the capacity rate (shown in Table 9 of Chapter II) times the monthly capacity delivered as determined by the preceding formula, and reduced for availability and reliability criteria as necessary. While the method and the formula appear initially to be fairly complex, its application is quite straightforward as shown by the following example:

Assume 1 kW of capacity is sold under a 20-year contract with delivery starting in May 1980, and that the generation in May was 595 kWh. The capacity factor is 595 kWh/(1 kW x 744 hours) or 80 percent

For the summer on-peak period, the capacity payment is equal to Factor 1 x CF x Annual capacity payment or 0.07333 x 0.80 x 1 kW x $82 per kW or $4.81

Since there is an average of 129 on-peak hours in each month of the summer season, the capacity payment expressed in terms of energy generation is $4.81/(0.80 x 129 hours) or 4.66¢ per kWh. Reducing the capacity payment by 50 percent for emergency availability results in a payment of 2.33¢ per kWh.

In terms of energy generation, the price for capacity in the above example will always be 4.66¢ or 2.33¢ per kWh, regardless of the capacity factor, unless SCE changes Factor 1 and/or the $82 per kW-year rate, for energy generated up to a calculated capacity factor of 100 percent. Since the capacity factor is calculated using the contract capacity, which may be less than the installed capacity, the calculated capacity factor in a very wet month might be greater than 100 percent. In the event that the actual capacity factor were greater than 100 percent, the average price for the capacity would be less than 4.66¢ per kWh because in terms of cents-per-kilowatthour the capacity payment would be averaged over all kilowatthours generated.

For a 20-year power sales contract with SCE starting in May 1980, the estimated prices that SCE would pay for generation delivered to it during May, June, and July, 1980 are shown in Table G-1.

Table G-1. Prices SCE Would Pay for Generation Under a 20-year power sales contract starting in May 1980 (in cents per kWh)

Season	Time	Capacity	Energy	Total
Summer:	On-peak	2.33	4.70	7.03
	Mid-peak	0.24	4.70	4.94
	Off-peak	0.08	4.60	4.68
Winter:	On-peak	2.16	4.70	6.86
	Mid-peak	0.22	4.70	4.92
	Off-peak	0.10	4.60	4.70

The weighted-average rates for mid-1980 generation, calculated by combining the rates of 0.5¢ per kWh for capacity and 4.6¢ for energy or a total of 5.1¢ per kWh.

Since a 30- to 36-month lead time is expected for hydroelectric projects initiated in 1981, probably most of the of facilities in the preliminary feasibility study stage now will not be operating until late 1983 or 1984. The estimated prices that SCE would pay for power capacity and energy delivered to it for a 30-year power sales contract starting in 1984 are shown in Table G-1.

Table G-1. Prices SCE Would Pay for Generation
(30-year power-sales contract starting in 1984, in cents per kWh)

Season	Time	Capacity	Energy	Total
Summer:	On-peak	4.50	10.21	14.71
	Mid-peak	0.46	10.21	10.67
	Off-peak	0.15	9.99	10.14
Winter:	On-peak	4.20	10.21	14.41
	Mid-peak	0.42	10.21	10.63
	Off-peak	0.19	9.99	10.18

The estimated weighted-average rates for 1984 generation, calculated by combining the rates of 0.8¢ per kWh for capacity and 10.1¢ for energy or a total of 10.9¢ per kWh.

San Diego Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators for Installations of 100 kW or Less

On August 22, 1980, San Diego Gas and Electric Company (SDG&E) published its interim proposed policy for purchasing power from cogeneration and small power production facilities including hydroelectric installations. The proposed policy included an energy price available under two options plus an incentive payment for capacity. One of the options is a weighted-average price applied to all energy delivered to SDG&E; the second option is a time-of-delivery price--special metering equipment determines the hours when energy is delivered to SDG&E.

Energy Rate. The energy rate is divided into six parts relating to the time-of-day and two seasons. The highest energy value occurs during on-peak hours on weekdays and includes a greater number of hours during the peak-load summer season. The on-peak hours during the May 1 to September 30 summer season are 7 hours daily between 10 am and 5 pm, except on holidays. The on-peak hours during the rest of the year are 4 hours daily between 5 pm and 9 pm, except on holidays.

The lowest energy value occurs during off-peak hours: 13 hours on weekdays between 9 pm and 10 am and 24 hours on weekdays and holidays. The holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans' Day, Thanksgiving Day, and Christmas. A semi-peak rate is in effect during all hours that are not designated as being either on-peak or off-peak hours.

The energy rates for a three-month period are based on the average incremental price that SDG&E paid for fuel during the preceeding three-month period. For the period May 1 through July 31, 1980, the energy prices paid by SDG&E for the time-of-day optional rate were

On-peak hours	6.537¢ per kWh
Semi-peak hours	6.005¢ per kWh
Off-peak hours	5.004¢ per kWh

The price paid under the optional weighted-average rate was 5.420¢ per kWh.

Capacity Rate. In addition to the energy price, SDG&E will make an incentive payment based on the calculated capacity factor of energy delivered. The capacity factor is calculated monthly as the ratio of the kilowatthour generated during the month divided by the multiplication of the highest average kilowatt during any 15-minute period times the total number of hours in the month. The capacity incentive payment schedule is:

Capacity Factor	Incentive Payment
0%-14%	\$0.00 per kW
15%-49%	0.70 per kW
50%-85%	1.30 per kW
over 85%	2.00 per kW

The combined capacity and energy price for a small hydroelectric installation operating at an 80% capacity factor with the output delivered to SDG&E is estimated as:

Capacity price = \$1.30/kW x 1 kW/595 kWh	= 0.2¢ per kWh
Energy price (weighted average)	= 5.4¢ per kWh
Total	= 5.6¢ per kWh

SECTION G-3B

San Diego Gas and Electric Company's Energy Purchase Prices for Small Power Producers and Cogenerators for Installations of Greater than 100 kW

On August 22, 1980, SDG&E also published its interim proposed policy for purchasing power from cogeneration and hydroelectric facilities with capacities greater than 100 kW. The energy price paid by SDG&E is the same as the time-of-day rates specified for installations with capacities less than 100 kW. A capacity payment would be made under one of two options selected by a seller of the hydroelectric generation who meets certain minimum provisions.

Under one option for capacity payment, the generating facility must be fully dispatchable by SDG&E. The rate for capacity payments is shown in Table 9 of Chapter II and the minimum provisions are:

- Capacity must be available for all on-peak and semi-peak hours with forced outages not to exceed 15% of those hours each month and scheduled outages not to exceed 30 days per year.

- All scheduled outages must be scheduled and performed during periods agreed to by SDG&E.

- SDG&E must be notified 24 hours in advance of any anticipated increases or decreases in generator output and notified quarterly of the estimated output and scheduled maintenance for the next 4 months.

- SDG&E may derate the generating capacity, based on tests, studies, or prior performance.

Under the second option for capacity payment, the rate for payment is based on the amount of capacity actually delivered to SDG&E and is calculated as:

Monthly payment =
contract capacity x monthly factor x seasonal factor x contract payment rate (Table 9, Chapter II)

where

$$\text{Monthly factor} = \frac{Q}{C \times (H - S) \times 0.85}$$

Seasonal factor (May through September) = 0.1147

(October through April) = 0.0609

and

Q = kilowatts delivered during on-peak and semi-peak hours

C = Contract capacity in kilowatts

H = Number of on-peak and semi-peak hours

S = Number of hours that output is unavailable during on-peak and semi-peak hours because of scheduled maintenance

The monthly factor cannot exceed 1.0, and if less than 0.5, no capacity payment will be made. If S exceeds 75% of H, the monthly factor will be the same as that for the previous month.

The same minimum provisions apply to the monthly-delivered capacity payment option as for the fully-dispatchable option. For hydroelectric installations at existing dams or hydraulic structures, where water is released for other purposes and cannot be dispatched by SDG&E, the monthly delivered-capacity option would be applicable in most cases.

The payment for capacity under the SDG&E rate can vary significantly from month-to-month and from season-to-season with the rate heavily weighted toward the summer season as shown by the following example:

Assume 1 kW of capacity is sold under a 20-year contract with delivery starting in May 1980, and that the generation in May was 595 kWh with 231 kWh being generated during on-peak and semi-peak hours.

On-peak hours	= 7 hr per day x 21 =	147 hr
Semi-peak hours	= 4 hr per day x 21 =	84 hr
Off-peak hours	= (13x21) + (24x10) =	513 hr
Total		744 hr

Assume generation is available during all on-peak and semi-peak hours, and

$$\text{Monthly factor} = \frac{231\ \text{kWh}}{1\ \text{kW} \times 231\ \text{hr} \times 0.85} = 1.18$$

However, since the monthly factor cannot exceed 1.0,

Payment in a summer month = \$35 x 1.0 x (0.1147/595) = 0.67¢ per kWh

Payment in a winter month = \$35 x 1.0 x (0.0609/595) = 0.36¢ per kWh

The average payment for capacity over a year period with the generating unit out of service for scheduled maintenance 15% of the time and output available during all other on-peak and semi-peak hours would be about 0.5 cents per kWh. The weighted-average price for small hydroelectric generation at mid-1980, as estimated from the published SDG&E rates, is

Capacity price	=	0.5¢
Energy price (weighted-average)	=	5.4¢
Total per kWh	=	5.9¢

Since a 30- to 36-month lead time is expected for hydroelectric projects initiated in 1981, it is likely that most of the sites presently in the preliminary feasibility stage will not be available for operation until late 1983 or early 1984. For a 25-year power sales contract starting in 1984, the estimated price that SDG&E would pay for capacity and delivered to it in 1984 is

Capacity price	=	1.3¢
Energy price (weighted-average)	=	11.7¢
Total per kWh	=	13.0¢

APPENDIX H

Financing Small Hydroelectric Projects

APPENDIX H

Financing Small Hydroelectric Projects

Historically, hydroelectric projects have usually been large developments undertaken by local public bodies, state and federal agencies, or investor-owned electric utilities. Public entities generally finance such developments by issuing general obligation or revenue bonds; private utilities generally use a combination of debt and equity financing. These sources of funds are best suited to large projects which require capital in amounts greater than $5 million and where the cost of financing can be spread over a significant amount of investment funds.

Most small hydroelectric projects only require an investment of $1 million to 5 million. Recently, new sources of funds and new financing methods have become available to encourage the development of small hydroelectric projects. These include: (1) State and federal grants for feasibility studies; (2) Federal loans for feasibility studies and license applications; and (3) Federal loans and grants under a number of federal programs that were originally established for purposes other than hydroelectric projects.

Federal Funding

U.S. Department of Energy Grants. In early 1978, the U.S. Department of Energy (DOE) solicited proposals for feasibility studies of low-head hydroelectric generation in order to add hydroelectric generation to existing dams with capacities between 50 kW and 15 000 kW, and heads of 20 m (66 ft) or less. A total of 54 grants were awarded by DOE for such studies. Three owners received money to study 15 sites in California (Table H-1).

Table H-1: Projects in California Receiving DOE Grant for Feasibility Study

Owner	Project
City of Redding	Lake Redding
Modesto Irrigation District	Modesto Reservoir
	Stone Drop
Turlock Irrigation District	Drop No. 1
	Drop No. 2
	Drop No. 6
	Drop No. 7
	Drop No. 9
	Main Canal
	Canal Creek
	Fairfield Drop
	Escaladian Headworks
	Woodward Dam
	Frankenheimer Drop
	Goodwin Dam

In 1978, DOE also solicited proposals for grants of 25 percent of the cost of installing hydroelectric plants with installed capacities of up to 15 MW at existing dams where feasibility studies had been completed, and technical feasibility and economic viability was indicated. The DOE awarded grants for the construction of low-head hydroelectric projects. One grant was awarded in California to the Turlock Irrigation District for a power plant at Drop No. 1.

In 1979, DOE solicited proposals for grants of 15 percent of the construction costs for hydroelectric developments of up to 25 MW at existing dams where feasibility studies had been completed. This solicitation coincided with the completion of feasibility studies funded by DOE's 1977 feasibility grants. Of the 15 grants awarded by DOE for the construction of low-head hydroelectric projects in this second round, one grant was offered to the United Water Conservation District for the Lake Piru site in California. However, the District did not accept the grant.

At this time, DOE does not plan to make further grants for feasibility studies or for the construction of small hydroelectric projects, but it is encouraging potential site developers to use the DOE loan program under Title IV of PURPA.

U.S. Department of Energy Loans. Title IV of the Public Utility Regulatory Policies Act of 1978 (PURPA) authorized the Secretary of Energy to make loans for conducting feasibility studies and for preparing applications for licenses or any other government approvals for small hydroelectric projects at existing dams. The loan program established by DOE provides up to 90 percent of the cost of a feasibility study and a license application at a low-interest rate of about 7.25 percent.

Currently, this loan program is the best source of study and approval funds. The maximum amounts are loans of $50,000 each for a feasibility study and license application. The term of the loans are 10 years and repayment is unnecessary during the first 4 years. If a feasibility study indicates that a project is not technically or economically viable, DOE may forgive repayment of the loan.

Title IV also authorizes loans for building small hydroelectric projects, but at this time, Congress has not appropriated funds for these loans.

The DOE loan application is quite involved. A developer must have a preliminary assessment of the potential site before the application can be adequately completed. The developer must also have a Preliminary Permit or a License Exemption from FERC to be eligible. Currently, it takes about 6 weeks to process a loan application, and 6 to 9 months to obtain a Preliminary Permit.

An application for a DOE loan requires the following information:

Introductory Material:

Abstract of the Proposed Project
Table of Contents

Technical Data:

- Project Data
  - Definition of Key Tasks
  - Schedule of Key Tasks
- Personnel and Organization Experience
  - Related Job Experience
  - Resumes
- Access to or Possession of Site
- Federal Energy Regulatory Commission Status

Business Data:

- Applicant Organization Information
  - Description
  - Financial Data: Income and Expense Statement
    Balance Sheet
- Project Cost Information
  - Budget Summary
  - Amount of Loan and Percentage of Project Cost
  - Description of Other Financial Assistance
  - Pending Litigation Against Applicant

Applicants must also provide supplemental information depending on the type of loan requested, i.e. feasibility study or licensing. All applications must have a cover letter and a completed copy of Standard Form 424, Federal Assistance. Inquiries and requests for applications should be directed to:

U.S. Department of Energy
333 Market Street
San Francisco, CA 94105
(415) 764-7084

Other Potential Sources of Federal Funding

A small hydroelectric project might also be eligible for financial assistance from a number of other federal funding programs.

Urban Development Action Grants (UDAG). These grants are authorized under Title I of the Housing and Community Development Act of 1974 and were extended in 1977. The UDAG program is administered by the U.S. Department of Housing and Urban Development (HUD). It was designed to assist severely distressed cities and urban counties through economic development and neighborhood revitalization. The program seeks to create a partnership between local government, the community, and private industry by allowing qualifying communities to use federal funds to stimulate or increase private investment. Under the program, HUD can make a grant to a community which can then loan the funds to a private developer at 5 percent interest. The developer repays the loan to the community over a specified term and the community uses the loan payments for local improvements to alleviate physical and economic deterioration. The UDAG program could provide up to 25 percent of the construction costs of a hydroelectric project located in a severely distressed community. Further information can be obtained from the HUD regional office:

U.S. Department of Housing and Urban Development
450 Golden Gate Avenue, Room 8460
San Francisco, CA 94102
(415) 556-4752

Resource Conservation and Development (RCD) Loans. These loans are authorized under the Bankhead-Jones Farm Tenant Act of 1937 which is administered by the Farmers Home Administration (FmHA) of the U.S. Department of Agriculture. The purpose of the program is to assist rural public agencies to develop water resource and to increase local economic opportunities. The program promotes preserving natural resources, developing and protecting recreational facilities, preventing impairment of dams and reservoirs, and protecting public lands. An RCD loan could provide up to $250,000--at 5 percent interest--for the construction of a small hydroelectric project located in an authorized RCD area. Further information can be obtained from the regional Soil Conservation Service office:

Soil Conservation Service
2828 Chiles Road
Davis, CA 95616
(916) 758-2200

Community Facilities Loans (CFL). This program was authorized in 1961 as a part of Public Law 87-128. The program is administered by FmHA to assist rural areas with 10,000 or fewer residents to conserve, develop, use, and control water, and to install and improve drainage and recreation facilities. Since hydroelectric development uses and controls water, it can be partially financed under the CFL program. The loans, at 5 percent interest, are available to public agencies or nonprofit corporations. Further information can be obtained from the state FmHA office:

Farmers Home Administration
459 Cleveland Street
Woodland, CA 95695
(916) 666-3382

Business and Industrial Loans (BIL). This program was also authorized in 1961 as a part of Public Law 87-128 and is administered by FmHA. The purpose of the BIL program is to assist rural areas with populations in excess of 50,000 located near a city having a population density exceeding 100 persons per square mile. It promotes rural industrialization to improve business, industry, and employment. The loans--at 5 percent interest--are available to public, private, or cooperative entities for up to 50 percent of a project's development costs. Further information can be obtained from the state FmHA office listed above.

Watershed Protection and Flood Prevention Loans. These loans are available to local entities for sharing the costs of improving designated watersheds by flood prevention, water quality management, sedimentation control, fish and wildlife development, and water storage. The total amount available for any particular watershed is $5 million. This loan program is not particularly suitable for hydroelectric development at existing hydraulic structures because such facilities generally use existing streamflows or releases and would not alter that existing regimen. Further information can be obtained from the state FmHA office listed above.

Rural Electrification Loans. These loans are authorized by the Rural Electrification Act of 1936 which is administered by the Rural Electrification Administration (REA). Loans are available to rural electric cooperatives, public utility districts, power companies, municipalities, and other qualified power suppliers for the purpose of providing central station electric service in rural areas. Rural areas are defined as any area not included within the boundaries of a city, village, or borough having a population in excess of 1500. In general, loans are available only to REA cooperatives, although loan guarantees may be available if the net result of the financing is to provide or improve electric service to rural areas. Further information can be obtained from the REA:

Office of Information and Public Affairs
Rural Electrification Administration
U.S. Department of Agriculture
Washington, DC 20250
(202) 447-5606

Business Development Assistance Loans. This program of providing and guaranteeing loans was authorized by Public Law 89-136 and is administered by the Economic Development Administration (EDA). The purpose of the loans is to encourage industrial and commercial expansion in designated areas by assisting businesses which will create new permanent jobs, or will expand or establish plants in redevelopment areas. The only projects eligible for loans are those that have been unable to receive funding through banks or other private lending institutions. Long term loans of up to 65 percent of a project's development costs are available to individuals, private or public corporations, and Indian tribes. This program may be useful to businesses related to a local hydroelectric project. Further information can be obtained from the regional EDA office:

Economic Development Administration
Lake Union Building
1700 Westlake Avenue North
Seattle, WA 98109
(206) 442-4740

Small Reclamation Projects Program. The Small Reclamation Projects Act of 1956 provided loans and/or grants under Public Law 84-984. It is administered by the Water and Power Resources Service (WPRS; formerly the Bureau of Reclamation) of the U.S. Department of the Interior. The WPRS is responsible for irrigation or drainage projects including those with multiple-purpose uses such as municipal and industrial water supplies, flood control, fish and wildlife, recreation, and hydroelectric power. Hydroelectric development can be funded if it can be accomplished as an addition to the other water supply functions of the project. Several irrigation dams and reservoirs in California have been funded under Public

Law 87-984 including Virginia Ranch Dam, Indian Valley Dam, and Jackson Valley Dam, which are among the 28 preliminary feasibility studies discussed in Appendix C. Further information regarding loans for hydroelectric projects can be obtained from the WPRS regional office:

Northern California	Southern California
U.S. Water and Power Resources Service 2800 Cottage Way Sacramento, CA 95825 (916) 484-4228	U.S. Water and Power Resources Service P.O. Box 427 Nevada Highway & Park Street Boulder City, NV 89005 (702) 293-2161

Community Services Administration Grants. These grants are available for coordinating efforts to get project development funds. Planning assistance, provided through the International Science and Technology Institute, is available and is aimed at (1) completing applications for financial assistance, (2) planning steps to be taken to retrofit a dam, and (3) developing a plan for use of hydropower output. For further information contact:

Community Services Administration
1200 19th Street NW, Room 334
Washington, DC 20506
(202) 632-6503

Comprehensive Employment and Training Act (CETA) Funds. Project funding may be available from CETA through state, regional, or local government agencies. Funding is mainly for wages, fringe benefits, and training. For further information contact:

Proaction Institute
206 Urban Planning Building
Michigan State University
East Lansing, Michigan 48824
(517) 353-9361

Miscellaneous Federal Programs. Further federal funding is anticipated from the U.S. Department of Agriculture (USDA). The USDA has proposed a rule which would make loans available to communities with populations of up to 10,000 for the construction or modification of hydroelectric facilities.

If the rule is finalized in its present form the Farmers Home Administration Community Loan Program would make funds available for small-scale hydroelectric projects not eligible for assistance from the USDA's Rural Electrification Administration, which can loan only to communities with populations less than 1500. According to USDA, potential loan applicants would be public bodies and would include municipalities, counties, districts, or other political subdivisions of a state.

Eligible loan proposals would include the restoration of deactivated dams and hydroelectric generators, enlargement of existing plants, and construction of new facilities. Loans could also be used to finance the building of transmission lines from generating sites to distribution systems.

State Funding

California Energy Commission Feasibility Grants. In 1979 and 1980 the California Energy Commission (CEC) cofunded 18 feasibility studies for potential small hydroelectric sites at existing dams and aqueducts. The CEC funded up to 50 percent of the cost of these studies. Inquiries regarding the availability of future funding for small hydroelectric feasibility studies should be directed to:

California Energy Commission
1111 Howe Avenue
Sacramento, CA 95825
(916) 920-6106

Other Potential Sources of State Funding

Funding for small hydroelectric development received significant attention from the Legislature. Recently chaptered bills which provide funding for small hydroelectric development include:

Chapter 1358, Statutes of 1980 (AB 74). This bill permits cities and counties to issue industrial development bonds to finance, among other projects, private energy development projects including small hydroelectric projects. Up to $200,000,000 in bonds may be sold statewide. A participating city or county must establish a local industrial development authority to administer the program, and employment, conservation, and consumer benefits must be shown before a project is eligible for this type of financing. For further information on the program contact:

Office of the State Treasurer
915 Capitol Mall
Sacramento, CA 95814
Attention: Jim Sargeant
(916) 322-5471

Chapter 908, Statutes of 1980 (AB 2324). This bill creates a California Alternative Energy Source Financing Authority which is authorized to issue up to $200,000,000 in revenue bonds to finance the construction of facilities using alternative energy sources. Hydroelectric projects under 25 megawatts developed by private individuals or organizations are eligible for financing by means of these bonds if they are selected by the Authority. Criteria for selection include technological feasibility, financial soundness, and likelihood of reducing reliance on fossil fuels. Special emphasis is given to financing small (under $1,000,000 or one megawatt) projects. For more information on the program contact:

Office of State Treasurer
915 Capitol Mall
Sacramento, CA 95814
(916) 445-8968

Chapter 1327, Statutes of 1980 (AB 2893). This bill allows for rapid amortization of alternative energy production equipment for state income tax purposes. Hydroelectric generating equipment installed before January 1, 1986 with an installed capacity of less than 25 MW is eligible for this deduction. For equipment with a life of over 15 years (hydroelectric projects typically have useful lives of 50 years), only a proportionate amount of the value of the asset is eligible for this amortization method. For more information contact:

Franchise Tax Board
Sacramento, CA 95867
(916) 355-0370
From Southern California: (800) 852-5711
From Northern California: (800) 852-7050

Chapter 899, Statutes of 1980 (AB 2973). This bill creates a $120,000,000 Energy and Resources Fund in the State Treasury and provides for yearly appropriations to maintain the fund at this amount. The Fund consists of an Energy Account and a Resources Account with the amounts allocated to each to be determined by the annual budget Bill. No money may be transferred to the Energy Account after December 31, 1981, unless a Department of Energy has been created or the California Energy Commission has been reorganized. Projects to be funded from the Energy Account must be short-term projects, not on-going programs. Criteria for selection are: potential for reducing use of oil and natural gas; potential for widespread use throughout the State by 1990, and feasibility. All appropriations will be made by the annual Budget Bill, and will be for state-administered programs. The bill creating the Energy and Resources fund does not provide any direct funding of small hydroelectric projects.

Chapter 733, Statutes of 1980 (AB 3048). This bill establishes a program, to be managed by the Department of Food and Agriculture in cooperation with the California Energy Commission, to demonstrate the effectiveness and economic feasibility of energy conservation and renewable resource energy technologies in agriculture. The program will include financial assistance in the form of loans, guarantees, leases and participating agreements to encourage energy conservation and renewable resource use in agriculture. Among the projects eligible for assistance are small hydroelectric generators of less than 100 kW at existing facilities associated with agricultural water use. Inidividuals, businesses and public agencies are all eligible to apply for assistance. For further information contact:

Department of Food and Agriculture
1220 N Street, Room 104
Sacramento, CA 94814
Attention: Steve Shaffer
(916) 322-5227

Chapter 819, Statutes of 1980 (SB 16). This bill creates a nonprofit corporation to provide financing assistance for qualified small businesses in the alternative energy industry. The corporation (BIDCO) has a $2.5 million line of credit with the state and will leverage this money with other government loan programs. Firms will not be eligible for assistance unless they have applied for a loan at one or more California banks and have been denied such a loan. For more information contact:

SAF BIDCO
Department of Economic and Business Development
1120 N Street
Sacramento, CA 95814
(916) 322-9725

Bond Financing

Bonds sold by public entities generally fall into two categories: general obligation bonds and revenue bonds. Payment of the principal and interest of a general obligation bond is backed by the taxing power of the entity issuing the bond. In contrast, revenue bonds restrict the source of payment to the revenues from the project financed by the bonds.

Interest on bonds issued by the State of California or a local government in the State is exempted by the State Constitution from California income tax. Revenue bonds sold by a public entity to finance hydroelectric development are tax-exempt under both State and Federal law provided the power is used by or sold to a public agency. However, so-called "industrial development bonds" issued by public entities may be subject to federal income tax. As set forth in Internal Revenue Code (IRC) Section 103(b) a revenue bond sold by a public entity is an industrial development bond if more than 25 percent of the output of the financed project is sold to a private entity over the term of the bond, and certain other conditions are met.

Several special provisions of the IRC allow public entities to issue tax-exempt industrial development bonds (IDB). Section 103(b)(4)(E) permits a public entity to issue tax-exempt bonds and sell project output to a private entity if the generation is used by the general populace within two local contiguous counties.

Section 103(b)(6)(A),(D) allows tax-exempt financing under certain circumstances for hydroelectric facilities by both public and private entities (where state statutes provide for industrial development bond financing in general and for hydroelectric facilities in particular) for small projects costing less than $10 million. Section 103(b)(4)(H), added to the IRC by the Windfall Profit Tax Act of 1980 (P.L. 96-223), permits the use of tax-exempt IDB's for financing hydroelectric projects with an installed capacity of up to 125 megawatts at existing dams and hydraulic structures that were completed before October 18, 1979, that are owned by a governmental body, and where no changes are made to water releases or streamflow regimen. The entire facility may be financed with tax-exempt IDB's where the installed capacity does not exceed 25 megawatts. A formula is provided to determine what fraction of the costs of a 26-125 megawatt facility may be financed by tax-exempt IDB's. Provided these conditions are met, a public agency can now finance all or a part of its small hydro development with tax-exempt IDB's even if all the project's generation is sold to a utility such as PG&E or SCE under PURPA as discussed in Chapter II.

The interest rates for tax-exempt revenue bonds at mid-1980 ranged between 9 and 10 percent.

Taxable revenue bonds can be issued by both public and private entities to finance the development of small hydroelectric projects. Such bonds would be free of the power sale restrictions placed on tax-exempt bonds, and project generation could be sold under PURPA as discussed in Chapter II. The interest rates for taxable bonds at mid-1980 ranged betwen 12 and 14 percent.

A number of financial institutions arrange for the issuance of all types of bonds and provide investment banking services such as underwriting, assisting with bond rating agencies, placing bonds, and maintaining a secondary market for trading of bonds through local offices throughout the Nation. Further information can be obtained from any investment banking house. The issuance of bonds is a complex activity and the prospective developer may desire the services of a financial advisor specializing in the sale of bonds. In addition, because of the complexity of the tax and other laws governing the issuance of bonds, legal counsel specializing in bond sales should be consulted.

Private Financing

The Windfall Profits Tax Act of 1979 provides that the owner of a small hydroelectric project is entitled to an additional 11 percent nonrefundable tax credit, making the total of such credits about 21 percent of project cost. The additional investment tax credit is to encourage the private development of small hydroelectric projects. However, the additional 11 percent credit cannot be taken on that part of a project that is financed with tax-exempt bonds. Private developers can use a variety of financing methods limited only by their imaginations and the willingness of lending institutions to make development funds available. A rule-of-thumb proportion of equity investment (or its equivalent) is in the range of 25 to 30 percent with the balance being long-term debt.

Combination Financing

Since there are a number of federal loan and grant programs for partial funding of small hydroelectric developments, combination financing is possible. With the high current interest rates for bonds and mortgage loans, partial funding of hydroelectric development by federal grants or low interest loans may make the difference between economic feasibility and infeasibility. Funding for each potential project must be pursued on a case-by-case basis since grant or loan eligibility is very restrictive.

An example of combination financing for a private development might be a UDAG loan for 25 percent of project costs at 5 percent interest, an IDB for 50 percent of project costs at 9 percent interest, and an equity or a mortgage loan for the remaining 25 percent of project costs at 14 percent interest. The weighted average net cost of money would be about 9.25 percent without allowance for investment tax credits.

At mid-1980, the prospects for federal grants or loans to assist in financing small hydroelectric projects are unclear. While such grants and loans might be authorized by law, Congress must appropriate the funds for most loans and grants and make them available. Certain programs, such as the DOE loan program for feasibility studies and licensing, were funded for specific amounts when enacted. The DOE loan program under Title IV of PURPA authorized $10 million in loans for each fiscal year 1978 through 1980 with any balance to remain available until expended. For other federal programs, approval of a grant or loan may not necessarily mean that funds have been appropriated.

Costs of Financing

Fixed Cost. The fixed cost of financing a small hydroelectric project by issuing bonds includes the cost of money represented by the interest rate on the bonds issued, net interest during construction, bond underwriting and sales expenses, and repayment of the debt. A revenue bond issue would also include a reserve fund, usually equal to one year's principal and interest payments. The reserve fund, which provides a measure of security to the bondholder in the event of a default, is invested in short-term securities and earns interest which is credited toward principal and interest payments. The net interest during construction consists of capitalized interest, funded from the bond issue itself, less interest earnings on unexpended bond proceeds during the construction period. For a small hydroelectric project, the actual construction period (after receipt of construction authorizations and permits) is about 12 months. The bond underwriting and sales expenses will vary from about 3.5 to 5 percent of the bond issue with the lesser percentages needed for larger bond issues. Assuming a tax-exempt bond issue with 9 percent interest for 35 years (i.e., level debt service), the annual fixed cost of financing can be calculated as follows:

Interest During Construction	4.5% of Project Cost
Bond Reserve Fund	9.464% of Bond Issue
Interest Earnings	7.0% of Bond Reserve Fund
Financing Costs (average)	4.0% of Bond Issue

$$\text{Bond Issue} = \frac{1.045}{1-(0.04 + 0.09464)} \times \text{Project Cost}$$

$$= 1.21 \times \text{Project Cost}$$

Annual Fixed Cost:

Net Fixed Cost	= Debt Service - Interest Earnings	
Debt Service	= 1.21 x 0.09464	= 0.1143
Interest Earnings	= 0.07 x 0.1143	= 0.0080 (credit)
Net Fixed Cost	= 0.1143 - 0.0080	= 0.1063 x Project Cost

There has been some indication at mid-1980, that uncertain economic conditions may make buyers reluctant to purchase bonds with terms longer than 20 years. If the term of the tax-exempt bond issue with a 9 percent interest rate was 20 years rather than 35 years, the annual fixed cost of financing would be 12.5 percent, calculated as follows:

Interest During Construction	4.5% of Project Cost
Bond Reserve Fund	10.955% of Bond Issue
Interest Earnings	7.0% of Bond Reserve Fund
Financing Costs (average)	4.0% of Bond Issue

$$\text{Bond Issue} = \frac{1.045}{1-(0.04 + 0.10955)} \times \text{Project Cost}$$

$$= 1.23 \times \text{Project Cost}$$

Annual Fixed Cost:

Debt Service	= 1.23 x 0.10955	= 0.1346
Interest Earnings	= 0.07 x 0.1346	= 0.0099 (credit)
Net Fixed Cost	= 0.1346-0.0099	= 0.1252 x Project Cost

Similarly, the annual fixed cost of financing a 35-year taxable bond issue with an interest rate of 12 percent would be 14.4 percent of the project costs. If the term of the bonds was 20 years, the annual fixed costs would be 16.0 percent of project costs.

Financing small hydroelectric projects by issuing revenue bonds would probably be 100-percent debt financing. For private financing, the project would likely be financed by some combination of debt and equity financing with a minimum of 20 percent equity. The return on equity could vary over a wide range as determined by time and by the investor(s) financial status. For example, during the early years of a project an investor might be willing to accept a zero or negative return on his investment in return for investment tax credits and potential long term benefits. However, the upper range of allowable interest rates for debt financing is likely to be 15 percent for small hydroelectric projects because beyond that point a prospective investor would probably seek some alternative investment opportunity. At 15 percent interest, the fixed annual cost for economic analyses could be as high as 17.8 percent of the project costs for 20-year debt financing calculated as follows:

Interest During Construction	7.5% of Project Cost
Equity	20% of Investment
Long-term Debt	80% of Investment
Financing Costs	5% of Investment

Investment = 1.075 x 1.05 x Project Cost

Annual Fixed Cost:

Debt Service	= 0.80 x 1.05 x 1.075 x 0.1598	= 0.1443
Return on Equity	= 0.20 x 1.05 x 1.075 x 0.15	= 0.0339
Net Fixed Cost	= 0.1346-0.0099	= 0.1782 x Project Cost

Similarly, the annual fixed cost of financing for 35-year debt and a 15 percent interest rate would be about 16.2 percent of project cost.

In summary, there would be range of annual fixed costs for small hydroelectric plants depending on the interest rates and the period of financing (Table H-2).

Table H-2. Annual Fixed Cost Rates Shown as Percentage of Total

Term of Debt	Interest Rate 9%	12%	15%
20 years	12.5	16.0	17.8
35 years	10.6	14.4	16.2

Operating Costs. In addition to the annual fixed cost of ownership, a developer must consider the cost of operating a project. This includes insurance on equipment, a provision for interim replacements, labor and materials for operation and maintenance, and where applicable, local property taxes.

The principal construction-cost components of a small hydroelectric project located at an existing hydraulic structure are the civil and structural works (FERC accounts 331 and 332) and the mechanical and electrical equipment (FERC accounts 333 and 334). Unless the developer elects to be self-insured, a large public body such as an irrigation district, might, insurance is needed to protect the developer in the event of damage to major equipment. Annual premiums for such insurance have increased significantly during the past year and currently are about 8.5 percent of the insured value with a 25 percent deductible provision. As more small hydroelectric projects are placed in operation and additional operating experience is obtained, and additional insurance companies enter the field, it is possible that insurance premiums in the future may be significantly less than current levels.

With proper maintenance, hydraulic turbines and electric generators have a useful life well in excess of the 20-year to 35-year economic life of a long-term debt. It is not uncommon for a turbine/generator to operate for 50 years before a major repair is necessary. Rewinding the electric generator and perhaps replacing the bearings will begin another 50-year operating cycle. Since some accessory mechanical and electrical equipment will have useful lives shorter than the financing period, it is desirable to provide a contingency fund for such interim replacements. As a part of the annual operating costs, an allowance of 0.3 percent of the total cost of the mechanical and electrical equipment provides a sinking fund for interim replacements.

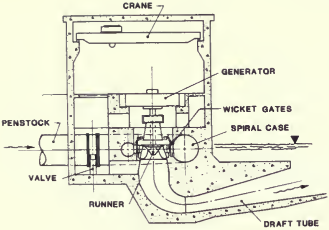
The cost of labor and materials for operating and maintaining a small hydroelectric plant will vary widely from site to site. At one site where hydroelectric generation is a by-product of irrigation releases, the operating cost may be negligible since an operator must operate a valve to control the releases with or without a hydroelectric plant at the site. At another site where hydroelectric generation is a by-product of flood control releases, it may be necessary to have a full time operator on call for hydroelectric operation (or an agreement with the operator of the flood control dam). In any event, operation and maintenance costs are small components of the overall annual cost of a hydroelectric facility.

Local property taxes, when applicable, could be a potential deterrent to developing small hydroelectric projects because of the high capital-intensive nature of the facility. About 70 to 80 percent of the annual costs of owning and operating a small hydroelectric facility are fixed by the amount of capital investment required for construction; about 20 to 30 percent represent annual operating costs. Of that 20 to 30 percent, the variable portion related to hours of operation is almost negligible. If property taxes are assessed on 100 percent of actual investment, the annual fixed costs could be increased by as much as 25 percent. In some areas of the U.S., tax stabilization can be negotiated and property taxes can be paid on the value of generation rather than on the investment in property.

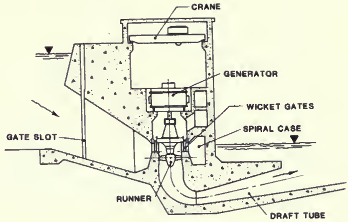
APPENDIX I

Hydroelectric Equipment

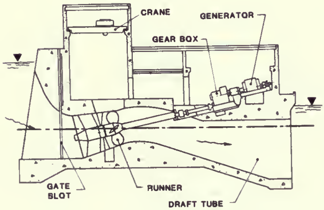
Figure I-1 Types of Turbines



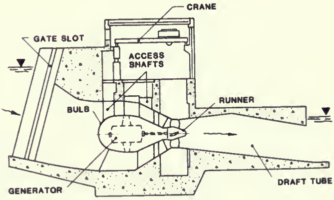
FRANCIS TURBINE



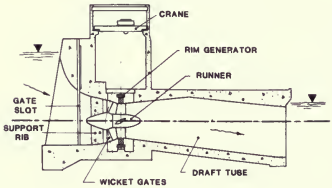
PROPELLER OR KAPLAN TURBINE



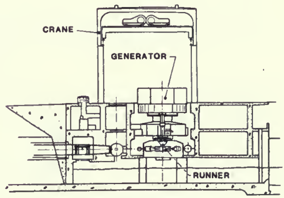
TUBE-TYPE TURBINE



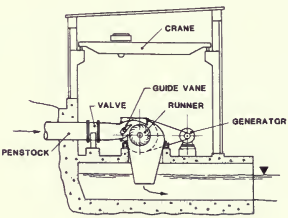
BULB TURBINE



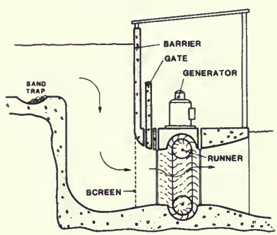
RIM GENERATOR



IMPULSE TURBINE



CROSS - FLOW IMPULSE TURBINE



THE SCHNEIDER LIFT TRANSLATOR

APPENDIX I

Hydroelectric Equipment

The principal pieces of equipment in a small hydroelectric plant are the inlet valve, turbine, electric generator, control and protection equipment, circuit breaker, transformer, and transmission connection. Miscellaneous equipment includes a crane (unless access is provided for use of a mobile crane), station lighting and power systems, a fire protection system, heating and ventilation equipment, and sanitary facilities. Except for the turbine and generator all of the equipment is standard industrial equipment which need not be discussed here.

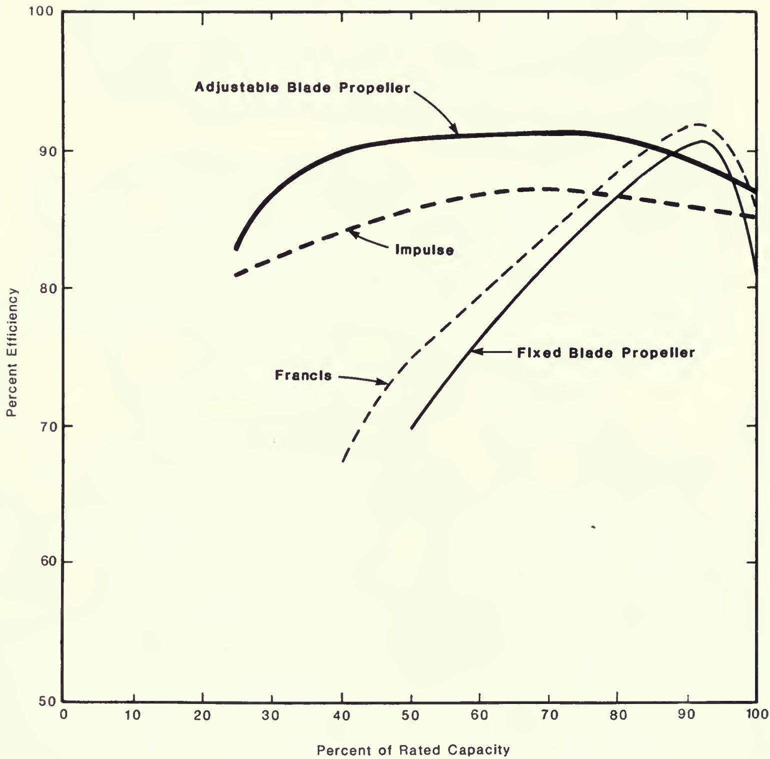
The capacity of a specific hydroelectirc site is determined by water flow and the available head. Selection of the type of turbine needed to drive an electric generator is based primarily on the head. Table I gives the range of operational heads for several types of turbines. Propeller turbines with adjustable-pitch blades -- also know as Kaplan turbines -- are useful where flows vary widely. Several manufacturers have developed other small turbines, such as rim-types and crossflow-types, which have special characteristics that might be preferred for some projects. The most common types of turbines are shown in Figure I-1. Typical performance curves for various types of hydraulic turbines are shown in Figure I-2.

Table I. Types of Turbines Used for Various Heads

Turbine	Operational Head
Lift Translator	Low: less than 0.5 m to 15 m (1.5 ft to 50 ft.)
Tube-type	Low: less than 16 m (50 ft)
Impulse- or Pelton-type	High: greater than 60 m (200 ft)
Vertical Propeller-type	Low to Medium: 4.6 m to 60 m (15 ft to 200 ft)
Francis-type (horizontal or vertical)	Low to High: 9.4 m to 300 m (30 ft to 980 ft)

The generator can be either a synchronous-type or induction-type. A synchronous generator is brought to operating speed by the turbine, synchronized to the electric system voltage and frequency, and then connected to the electric system. Once connected, the turbine-generator unit continues to operate at its synchronous speed. An induction generator

Figure I-2 Typical Performance Curves for Various Types of Hydraulic Turbines



is an electric motor that is operated as a generator. It is generally started as a motor without water flowing through the turbine. When the unit is up to speed the valves or gates are opened and it begins to operate as a generator. The type of generator used depends on the characteristics of the transmission system and the distance to other electrical power sources. Generally, a synchronous generator is more suitable for small hydroelectric projects because the sites are usually located some distance from other generating facilities. The efficiency of small generators ranges between 92 and 96 percent, and changes very little with variations in the head and flow. With a transformer efficiency of 98 percent this gives a plant an overall efficiency of about 85 percent of its rated capacity.

Francis Turbines. A Francis turbine has fixed vanes. Water enters the turbine in a radial direction on a plane perpendicular to the turbine-generator shaft, then changes direction 90 degrees, and is discharged in an axial direction, parallel to the shaft. The principal components of the turbine are a water spiral supply case to carry water to the runner, the runner itself, wicket gates to control the amount of water reaching the runner and to distribute it equally around the runner, and a draft tube to carry the water away from the turbine. The turbine can be mounted either vertically or horizontally depending on by site conditions.

The Francis turbine can operate over a range of about 30 to 110 percent of its design flow and about 60 to 150 percent of its design head. The peak efficiency of about 88 to 92 percent usually occurs is at about 90 to 95 percent of its rated capacity. Below 90 percent of its rated capacity, the turbine's efficiency drops fairly rapidly to about 75 percent at 50 percent of its rated capacity.

Propeller Turbines. A propeller-type turbine has a runner with three to six blades. The water passes through the runner in an axial direction parallel to the shaft. The principal components of the propeller turbine are similar to those of a Francis turbine. The pitch of the blades can be either fixed or adjustable; adjustable blades permit the turbine to operate with greater efficiency over a wider range of water flows.

Propeller turbines can be mounted either vertically or horizontally. One American manufacturer developed a standardized design for a horizontally-mounted propeller turbine with an S-shaped tubular water-supply case. This variation of the propeller turbine is discussed below as a tube turbine. Other variations of the horizontal propeller turbine include bulb and rim configurations also discussed below. The vertical propeller turbine has been the most-commonly used turbine in the past.

Vertical propeller turbines are available for heads ranging from 4.6 m to 61 m (15 ft to 200 ft). Propeller turbines can be operated over a range of about 30 to 100 percent of their design flow if provided with adjustable blades, and 40 to 140 percent of design head. Peak efficiency occurs at 90 to 95 percent of the rated capacity and, for a fixed blade propeller, will be about the same or slightly less than the Francis turbine at 88 to 92 percent. Below 90 percent of the rated capacity, turbine efficiency will drop off more rapidly than with the Francis turbine to about 70 percent at 50 percent of the rated capacity (Figure I-2).

Tube type Turbines. Tube-type turbines are horizontal or slant-mounted propeller runners with the electric generator located outside the water-supply case. This arrangement is accomplished using an S-type water passageway that includes the intake valve or gate, turbine, and draft tube as a single unit with the turbine-generator shaft extending out of the tube at the top bend of the S-shape. Tube-type turbines can have either fixed or adjustable blades. The performance characteristics for a tube-type turbine are similar to those for propeller turbines. The operating range with adjustable blades is greater than for a fixed-blade propeller turbine but less than for a Kaplan (vertical adjustable-blade propeller) turbine.

Tube-type turbines can be connected to the generator either directly or through a speed increaser gear box. The speed increaser lowers the plant's efficiency but allows the generator to be physically smaller with a corresponding reduction in manufacturing cost. The choice of direct or speed-increaser coupling is an economic decision. The advantages of using a speed increaser gear box is greater with lower heads.

Standardized tube-type turbines are available from one American manufacturer in ten sizes ranging up to a 5000 kW capacity and for heads of 1.8 m to 15 m (6 ft to 50 ft). At least one standardized tube-type turbine is operating successfully at about a 65-foot head after appropriate modification of the runner. The use of a tube-type turbine is generally limited to a maximum head of 15 m to 18 m (50 ft to 60 ft).

Bulb Turbines. A bulb turbine is a horizontal propeller-type unit whose generator is contained in a bulb immersed in the flow of water within the water-supply case. The bulb, held in place by structural supports, is provided with access shafts for maintenance. The performance characteristics and operating ranges of bulb turbines are similar to those of tube-type turbines with about a one percent improved efficiency since the flow of water is in a straight line rather than changed in direction by the S-shape.

The bulb turbine's compact design reduces the size of the powerhouse needed but introduces the need for additional structural supports to position the bulb within the water-supply case. Access to the generating unit for maintenance is more difficult than with other types of turbines.

The bulb turbine is available from foreign manufacturers and has been used successfully in low-head hydroelectric installations in Europe.

Rim Turbines. The rim-type turbine is similar to the bulb turbine except that the generator rotor is mounted on the periphery of the turbine runner blades. The concept was developed by a Swiss manufacturer 40 years ago and given the name "Straflo." About 75 units presently in service have capacities ranging from 1000 KW to 1900 kW at heads of 7.9 to 9.1 metres (26 to 30 feet). The rim design requires a water sealing arrangement between the water-supply case and the rotating outer rim; this limits this type of installation to fixed-blade runners under 2000 kW in size and under 9.8 m (32 ft) of head. The manufacturer is seeking to develop a new sealing design for use with higher heads and increased capacities.

The performance characteristics of the rim-type turbine are similar to those of the bulb turbine. The rim-type design is simple and compact requires less civil works and a smaller power house than other types of turbine/generators.

Impulse Turbines. An impulse turbine (also known as a pelton wheel) uses one or more nozzles to direct water at the buckets of a runner in a nonpressurized space. Impulse turbines are used for installations with heads above about 45.7 m (150 ft). Unless the head is greater than several hundred feet, other types of turbines are likely to result in a lower-cost installation. The design and installation of an impulse turbine for high-head hydropower is relatively simple with lower maintenance than for other types of turbines. The unit consists of one or more nozzles, each with a needle valve, a one-piece cast runner and a direct-connected electric generator. No draft tube is required.

Impulse turbines have very flat efficiency curves and may be operated down to loads of 20 percent of their rated capacity (Figure I-2).

Cross-flow Turbines. The cross-flow turbine is a variation of the impulse turbine. It was developed by a West German manufacturer and given the name "Ossberger Turbine." The cross-flow turbine has a cylindrical runner with adjustable inlet-guide vanes to direct the flow of water and a conical draft tube. The draft tube creates a pressure below one atmosphere in the runner chamber thereby using the head between the runner centerline and the centerline and the tailrace water level. This head is lost in impulse turbine installations.

The performance characteristics of the cross-flow turbine are similar to those of an impulse turbine; it has a very flat efficiency curve over a wide range of flow conditions. However, the peak efficiency of the cross-flow turbine is 83 to 85 percent as compared with an 88 to 92 percent efficiency with other types of turbines.

Schneider Lift Translator. Conventional turbine technology remains static, but one new device has been developed that may be applicable to certain low-head projects. The Schneider Lift Translator is still in the research and development stage, but several prototypes are being manufactured for trial installation as a part of a U. S. Department of Energy (DOE) grant. Basically, the Schneider device resembles a series of venetian blinds mounted in a somewhat oval shape. It has the potential to produce power under very low-head conditions. The trial installations will attempt to use it in existing conduits. A lift translator was recently installed on an irrigation canal in Richvale (Butte County), California.

The basic lift translator design operates with heads between 0.5 m and 15.2 m (1.5 ft) and (50 ft) and has a capacity of 1 kW to 50 kW. Other units are available for higher heads and higher capacities of up to 5000 kW.

APPENDIX J

Manufacturers of Small Hydroelectric Equipment

APPENDIX J

Manufacturers of Small Hydroelectric Equipment

United States

Alexis Pastuhov
P. O. Box 62
Harvard, MA 01451
(617) 456-8834

Allis-Chalmers
Hydro-Turbine Division
East Berlin Road
P. O. Box 712
York, PA 17405
(717) 792-3511

American Ligurian Company
15 Ralsey Road South
P. O. Box 1005
Stanford, CT 06902
(203) 324-7351

Arbanas Industries
24 Hill Street
Xenia, OH 45385
(513) 372-1884

Axel Johnson Corporation
Spear Street Tower
1 Market Plaza
San Francisco, CA 94105
(415) 777-3800

Beckwith Electric Company, Inc.
11811 62nd Street North
Largo, FL 33543
(813) 535-3408

Boeing Engineering and Construction
P. O. Box 3707
M.S. 8C-12
Seattle, WA 98124
(206) 773-8891

Border Electric Company
Route 1
Blaine, WA 98230
(206) 322-5545

Brown Boveri Corporation
1460 Livingston Avenue
North Brunswick, NJ 08902
(201) 932-6000

Canyon Industries
5342 Mosquito Lake Road
Deming, WA 98244
(206) 592-5552

Cascade Patterns
1309 Glenwood Drive
Mount Vernon, CA 98273
(206) 856-6608

Charmilles
EURO-USA Company
779 Barbara Avenue
Solana Beach, CA 92075
(714) 775-7974

Control Devices Pacific
P. O. Box 1485
Burlingame, CA 94610
(415) 347-3773

Electric Machinery Manufacturing Company
A Division of Turbodyne Corp.
800 Central Avenue
Minneapolis, MN 55413
(612) 378-8000

Essex Turbine
Kettle Cove Industrial Park
Magnolia, MA 01930
(617) 525-3523

Fuji Electric Ltd.
Nissho-Iwai
Suite 1900
700 South Flower Street
Los Angeles, CA 90017

General Electric Company
One River Road
Schenectady, NY 12345
(518) 385-5444

Hannon Electric Company
1605 Waynesburg Drive S. E.
Canton, OH 44707
(216) 456-4728

Hydro Energy Systems, Inc.
Two World Trade Center
New York, NY 10048
(212) 466-1404

Hydrotool Corporation
2640 Industry Way
Lynwood, CA 90262
(213) 639-4402

Hydrowest
38 Tam O'Shanter Road
Alamo, CA 94507
(415) 837-7679

Independent Power Developers
P. O. Box 1467
Noxon, MT 59853
(406) 847-2315
or
P. O. Box 285
Sandpoint, ID 83864
(208) 263-2166

The James Leffel and Company
426 East Street
Springfield, OH 45501
(513) 323-6431

Kvaerner-Moss, Inc.
800 Third Avenue, 31st Floor
New York, NY 10022
(212) 752-7310

Lima Electric Company
200 East Chapman Road
P. O. Box 918
Lima, OH 45802
(419) 227-7327

National Tank and Pipe Company
P. O. Box 7
10037 S. F. Mather Road
Clackamas, OR 97105
(503) 656-1991

Nissho Iwai American Corporation
700 South Flower Street, Suite 1900
Los Angeles, CA 90017
(213) 688-0600

Oriental Engineering & Supply Company
1485 Bayshore Boulevard, Suite 368
San Francisco, CA 94124
(415) 467-8616 or (415) 325-0925
or
670 Newell Road
Palo Alto, CA 94303
(415) 325-0925

Pullman Incorporated
200 South Michigan Avenue
Chicago, IL 60604
(312) 322-7167

Pumps, Pipes and Power
Kingston Village
Austin, NV 89310
(702) 964-2483

Rand Corporation
1700 Main Street
Santa Monica, CA 90406
(213) 393-0411

Short Stoppers Electric
Route 4, Box 247
Coos Bay, OR 97420
(503) 267-3559

Siemens-Allis, Inc.
6400 Westminster Avenue, Suite 219
Westminster, CA 92683
(714) 894-7509
or
Box 2168
Milwaukee, WI 53241
(415) 325-0925

Small Hydroelectric Systems
and Equipment
P. O. Box 124
Custer, CA 98240
(206) 366-7696

Sulzer Brothers, Inc.
1255 Post Street
San Francisco, CA 94109
(415) 441-7230

Toshiba International Corporation
465 California Street, Suite 430
San Francisco, CA 94104
(415) 434-2340

Trident Engineering
Box 11232 Piedmont Station
Oakland, CA 94611
(415) 986-6558

Westinghouse Electric Corp.
700 Braddock Avenue
East Pittsburgh, PA 15112
(412) 255-3800

Wind and Water Power
P. O. Box 49
Harrisville, NH 03450
(603) 827-3367

Canadian

Barber Hydraulic Turbine, Ltd.
Barber Point, Box 340
Port Colborne, Ontario L3K 5W1
Canada
(416) 363-4929

Dominion Engineering Works, Ltd.
P. O. Box 220
Montreal, Quebec H3C 2S5
Canada
Telex 05-25168

F. W. E. Stapenhorst Inc.
285 Labrosse Avenue
Point Clair, Quebec H9R 1A3
Canada
(514) 695-2044

Niagara Water Wheels, Ltd.
706 E. Main Street
Welland, Ontario L3B 3Y4
Canada

Foreign

A. B. Bofors-Nohab
S-46101
Trollhattan
Sweden

Alsthom
38 Avenue Kle'ber
75784 Cedex 16
Paris
France

Ateliers des Charmilles SA,
109 Rue De Lyon
CH-1211 Geneva 13
Switzerland

Balaju Yantra Shala (P) Ltd.
Balaju, Katmandu
Nepal

Barata Metal Words and Engineering PT
J. L. Ngagel (109)
Surabaya
Indonesia

Boving and Company, Ltd.
Villiers House, 41-47 Strand
London, WC2N 5LB
England

Briau SA
BP 43
37009
Cedex
Tourse
France

Drees and Company GMBH
Postfach 42
4760 Werl/West
West Germany

Elektro GMBH
St. Gallertrasse 27
Winter Thur
Switzerland

Escher-Wyss, Ltd.
Hardstrasse 319
CH-005 Zurich
Switzerland

Fuji Electric Company, Ltd.
12-1 Yurakucho, 1-Chome
Chiyoda-ku
Tokyo
Japan

Gilbert, Gilkes and Gordon, Ltd.
Westmoreland, LA9 7BZ
England

Hitachi Ltd.
New Marie Building
Maranouchi
Chiyoda-ku
Tokyo
Japan

J. M. Voith GMBH
Postfach 1940
D-7920 Heidenheim
West Germany

Jyoti, Ltd.
Industrial Area
P. O. Chemical Industries
Barodo 390 033
India

Karlstads Mekaniska Weskstad
Fack S-681 01
Kristinehamn
Sweden

KMW
AN Warlstads Mekauiska Werkstad
S-681-01
Kristinehamn 1
Sweden

Kvaerner Brug A/S
Box 3610
Olso
Norway

Land and Leisure Services
Priory Land
St. Thomas Launceston
Cornwall
England 8400

LMX (Lemingrad Metal Works)
KTEP (Karkov Metal Works)
V/O Energomach Exprot 35
Mosfilmovskaya
Moscow V-330
USSR

Maschinenfabrik B. Maier
Postfach 320
Brockhagner Strasse 14/20
4812 Brackwede
West Germany

Maschinenfabrik Kossler GMBH
A-3151 St. Polten
St. Georgen
Austria

Mitsubishi Heavy Industries Ltd.
5-1 Maranouchi, 2-Chome
Chiyoda-ku
Tokyo 100
Japan

Neyrpic Department Turbines
75, Rue Feneral Margin
38100 Genboble
France

Officiene Buehler
Canton Ticino
Switzerland

Ossberger
Postfach 425
D-8832 Weissenburg/Bayern
West Germany

OY Tampella AB
P. O. Box 267
33101 Tampere 10,
Finland

Riva Calzoni Sp A
Via Standhal 34
20144 Milan
Italy

Tokyo Shibaura Electric Co., Ltd.
(Toshiba)
Producer Goods Export Division
Uchisalwaichom, 1-Chome
Chiyoda-ku
Tokyo 100
Japan

Voest-Alpine Mortan AG
Muldenstrasse 5,
A-4020 Linz
Austria

Westward Mouldings, Ltd.
Greenhill Works
Delaware Road
Gunnislake, Cornwall
England

CONVERSION FACTORS

Quantity	To Convert from Metric Unit	To Customary Unit	Multiply Metric Unit By	To Convert to Metric Unit Multiply Customary Unit By
Length	millimetres (mm)	inches (in)	0 03937	25 4
	centimetres (cm) for snow depth	inches (in)	0 3937	2 54
	metres (m)	feet (ft)	3 2808	0.3048
	kilometres (km)	miles (mi)	0.62139	1.6093
Area	square millimetres (mm^2)	square inches (in^2)	0.00155	645 16
	square metres (m^2)	square feet (ft^2)	10.764	0.092903
	hectares (ha)	acres (ac)	2 4710	0.40469
	square kilometres (km^2)	square miles (mi^2)	0.3861	2.590
Volume	litres (L)	gallons (gal)	0 26417	3.7854
	megalitres	million gallons (10^6 gal)	0 26417	3 7854
	cubic metres (m^3)	cubic feet (ft^3)	35.315	0.028317
	cubic metres (m^3)	cubic yards (yd^3)	1.308	0.76455
	cubic dekametres (dam^3)	acre-feet (ac-ft)	0.8107	1.2335
Flow	cubic metres per second (m^3/s)	cubic feet per second (ft^3/s)	35.315	0.028317
	litres per minute (L/min)	gallons per minute (gal/min)	0 26417	3.7854
	litres per day (L/day)	gallons per day (gal/day)	0.26417	3 7854
	megalitres per day (ML/day)	million gallons per day (mgd)	0 26417	3.7854
	cubic dekametres per day (dam^3/day)	acre-feet per day (ac-ft/day)	0 8107	1.2335
Mass	kilograms (kg)	pounds (lb)	2.2046	0.45359
	megagrams (Mg)	tons (short, 2,000 lb)	1.1023	0.90718
Velocity	metres per second (m/s)	feet per second (ft/s)	3 2808	0 3048
Power	kilowatts (kW)	horsepower (hp)	1.3405	0.746
Pressure	kilopascals (kPa)	pounds per square inch (psi)	0 14505	6 8948
	kilopascals (kPa)	feet head of water	0.33456	2.989
Specific Capacity	litres per minute per metre drawdown	gallons per minute per foot drawdown	0.08052	12 419
Concentration	milligrams per litre (mg/L)	parts per million (ppm)	1.0	1.0
Electrical Conductivity	microsiemens per centimetre (uS/cm)	micromhos per centimetre	1.0	1.0
Temperature	degrees Celsius (°C)	degrees Fahrenheit (°F)	(1 8 × °C)+32	(°F−32)/1.8

State of California—Resources Agency
Department of Water Resources
P.O. Box 388
Sacramento
95802