4.16 Other NEPA Analyses

This chapter includes a discussion of several topics that are required for NEPA analysis, but that are not required for CEQA analysis. These topics include Power Generation and Economics, Socioeconomics, Environmental Justice, and Indian Trust Assets. Under NEPA, an EIS must address economic and social effects.

Power Generation and Economics

Affected Environment

Facility Descriptions

PG&E operates hydroelectric facilities in the Battle Creek watershed. This set of facilities is operated under FERC license 1121 and is referred to as the Battle Creek Hydroelectric Project. PG&E has owned and operated the Hydroelectric Project since 1919. Between 1900 and 1912, Battle Creek was developed into one of the earliest hydroelectric systems in the western United States. The facilities consist of a series of small diversions, several long canals, and low-volume/high-head power generators. The system includes five hydroelectric powerhouses (Volta 1, Volta 2, South, Inskip, and Coleman Powerhouses) with a combined nameplate capacity of 36.3 megawatts (MW). The area served by the Hydroelectric Project has a summer peak load of approximately 157 MW and is growing at approximately 0.77 MW per year (0.5%) (California ISO 1998). Table 4.16-1 shows the normal operating capacity and historical average annual energy production from the Hydroelectric Project. Figure 4.16-1 shows the historical monthly power generation for Battle Creek facilities.

Table 4.16-1. Historical Generation Production 1975 through 1999

Powerhouse	Normal Operating Capacity (MW)	Average Annual Energy, Gigawatt hours (GWh)
Volta 1	9.0	53.3
Volta 2	0.9	6.7
South	7.0	50.1
Inskip	8.0	52.7
Coleman	13.0	82.5
Total	37.9	245.3

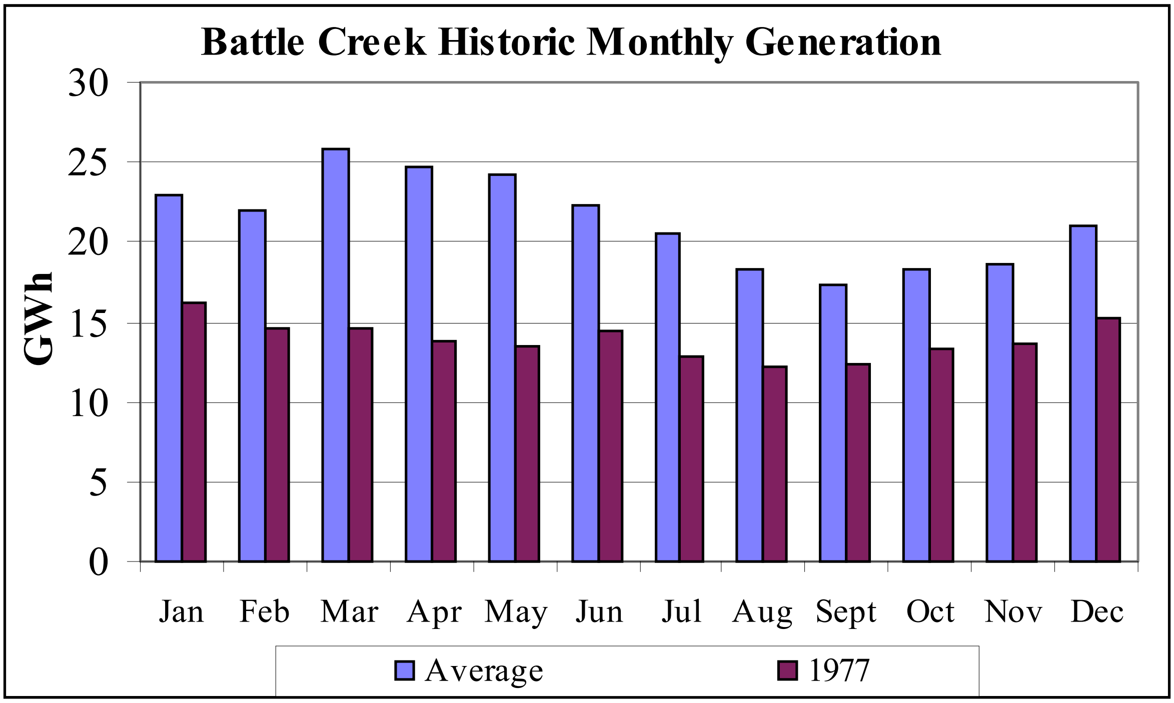

Figure 4.16-1. Historical Monthly Generation Production[1]

Flows from the upper reaches of North Fork Battle Creek are diverted via the Al Smith and Keswick diversions to Lake Grace and Lake Nora, where water is fed into the Volta 1 and Volta 2 Powerhouses for generation. The tailrace of Volta 2 connects directly to the Cross Country Canal, which transports water to South Fork Battle Creek for use in the South, Inskip, and Coleman Powerhouses. Water is also diverted from North Fork Battle Creek to powerhouses situated on South Fork Battle Creek via the North Battle Creek Feeder diversion, which diverts additional water into the Cross Country Canal, and via the Eagle Canyon diversion and canal, which transport water for use in the Inskip and Coleman Powerhouses. The Wildcat diversion and canal also divert water from North Fork Battle Creek to the Coleman Canal, where water is transported to the Coleman Powerhouse near the base of the watershed.

In upper South Fork Battle Creek, water is diverted at the South diversion for use in the South Powerhouse (along with diversions from the Cross Country Canal). The Inskip diversion diverts the outflow of the South Powerhouse and additional South Fork Battle Creek water to the Inskip Powerhouse. As noted above, the Inskip Powerhouse also receives North Fork Battle Creek water via the Eagle Canyon Canal. The Coleman diversion diverts the outflow of the Inskip Powerhouse and additional South Fork Battle Creek water to the Coleman Powerhouse from the Coleman Canal. The Coleman Canal also receives additional North Fork Battle Creek water directly from the Wildcat Canal. Several additional small diversions are scattered throughout the watershed,

[1] Critical dry year, 1977; historical production is prior to the construction of Volta 2 Powerhouse.

including diversions on Digger, Ripley, Soap, and Baldwin Creeks (see Chapter 3 descriptions). The flows of numerous springs are captured by a variety of measures for hydroelectric production.

No Action Alternative instream flow requirements for the watershed are described under Article 33 of the FERC license as maintaining a 3-cfs instream flow below all North Fork Battle Creek diversions and a 5-cfs instream flow below all South Fork Battle Creek diversions.

Volta 2 Powerhouse—Hydroelectric Turbine

Current instream flows, however, differ from the FERC license flows as a result of the 1998 Interim Flow Agreement, which provided for partial compensation to be paid to PG&E for power revenue forgone because of increased instream flows released at specific Hydroelectric Project diversion points. Under the terms of the Interim Agreement, which expired at the end of February 2001, PG&E provided the first 12.5 cfs released at Eagle Canyon and Coleman Diversion Dams. Releases at these sites in excess of 12.5 cfs, but not to exceed 35 cfs, were considered to be flows for which Reclamation would compensate PG&E. This Interim Flow Agreement reduces the average annual energy from the Hydroelectric Project by 18.45 GWh.

In addition to the augmented flows at the Eagle Canyon and Coleman diversions, PG&E suspended diversion of water from the Wildcat Diversion Dam. Reclamation compensated PG&E for 50% of the historical diversions at Wildcat Diversion Dam.

PG&E, Reclamation, and others are currently (April 2003) pursuing the development of a new interim agreement for augmented flows, similar to the previous agreements, that will bridge the time period until the Restoration Project measures have been implemented. In that new agreement, more focus is anticipated on North Fork Battle Creek, where the increased flows are more beneficial in terms of providing habitat for target species.

Regional Power Supplies

PG&E historically has had responsibility for generating, purchasing, transmitting and distributing electricity to its customers. However, with the start of the California competitive generation market in 1998, the California Power Exchange (CalPX) and Independent System Operator (ISO) were responsible for conducting a competitive bidding process for procuring electricity resources and for operating the transmission system throughout California to provide reliable electricity service at minimum cost. Soon after, the CalPX ceased to function in 2001, and DWR began purchasing power for the state's electricity consumers. PG&E resumed purchasing power for its customers in 2003. The Hydroelectric Project is operated in conjunction with PG&E's other generating resources to help meet the electricity demands of its customers.

Power Value Forecasts and Replacement Energy Cost

The alternative source of power currently available to PG&E is increased purchases. The latest California Energy Commission (CEC) Electricity Outlook report, published in February 2002, is a source of power value forecasts (California Energy Commission 2002). The CEC 2002–2012 Electricity Outlook report assesses California's electricity system over the next 10 years, focusing on supply and demand forecasts, reliability, wholesale spot market and retail prices, demand responsiveness, renewable generation initiatives, and environmental issues. The CEC conducted a simulated average annual wholesale spot prices for the years 2002, 2005, 2008, and 2012. Six scenarios were simulated and the average, on-peak, and off-peak prices for each year were generated.

The simulation yields an average wholesale price in 2002 in California of $34 to $37 [nominal $/MWh], depending on the extent to which demand returns to trend levels (levels before the summer of 2001). As large amounts of capacity are added during 2003–2005, prices fall. New, efficient combined cycles replace higher-cost steam turbines; expensive peaking units are needed in fewer hours of the year. As an adequate amount of transmission capacity is available to deliver energy from the Southwest into southern California, and from the Northwest into northern California, capacity additions in neighboring regions serve to lower prices in the state. Prices reach their low point in 2004–2005 as reserve margins in both the California ISO control area and the WSCC reach their peaks. As demand growth outpaces capacity addition after 2005, spot prices rise through 2012, their level depending on the extent to which reserve margins decline. (California Energy Commission 2002).

From an examination of daily and seasonal variations in prices, "the simulation yields monthly average wholesale prices that are lowest during May–June and higher during November–December than during the summer months" (California Energy Commission 2002).

The wholesale market price for electricity in any hour is set by the operating cost of the most expensive generation unit dispatched to meet demand (the "marginal unit") during that hour (Table 4.16-2). As new, efficient gas-fired capacity comes on line, reserve margins increase, reducing the need for older expensive units. This has the effect of reducing prices most in those periods in which the older expensive units were needed the most: peak hours during the summer. At the same time, maintenance rates for existing facilities have increased substantially during the past 2 years. As much of this maintenance is performed after prolonged operation during the summer, less-efficient plants are needed more often in November–December than would otherwise be the case. (California Energy Commission 2002).

Table 4.16-2. Average Annual Wholesale Spot Prices (Nominal $/MWh)

Average Price				
Scenario	2002	2005	2008	2012
High	$34	$27	$32	$37
Baseline	$35	$28	$32	$38
Low	$36	$29	$34	$40
Lower	$36	$30	$35	$41
Lowest	$36	$30	$36	$44
On Peak[2] Price				
Scenario	2002	2005	2008	2012
High	$42	$30	$35	$41
Baseline	$43	$31	$36	$42
Low	$45	$33	$38	$45
Lower	$45	$35	$40	$47
Lowest	$45	$35	$42	$51
		Off Peak Price		
Scenario	2002	2005	2008	2012
High	$27	$24	$28	$34
Baseline	$27	$25	$29	$34
Low	$28	$25	$29	$35
Lower	$28	$26	$30	$36
Lowest	$28	$26	$31	$37

[2] Peak hours are Monday–Friday, 6 AM–10 PM

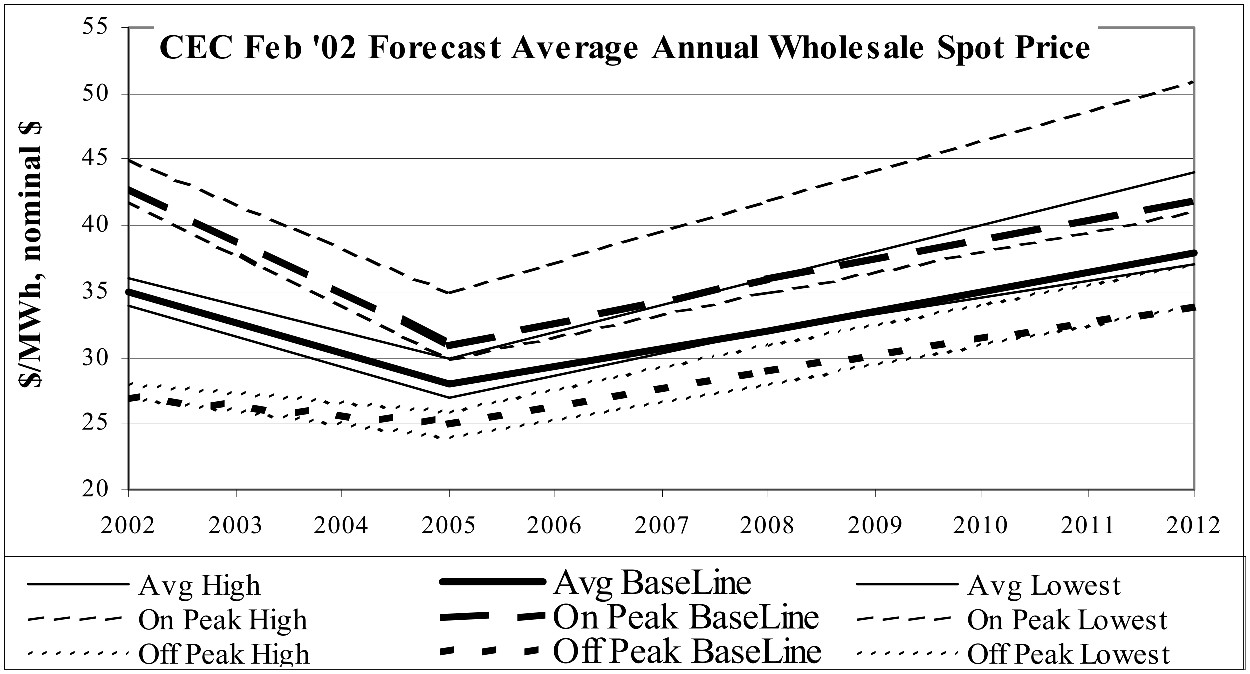

Figure 4.16-2
February 2002 Average Annual Wholesale Spot Price Forecast

From the above chart (Figure 4.16-2), the 2003 average annual wholesale spot price (average price for the baseline scenario) of about 3.4 cents will be deemed the current replacement energy cost. This forecast does not include capacity or ancillary services value. Because the Hydroelectric Project does not provide any significant ancillary services, no value for ancillary services will be included in the value of replacement power. However, a capacity value of about $75 per kilowatt (kW) per year at a 50% capacity factor (equivalent to about 1.71 cents per kilowatt-hour [kWh]) has been added to the energy values to develop a total replacement power cost of 5.11 cents per kWh. This replacement power cost of 5.11 cents per kWh will be used in the economic analyses in this EIS/EIR.

System Reliability

The Hydroelectric Project has been identified by California ISO as being needed for local system reliability. In 1998, a reliability must run (RMR) study was conducted by California ISO for the Hydroelectric Project.[3] The California ISO identified the Battle Creek area as covering the north central portion of Tehama County and the south central portion of Shasta County. The Battle Creek area is located east and south of Redding and includes the cities of Red Bluff, Los

[3] 1998 Five-Year RMR Study – Final Report and Study Data, Appendix 2 by Peter Mackin/Grid Planning, California ISO, September 1998

Molinos, and Whitmore. For both 1999 and 2003 modeling, the current transmission system configuration was used.

Internal generation in the Battle Creek Area consists of nine hydro generators (total maximum generation = 42.9 MW) and 12.6 MW of Qualifying Facility (QF) generation. Tables 4.16-3 and 4.16-4 show the internal generation facilities for the Battle Creek Area. (California ISO 1998).

Table 4.16-3. Battle Creek Area Load and Resources Modeled for 1999–2003 RMR Analysis

Year	1999	2003
Load		
Customer Load (MW)	157	163
Transmission Losses (MW)	7	9
Total Load + Losses (MW)	164	172
Generation—Dependable Operating Capacity		
Steam Turbines (MW)	0.0	0.0
Combustion Turbines (MW)	0.0	0.0
Hydro (MW)	42.9	42.9
QFs (historical levels) (MW)	7.0	7.0
Total Generation (MW)	49.9	49.9

Table 4.16-4. Battle Creek Area Generator Capacities

Name	Owner	River System	Nameplate Capacity (MW)
Inskip	PG&E	Battle Creek	8.0
South	PG&E	Battle Creek	7.0
Volta 1	PG&E	Battle Creek	9.0
Volta 2	PG&E	Battle Creek	0.9
Coleman	PG&E	Battle Creek	13.0
Kilarc Unit 1	PG&E	Cow Creek	1.6
Kilarc Unit 2	PG&E	Cow Creek	1.6
Cow Creek Unit 1	PG&E	Cow Creek	0.9
Cow Creek Unit 2	PG&E	Cow Creek	0.9
Total			42.9

Determination of Must Run Unit Requirements

An analysis of the Battle Creek RMR area was performed consistent with the Must Run Study Plan. The Battle Creek RMR area was analyzed using the 1999 and 2003 power flow and stability models. Loads in PG&E's Humboldt, North Valley, Sierra, and Sacramento Divisions were scaled to their area non-simultaneous levels to maximize the stress on the system. These load levels were selected to simulate the 1-in-5 heat-wave load levels that were called for in the RMR Study Criteria. The load levels used for each area are shown in Table 4.16-5.

Table 4.16-5. Load Scaling Factors Used for the Battle Creek Area

Division	1999 Base Case Load (MW)	1999 Non-Simultaneous Load (MW)	Increase	2003 Base Case Load (MW)	2003 Non-Simultaneous Load (MW)	Increase
Humboldt	91	123	35%	93	131	41%
North Valley	628	782	24%	672	815	21%
Sierra	879	990	13%	936	1091	17%
Sacramento	824	990	20%	881	1069	21%

Critical Contingency Analysis

The amount of required [RMR] generation for the Battle Creek area under conditions modeled in the 1999 and 2003 base cases is determined by a single transformer outage. For the Battle Creek Area this contingency was loss of the Cottonwood 230/60 kilovolt (kV) transformer (loss of the Cascade 115/60 kV transformer is also a very severe contingency). For this particular outage, the system limitation that determines the amount of required RMR generation is the loading on the remaining Cascade 115/60 kV transformer.

Contingency Analysis Summary

Table 4.16-6 lists branch loading and bus voltage for major contingencies in the Battle Creek Area that are affected by RMR units. There are a number of contingencies in PG&E's Sacramento, Sierra, and North Valley Divisions that result in violations of the RMR reliability criteria as well as PG&E's own internal Planning Criteria. As system performance during these outages is not affected by either the presence or absence of RMR generation, these particular outages are not listed in Table 4.16-6. In addition, for each scenario, Table 4.16-6 includes only the outages that caused the lowest bus voltage or highest branch loading.

As shown in Table 4.16-6, the minimum number of RMR units needed to meet the study criteria for the Battle Creek Area is nine. The contingency that determines this requirement is loss of the Cottonwood 230/60 kV transformer. (Table 4.16-6 also shows that loss of the Cascade 115/60 kV transformer is a very severe outage.)

Table 4.16-6. Battle Creek Area Must Run Study Contingency Analysis Results Summary

			Battle Creek Generation		Min. Voltage		Voltage Deviation (%)	Max. Line Loading		
Previous Contingency	Contingency	Year	QF (MW/# Units)	Hydro (MW/# Units)	p. u.	Bus		% Normal	% Emergency	Line
None	Open Cottonwood 230/ 60 kV Transformer [4]	1999	7.0/9	42.9/9	-	-	-	-	-	-
None	Open Cascade 115/ 60 Transformer	1999	7.0/9	42.9/9	0.96	Antler 60.0	-3.9	90.5	90.5	Cottonwood 230/ 60 kV Transformer
Coleman Unit Out (7 MW)	Open Cottonwood 230/ 60 kV Transformer 2	1999	7.0/9	42.9/9	-	-	-	-	-	-
Coleman Unit Out (7 MW)	Open Cascade 115/ 60 Transformer	1999	7.0/9	42.9/9	0.97	Antler 60.0	-3.6	99.8	99.8	Cottonwood 230/ 60 kV Transformer

Analysis of Off-Peak Load Case

The Battle Creek Area was analyzed using the 1999 Light Winter Must-Run base case. After shutting down all 10 Battle Creek Area units, the voltage at Kilarc 60 kV dropped to 1.104 power units (p.u.) from its pre-outage level of 1.116 p.u. All other buses in the Battle Creek Area exhibited similar performance. These results demonstrate that the Battle Creek area units are not needed during the off-peak for voltage control.

Load Management Alternatives

Table 4.16-7 shows the amount of load that would need to be dropped following a contingency in order to maintain reliability with a minimum of RMR contracts, for the Battle Creek Area. Because the transmission ties into the Battle Creek Area are weak, it is not possible to support all of the peak load in the area with no

[4] This contingency could not be solved with the power flow program. This situation indicates potential voltage collapse or dynamic instability for this contingency.

RMR generation. The amount of load management described below is based on the assumption of having no Cow Creek or Battle Creek units under RMR contracts.

The limiting contingency for this analysis was loss of the Cottonwood 230/60 kV transformer bank (because the other generation in the area is fairly minimal, no additional units were removed (i.e., this analysis did not look at overlapping outages). If this contingency were to occur, approximately 89 MW of load would need to be dropped in the Battle Creek Area to maintain branch loadings within ratings on the system.

The above analysis was performed by scaling all load in the area until the reliability criteria violations no longer occurred. Selective load tripping may reduce the amount of load tripping that is required, but such an analysis is beyond the scope of this study.

Table 4.16-7. Battle Creek Area Load Shedding Requirements

Scenario	Previous Outage	Load Shedding Required in 1999 (MW)	Load Shedding Required in 2003 (MW)
Loss of the Cottonwood 230/60 kV Transformer Bank[5]	None	89	97

Estimated Hours of Exposure

An analysis was performed to determine the approximate level of exposure to RMR reliability criteria violations if not all RMR units were not available. For this analysis, the load in PG&E's North Valley Division was reduced until all RMR reliability criteria violations no longer occurred. For the Battle Creek area, the worst contingency is an outage of the Cottonwood 230/60 kV transformer. For this outage the load level in the Battle Creek Area would need to be reduced to 42% of the area peak for all RMR criteria to be satisfied[6]. Using the 1997 load duration curve for the PG&E area, the percentage of time that the North Bay Area is at risk of RMR reliability criteria violations is 90%."

[5] The load shedding requirement was calculated by subtracting the Cascade 115/60 kV transformer rating and the remaining internal Battle Creek Area generation from the Battle Creek Area load for each year.

[6] For this analysis, the acceptable load level was calculated by dividing the rating of the Cascade 115/60 kV transformer bank by the peak load in the Battle Creek Area. In addition, voltage and dynamic stability were not checked for this analysis

Environmental Consequences

This section discusses power generation resource effects. Battle Creek hydroelectric power is a low-cost power-generating complex compared to other fossil-fueled generation facilities that might substitute for it, avoids some power plant air emissions, and contributes to a diversified generation resource mix. In addition, the Hydroelectric Project helps support the reliability of the local transmission system. If the electricity generating capacity of the Hydroelectric Project were replaced with fossil-fueled resources, greenhouse gas emissions could potentially increase by almost 35,000 metric tons of carbon per year.[7] Section 4.11 discusses the air quality consequences associated with the Restoration Project alternatives.

Assessment of Effects

This section assesses the effects of the action alternatives. For purposes of this analysis, the No Action Alternative is used as the environmental baseline. The No Action Alternative represents power production in the absence of the Interim Agreement. Effects are identified by comparing the components of each alternative to the No Action Alternative conditions. The significance of an effect is then assessed using the significance criteria. The Restoration Project alternatives are described more fully in Chapter 3, "Project Alternatives."

Hydroelectric Project capacity represents about 20% of the local electricity demand,[8] and about 0.1% of the California ISO market for the entire state of California. The load level in the Battle Creek area would need to be reduced to 42% of the area peak for all RMR criteria to be satisfied. This decrease in load is equivalent to about 91 MW. A reduction in generation capacity in excess of about 91 MW would be considered substantial. As the entire Hydroelectric Project output is only 42.9 MW, no Restoration Project alternative would result in a substantial effect on local or regional power supplies.

The ability to maintain low-cost, renewable, indigenous, and air emission–free hydroelectric power in the Battle Creek watershed is determined by maintaining the annual cost of Hydroelectric Project power at less than the annual replacement power costs. The annual Hydroelectric Project power costs and replacement power costs have been estimated using FERC's current cost method to derive the annual costs and benefits in 2003 dollars. This method uses current California electricity market conditions and current costs of owning and operating the Hydroelectric Project, plus the costs of implementing the Restoration Project alternatives. Future inflation and escalation of prices and costs are not considered.[9]

[7] Source of greenhouse gas emission from FERC's March 2003 Draft Environmental Impact Statement for Pit 3, 4, 5 Hydroelectric Project in Northern California
[8] 1998 Five-Year RMR Study – Final Report and Study Data, by Peter Mackin/Grid Planning, California ISO, September 1998
[9] See *Mead Corporation, Publishing Paper Division*, 72 FERC 61,027 (July 13, 1995).

The annual cost of project power includes all the costs of owning and operating a project. The Hydroelectric Project cost components include unrecovered past capital additions (e.g., the depreciated plant-in-service costs, or net book value), license amendment costs, future capital replacements, routine operations and maintenance costs, FERC fees, taxes, insurance, and the cost of implementing the Restoration Project alternatives. A fixed charge rate of 14% is used to annualize the costs of capital improvements (capital improvements have a service life in excess of 1 year and are repaid over time) and includes capital recovery (with a cost of capital of about 9%), taxes, and insurance costs. Expenses, such as payroll costs, are paid in the year the expenditure is made and do not include any tax or insurance component.

The net book value represents the cost of owning the facilities and reflects unrecovered past capital expenditures. The net book value of the Hydroelectric Project is currently $34.6 million. All of the other costs listed above represent future costs. An average of $300,000 per year is spent on capital additions for the Hydroelectric Project. Construction and decommissioning costs of the various Restoration Project alternatives are additional. The current annual operation and maintenance costs for the Hydroelectric Project total about $1.7 million per year. These costs would change under the various Restoration Project alternatives. In general, operation and maintenance costs increase with added facilities (i.e., fish screens, ladders) and decrease with removed facilities (i.e., decommissioned diversion dams). Cost allowances are also included for periodic storm damage repairs, one-time screen and ladder repairs, replacement power during construction, and PG&E's license amendment costs. Also shown are reimbursed forgone power costs and annual power benefits. The total cost of Hydroelectric Project power, net benefits, and cost of production are shown with and without the cost-sharing agreement of the MOU under the Five Dam Removal Alternative. Table 4.16-8 summarizes the annual cost of Hydroelectric Project power in 2003 dollars.

The annual cost of project power, on a cent–per-kWh basis, depends on the energy production from the project. The Hydroelectric Project's average annual energy production and dependable capacity are affected by the available stream flow (which varies with changing hydrologic conditions), minimum instream flow requirements, the scope of decommissioned facilities, and other environmental constraints such as ramping rates. The Hydroelectric Project historically has produced 245,300 MWh per year.[10] Table 4.16-9 summarizes the Hydroelectric Project's simulated average annual energy production and dependable capacity for the alternatives analyzed in this EIS/EIR.

Dependable capacity is the load-carrying ability of a hydroelectric plant under adverse hydrologic conditions for a specified time interval and period of a particular electric system load. Dependable capacity is based on a project's load-carrying ability during a dry hydrologic year coincident with the peak electric system load. Currently, the peak system load occurs during summer heat storms

[10] Actual average over the 25-year period of 1975–1999.

when the use of air-conditioning is high. Simply stated, if a powerhouse with flow-regulating capability has enough water to operate at its installed capacity for an average of 4–6 hours per day during July and August under dry hydrologic conditions, its dependable capacity is equal to its installed capacity. If sufficient water is unavailable and if a powerhouse cannot re-regulate the flow of water to match the system peak, its dependable capacity is less than its installed capacity. Because the Hydroelectric Project powerhouses are base-loaded facilities without significant water storage capabilities, dependable capacity declines with energy production. Table 4.16-9 summarizes the dependable capacity for the various alternatives.

Table 4.16-8. Detailed Cost of Project Power for the Hydroelectric Project

	No Action Alternative	Five Dam Removal Alternative	No Dam Removal Alternative	Six Dam Removal Alternative	Three Dam Removal Alternative
Average Annual Energy (GWh)	230.89	162.17	190.56	137.05	159.57
One-Time and Annually Recurring Cost Descriptions ($1,000s)					
Unrecovered Sunk Costs, or Net Book Value	$34,600	$34,600	$34,600	$34,600	$34,600
Future Capital Additions (per year)	$300	$300	$300	$300	$300
Operation and Maintenance (per year)	$1,700	$1,783	$1,880	$1,750	$1,947
Storm Repairs (every 10 years)	$500	$500	$500	$500	$500
Construct Screens and Ladders[11]	$0	$38,230	$45,560	$26,380	$32,850
One-Time Screen and Ladder Repairs	$0	$600	$1,200	$400	$600
Decommissioning Costs[12]	$0	$12,062	$0	$20,752	$17,590
Environ Compliance, Monitoring and Mitigation[12]	$0	$7,255	$7,255	$7,255	$7,255
MLTF Pathogen Problem Resolution[12]	$0	$2,329	$2,329	$2,329	$2,329
Future Water Acquisition	$0	$3,000	$3,000	$3,000	$3,000
Construction Outage Costs	$0	$1,259	$955	$841	$790
FERC License Amendment/EIS/EIR[12]	$0	$4,750	$4,750	$4,750	$4,750
Reimbursed Forgone Power (net present value)	$0	$2,080	$0	$0	$0
2003 Power Benefits (per year)	$11,798	$8,287	$9,738	$7,003	$8,154
FERC Current Cost Method (Annual cost in 2003 dollars; $1,000s/year)					
Unrecovered Sunk Costs, or Net Book Value	$4,844	$4,844	$4,844	$4,844	$4,844
Future Capital Additions	$427	$427	$427	$427	$427
Operation and Maintenance	$1,700	$1,783	$1,880	$1,750	$1,947
Storm Repairs	$140	$140	$140	$140	$140
Construct Screens and Ladders	$0	$5,352[1]	$6,819	$3,693	$4,599
One-Time Screen and Ladder Repairs	$0	$84	$168	$56	$84

[11] Reclamation updated construction cost estimated dated June 2003.

	No Action Alternative	Five Dam Removal Alternative	No Dam Removal Alternative	Six Dam Removal Alternative	Three Dam Removal Alternative
Decommissioning Costs	$0	$1,689[1]	$0	$2,799	$1,422
Environ Compliance, Monitoring and Mitigation	$0	$1,016	$1,016	$1,016	$1,016
MLTF Pathogen Problem Resolution	$0	$326	$326	$326	$326
Future Water Acquisition	$0	$420	$420	$420	$420
Construction Outage Costs	$0	$122	$93	$82	$77
FERC License Amendment/EIS/EIR	$0	$665	$665	$665	$665
Reimbursed Forgone Power	$0	$202[1]	$0	$0	$0
2003 Power Benefits	$11,798	$8,287	$9,738	$7,003	$8,154
FERC Current Cost Method (Annual net cost in 2003 dollars; $1,000s/year					
Total Cost of Power (including Net Book Value)	$7,111	$7,863 to $16,666[2]	$16,798	$16,218	$15,967
Going-Forward Cost of Power (excluding Net Book Value)	$2,267	$3,019 to $11,822[2]	$11,954	$11,374	$11,123
Total Net Benefits (including Net Book Value)	$4,688	$424 to -$8,379[2]	-$7,060	-$9,214	-$7,813
Net Benefits on a Going-Forward Basis (excluding Net Book Value)	$9,533	$5,268 to -$3,535[2]	-$2,216	-$4,370	-$2,969
Total Cost of Power ($/MWh)	30.8	48.5 to 102.8[2]	88.1	118.3	100.1
Going-Forward Cost of Power ($/MWh)	9.8	18.6 to 72.9[2]	62.7	83.0	69.7

Notes:
[1] These costs are paid by others (not PG&E) under the cost-sharing provisions of the MOU.
[2] First figure in range is with cost-sharing provisions of the MOU; second figure is without.

Table 4.16-9. Average Annual Energy, Dependable Capacity, Power Benefits, and Total Cost of Project Power for the Hydroelectric Project

Alternative	Average Annual Energy (MWh)	Dependable Capacity (MW)	Annual Power Benefits (2003 dollars)	Annual Total Cost of Hydroelectric Project Power (2003 dollars)
No Action Alternative	230,890	13.5	$11,798,000	$7,111,000
Five Dam Removal Alternative	162,170	7.4	$8,287,000	$7,863,000*
No Dam Removal Alternative	190,560	9.1	$9,738,000	$16,798,000
Six Dam Removal Alternative	137,050	6.3	$7,003,000	$16,218,000
Three Dam Removal Alternative	159,570	7.4	$8,154,000	$15,967,000

* With cost-sharing agreement of the MOU.

Summary of Effects

Estimated Generation, Power Benefits, and Cost of Project Power

Table 4.16-9 summarizes the estimated average annual energy, dependable capacity, annual power benefits, and the annual cost of power from the Hydroelectric Project under the various alternatives. Modeled energy production ranges from 230,890 MWh under the No Action Alternative to 137,050 MWh under the Six Dam Removal Alternative. Because the Hydroelectric Project is operated as a base-loaded facility, dependable capacity trends are similar to those for energy production. Dependable capacity ranges from about 13.5 MW under the No Action Alternative to 6.3 MW under the Six Dam Removal Alternative. Annual power benefits of the entire Hydroelectric Project range from $11,798,000 under the No Action Alternative to $7,003,000 under the Six Dam Removal Alternative. The total cost of project power ranges from $7,111,000 per year under the No Action Alternative to $16,798,000 per year under the No Dam Removal Alternative.

Table 4.16-10 summarizes the forgone generation and the increased cost of power for California electricity consumers under the various alternatives. The cost of power under the No Action Alternative is already reflected in customer rates and, therefore, has no incremental cost of power. Average annual generation would decrease by 40,330 MWh under the No Dam Removal Alternative, while forgone generation under the Six Dam Removal Alternative would be 93,840 MWh per year. California's electricity consumers would see an increase in the cost of power of about $2.3 million per year under the No Dam Removal Alternative. Under the Six Dam Removal Alternative, California's cost of power would increase by about $4.9 million a year. The increase in the cost of power under the Five Dam, Six Dam, and Three Dam Removal Alternatives would exceed $3 million per year.

Table 4.16-10. Forgone Generation and Increase in Cost of Power for the Hydroelectric Project

		Annual Increase in Cost of Power (2003 dollars)		
Alternative	Forgone Generation (MWh/year)	Replacement Power Cost for Forgone Generation	Increased Operation and Maintenance Costs	Total Increase in Annual Cost of Power
No Action Alternative	0	$0	$0	$0
Five Dam Removal Alternative	68,720	$3,512,000	$106,800	$3,618,800
No Dam Removal Alternative	40,330	$2,061,000	$228,200	$2,289,200
Six Dam Removal Alternative	93,840	$4,795,000	$66,300	$4,861,300
Three Dam Removal Alternative	71,320	$3,644,000	$121,400	$3,765,400

No Action Alternative

Under the No Action Alternative, the Hydroelectric Project would operate according to the provisions of its current FERC license. The Interim Agreement would cease, and the license-required minimum instream flows below dams of 3 cfs in North Fork Battle Creek and 5 cfs in South Fork Battle Creek would resume. Existing fish ladders would continue to be operated and maintained. Fish screening would not be included. PG&E would continue to maintain license-required stream gages, documentation, and operations criteria. Ongoing operation, maintenance, and capital expenditures would not change. All costs associated with this alternative would be the responsibility of PG&E. This alternative would not result in any effects to the cost of power.

Five Dam Removal Alternative (Proposed Action)

Effect—Increased cost of project power. Table 4.16-11 shows the incremental generation and cost-of-replacement-power effects of the Five Dam Removal Alternative as measured against the No Action Alternative. Average annual energy production is estimated to decrease by 68,720 MWh, and the dependable capacity would decrease by 6.1 MW. This decrease in energy production would likely increase the operation of fossil-fueled generating resources. The additional replacement power costs and increase in Hydroelectric Project operation and maintenance costs would, under cost-of-service ratemaking, increase California's annual cost of power by $3,618,800. The increased annual total and going-forward cost of Hydroelectric Project power, with the cost-sharing agreement, would still be less than the annual power benefits, demonstrating that the Hydroelectric Project would continue to be a low-cost source of electricity. Table 4.16-12 shows the cost of Hydroelectric Project power relative to the annual power benefits. The Five Dam Removal Alternative would not have an adverse effect on power generation and economics.

Table 4.16-11. Incremental Generation and Cost Effects of the Five Dam Removal Alternative as Measured against the No Action Alternative

		Change in California's Annual Cost of Power (2003 dollars)		
Change in Average Annual Energy (MWh)	Change in Dependable Capacity (MW)	Replacement Power Cost for Change in Generation	Increased Operation and Maintenance Cost	Total Change in Annual Cost of Power
(68,720)	(6.1)	$3,512,000	$106,800	$3,618,800

Table 4.16-12. Annual Cost of Hydroelectric Project Power and Power Benefits under the Five Dam Removal Alternative (2003 dollars)

Annual Cost of Hydroelectric Project Power[12]	Annual Power Benefits	Net Annual Power Benefits
$7,8635,000 total	$8,287,000	$424,000
$3,019,000 going forward	$8,287,000	$5,268,000

No Dam Removal Alternative

Effect—Increased cost of project power. Table 4.16-13 shows the incremental generation and cost-of-replacement-power effects of the No Dam Removal Alternative as measured against the No Action Alternative. Average annual energy production is estimated to decrease by 40,330 MWh, and the dependable capacity would decrease by 4.4 MW. This decrease in energy production would likely increase the operation of fossil-fueled generating resources. The additional replacement power costs and increase in Hydroelectric Project operation and maintenance costs would, under cost-of-service ratemaking, increase California's annual cost of power by $2,289,200. Table 4.16-14 shows the cost of Hydroelectric Project power relative to the annual power benefits.

Table 4.16-13. Incremental Generation and Cost Effects of the No Dam Removal Alternative as Measured against the No Action Alternative

		Change in California's Annual Cost of Power (2003 dollars)		
Change in Average Annual Energy (MWh)	Change in Dependable Capacity (MW)	Replacement Power Cost for Change in Generation	Increased Operation and Maintenance Cost	Total Change in Annual Cost of Power
(40,330)	(4.4)	$2,061,000	$228,200	$2,289,200

Table 4.16-14. Annual Cost of Hydroelectric Project Power and Power Benefits under the No Dam Removal Alternative (2003 dollars)

Annual Cost of Hydroelectric Project Power	Annual Power Benefits	Net Annual Power Benefits
$16,798,000 total	$9,738,000	($7,060,000)
$11,954,000 going forward	$9,738,000	($2,216,000)

The increased annual going-forward cost of project power would be more than the annual power benefits, demonstrating that the Hydroelectric Project would not be a source of low-cost electricity. In addition, the increased annual total cost of project power would be more than annual power benefits (i.e., PG&E would

[12] With cost sharing MOU in place.

not recover all of its past capital investments). The No Dam Removal Alternative would have an adverse effect on power generation and economics.

Six Dam Removal Alternative

Effect—Increased cost of project power. Table 4.16-15 shows the incremental generation and cost-of-replacement-power effects of the Six Dam Removal Alternative as measured against the No Action Alternative. Average annual energy production is estimated to decrease by 93,840 MWh, and the dependable capacity would decrease by 7.2 MW. This decrease in energy production would likely increase the operation of fossil-fueled generating resources. The additional replacement power costs and increase in the Hydroelectric Project's operation and maintenance costs would, under cost-of-service ratemaking, increase California's annual cost of power by $4,861,300. Table 4.16-16 shows the cost of Hydroelectric Project power relative to the annual power benefits.

Table 4.16-15. Incremental Generation and Cost Effects of the Six Dam Removal Alternative as Measured against the No Action Alternative

		Change in California's Annual Cost of Power (2003 dollars)		
Change in Average Annual Energy (MWh)	Change in Dependable Capacity (MW)	Replacement Power Cost for Change in Generation	Increased Operation and Maintenance Cost	Total Change in Annual Cost of Power
(93,840)	(7.2)	$4,795,000	$66,300	$4,861,300

Table 4.16-16. Annual Cost of Hydroelectric Project Power and Power Benefits under the Six Dam Removal Alternative (2003 dollars)

Annual Cost of Hydroelectric Project Power	Annual Power Benefits	Net Annual Power Benefits
$16,218,000 total	$7,003,000	($9,214,000)
$11,374,000 going forward	$7,003,000	($4,370,000)

The increased annual going-forward cost of project power would be significantly more than the annual power benefits, demonstrating that the Hydroelectric Project would not be a source of low-cost electricity. The increased annual total cost of Project power would also be more than annual power benefits (i.e., PG&E would not recover all of its past capital investments). The Six Dam Removal Alternative would have an adverse effect on power generation and economics.

Three Dam Removal Alternative

Effect—Increased cost of project power. Table 4.16-17 shows the incremental generation and cost-of-replacement-power effects of the Three Dam Removal Alternative as measured against the No Action Alternative. Average annual energy production is estimated to decrease by 71,320 MWh, and the dependable capacity would decrease by 6.1 MW. This decrease in energy production would likely increase the operation of fossil-fueled generating resources. The additional replacement power costs and increase in the Hydroelectric Project's operation and maintenance costs would, under cost-of-service ratemaking, increase California's annual cost of power by $3,765,400. Table 4.16-18 shows the cost of Hydroelectric Project power relative to the annual power benefits.

Table 4.16-17. Incremental Generation and Cost Effects of the Three Dam Removal Alternative as Measured against the No Action Alternative

		Change in California's Annual Cost of Power (2003 dollars)		
Change in Average Annual Energy (MWh)	Change in Dependable Capacity (MW)	Replacement Power Cost for Change in Generation	Increased Operation and Maintenance Cost	Total Change in Annual Cost of Power
(71,320)	(6.1)	$3,644,000	$121,400	$3,765,400

Table 4.16-18. Annual Cost of Hydroelectric Project Power and Power Benefits under the Three Dam Removal Alternative (2003 dollars)

Annual Cost of Hydroelectric Project Power	Annual Power Benefits	Net Annual Power Benefits
$15,967,000 total	$8,154,000	($7,813,000)
$11,123,000 going forward	$8,154,000	($2,969,000)

The increased annual going-forward cost of project power would be more than annual power benefits, demonstrating that the Hydroelectric Project would not be a source of low-cost electricity. In addition, the increased annual total cost of project power would also be more than the annual power benefits (i.e., PG&E would not recover all of its past capital investments). The Three Dam Removal Alternative would have an adverse effect on power generation and economics.

Socioeconomics

Affected Environment

The project area lies on the border of Tehama and Shasta Counties in northern California. The largest urban areas near the project area are Red Bluff, approximately 25 miles southwest in Tehama County, and Redding, approximately 30 miles northwest in Shasta County. The unincorporated community of Manton is located in Tehama County on the eastern edge of the project area near the border with Shasta County. The unincorporated community of Shingletown is located approximately 3 miles north of the project area in Shasta County. Table 4.16-19 summarizes the demographic characteristics of California, Tehama and Shasta Counties, Red Bluff, and Redding.

Table 4.16-19. State and County Demographics (2000)

	California	Tehama County	Shasta County	Red Bluff	Redding
Total population	33,871,648	56,039	163,256	13,147	80,865
Median household income in 1999 ($)	47,493	31,206	34,335	27,029	34,194
Median age	33.3	37.8	38.9	33.7	36.7
Unemployment (%)	4.0	6.4	5.6	6.6	4.5

Source: U.S. Census Bureau 2001a, 2001b

Regional Setting

Tehama County

Tehama County encompasses 2,951 square miles (1,888,670 acres) and is located in the north-central part of California, approximately 120 miles north of Sacramento.

Population. In January 2002, the California Department of Finance estimated the population of Tehama County at 56,900, which represented approximately 0.2% of the estimated California population. Tehama County ranks forty-first in population among California's 58 counties. The majority of the population lives in rural areas or unincorporated cities. The largest city, Red Bluff, has a population of 13,350. The population has been relatively stable and is below the experienced average growth in California.

Demographics. Tehama County's ethnic composition is 82.6% White; 12.1% Hispanic or Latino; 1.8% American Indian, Eskimo, or Aleut; 0.5% Black; 0.7% Asian; and 2.3% other. The median age in Tehama County is 37.8 years, about 4.5 years older than the median age in California as a whole (U.S. Census Bureau 2001b).

Employment and Income. Of the 34,537 people in the Tehama County civilian work force in 2000, 23,620 were employed (California Department of Finance 2002). The unemployment rate was 6.4%, 2.4% higher than the California average. Manufacturing, trade, and services were the largest non-government industries, employing approximately 10,050 people, or 40% of the employed work force. State and local government employed 3,260 workers, or 13% of total employment. Approximately 1,440 workers, or 6.1% of the employed work force, were involved in agricultural services.

In 1999, Tehama County had a per capita personal income of $18,879, ranking it fiftieth among California's 58 counties. This figure was 83.1% of the state average of $22,711, and 87.5% of the national average of $21,587 (California

Department of Finance 2003). In 1988, the per capita personal income in Tehama County was $12,377, ranking the county fifty-fifth in California. Over the past 10 years, the average annual growth rate of per capita personal income was 3.6%. During this same period, the average annual growth rate for California was 3.6% and for the United States, 4.6%.

In 1998, Tehama County had a total personal income of $950,664,000, ranking it forty-third in California and accounting for 0.1% of the state total. In 1988, total personal income in Tehama County was $583,855,000 and ranked forty-third in California. Over those 10 years, the average annual growth rate of total personal income was 5.0%. During this same period, the average annual growth rate for California was 5.1% and for the United States, 5.6%.

Total personal income includes the earnings (wages and salaries, other labor income, and proprietors' income), transfer payments, dividends, interest, and rent received by the residents of Tehama County. In 1998, earnings constituted 55.0% of total personal income (compared with 57.1% in 1988); dividends, interest, and rent, 20.0% (compared with 21.8% in 1988); and transfer payments, 25.0% (compared with 21.2% in 1988). From 1988 to 1998, earnings increased an annual average of 4.6%; dividends, interest, and rent, 4.1%; and transfer payments, 6.7%.

Earnings of persons employed in Tehama County increased from $310,556,000 in 1988 to $488,503,000 in 1998, an average annual growth rate of 4.6%. The largest industries in 1998 were services, with 20.2% of earnings; state and local government, 19.0%; and retail trade, 17.1%. In 1988, the largest industries were durable goods manufacturing, with 19.0% of earnings; state and local government, 18.1%; and services, 16.7%. Of the industries that accounted for at least 5% of earnings in 1998, the slowest-growing industry from 1988 to 1998 was durable goods manufacturing (12.8% of earnings in 1998), which increased at an average annual rate of 0.6%. The fastest-growing industry was retail trade, which increased at an average annual rate of 8.1%.

Estimated nonagricultural wage and salary employment and number of establishments are indicated in Table 4.16-20.

Proprietors' employment and farm employment accounted for the additional 8,040 employees, or approximately 35.6% of the employed civilian work force not included in the wage and salary category. Farm employment totaled 2,741 workers in 1998, or approximately 1.2% of the employed work force.

Table 4.16-20. Tehama County Labor Statistics

Industry	Number of Establishments	Number of Employees
Construction and mining	116	380
Manufacturing	64	2,550
Transportation–utility	55	430
Trade	292	4,430
Finance, insurance, real estate	89	670
Services	354	2,900
Federal government		250
State and local government		2,950

Source: Bureau of Labor Statistics 1999

Sales. In 1998, total taxable sales were $397.6 million, of which $280.7 million was attributable to retail sales.

Housing and Social Services. Tehama County has more than 40 hotels, motels, and trailer parks; one hospital; and 120 health care and social assistance centers, including three emergency facilities. Red Bluff, the largest city in the county, has a housing inventory of 3,415 single-family residences, 1,727 multifamily residences, and 304 mobile homes (California Department of Finance 2000b).

Agriculture. Tehama County is predominantly rural in nature with approximately 47% of the total land area in agricultural production. In 1997, there were 1,362 farms; approximately 57% of these farms operated on 50 acres or less. Total farm production for 1997 was $107,102,000, an increase from the 1992 figure of $95,041,000. Approximately 51% of the farms sold $10,000 or less of market production in 1997. This indicates that farming was not the sole revenue source for the majority of operators. Table O-1 in Appendix O compares 1992 and 1997 agricultural production statistics for Tehama County.

Shasta County

Shasta County encompasses 3,786 square miles (2,422,820 acres) and is located in the extreme northern end of the Sacramento Valley, equidistant from Los Angeles and Seattle on Interstate 5. It is 160 miles north of Sacramento and 230 miles northeast of San Francisco. The incorporated cities in Shasta County are Anderson, City of Shasta Lake, and Redding, the county seat. Bisected by the Sacramento River, Redding is a growing center of commerce and industry and the nationally recognized metropolitan marketplace of northern California, serving the adjacent counties of Tehama, Trinity, and Siskiyou.

Population. The 2002 population of 169,200 ranked Shasta County twenty-ninth among California's 58 counties. The growth rate for 2001 was 1.5%. The population in 1990 was 147,036, indicating an average annual growth rate between 1990 and 2002 of 1.4%.

Demographics. Shasta County's ethnic composition is 88.9% White; 4.4% Hispanic or Latino; 2.2% American Indian and Alaska Native; 0.6% Black; 1.5% Asian; and 2.4% other. The median age in Shasta County is 38.9 years, 5.6 years older than the median age in California as a whole. (U.S. Census Bureau 2001a.)

Employment and Income. In 1999, the civilian work force was composed of 75,000 workers; 69,800 of these workers were employed. The unemployment rate was 6.9%, which was higher than the California average of 4%.

In 1998, Shasta County residents had a per capita personal income of $21,986, which ranked the county thirty-first of California's 58 counties. This figure was 78% of the state average of $28,163, and 81% of the national average of $27,203. In 1988, the per capita personal income of Shasta County was $15,301, ranking the county thirty-fifth in California. The average annual growth rate of per capita personal income in Shasta County over the past 10 years was 3.7%. The average annual growth rate for California was 3.6% and for the United States, 4.6%.

In 1998, Shasta County had a total personal income of $3,609,108,000, ranking the county thirtieth in California and accounting for 0.4% of the state total. In 1988, the total personal income in Shasta County was $2,090,568,000 and ranked thirty-first in California. Over those 10 years, the average annual growth rate of total personal income in Shasta County was 5.6%. During this same period, the average annual growth rate for California was 5.1% and for the United States, 5.6%.

In 1998, earnings constituted 58.7% of total personal income (compared with 60.8% in 1988); dividends, interest, and rent, 19.7% (compared with 20.6% in 1988); and transfer payments, 21.6% (compared with 18.7% in 1988). From 1988 to 1998, earnings increased an annual average of 5.2%; dividends, interest, and rent, 5.2%; and transfer payments, 7.2%.

Earnings of persons employed in Shasta County increased from $1,352,812,000 in 1988 to $2,249,599,000 in 1998, an average annual growth rate of 5.2%. The largest industries in 1998 were services, with 30.3% of earnings; state and local government, 15.9%; and retail trade, 12.5%. In 1988, the largest industries were services, with 24.6% of earnings; state and local government, 16.6%; and retail trade, 12.5%. Of those industries that accounted for at least 5% of earnings in 1998, the slowest-growing industry from 1988 to 1998 was durable goods manufacturing (6.2% of earnings in 1998), which increased at an average annual rate of 1.3%. The fastest-growing industry was services, which increased at an average annual rate of 7.4%.

Estimated nonagricultural wage and salary employment and number of establishments are indicated in Table 4.16-21.

Table 4.16-21. Shasta County Labor Statistics

Industry	Number of Establishments	Number of Employees
Construction and mining	568	3,600
Manufacturing	245	4,200
Transportation–utility	227	3,900
Trade	1,280	14,500
Finance, insurance, real estate	348	1,800
Services	1,631	18,500
Federal government		1,200
State and local government		9,800

Source: Bureau of Labor Statistics 1999

Proprietors' income and farm employment accounted for the additional 10,300 employees, or about 15.2% of the employed civilian work force not included in the wage and salary category. In 1998, farm employment totaled 1,584 workers, or approximately 2.3% of the employed work force.

Sales. Total taxable sales in 1998 were $1,654,100,000; retail sales accounted for $1,161,500,000 of that amount.

Housing and Social Services. In 1999, the housing stock in Shasta County was composed of 71,042 units (47,633 single family residences; 11,136 multifamily residences; and 12,273 mobile homes and trailers). The vacancy rate was 7.4% and the standard housing cost of living index was 101.65%.

Shasta County has approximately 40 motels and hotels, 12 major shopping areas, and two major hospitals (with 368 physicians and surgeons).

Agriculture. Shasta County is predominantly rural in nature with approximately 13% of the total land area in agricultural production. In 1997, there were 850 farms with approximately 61% on 50 acres or less. Total farm production for 1997 was $31,349,000, a decrease from the 1992 figure of $33,198,000. Seventy percent of these farms sold $10,000 or less of market production in 1997. This indicates that farming was not the sole family revenue source for the majority of operators. Table O-2 in Appendix O compares 1992 and 1997 agricultural production statistics for Shasta County.

Local Setting

Demographics

The study area falls within two census tracts (CTs): CT 1 in Tehama County and CT 126.02 in Shasta County. Two census designated places (CDPs) occur within or near the study area. The Manton CDP includes a portion of the study area near the community of Manton. The Shingletown CDP is located outside of the study area, but is included because of its close proximity. Tables 4.16-22 and 4.16-23 provide a summary of the demographics of CT 1, CT 126.02, Manton CDP, and Shingletown CDP.

Table 4.16-22. Local Area Demographics (2000 Census)

	Census Tract 1, Tehama County	Census Tract 126.02, Shasta County	Manton CDP	Shingletown CDP
Total Population	4,636	5,807	372	2,222
Per capita income in 1999 ($)	17,279	18,796	19,127	16,303
Median Age	43.1	45.3	50.7	45.9
Unemployment (%)	5.7%	6.6%	7.3%	7.2%

Table 4.16-23. Local Area Racial Composition (2000 Census)

	Census Tract 1, Tehama County	Census Tract 126.02, Shasta County	Manton CDP	Shingletown CDP
White alone	87%	92%	90%	93%
Hispanic or Latino	8%	3%	<1%	2%
Black or African American alone	<1%	<1%	0%	<1%
American Indian and Alaska Native alone	2%	3%	2%	2%
Asian alone	<1%	<1%	<1%	<1%
Native Hawaiian and Other Pacific Islander alone	<1%	<1%	<1%	0%
Other	2%	2%	6%	2%

Local Businesses. **Trout Farm Operations.** MLTF is a private aquaculture venture that raises and sells rainbow trout primarily for stocking private, fee-fishing lakes (Figure 4.16-3). In the past, MLTF sold live rainbow trout eggs; however, it no longer serves this market. MLTF operates 12 flow-through trout culture facilities, nine of which may be affected by the Restoration Project. Six facilities are located in the Battle Creek watershed, and three are in the Paynes Creek watershed, approximately 5–7 air miles south of South Fork Battle Creek.

MLTF leases land at freshwater spring sites from local landowners and has a substantial investment in hatcheries, rearing pens, and water treatment equipment. The rent that local landowners receive from MLTF is, in some cases, a substantial portion of their annual incomes. MLTF employs 20 workers.

Environmental Consequences

Summary of Effects

No adverse social effects are expected to occur in Shasta and Tehama Counties under the No Action Alternative or the Action Alternatives (i.e., Five Dam Removal, No Dam Removal, Six Dam Removal, and Three Dam Removal). The actions would not alter the social environment. Potential change in employment and income associated with any of the alternatives is not expected to result in a substantial change in regional economic activity. However, the Action Alternatives could have an adverse effect on the local economy, employment, and income as a result of potentially ceasing operations at the MLTF's Willow Springs, Jeffcoat East, and Jeffcoat West facilities.

No Action Alternative

Under the No Action Alternative, no substantial change in regional or local employment or income levels is expected because no restoration activities would occur. No change in power production, operation of private fish-rearing facilities, or other economic activities associated with the continued operation of the Hydroelectric Project are expected. In addition, no change in agricultural production from lands crossed by the project or adjacent to project facilities is expected.

As described in Section 4.1 "Fish," the continued introduction of anadromous fish to the upper watershed as part of other ongoing programs could increase the potential for IHN virus to spread to some of the fish-rearing facilities of MLTF. Currently, MLTF diverts flow from two springs as the primary source of flowing water to three of their fish culture operations: Willow Springs, Jeffcoat East, and Jeffcoat West. Historically, the spring flow has supported the production of relatively disease-free (i.e., IHN-free) rainbow trout. The flow diverted from the springs, however, includes seepage from Eagle Canyon, Inskip, and perhaps other canals. Seepage from Eagle Canyon and Inskip canals potentially contains pathogens that are conveyed by water diverted from North Fork and South Fork Battle Creek. Steelhead and chinook salmon that are present in Battle Creek carry pathogens, including IHN.

The pathogens will continue to be present under the No Action Alternative and continue to place the cultured fish at risk of contracting diseases from the spring water supply that receives canal seepage. The No Action Alternative would substantially increase the abundance of chinook salmon and steelhead in Battle Creek (Section 4.1, "Fish"). Increased abundance of chinook salmon and steelhead and occurrence upstream of Eagle Canyon, North Battle Creek Feeder, Inskip, and South diversion dams potentially increases the occurrence of pathogens in the water diverted from South Fork and North Fork Battle Creek. In this event, production from the MLTF facilities could cease, resulting in an adverse effect on regional and local employment and income.

Five Dam Removal Alternative (Proposed Action)

Effect—Potential decrease of regional and local employment and income. As described in Section 4.1 "Fish," increasing the habitat available to anadromous fish within the Battle Creek watershed could increase the potential of IHN virus to spread to MLTF's Jeffcoat East, Jeffcoat West, and Willow Springs fish-rearing facilities. Increased abundance of chinook salmon and steelhead and occurrence upstream of Eagle Canyon, North Battle Creek Feeder, Inskip, and South diversion dams potentially increases the occurrence of pathogens in the water diverted from South Fork and North Fork Battle Creek. The number of adult steelhead and chinook salmon spawning in Battle Creek may increase to several thousand adults under the Five Dam Removal Alternative, at least an order of magnitude greater than existing abundance. Increased levels of pathogens conveyed to the springs by canal seepage would increase the potential for infecting rainbow trout reared by MLTF.

The potential for exposure of aquaculture-reared rainbow trout (or other salmonid species) at MLTF is positively correlated with the number of anadromous salmonids entering Battle Creek above the intakes to Eagle and Inskip canals, which have waters that cross-connect via seepage to spring-fed water supplies servicing MLTF Jeffcoat and Willow Springs facilities. Once exposed to pathogens such as IHNV, these cultured fish will be unmarketable because of DFG codes and regulations prohibiting the planting of diseased fish or fish carrying serious pathogens. The economic consequences of pathogen exposure (even without apparent disease) are very serious for MLTF.

In the event these fish-rearing facilities were to become infected with the IHN virus, fish production most likely would cease. The effect on employment and income is difficult to estimate because it is not known whether MLTF would continue operation of its other fish-rearing facilities. In the event MLTF completely ceased operation, it is estimated that up to 20 employees would lose their jobs with an estimated combined annual income of $380,000. Some secondary economic effects also may occur because MLTF would no longer purchase supplies needed for operation of the fish-rearing facilities from local or regional suppliers and would no longer pay lease payments to local land owners where facilities are located.

The jobs lost in the event MLTF ceases operation represent less than 1% of the 23,620 persons employed in Tehama County in 2000. However, the loss of the operation would adversely affect MLTF and would result in the loss of an important employment source to the local economy. The 1999 MOU signatories are currently discussing measures with the MLTF to minimize potential adverse effects the IHN virus may have on the trout farms.

Effect—Slight increase of regional sales/receipts during construction. The estimated combined regional sales/receipts for Tehama and Shasta Counties were approximately $5.8 billion in 2002. If labor costs are assumed to comprise approximately 35% of the total construction budget (Table 4.16-24), a potential amount of $9.4 million would be expended on material and equipment during the implementation of the Five Dam Removal Alternative, and most activity would occur in the first few years of the project. If these expenditures were made within Tehama and Shasta Counties, they would represent an increase of less than 0.2% in regional sales/receipts. These expenditures would benefit the regional economy by maintaining or increasing employment and income levels in those sectors that would supply goods and services to contractors during the construction phase of the Restoration Project.

Table 4.16-24. Estimated Construction Costs for the Restoration Project ($ Million)

Restoration Project Feature	Five Dam Removal Alternative	No Dam Removal Alternative	Six Dam Removal Alternative	Three Dam Removal Alternative
North Battle Creek Feeder Diversion Dam	$3.14	$3.14	$3.14	$3.14
Eagle Canyon Diversion Dam	$3.68	$3.68	$2.00	$2.00
Wildcat Diversion Dam	$1.02	$1.67	$1.02	$1.02
South Diversion Dam	$1.62	$4.32	$1.62	$4.32
Soap Creek Feeder	$0.050	$0.00	$0.050	$0.00
Inskip Diversion Dam/South Powerhouse	$10.92	$7.74	$10.92	$10.04
Lower Ripley Creek Feeder	$0.020	$0.00	$0.020	$0.00
Coleman Diversion Dam/Inskip Powerhouse	$6.36	$5.40	$5.95	$2.40
Total Construction Costs	$26.810	$25.95	$24.720	$22.92

Estimated construction costs provided by Reclamation, June 2003.

Effect— Slight increase of construction-related jobs during Restoration Project construction. The 1999 regional civilian labor force comprised 97,130 workers, with unemployment around 6.85%, split evenly between Tehama and Shasta Counties. The size of the labor force has remained relatively constant on an annual basis. Assuming a stagnant labor force growth rate and further assuming that the existing regional labor pool would accommodate the Restoration Project's labor requirements, there could be a shift in employment of approximately 42 full-time job equivalents to the Restoration Project from the existing labor pool of 97,130 workers. However, should the labor requirements for the Restoration Project call for a specialization not found regionally, up to 42 full-time job equivalents could originate from other areas. If all of these 42 full-time job equivalents originated from other areas, this would represent an increase to the regional labor force of 0.04% during the Restoration Project's peak year labor requirement. New workers entering the labor force would benefit the regional economy by increasing expenditures for goods and services.

There would not be a substantial indirect or secondary effect because the region contains sufficient housing, lodging, food services, transportation, and health care to accommodate the 42 new full-time job equivalents.

No Dam Removal Alternative

Rather than removing Wildcat, Coleman, Lower Ripley Creek Feeder, Soap Creek Feeder, and South Diversion Dams, as under the Five Dam Removal Alternative, the No Dam Removal Alternative would install fish screens and fish ladders at Wildcat, Coleman, and South Diversion Dams, and Lower Ripley Creek Feeder and Soap Creek Feeder would be left in place.

Effect—Potential decrease of regional and local employment and income. Under the No Dam Removal, diversions from South Battle Creek and diversions from North Battle Creek would continue to supply flow to the Inskip Canal and other up-slope canals. Seepage from the canals would potentially contaminate the spring supplying the Willow Springs facility. The increased abundance and upstream extent of steelhead and chinook salmon would increase the potential for infecting the spring flow supplying the Willow Springs facility. Eagle Canyon diversions would continue under the No Dam Removal alternative. Seepage from Eagle Canyon Canal would continue to potentially contaminate the flows supplying the Jeffcoat East and West facilities. The increased abundance and upstream extent of steelhead and chinook salmon would increase the potential for infecting the spring flow supplying the Jeffcoat East and West facilities. These effects on the MLTF facilities are similar to effects described above for the Five Dam Removal Alternative. The 1999 MOU signatories are currently discussing potential measures with the MLTF to minimize potential adverse effects the IHN virus may have on the trout farms.

Effect—Slight increase of regional sales/receipts during construction. The estimated combined regional sales/receipts for Tehama and Shasta Counties were approximately $5.8 billion in 2002. If labor costs are assumed to comprise approximately 35% of the total construction budget (Table 4.16-24), a potential amount of $9.1 million would be expended on material and equipment during the implementation of the No Dam Removal Alternative, and most activity would occur in the first few years of the project. If these expenditures were made within Tehama and Shasta Counties, they would represent an increase of less than 0.2% in regional sales/receipts. These expenditures would benefit the regional economy by maintaining or increasing employment and income levels in those sectors that would supply goods and services to contractors during the construction phase of the Restoration Project.

Effect—Slight increase of construction-related jobs during Restoration Project construction. The No Dam Removal Alternative would employ approximately 70 construction workers, as opposed to the 90 workers anticipated to be employed under the Five Dam Removal Alternative as described above. Beneficial socioeconomic effects are anticipated to be slightly less because fewer workers would be required during the construction phase and the short-term expenditures for goods and services would be lower.

Six Dam Removal Alternative

Rather than installing a fish screen and fish ladder at the Eagle Canyon Diversion Dam, as with the Five Dam Removal Alternative, the Six Dam Removal Alternative would remove the dam, which would require a lower cost and less effort than installing a fish screen and fish ladder. Once the dam has been removed, diversions to the Eagle Canyon Canal would be terminated.

Effect—Potential decrease of regional and local employment and income. The Six Dam Removal Alternative would substantially increase the abundance of chinook salmon and steelhead in Battle Creek (Section 4.1, "Fish"). Increased abundance of chinook salmon and steelhead and occurrence upstream of North Battle Creek Feeder, Inskip, and South diversion dams potentially increases the occurrence of pathogens in the water diverted from South Fork and North Fork Battle Creek. Increased levels of pathogens conveyed to the springs by canal seepage would increase the potential for infecting rainbow trout reared by MLTF.

The springs supplying Jeffcoat East and West are potentially contaminated by seepage from the Eagle Canyon Canal. Eagle Canyon Diversion Dam would be removed under the Six Dam Removal alternative. The diversion and flow in Eagle Canyon Canal would cease and no longer contribute seepage to the springs that supply Jeffcoat East and West. The Six Dam Removal alternative would eliminate the existing and future potential for infecting spring flows supplying the Jeffcoat East and West facilities. Therefore, implementing the Six Dam Removal Alternative would have similar effects on the Willow Springs facility as the Five Dam Removal Alternative and no effect on the Jeffcoat East and West Facilities. The effect on the Willow Springs facility would be similar to that described above for the Five Dam Removal Alternative. The 1999 MOU signatories are currently discussing potential measures with the MLTF to minimize potential adverse effects the IHN virus may have on the trout farms.

Effect—Slight increase of regional sales/receipts during construction. The estimated combined regional sales/receipts for Tehama and Shasta Counties were approximately $5.8 billion in 2002. If labor costs are assumed to comprise approximately 35% of the total construction budget (Table 4.16-24), a potential amount of $8.65 million would be expended on material and equipment during the implementation of the Six Dam Removal Alternative, and most activity would occur in the first few years of the project. If these expenditures were made within Tehama and Shasta Counties, they would represent an increase of less than 0.2% in regional sales/receipts. These expenditures would benefit the regional economy by maintaining or increasing employment and income levels in those sectors that would supply goods and services to contractors during the construction phase of the Restoration Project.

Effect—Slight increase of construction-related jobs during Restoration Project construction. The Six Dam Removal Alternative would employ approximately the same number of construction workers as the Five Dam Removal Alternative. Beneficial socioeconomic effects are anticipated to be essentially the same as those described above for the Five Dam Removal Alternative.

Three Dam Removal Alternative

Socioeconomic effects would be similar to those described for the Five Dam Removal Alternative. Rather than removing Lower Ripley Creek Feeder, Soap Creek Feeder, and South Diversion Dams, as under the Five Dam Removal Alternative, the Three Dam Removal Alternative would install fish screens and fish ladders at the South Diversion Dam, and Lower Ripley Creek Feeder and Soap Creek Feeder would be left in place.

Effect—Potential decrease of regional and local employment and income. Under the Three Dam Removal Alternative, rather than installing a fish screen and fish ladder at Eagle Canyon Diversion Dam, this dam would be removed. Diversions from North Fork and South Fork Battle Creek under the Three Dam Removal alternative would continue to supply flow to the Inskip Canal and other up-slope canals. Seepage from the canals would potentially contaminate the spring supplying the Willow Springs facility. The increased abundance and upstream extent of steelhead and chinook salmon would increase the potential for infecting the spring flow supplying the Willow Springs facility.

The springs supplying Jeffcoat East and West are potentially contaminated by seepage from the Eagle Canyon Canal. Eagle Canyon Diversion Dam would be removed under the Six Dam Removal alternative. The diversion and flow in Eagle Canyon Canal would cease and no longer contribute seepage to the springs that supply the Jeffcoat East and West facilities. This alternative would eliminate the existing and future potential for infecting spring flows supplying the Jeffcoat East and West facilities.

Therefore, implementing the Three Dam Removal Alternative would have similar effects on the Willow Springs facility as the Five Dam Removal Alternative, and no effect on the Jeffcoat East and West Facilities. The effect on the Willow Springs facility would be similar to that described above for the Five Dam Removal Alternative. The 1999 MOU signatories are currently discussing potential measures with the MLTF to minimize potential adverse effects the IHN virus may have on the trout farms.

Effect—Slight increase of regional sales/receipts during construction. The estimated combined regional sales/receipts for Tehama and Shasta Counties were approximately $5.8 billion in 2002. If labor costs are assumed to comprise approximately 35% of the total construction budget (Table 4.16-24), a potential amount of $8.0 million would be expended on material and equipment during the implementation of the Three Dam Removal Alternative, and most activity would occur in the first few years of the project. If these expenditures were made within Tehama and Shasta Counties, they would represent an increase of just above 0.1% in regional sales/receipts. These expenditures would benefit the regional economy by maintaining or increasing employment and income levels in those sectors that would supply goods and services to contractors during the construction phase of the Restoration Project.

Effect—Slight increase of construction-related jobs during Restoration Project construction. The Three Dam Removal Alternative would employ fewer construction workers than the Five Dam Removal Alternative (77 workers vs. 90 workers). Beneficial socioeconomic effects are anticipated to be slightly less than the Five Dam Removal Alternative, as described above, because fewer workers would be required during the construction phase and the short-term expenditures for goods and services would be lower.

Environmental Justice

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires each federal agency to identify and address disproportionately high and adverse human health or environmental effects of their actions on minorities and low-income populations and communities. It requires federal agencies to adopt strategies to address environmental justice concerns within the context of agency operations.

The mission of the California Environmental Justice Program is to accord the highest respect and value to every individual and community; it requires that the California Environmental Protection Agency and its boards, departments and offices conduct their public health and environmental protection programs, policies, and activities in a manner that is designed to promote equality and afford fair treatment, full access, and full protection to all Californians, including low-income and minority populations. The California Environmental Protection Agency is firmly committed to the achievement of environmental justice. Environmental justice for all Californians is a priority for the California Environmental Protection Agency.

The California Government Code (Section 65040.12) defines environmental justice as "The fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations and policies." This statute obligates the SWRCB as state lead agency for CEQA to do the following:

- Conduct all programs, policies, and activities in a manner that ensures the fair treatment of people of all races, cultures, and income levels, including minority populations and low-income populations of the State.

- Promote enforcement of all health and environmental statutes within its jurisdiction in a manner that ensures the fair treatment of all Californians, irrespective of race, culture, and income.
- Ensure greater public participation from environmental justice stakeholders in the development, adoption, and implementation of environmental regulations and policies.
- Identify among people of different socioeconomic classifications any differential patterns of consumption of natural resources.

Affected Environment

The dams to be removed and the fish screens, ladders, and related water conveyance facilities to be improved as part of the Restoration Project are located on lands managed for grazing, fisheries restoration, and hydropower generation. As discussed in Section 4.6, "Land Use," and the socioeconomics discussion provided above in this section, construction operation, and maintenance activities associated with the Restoration Project are not expected to result in a substantial changes to, or conflict with, existing land uses or result in substantial change in the socioeconomic characteristics of the study area. The restoration project could benefit employment and income in the study area as a result of enhancing the anadromous fishery. Conversely, the Restoration Project could adversely affect employment and income in the study area by reducing or eliminating production from the MLTF, a privately owned fish hatchery with some operations located within the study area.

As indicated in the socioeconomics discussion provided above, the study area falls within Tehama County CT 1 and Shasta County CT 126.02. Because of the large area encompassed by CT 1 and CT 126.02, the environmental justice analysis was based on the demographic information reported for the Manton CDP. The Manton CDP is located within and adjacent to the study area and, because of its smaller size, provides a more accurate representation of the ethnicity and income level of persons living within the study area.

The 2000 U.S. Census indicates 372 persons reside within the Manton CDP. The ethnic composition of the Manton CDP is 95 percent White, followed by American Indian (3%), and Black or African American (1%) (U.S. Census Bureau 2003a). The ethnic composition of Tehama County is 85% White, followed by American Indian, Eskimo, or Aleut (2%); Asian and Black or African American (both less than 1%); and other (12%) (U.S. Census Bureau 2001b). The ethnic composition of Shasta County is 89% White, followed by American Indian, Eskimo, or Aleut (3%); Asian (2%); Black or African American (1%); and other (5%) (U.S. Census Bureau 2001a).

Per capita income within the Manton CDP was $19,127 (U.S. Census Bureau 2003b). Per capita income in Tehama County and Shasta County was $15,793 and $17,738, respectively (U.S. Census Bureau 2003c and 2003d). Approximately 9% of families residing within the Manton CDP have incomes below the poverty level, whereas 13% of the families residing within Tehama County and 11% of the families residing within Shasta County have incomes below the poverty level. This suggests that income levels within the Manton CDP are similar to income levels for Shasta and Tehama counties as a whole.

Most workers residing within the Manton CDP are employed in management, professional, and related occupations (24 persons) or the sales and office occupations sector (43 persons) (U.S. Census Bureau 2003b). Only six workers were employed in the farming, fishing, or forestry occupations. Average one-way commute time for workers originating from the Manton CDP was 34 minutes. The one-way commute time and the predominate occupation types suggests that most workers commute to places of work outside of the study area (possibly Red Bluff or Redding).

Environmental Consequences

As discussed above, the study area does not have a high minority or low income population. Most workers commute outside the study area to their places of employment and income levels are similar to county averages. Construction, operation, and maintenance of the Restoration Project would not result in a disproportionate effect on a minority and/or low-income communities.

In addition, the lead agencies have engaged stakeholders for input at all levels of the project decision-making process to ensure early, accessible, and meaningful participation. By their participation in ongoing local watershed efforts, the agencies have included stakeholders in the decision-making process and have explored opportunities to address environmental justice within current statutory and regulatory structures.

Indian Trust Assets

Indian trust assets are legal interests in assets held in trust by the Federal government for Indian tribes or individuals. The trust relationship usually stems from a treaty, executive order, or act of Congress. Assets are anything that holds monetary value, and can be real property, physical assets, or intangible property rights. Examples of trust assets are lands, minerals, hunting and fishing rights, and water rights. Indian rancherias, reservations, and public domain allotments are frequently placed in trust status.

Reclamation's Indian trust asset policy states that Reclamation will carry out its activities in a manner that protects Indian trust assets and avoids adverse effects when possible. When Reclamation cannot avoid adverse effects, it will provide appropriate mitigation or compensation.

Affected Environment and Environmental Consequences

A search of the geographical information system coverage for California Indian reservations and public domain allotments failed to show any tribal or Indian lands in the vicinity of the Restoration Project area (Reclamation and USFWS 1999). Given the absence of Indian lands within or near the Restoration Project area, there will be no adverse effects to Indian trust assets from the Restoration Project.

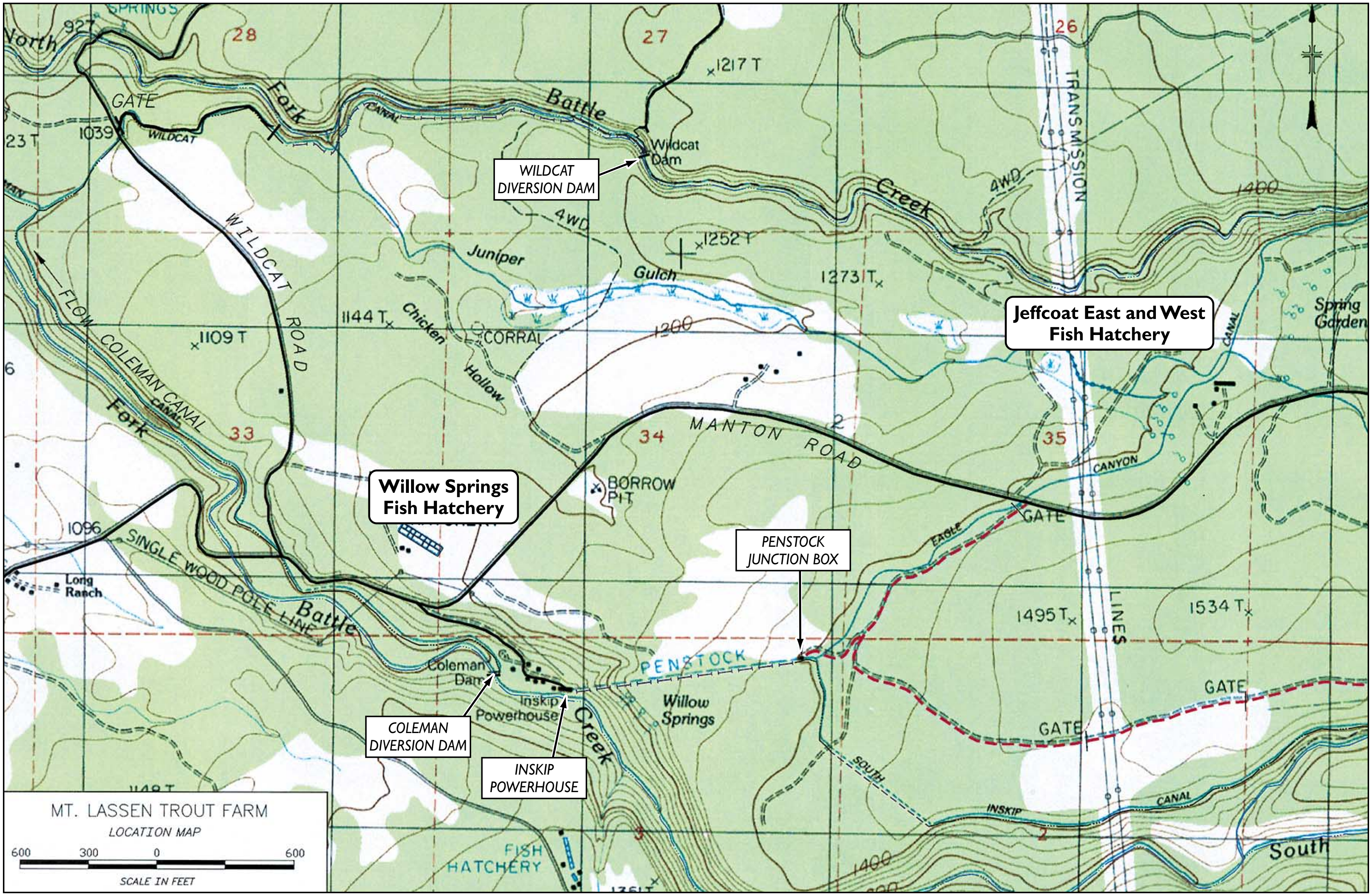

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Figure 4.16-3
Mount Lassen Trout Farm Hatcheries