MOKELUMNE WATERSHED AVOIDED COST ANALYSIS:

Why Sierra Fuel Treatments Make Economic Sense

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FOREST SERVICE U.S. DEPARTMENT OF AGRICULTURE

Chapter 6: Electricity and Water Utilities in the Mokelumne Watershed

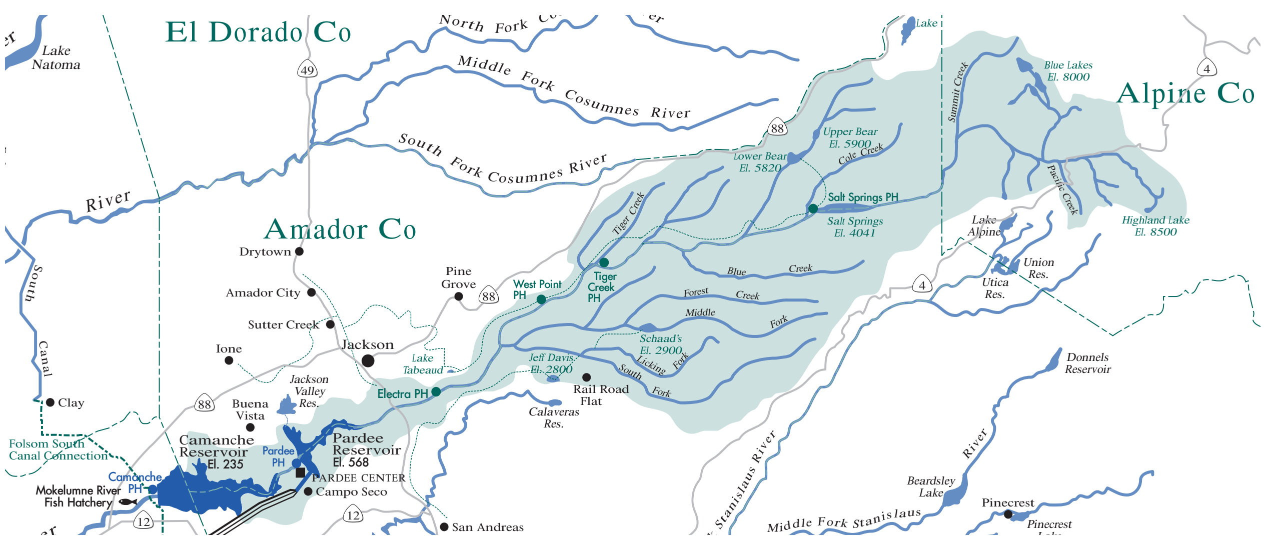
6.1 Context

In this section we use model results to describe the potential effects of the predicted postfire sediment movement in the Mokelumne River on reservoirs in the upper Mokelumne watershed as well as its subsequent effect on utility electricity generation and water supply, including potential costs. Pacific Gas and Electric (PG&E) and East Bay Municipal Utility District (EBMUD) both own and operate land and infrastructure in the Mokelumne watershed, with PG&E operations located upstream of EBMUD. Figure 6.1 shows the location of Pardee and Camanche reservoirs, which are owned and operated by EBMUD, as well as the upstream facilities that belong to PG&E. In addition to PG&E's operations, the Calaveras Public Utility District (CPUD) operates two reservoirs within the watershed (Schaad's and Jeff Davis), and the Amador Water Agency (AWA) operates two diversions. Potential fire/postfire impacts on CPUD and AWA operations were not part of the scope of this study.

PG&E's operations are oriented toward electricity generation, and EBMUD is primarily focused on water supply to its service area. The intricate system of storage, diversion, and conveyance throughout the watershed has allowed these utilities, and other water right holders, to provide reliable power and water to their respective customers.

In this section, we describe how and why reservoir storage capacity is valuable to PG&E and EBMUD. We use this understanding of how and why storage capacity is currently valuable to their operations and objectives to estimate the value of lost storage capacity.

Figure 6.1: Upper Mokelumne utility powerhouses and reservoirs



Source: EBMUD

EBMUD recognizes and acknowledges the importance of reservoir storage capacity in the Mokelumne watershed. In EBMUD's initial 2040 plan from 2009, in addition to investments in water conservation, water recycling, and new supplemental supplies, the District sought to include the potential increase in the Pardee Dam height to increase storage capacity for drought supply purposes. This would have flooded up to 1.4 miles of the upper portion of the river. A coalition successfully contested this plan in court. The revised 2011 plan kept some elements of the 2009 plan, such as water conservation, water recycling, and water transfers, but the revision did not include Pardee Reservoir expansion and instead considered other drought solutions, such as partnering in expanding Los Vaqueros Reservoir, a future expanded Lower Bear Reservoir, groundwater banking in Sacramento and San Joaquin Counties, and desalination.

PG&E representatives report that their organization is not concerned with reservoir sedimentation in the upper Mokelumne watershed, largely due to the fact that the bulk of their storage capacity is upstream of areas contributing sediment. In addition, Tiger Creek Afterbay, which provides storage and depth for diversions, can open gates that allow the flushing of sediment downstream, although federal licensing and state water quality requirements place some restrictions on the timing of such flushes, and an approval process typically takes time. PG&E reports that it has taken precautions to design and manage for fire and debris flows in terms of avoiding direct interruptions to their operations. Direct fire effects and sediment pulses from debris flows or major storms would generate short-term costs and likely interruptions in some operations, particularly if access were compromised. Large storm events can act as a natural flushing mechanism to move sediment and debris downstream from where they originally collect after eroding from the hillside or banks. And flushing sediment does not remove it from the river, but rather sends it downstream. Because of how Pardee Dam is constructed and due to its surrounding geography, it does not have the flushing capability of Tiger Creek Afterbay dam. This leads to a distributional issue in the long run, as sediment makes its way into Pardee Reservoir from the upstream channels and reservoirs.

In the remainder of this chapter, we identify the utility infrastructure in the upper Mokelumne watershed, including its operation and value, and discuss how these operations and values are affected by sediment associated with wildfire. We provide value estimates for the effects on electricity generation and water supply. This includes effects from a variety of scenarios because the utilities have multiple options for responding to sediment loads, such as changing operations, flushing sediment downstream, or dredging sediment.

6.2 Upper Mokelumne Utility Infrastructure

PG&E operates 12 dams and diversions in the upper Mokelumne, with a total initial storage capacity of 273 million cubic meters (Table 6.1). 6.5 million cubic meters of original storage capacity for PG&E is downstream of Salt Springs Reservoir and in the scope area for this study (hereafter referred to as the affected area). EBMUD has two major reservoirs in the affected area, with a total original storage capacity of 790 million cubic meters, nearly three times that of PG&E within the watershed, and more than 100 times the storage capacity in the affected area as PG&E.

Table 6.1: Historic capacity of reservoirs in the upper Mokelumne watershed

Dam name	Owner	Reservoir name	Original capacity (thousand cubic meters)	County	Year com-plete
Lower Blue Lake	PG&E	Lower Blue Lake	5,304	Alpine	1903
Upper Blue Lake	PG&E	Upper Blue Lake	9,251	Alpine	1901
Twin Lake	PG&E	Twin Lake	1,604	Alpine	1901
Meadow Lake	PG&E	Meadow Lake	6,365	Alpine	1903
Bear River	PG&E	Bear River	8,410	Amador	1900
Lower Bear River	PG&E	Lower Bear	60,132	Amador	1952
Salt Springs	PG&E	Salt Springs Reservoir	175,031	Amador	1931
Tiger Creek Regulator	PG&E	Tiger Creek Regulator	645	Amador	1931
Tiger Creek Forebay	PG&E	Tiger Creek Forebay	44	Amador	1931
Tiger Creek Afterbay	PG&E	Tiger Creek Afterbay	4,885	Amador	1931
Electra	PG&E	Electra Diversion	80	Amador	1947
Lake Tabeaud	PG&E	Lake Tabeaud	1,443	Amador	1901
Schaad Lake	CPUD	Schaad Reservoir	1,740	Calaveras	1939
Jeff Davis	CPUD	Jeff Davis Reservoir	1,750	Calaveras	1973
Pardee	EBMUD	Pardee Reservoir	259,031	Amador	1929
Camanche	EBMUD	Camanche Reservoir	530,397	San Joaquin	1963

Source: UC Davis Center for Watershed Sciences. 2013. Hydra.ucdavis.edu.

For electricity generation, PG&E has four powerhouses in the affected area, for a total of 214.5 megawatts (MW) of generation capacity, compared to EBMUD's 34 MW of capacity (Table 6.2). PG&E primarily relies upon precipitation and storage capacity upstream of all four of its powerhouses for its supply. PG&E powerhouses depend mostly on off-channel surface and subsurface conveyance within the affected project area, totaling 54 km in length (Table 6.3).

Table 6.2: Powerhouses in the upper Mokelumne watershed

Dam name	Owner	Year online	Storage reservoir	capacity (MW)
Salt Springs	PG&E	1931	Salt Springs	44
Tiger Creek	PG&E	1931	Tiger Creek Regulator	58
West Point	PG&E	1948	Tiger Creek Afterbay	14.5
Electra	PG&E	1948	Lake Tabeaud	98
Pardee	EBMUD	1930	Pardee	23.6
Camanche	EBMUD	1963	Camanche	10.6

Sources: PG&E and the UC Davis Center for Watershed Sciences. 2013. Hydra.ucdavis.edu.

Table 6.3: PG&E conveyance structures in the upper Mokelumne watershed

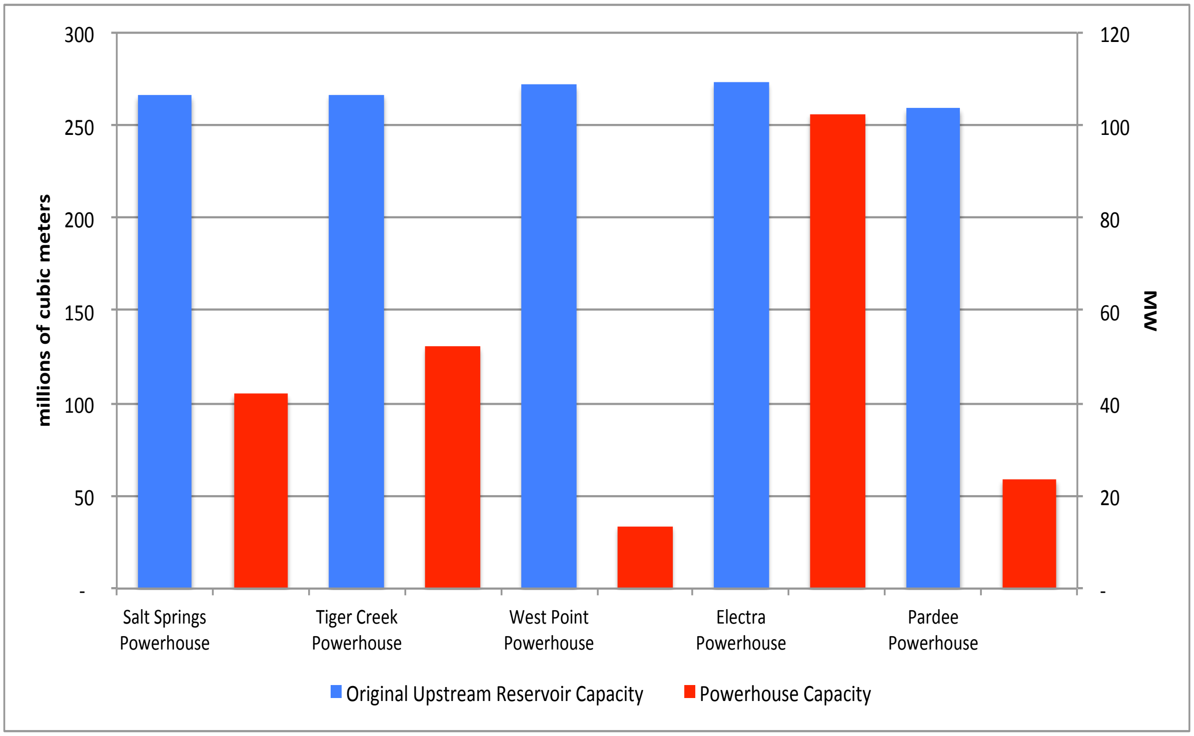
Conveyance	Length (km)	Start-End
Salt Springs Tunnel & Penstock	3.6	Lower Bear Reservoir – Salt Springs Powerhouse[1]
Upper Tiger Creek (canal)	26.6	Salt Springs Powerhouse – Tiger Creek Regulator Reservoir
Tiger Creek (canal)	3.8	Tiger Creek Regulation Reservoir – Tiger Creek Forebay
Tiger Creek Penstock	1.4	Tiger Creek Forebay – Tiger Creek Afterbay
West Point Tunnel & Penstock	4.3	Tiger Creek Afterbay – West Point Powerhouse
Electra Tunnel	13.6	West Point Powerhouse – Lake Tabeaud
Electra Penstock	0.9	Lake Tabeaud – Electra Powerhouse

Source: Foothill Conservancy and UC Davis Center for Watershed Sciences. 2013. Hydra.ucdavis.edu.

Based on the effects of wildfire and fuel treatment described in Chapter 3, we focus our assessment of effects for electricity generation on the four PG&E powerhouses and EBMUD's at Pardee Dam. PG&E and EBMUD do not manage their infrastructure in conjunction (but they do coordinate some operations) and they have different primary objectives (electricity vs. water), consequently we attribute only EBMUD-controlled storage capacity for use in its electricity operations at Pardee (Figure 6.2). Figure 6.2 also demonstrates that PG&E's storage capacity is almost completely contributed by Salt Springs Reservoir and upstream (i.e., upstream reservoir capacity for Electra Powerhouse is the summation of the capacity of reservoirs upstream of the powerhouse – the fact that its capacity only slightly exceeds that of Salt Springs indicates that there is not much storage between Salt Springs Powerhouse and Electra Powerhouse). Consequently, storage located in the affected area can be used for operations and daily management, but it does not make a significant contribution to PG&E's ability to capture peak flows for later use at times of increased generation value.

[1] Salt Springs Powerhouse has two units, one of which is fed via the penstock from Cole Creek and Lower Bear Reservoir, while the other is fed directly from Salt Springs Reservoir through the dam.

Figure 6.2: Powerhouse and original reservoir capacity

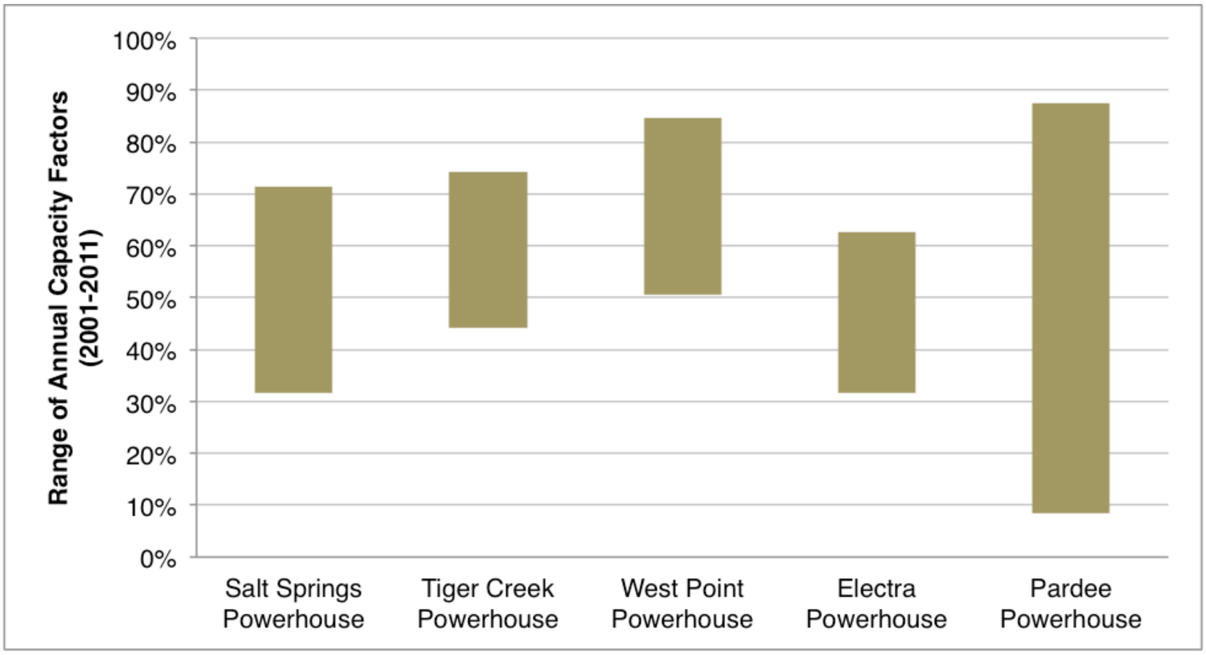


Source: ECONorthwest, with data from UC Davis Center for Watershed Sciences. 2013. Hydra.ucdavis.edu.

6.3 Upper Mokelumne Electricity Operations

The infrastructure described above outlines electricity generation opportunities for PG&E and EBMUD. The U.S. Energy Information Administration (EIA) provides data on the historical operation of these facilities. In Figure 6.3, the annual capacity factor is defined as the amount of electricity a powerhouse generates in a year divided by the amount of electricity that powerhouse could potentially generate over that time period. The difference between potential generation and actual generation is often due to the available water supply to produce energy combined with legal and operational constraints on generation and diversions. For the PG&E powerhouses, the lowest capacity utilization over the decade occurred in 2007 and 2008; for Pardee Powerhouse, the lowest utilization was in 2002. Dry years typically correspond with low utilization and wet years correspond to high utilization, although water availability and capacity factor do not perfectly correlate. All five powerhouses have experienced a wide range of operations, with each experiencing years of 50% or less capacity factor from 2001 to 2011, and none reaching 90% or above in a year. This demonstrates that increased available water supply would generally provide increased energy generation potential throughout the affected system. Other factors in the management of these systems that can lower the capacity factor for a given powerhouse include planned or forced outages and equipment maintenance and upgrades.

Figure 6.3: Annual capacity factors



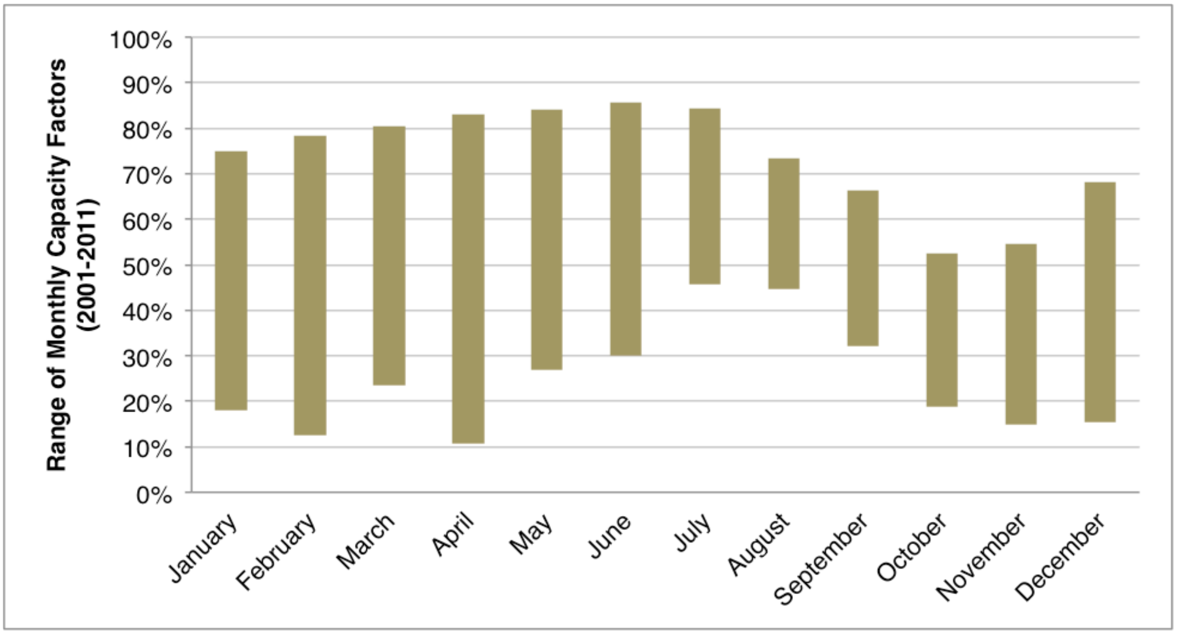
Source: ECONorthwest, with data from U.S. Energy Information Administration. Form EIA-923 Detailed Data. Retrieved from http://www.eia.gov/electricity/data/eia923/index.html. June 2013.

When aggregating the five powerhouses and analyzing the overall monthly energy generation from 2001 to 2011, May through July is the period with the highest utilization (Figure 6.4). Total annual electricity generation for the five powerhouses ranges from 695,000 megawatt hours (MWh) in 2007 to twice that—1.4 million MWh—in 2005 and 2006 (Figure 6.5). The total capacity for generation of these five powerhouses is 2.05 million MWh annually, although late summer water availability and management needs make this level impossible to achieve.

Monthly capacity factors are based on both monthly fluctuations in demand for electricity as well as monthly fluctuations in the available supply of water to generate it. However, it is difficult to directly align market rates and water availability because PG&E manages a complex network of varied electricity sources and faces opportunities to purchase and sell electricity generated outside of California. Alignment attempt are further complicated by the broader California energy market and the California Independent System Operator.

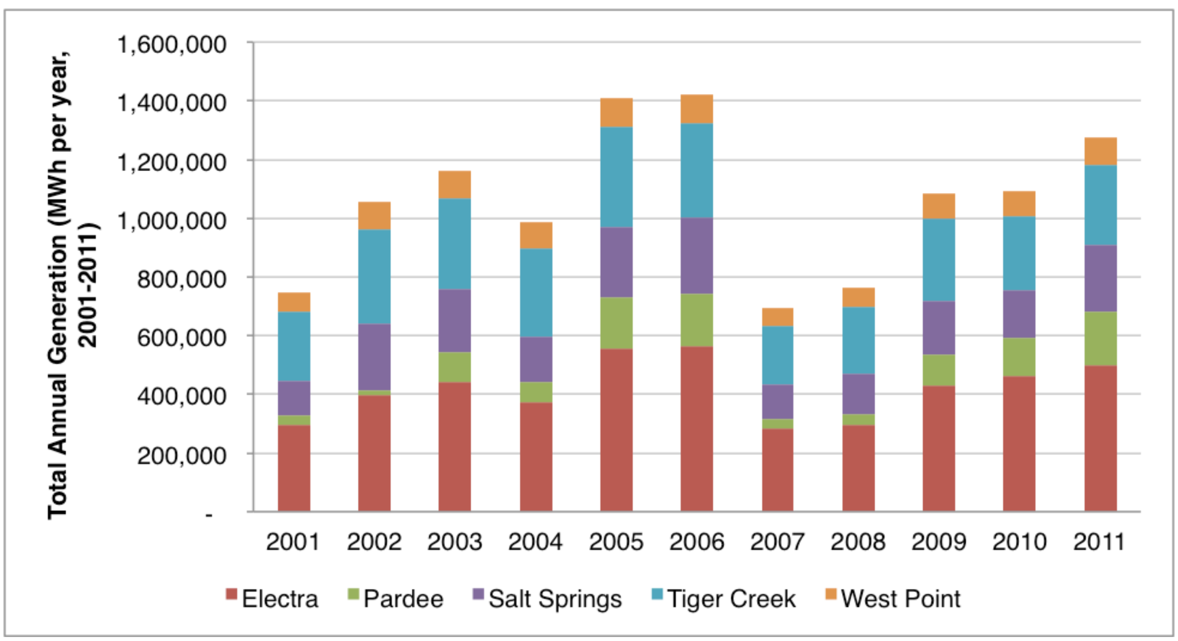
Electra Powerhouse is the largest of the five powerhouses and it consistently generates the most electricity (Figure 6.6). In normal and wet water years, all five powerhouses operate at a high capacity factor from March through June then drop off through the rest of the summer and fall. There is no substantial storage downstream of Salt Spring Reservoir for PG&E; the water flowing out of Salt Springs and its powerhouse is the primary source of water for generation in the subsequent downstream powerhouses that PG&E operates. Therefore, generation across the four PG&E powerhouses generally correlates, although the relatively small diversion and storage opportunities below the Salt Springs powerhouse allow PG&E some flexibility to lag generation downstream to a minor degree. Storage for EBMUD's power generation is largely based on storage within Pardee Reservoir.

Figure 6.4. Monthly capacity factors



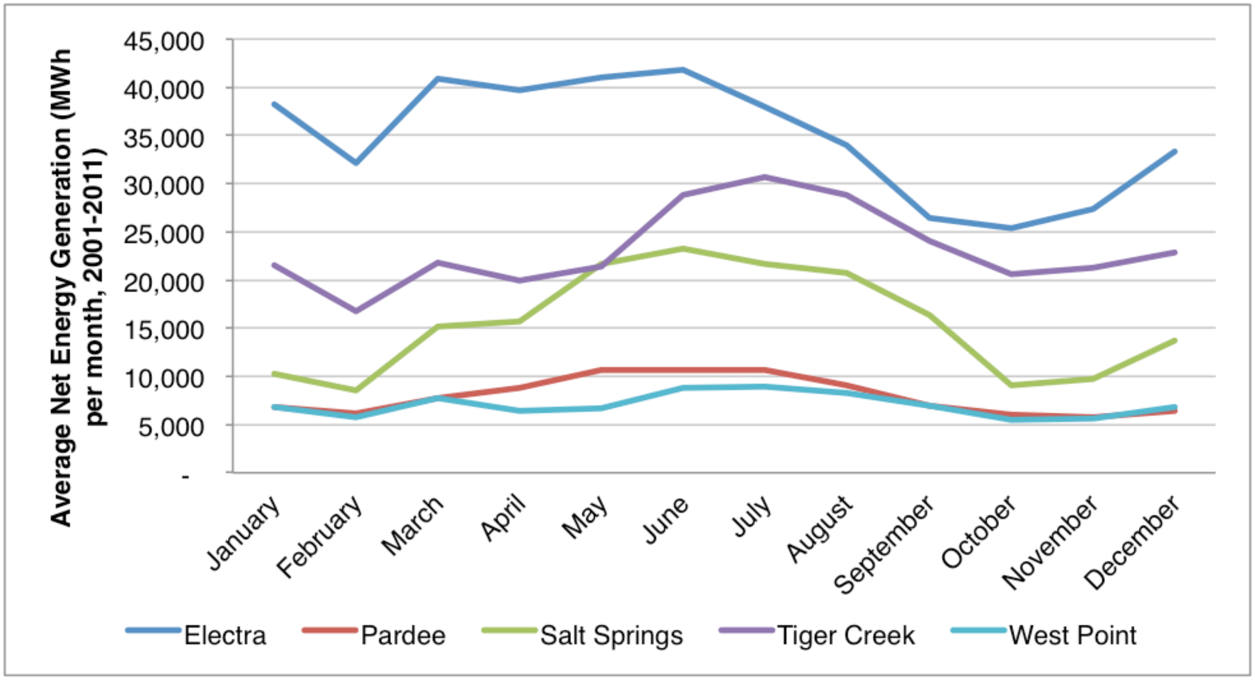
Source: ECONorthwest, with data from U.S. Energy Information Administration. Form EIA-923 Detailed Data. Retrieved from http://www.eia.gov/electricity/data/eia923/index.html. June 2013.

Figure 6.5. Annual electricity generation (of 2.05 million MWh annual capacity)



Note: Dry years: 2001, 2004, 2007, and 2008; below-normal years: 2002, 2003, 2009, and 2010; above-normal years: 2005; wet years: 2006 and 2011.
Source: ECONorthwest, with data from U.S. Energy Information Administration. Form EIA-923 Detailed Data. Retrieved from http://www.eia.gov/electricity/data/eia923/index.html. June 2013.

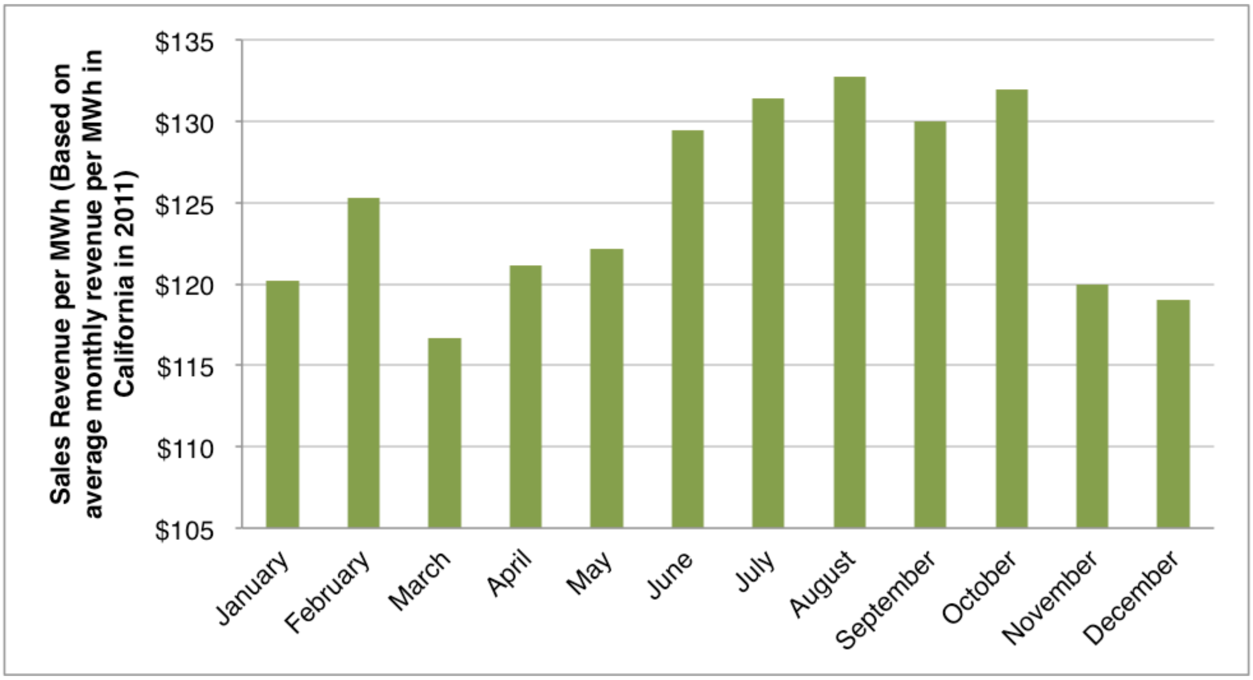
Figure 6.6: Monthly average electricity generation



Source: ECONorthwest, with data from U.S. Energy Information Administration. Form EIA-923 Detailed Data. Retrieved from http://www.eia.gov/electricity/data/eia923/index.html. June 2013.

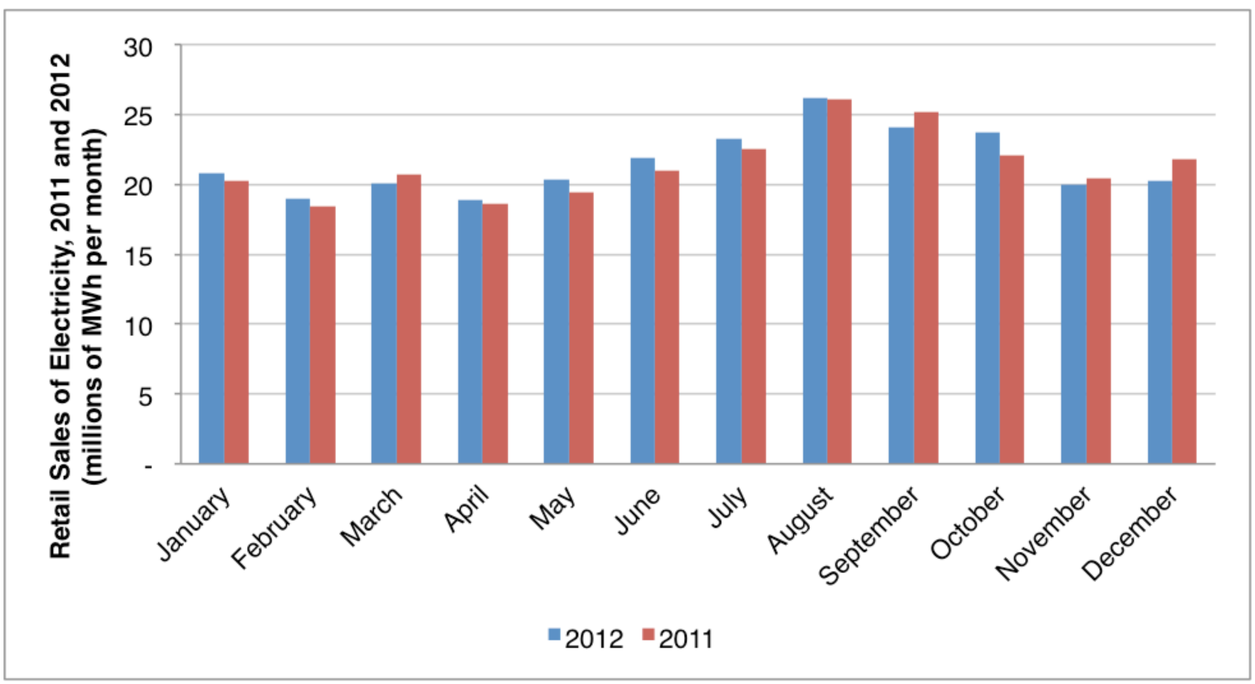
Overall, Figures 6.3 - 6.6 demonstrate that late summer water availability is likely insufficient for the five powerhouses to generate their maximum electricity potential, and in general, they experience peak usage in late spring through early summer. Demand and associated value, however, peak later in summer. After satisfying other regulatory and contractual requirements, PG&E would not be able to as readily address peak energy demand with a reduction in storage capacity. For example, 2011 data on the average monthly sales revenue to electricity generators demonstrates this peak in August, with high demand continuing through October (Figure 6.7). The electricity rate in Figure 6.7 is equal to the monthly sum of all revenue from end users (i.e., ratepayers) in California in 2011, divided by the total amount of electricity they used, in MWh. Similar to the peak in rates or prices, total electricity consumption across all consumers in California peaked in August, followed by September, in 2011 and 2012 (Figure 6.8).

Figure 6.7. Electricity rates by month, 2011



Source: ECONorthwest, with data from U.S. Energy Information Administration. Form EIA-923 Detailed Data. Retrieved from http://www.eia.gov/electricity/data/eia923/index.html. June 2013.

Figure 6.8. Monthly electricity consumption by all sectors in California, 2011 and 2012



Source: ECONorthwest, with data from U.S. Energy Information Administration. 2013. Electric Power Monthly. http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_4_a. Accessed June 2013.

The EIA provides national averages for operating costs by electricity generation technology, but does not include capital costs. For hydroelectric, from 2001 to 2011, the average operating cost per MWh was $4.50 and the average maintenance cost per MWh was $3.16, for total operating expense of $7.67 per MWh (US EIA 2011). These operating costs for electricity generation are substantially below the market sale rate per MWh, particularly at times of highest demand in late summer to early fall. This suggests the importance of these five Mokelumne powerhouses maintaining their current generation output as well as release timing flexibility, especially in the face of an uncertain future of climate change. The predictions for the Sierra Nevada, as we describe in Chapter 9, indicate that natural storage in snowpack will likely decline and the region will likely face a less predictable precipitation pattern. Hydropower provides roughly 15% of electricity generation in California (US EIA 2012).

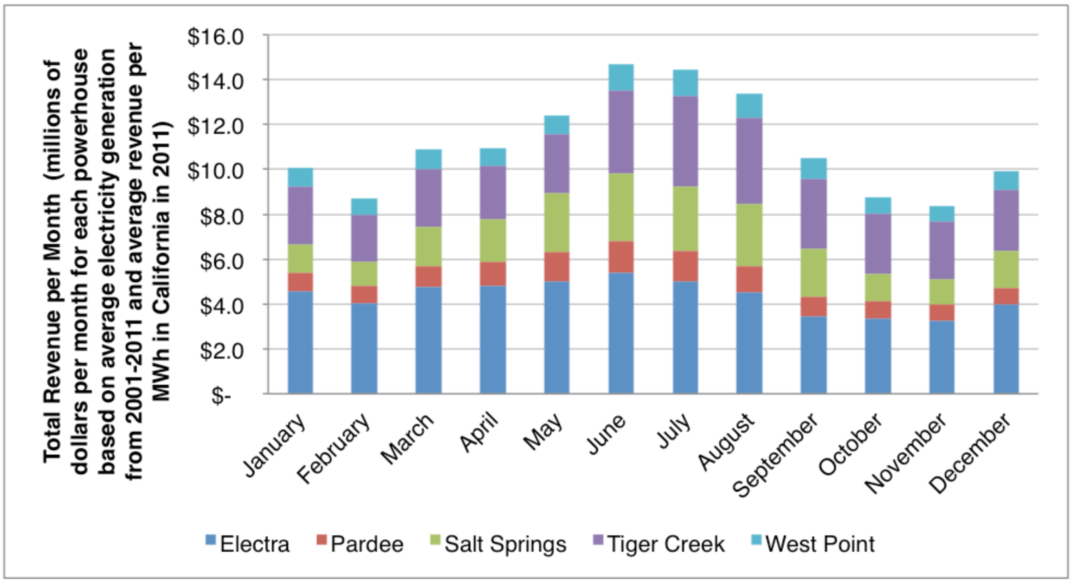
EBMUD's primary goal is water delivery; power generation is towards the bottom of the District's operating priorities. Optimizing for power generation would require moving water through EBMUD's powerhouses and out to Camanche Reservoir, rather than into the aqueduct to the East Bay. EBMUD has obligations below Camanche Reservoir to meet specific cold-water temperature guidelines, which, especially in the middle of summer, can require supplemental cold water from Pardee to Camanche. Once those requirements are met (water delivery to the East Bay and cold downstream water), EBMUD then optimizes for power production to achieve the best price for power sold. In short, EBMUD has very limited ability to modify its current operations and it will not put power revenue above water supply and environmental obligations.

To consider the difference in revenue for PG&E and EBMUD from changes in storage capacity, we must identify how the timing of electricity generation could be affected. In general, the preceding discussion suggests that PG&E and EBMUD generate electricity from the five powerhouses earlier than would be optimal given market demand. Consequently, decreases in storage capacity shift the share of electricity they can generate from late summer to spring and early summer from the water and snowmelt they are unable to store. We assume there is currently sufficient storage capacity and flexibility such that the changes in capacity described in Chapter 3 would not be sufficient to change operations under current precipitation patterns (versus under predicted climate change conditions). However, PG&E and EBMUD are constrained by various operational and environmental requirements associated with their hydropower licenses that constrain their ability to divert and deviate from the natural flow regime.

This analysis considers a 30-year timeframe of costs and benefits, and the climate chapter (9) describes how potential shifts in precipitation patterns, in combination with loss of storage, could affect overall annual generation. For now, however, we consider the difference in revenue over the course of a contemporary year, ignoring operating costs because they would be similar during any season. For this analysis we do not assume that the change in generation would be sufficient to affect rates. But at some scale across the Sierra Nevada, perhaps as a whole, if hydropower generation opportunities at that scale are insufficient during seasonal peaks, other energy sectors would need to fill the gap, likely leading to higher overall prices.

Based on historical generation and rates, monthly revenue from the five powerhouses ranges from roughly $8 million to nearly $15 million (Figure 6.9). Total monthly revenue captures daily peak and off-peak generation. Daily maximum temperature is closely correlated to daily peak demand in California (CEC 2010). The late summer periods with greatest average electricity demand also have the highest daily peaks. Because hydropower plays an important role in satisfying daily peak demand, the differences in monthly averages likely underestimate the seasonal value of storing water for generation during late summer.

Figure 6.9: Average monthly revenue generation by powerhouse



Source: ECONorthwest, with data from U.S. Energy Information Administration described earlier.

These estimates are based on average per-month electricity generation from 2001-2011, as well as monthly estimates of average revenue per MWh in 2011. The per-MWh revenue estimates represent an average of all electricity sales divided by the total MWh sold for each month in the State of California. In the next section we consider how modeled changes in erosion and sediment accumulation, with and without fuel treatment, could affect the ability of PG&E and EBMUD to optimize generation and revenue, where appropriate.

6.4 Sediment Effects on Electricity Generation

Based on the soils of the upper Mokelumne watershed and the reservoirs within it, it is likely that less than 5% of the sediment that reaches a reservoir in this basin would stay suspended in the reservoir's water column and flow out of the dam and further on downstream (US BOR 2006). The sediment delivery ratio discussed in Chapter 3, combined with the roughly 5% pass-through of material downstream, would mean that, of the sediment moving off the hillside, 23.75% would be expected to settle out in the next downstream reservoir. As previously discussed, Tiger Creek Afterbay is equipped with a slucing valve at the bottom of the dam that allows increased flushing of sediment out of the Afterbay. The extent to which PG&E is able to use this valve is regulated by their license and water quality regulations. Pardee Dam has no such valve, and therefore, under current circumstances, approximately 95% of the sediment that enters the reservoir would be expected to stay within it, reducing capacity for water storage.

As we demonstrated in Chapter 3, the Five Fire scenario and the resulting analyses suggest that fuel treatments would decrease the subwatershed erosion and sediment delivered to Tiger Creek Afterbay and Pardee Reservoir. We use the estimates from Table 3.8 to consider the change in storage capacity and overall sediment load with and without fuel treatments for these two key elements of the EBMUD and PG&E operations in the upper Mokelumne watershed. The first year after the fires would see an estimated loss of 21,000 cubic meters of capacity for Tiger Creek Afterbay, and 86,000 cubic meters for Pardee Reservoir (see Chapter 3 for model results and Appendices A-E for the model parameters used). After the 30 years described in the Five Fire scenario, the difference in decreased storage capacity as a result of sediment accumulation could be an estimated 24,000 cubic meters for Tiger Creek Afterbay (Table 6.4) and 102,000 cubic meters for Pardee Reservoir (Table 6.5).

Table 6.4: Tiger Creek Afterbay capacity with and without fuel treatments (cubic meters)

No treatments	Sediment erosion from hillsides	Sediment that reaches the reservoir	Remaining water storage
Year 0	-	-	1,158,974[2]
Year 1	158,790	41,285	1,117,689
Year 2	36,045	9,372	1,108,317
Year 30	277,107	72,048	1,036,269

Treatments	Sediment erosion from hillsides	Sediment that reaches the reservoir	Remaining water storage	Water storage protected by treatments
Year 0	-	-	1,158,974	-
Year 1	78,614	20,440	1,138,534	20,846
Year 2	20,849	5,421	1,133,114	24,797
Year 30	280,313	72,881	1,060,232	23,963

Note: *Water storage protected* identifies the change in sediment effects on reservoir capacity due to fuel treatments. Year 1 refers to the year the fires occur and when most of the sediment erodes. Year 2 sediment erosion is still above background levels (years 3-30), but much less than Year 1. Sediment that reaches the reservoir is calculated by multiplying the sediment erosion from hillsides amount by the Sediment Delivery Ratio (SDR). The slight decrease in storage protected between Year 2 and Year 30 is because the treatments lead to a small increase in background sedimentation over no treatments, therefore in years 3-30 the treatment areas are slightly more erosive. See Table 3.8 for more information.

These 30-year sediment accumulation totals with no treatments represent 11% of current capacity for Tiger Creek Afterbay and 0.098% of current capacity for Pardee Reservoir. If the average family in California uses 192 gallons of water a day, after 30 years the treatments would have protected enough storage to meet the yearly water needs for more than 375 families. The reductions in fuel-treatments-related sediment accumulation in these two reservoirs represent 2.1% for Tiger Creek Afterbay and 0.042% for Pardee Reservoir. Considering the total upstream storage capacity for PG&E's four powerhouses and assuming a 2% loss of storage capacity based on sedimentation rates from calculations following methods by Minear and Kondolf (2009), the loss of capacity with

[2] From bathymetric survey conducted in September, 2013. See Appendix F for more details.

no treatments represents 0.046% of PG&E storage capacity upstream of its four powerhouses. The avoided sedimentation represents 0.009% of PG&E's capacity.

Table 6.5: Pardee Reservoir capacity with and without fuel treatment (cubic meters)

No treatments	Sediment erosion from hillsides	Sediment that reaches the reservoir	Remaining water storage
Year 0	-	-	240,115,856[3]
Year 1	621,462	155,366	239,960,491
Year 2	117,454	29,364	239,931,127
Year 30	202,583	50,646	239,880,481

Treatments	Sediment erosion from hillsides	Sediment that reaches the reservoir	Remaining water storage	Water storage protected by treatments
Year 0	-	-	240,115,856	-
Year 1	278,940	69,735	240,046,121	85,631
Year 2	48,608	12,152	240,033,969	102,842
Year 30	206,448	51,612	239,982,357	101,876

Note: *Water storage protected* identifies the change in sediment effects on reservoir capacity due to fuel treatments. Year 1 refers to the year the fires occur and when most of the sediment erodes. Year 2 sediment erosion is still above background levels (years 3-30), but much less than Year 1. Sediment that reaches the reservoir is calculated by multiplying the sediment erosion from hillsides amount by the Sediment Delivery Ratio (SDR). The slight decrease in storage protected between Year 2 and Year 30 is because the treatments lead to a small increase in background sedimentation over no treatments, therefore in years 3-30 the treatment areas are slightly more erosive. See Table 3.8 for more information.

Based on the bathymetric survey data, the average erosion rate may be higher than our modeling suggests. Our models of hillslope erosion and debris flows did not include channel erosion or chronic sources of sediment, such as roads, which would be a likely source of coarse sediment (bedload) that has accumulated in the reservoirs. The results of the bathymetric survey indicate that over the course of the Afterbay's 82 years of operation, 3,725,615 cubic meters of sediment have accumulated, or 45,434 cubic meters a year. This is significantly higher than the roughly 10,000 cubic meters a year our modeling calculates as background. Naturally, over the course of 82 years, the watershed has seen numerous fires, road failures, and landslides; the 45,434 cubic meters a year is an average that evens out annual variations in erosion. However, if the previous 82 years are any guide to the next 30 years, and there were no change in the percentage of sediment that is flushed from the Afterbay, it would lose all of its capacity in approximately 26 years. Given the number of assumptions inherent in such a projection, along with the number of options PG&E has before them to flush sediment downstream, this scenario is not included in the economic analysis. Instead, it is included here to suggest that operational strategies used during the previous 80 years may need to be adjusted at some point in the next 30 years, and a change in

[3] Based on sedimentation rates calculated from a 1995 bathymetric survey performed by EBMUD, and then applied to the reservoir through 2012 to estimate current capacity.

operations due to sediment loading may have negative consequences to either PGE or EBMUD, or both.

Similarly for Pardee Reservoir, using the bathymetric results from the 1995 survey, which, when averaged over the 66 years from the build date to the survey, indicates an average of 225,183 cubic meters of sediment deposition a year, or a 0.1% yearly loss in capacity. Multiplying out to the end of our 30-year scenario (or 48 years from 1995), results in a 2043 capacity of 233,360,368 cubic meters, or a loss of 25,670,852 cubic meters of water. This is would represent a greater loss in capacity than our current modeling suggests, and EBMUD has fewer operational options to remove sediment from their reservoir than PG&E does on Tiger Creek Afterbay.

While it is evident that Tiger Creek Afterbay doesn't play an important overall role in storage, it does play a role in the operation of West Point Powerhouse. A short-term loss of use of Tiger Creek Afterbay could threaten the short-term ability to use West Point Powerhouse and its associated electricity and revenue generation. This would likely fall within the scope of PG&E's standard Winter Operating Plan, which calls for the shutdown of powerhouses during high-flow events to protect their infrastructure. Such an outage would last a few hours or days and usually occurs during low-demand periods where the loss in generation is therefore negligible. With a diversion at West Point Powerhouse, Electra Powerhouse can continue to generate electricity without the use of water from the Tiger Creek Afterbay diversion, capturing the water that is released through the Tiger Creek Dam.

From May 1st through June 15th (with a potential extension to July 4th), the Mokelumne Environmental Resource Committee (ERC), that oversees compliance with PG&E's Federal Energy Regulatory Commission (FERC) license, has agreed to provide recreational boating flows from Tiger Creek Afterbay for the Tiger Creek Dam Run on the weekends. Should the water storage capacity in Tiger Creek Afterbay diminish below a certain level, PG&E may be unable to meet its FERC license requirement to supply boating water flow rates for the Tiger Creek Dam Run. This would likely manifest in the inability to provide boating flows on consecutive days in a row, and would therefore affect the recreational use of the river. At such time, PG&E would either need to adjust operations to meet the boating flow requirements, which could affect generation, or be out of compliance on its FERC license.

The percentages of overall change in storage capacity are relatively low. We use them below to estimate effects on energy generation. First though, we consider the costs of dredging these sediment volumes. Later, we use them to consider the value of lost water storage for municipal water supply.

6.5 Sediment Dredging Costs

One of the few options available to PG&E and EBMUD to reclaim storage in their reservoirs would be to dredge the sediment. PG&E reports that they rarely use sediment dredging across their full range of California operations and that they have not conducted sediment dredging in the Mokelumne watershed. They have made clear that they have no expectations of conducting dredging there in the future. Still, dredging projects have recently been necessary for a number of reasons in California, as it is the only option for sediment management under some circumstances. We consider here what the costs of dredging would be but we are not suggesting that sediment dredging would be the most appropriate sediment management strategy. Rather, it is to provide context on other options to manage sediment in the upper Mokelumne. It also provides perspective on the potential cost of an unprecedented scenario that could require dredging to deal with a blockage or fouling of infrastructure, or if sediment loads eventually surpass a threshold in receiving bodies where they cannot be managed by other means.

A recent review of potential actions for ecosystem management in the Sacramento-San Joaquin Delta used an estimate of $6.50 per cubic meter for dredging costs (Medellin-Azuara et al. 2013). As part of the Klamath Hydroelectric Settlement Agreement, parties have investigated sediment-dredging costs for dams on the Klamath River, finding that removing 5 million cubic meters of deposited sediment would cost $97 million, or $20/cubic meter (Wright 2011). Additionally, they calculate that design engineering, construction oversight, legal fees, land fees for deposition, and similar actions would add an additional 25-35% in costs, bringing the full cost of dredging to roughly $26/cubic meter.

Assuming a dredging cost of $26/cubic meter, hypothetical dredging activities equate to a year 1 dredging cost for Pardee Reservoir under the no-treatment scenario of $4.1 million and for Tiger Creek Afterbay of $1.1 million (Table 6.6). This calculation assumes complete dredging of the volume of sediment that would have been avoided with fuel treatments (treatment difference in Table 6.4 - 5). If the true dredging cost of these reservoirs differs from our estimates, the changes would relate to the undiscounted costs in a 1-to-1 ratio (e.g., doubling the per unit dredging cost would double these total dredging cost estimates). Under a 30-year scenario of dredging expenses, the net present value of avoided dredging costs today would be $0.6 million for Tiger Creek Afterbay and $2.6 million for Pardee Reservoir.

Similar to other Sierra Nevada watersheds, the Mokelumne watershed has a history of gold mining, which used mercury as a tool to extract gold. In many Sierra reservoirs, this has led to the deposition of mercury in their sediment, which can complicate dredging. Plans to remove mercury-laden sediment from Combie Reservoir on the Bear River in the central Sierra Nevada call for $6.9 million of funding to remove 46,000-92,000 cubic meters of sediment containing 23 to 68 kilograms of mercury (Nevada Irrigation District 2011). This equates to $75-149/cubic meter, although more recent project descriptions suggest a goal of 153,000 cubic meters of sediment removal, which would equate, if costs don't similarly increase, to a cost of $45/cubic meter (Nevada Irrigation District 2012). Pardee Reservoir has been listed by the State of California as a 303d impaired waterbody due to mercury presence,[4] so the higher dredging costs are likely to apply there. To our knowledge, the sediment of Tiger Creek Afterbay has not been tested for the presence of mercury, although the fact that another reservoir downstream of it has been listed suggests that mercury is present in the watershed.

[4] http://www.waterboards.ca.gov/water_issues/programs/mercury/reservoirs/

If Mokelumne watershed sediment dredging costs turn out to be closer in cost to those of Combie Reservoir dredging costs, due to contamination from past mining operations, the undiscounted results would correspondingly increase. For example, at a dredging cost of $125/cubic meter, the first-year dredging cost would be $2.6 million for Tiger Creek Afterbay and $11 million for Pardee Reservoir.

Table 6.6: Sediment dredging costs ($ millions)

Reservoir, subwatershed		Year 1	Year 2	Year 30 total (undiscounted)	Year 30 total (discounted 3%)
Tiger Creek Afterbay	No treatment	$1.1	$0.2	$3.2	$2.5
	Treatment	$0.5	$0.1	$2.6	$1.9
	Difference	$0.5	$0.1	$0.6	$0.6
Pardee	No treatment	$4.1	$0.8	$6.2	$5.5
	Treatment	$1.8	$0.3	$3.5	$2.9
	Difference	$2.2	$0.5	$2.7	$2.6

Note: these costs are not included in final benefit compilation (conclusion) but rather are used for consideration and comparison.

6.6 Electricity Generation Costs of Fire and Sediment

Electricity generation in the upper Mokelumne can potentially be affected by fire in many ways. Wildfire can make it unsafe to operate transmission lines and therefore require that powerhouses be shut down for brief periods, and it can make powerhouses inaccessible by staff during and immediately following fire. Wildfire can lead to burn debris, landslides, and erosion fouling or damaging transmission, water conveyance, and other infrastructure. Also, flume structures have been damaged and require repair. PG&E reports that they coordinate closely with wildfire incident command teams to manage electricity generation and transmission infrastructure during wildfire events in ways that cause the shortest possible periods of disruption in operation.

Conversations with PG&E staff suggest that they do not expect significant disruptions in electricity generation due to sediment, and they do not expect loss of generation capacity or flexibility. We include the discussion in this section to consider the scale of risk associated with wildfire-based sediment effects in the project area for utilities. We do not include these calculations in the benefit/avoid cost results for the conclusion.

As a first consideration if no dredging occurs: there will be a loss of capacity for Pardee Reservoir and Tiger Creek Afterbay, although the true accumulation of sediment in the Afterbay would depend on flushing rates. If PG&E chooses to flush the sediment downstream via the sluicing valve, or if sediment is naturally flushed downstream during storm events, some percentage of it would eventually settle out into Pardee Reservoir. Consequently, the allocations of costs for electricity generation are somewhat a distributional issue, because if the sediment is flushed downstream, the costs shift to EBMUD as lost storage for municipal water supply. For this analysis, we assume any effect of sediment transported to Tiger Creek Afterbay would be experienced by PG&E operations in terms of storage capacity. In practice it might occur in the form of delays and loss of use for West Point powerhouse, as well as increased operation expenses as we discuss later.

Loss of storage capacity in a hydropower system would force a utility to generate electricity based solely on when water is available (natural runoff) rather than when value for that electricity is at its highest. Peak runoff for the Mokelumne is typically April through May. Therefore, if storage capacity is impacted by sediment deposition, it could force a proportional shift of electricity generation from the optimal time of generation based on demand and market rates (August) to the months of lower overall electricity value for hydropower during runoff (April & May). Utilizing 2011 sales revenue per MWh (Figure 6.7), the difference in revenue from electricity generated during April versus August would equate to 9% less revenue per MWh. We therefore estimate that the portion of water that cannot be stored because of lost storage capacity must be sold for 9% less revenue.

PG&E is able to manage storage capacity for powerhouses primarily via Salt Springs Reservoir, upstream of the affected area. EBMUD manages water in Pardee Reservoir primarily for water supply; electricity generation is a lesser priority. For future consideration and study, but not for inclusion in our the final benefit/avoided cost compilation, we take the share of lost storage to PG&E and EBMUD due to the Five Fire Scenario and assume it would lead to a proportional share of electricity generation that would experience the 9% decrease in revenue as discussed above. Therefore, we take the total revenue generated by both PG&E and EBMUD, multiply this by the share of storage capacity lost to sediment, and multiply this amount by 91% to identify the reduced revenue amount. We do this for each year, as the loss of storage capacity continues to have cumulative effects. It is important to focus on the difference in revenue with and without treatment to net out operating costs. We use data supporting Figure 6.9, with average annual generation from 2001 to 2011, and 2011 rates. We use revenue for Electra and West Point powerhouses for PG&E, and Pardee for EBMUD. Based on these data, average annual revenue for PG&E would be $63 million and $12 million for EBMUD, from the affected powerhouses.

The magnitude of the value of lost potential for peak electricity generation corresponds to the small share of storage capacity affected by the modeled sediment influx (Table 6.7). The 30-year undiscounted (total) preserved revenue generation potential for PG&E from the treatment scenario would be $157,000, or $103,000 at a 3% discount rate. The corresponding amounts are $139,100 and $90,700, respectively, for EBMUD.

Table 6.7: Gross revenue from electricity generation lost due to sedimentation ($ thousands)

Utility		Year 1	Year 2	Year 30 total (undiscounted)	Year 30 total (discounted 3%)
PG&E	No treatment	$8.9	$10.9	$551.6	$336.1
	Treatment	$4.4	$5.6	$394.4	$233.4
	Difference	$4.5	$5.4	$157.1	$102.7
EBMUD	No treatment	$7.1	$8.4	$284.6	$182.0
	Treatment	$3.2	$3.7	$145.4	$91.3
	Difference	$3.9	$4.7	$139.1	$90.7

Note: these costs are not included in final benefit compilation (conclusion) but rather are used for consideration and comparison.

This analysis assumes that the same total annual amount of electricity would be generated with lost storage capacity, because monthly capacity factors demonstrate substantial excess capacity, particularly during spring. If utilities reach their storage limits and are at maximum generation capacity, reduced storage would then equate to loss of generation for the corresponding volume, rather than generation at a time of lower rates.

Another point of relevance is the role of Tiger Creek Afterbay as the primary intake source for West Point Powerhouse and Electra Powerhouses. As such increased sedimentation in the Afterbay could eventually lead to a loss of ability to operate the water intakes that supply those powerhouses, at least for temporary periods. This especially pertains to West Point Powerhouse, as Electra Powerhouse does have the ability to divert instream flows for power generation. The monthly average revenue from 2001 to 2011 for the downstream PG&E powerhouses ranged from $3.3 to 5.4 million a month for Electra and $0.7 to 1.2 million for West Point. Taking these operations offline for a month of maintenance could mean the loss of millions of dollars in generation potential.

More broadly, fire occurrence as described in our Five Fire scenario can cause generation downtime of powerhouses in the vicinity, including Tiger Creek ($2.1 to $4.0 million per month) and Salt Springs ($1.1 to $3.0 million per month) powerhouses. This might manifest via direct fire damage or shutdown, interruption in access or conveyance, or other fire management interruptions. It is difficult to predict a likely scenario, and therefore the potential effect of fuel treatments on that outcome, but the modeled fire intensity along the access roads to those facilities demonstrate the potential danger from fire to block ingress to the facilities. Land managers and fire suppression representatives do report the greater capacity to defend infrastructure and manage wildfire behavior after treatment, so treatments offer a real potential to prevent or greatly reduce future fire-related interruptions. At the extreme, the monthly revenue ranges from $8 to $13 million per month for the four PG&E powerhouses, and $0.7 to 1.4 million for Pardee Powerhouse.

Based on the downstream geography of West Point and Electra Powerhouses and their potential to experience the widest range of these identifiable wildfire effects, we use the minimum value of their combined monthly generation value to represent the order of magnitude value for disruption in generation, which is $4 million. But a wide range of scenarios could cause this value to vary from thousands of dollars to tens of millions, depending on the length and cause of the outage.

6.7 Water Supply Effects

In this section we estimate the annual and cumulative value of lost storage capacity for water supply. While lost storage capacity for electricity generation in the Mokelumne translates to earlier generation at lower rates, a loss of storage capacity for a municipal water supply equates to a loss of capacity to store water during peak flows. All else in the system being equal, this would lead to a need for supplemental water sources to make up for the lost volume. Please refer to section 6.1 for how EBMUD has planned to meet its customers' needs. As described in their Water Supply Management Program, the options they have outlined may not be as cost effective per acre-foot as protecting the storage systems that are currently in place. This is especially true when compared to new surface storage options, as the best sites have already been used, and political pressure against new surface storage can increase planning costs or prevent implementation. This is why protecting existing sources of water from capacity reduction is important.

Studies continue to conclude that conservation provides the most cost effective option for increasing available water in California, particularly in agriculture.[5] A 2010 study by the Pacific Institute found agriculture irrigation efficiency in California could conserve water at a cost of $43 to $391 per acre-foot, an average of $185 per acre-foot (Cooley et al 2010). The Pacific Institute study also found that proposed new reservoirs for agriculture would have cost between $520 and $720 per acre-foot. Separately, a 2009 study by a team of California water experts found that new surface storage costs range from $350 to $1,070 per acre-foot, while desalination ranges from $500 to $2,500 per acre-foot (Hanak et al. 2009). This study found groundwater storage opportunities range from $10 to $600 per acre-foot, and they found agricultural water transfer prices range from $50 to $550 per acre-foot. Prices for water transferred between agricultural users in California are typically much lower than prices municipalities in California pay in times of water shortage. However, rural to urban water transfers often face strong opposition from rural communities and consequently are rare (Hanak et al. 2012), although EBMUD reached three such agreements in 2013.

Based on current available opportunities to increase water supply in the San Francisco Bay area, we conservatively assume a cost of $500 per acre-foot of water in terms of value of storage capacity in the upper Mokelumne watershed.[6]

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[5] See the latest California Water Action Plan: http://resources.ca.gov/california_water_action_plan/

[6] EBMUD's Water Supply Management Program 2040 Plan identifies a range of new supply options that range from $400 to $6,100 per acre-foot, with the majority being recycled sources. This suggests that costs of replacing water supply in the future could be substantially more than $500 per acre-foot. Source: EBMUD, 2012. Water Supply Management Program 2040 Plan. http://www.ebmud.com/sites/default/files/pdfs/wsmp-2040-revised-final-plan.pdf.

The 30-year undiscounted value of water supply for Pardee that is able to be stored because fuel treatments reduce fire footprint and severity is worth $1.2 million undiscounted, or $807,000 discounted (Table 6.8). The corresponding value from maintained capacity at Tiger Creek Afterbay is $295,000 undiscounted and $193,000 discounted. At higher replacement water supply costs, the undiscounted costs would proportionally increase, such as a $1,000 per acre-foot cost would equate to a $2.5 million cost for EBMUD as a result of lost Pardee Reservoir capacity.

Table 6.8: Value of water supply protected from sedimentation by fuel treatment ($ thousands)

Reservoir, subwatershed		Year 1	Year 2	Year 30 total (undiscounted)	Year 30 total (discounted 3%)
Tiger Creek Afterbay	No treatment	$16.7	$20.5	$1,035.7	$631.1
	Treatment	$8.3	$10.5	$740.7	$438.3
	Difference	$8.4	$10.1	$295.0	$192.8
Pardee	No treatment	$63.0	$74.9	$2,532.2	$1,619.5
	Treatment	$28.3	$33.2	$1,294.2	$812.2
	Difference	$34.7	$41.7	$1,238.0	$807.2

Note: Value is based on the assumption that replacement water would cost $500 per acre-foot. Years 1 and 2 presume higher than baseline sedimentation due fire, as predicted by the models. Years 3-30 would have baseline erosion rates.

6.8 Summary of Sediment Impacts on Utilities

In this section we consider how a range of possible effects that sediment deposition could affect utility operations in the Mokelumne, and how utilities might need to adjust their operations or actively address sedimentation. Because Salt Springs Reservoir is the primary water source for all of PG&E's hydropower facilities, storage capacity in Tiger Creek Afterbay is of low importance for PG&E as a share of overall storage capacity for the downstream powerhouses. Tiger Creek Afterbay capacity can play a role, however, in terms of uninterrupted operation of the downstream powerhouses, particularly as it relates to meeting its FERC obligations. PG&E has options for flushing sediment (deliberately or naturally), although the frequency and speed with which PG&E could arrange flushing events is somewhat ambiguous. Flushing also means that the sediment is released downstream and would in some proportion affect EBMUD's storage capacity in Pardee Reservoir. Still, the sediment does pose a risk to disrupt electricity generation and can reduce storage capacity, which affects the ability to use hydropower to meet demand.

Effects on Pardee Reservoir are not high in terms of a total share of storage capacity, but EBMUD has frequently demonstrated a desire to seek out solutions to dry year water scarcity, as discussed in its 2040 water plan. Dredging the sediment that would have been avoided with fuel treatment would cost $2.6 million or more over 30 years (discounted). The cost of replacing the lost water storage and resulting supply opportunities would cost EBMUD $800,000 or more over 30 years. Based on the risk that contaminated sediment could dramatically increase dredging costs, combined with the difficulty of securing alternative water supplies, the estimated dredging or water supply costs could reasonably double in cost. These costs could lead EBMUD to other supply sources, such as water transfers, groundwater banking, or increased use of their Sacramento River intake, all of which would come with their own costs. Under the fire conditions modeled in this analysis, treatments are predicted to reduce the rate of sedimentation in Pardee Reservoir, which would postpone the need to act on any of these alternatives.

Sediment dynamics, their impacts on local infrastructure, and how they could affect standing requirements within the watershed (e.g., FERC license), could not be fully assessed at the time of this report. As such, this chapter offers some perspectives on future impacts that could result from incidents in the watershed that have occurred in other areas (e.g., Denver and Rim Fire), but these numbers are not included in the final results because their accuracy need further review. The sediment impacts quantified for the avoided costs in this analysis are the $1 million in discounted, 30-year water supply protected by the treatments for Pardee Reservoir.

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Mokelumne Watershed Avoided Cost Analysis: Why Sierra Fuel Treatments Make Economic Sense

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Disclaimer

This report is rich in data and analyses and may help support planning processes in the watershed. The data and analyses were primarily funded with public resources and are therefore available for others to use with appropriate referencing of the sources. This analysis is not intended to be a planning document.

The report includes a section on cultural heritage to acknowledge the inherent value of these resources, while also recognizing the difficulty of placing a monetary value on them. This work honors the value of Native American cultural or sacred sites, or disassociated collected or archived artifacts. This work does not intend to cause direct or indirect disturbance to any cultural resources.

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