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Altering the Management of Hydroelectric Facilities in California to Account for Climate Change

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This Master’s Project

**Altering the Management of Hydroelectric Facilities in California to Account for Climate Change**

By

**Sarah Carter**

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Abstract

Climate change is currently not a factor in the management or relicensing of a hydroelectric project in California as per the Federal Energy Regulatory Commission. Climate change will alter the primary form of precipitation from snow to rain, which is problematic because snow is measurable, and a reliable source of runoff while rain is unpredictable. Two case studies were analyzed: a run of the river system on the Kern River and a conventional system on the North Fork Feather River. The Kern River is at lower elevation than the North Fork Feather River. The amount of energy produced by the Kern Canyon project has decreased from 559,560 mega-watt hours in 2005 to 15,517 mega-watt hours in 2014. The projects located on the North Fork Feather River, Poe, Rock Creek and Cresta’s production in 2006 was a total of 1,952,050 mega-watt hours and in 2014 only 733,241 mega-watt hours were produced. Climate change will continue to cause a decrease in production. The number of dry water years is predicted to increase from 11 between 1976 and 2010 to 36 between 2011 and 2099. The reduction of water availability will increase the number of obsolete facilities and will cause an increase in the removal rate, as the projects cannot be abandoned as per the license. The removal will cost a significant amount of money due to substantial mitigation efforts. The management of hydroelectric facilities will need to change to include the collection of rainwater during winter storm events, shorter operation licenses, and the use of better technology to accurately predict the amount of rainfall per storm event. If changes cannot be made, 7% of the power budget will be eliminated, as hydroelectric generation in California will no longer exist.
Acknowledgments

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Introduction

Hydroelectric power is a source of energy that has the potential to be a reliable, clean, and renewable. A renewable resource is defined as a source of energy that does not deplete a limited resource or produce pollution that would affect the air, land, or water quality (U.S. Department of the Interior, 2005). The fuel to create this electricity is fresh water, either from precipitation or snowmelt runoff. Globally, hydropower is responsible for 16% of the total power produced and represents 86% of the world’s renewable energy (Hamundudu and Killingtveit, 2012).

In the United States, renewable energy is 10% of all energy consumed (USGS, 2016). Hydropower accounts for 26% of the 10% renewable energy consumed (Foundation for Water & Energy Education, 2016). Other renewable sources are solar, 4%, wind, 18%, biofuels, 22%, and geothermal energy, 2% (USGS, 2016). Hydroelectric generation is the largest source of renewable energy throughout the United States. California is able to produce 2.1% of energy consumed in the state by hydropower (CA Energy Commission, 2016).

California has a large network of reservoirs, dams, and canals that supply water to the 287 hydroelectric facilities (Fig. 1) throughout the state (Ca. Energy Commission, 2016). The majority of the dams and powerhouses found in California were built between the 1930s and the 1970s (Null et al., 2014). California has a total combined capacity of 21,000 megawatts a year (Ca. Energy Commission, 2016). Hydroelectric facilities are found primarily in the Sierra Nevada Watershed but can also be found in Southern California and in coastal regions. Of the 287 hydroelectric facilities, 126 hold operating licenses through the Federal Energy Regulatory Commission (FERC, 2016).

The Federal Energy Regulatory Commission is responsible for issuing operating licenses to each hydroelectric facility. Hydroelectric projects that are not owned and operated by federal agencies, like the U.S. Bureau of Reclamation are required to possess a license. Each license allows the operator to generate electricity for 30-50 years (FERC, 2016). Each license has strict
conditions for stream flow minimums, water quality thresholds, the monitoring of special status species, and recreation.

The regulations are specific to each hydroelectric facility. The minimum flow requirements, stream temperatures, and dissolved oxygen levels will be affected by climate change. Currently, the affects of climate change are not included in the relicensing process. In the next thirty years, 94 of the licenses will need to be relicensed (FERC, 2016).

Climate change will alter the amount of water from snowmelt to rainfall. This change will make the water levels in the reservoirs unpredictable and hard to manage. Snow runoff supplies rivers throughout summer months. With a shift to rain, the water levels in reservoirs in conventional systems will be difficult to predict. Currently, technology is not accurate enough to predict how much rain will accumulate in reservoirs during a single storm event. Run of the river systems that depend on snowmelt will lose all water that is provided during the summer months. Stream water temperatures will increase due to an increase in air temperatures. This increase has been predicted to be between 1.5°C and 4.5°C within the Twenty-First Century (Cayan et al., 2008). Each water year is classified as wet, normal, dry, or critically dry. The affects of climate change will increase the number of dry water years from 11 between 1976 and 2010 (Freeman, 2011) to 16 between 2011 and 2050, which will limit the amount of available water.

Less water and increased temperatures will decrease the amount of electricity produced from hydrogenation. The large system of canals, dams, and powerhouses will not be as effective in producing electricity and will have to be removed. If a hydro project is deemed unusable, it will be decommissioned. This process requires the land to be reverted to its original state. This mitigation effort costs hundreds of millions of dollars. Due to large costs of removal, some facilities do not file to decommission the projects; water is passed through the powerhouses while no energy is produced, allowing for the license to be valid and saving the company a large sum of money. A project cannot be abandoned due to the operating license. The owner of a project is responsible for all activities in the project area, including but not limited to construction, recreation, species habitat, and water flow.
Statement of Purpose

The goal of this paper will be to analyze how climate change will affect the management strategies of California hydroelectric facilities. The current licensing processes of hydroelectric projects will also be analyzed along with how they should be altered to account for climate change. This paper will first explain how electricity is produced, the current regulations, and the general affects of climate change. The affects of climate change on environmental conditions will be evaluated in relationship to hydroelectric production, specifically on two case studies: the Kern River and the North Fork Feather River. Other factors that influence a hydroelectric project will also be explored. This includes the costs of upgrading and maintaining facilities and the process of removing a hydroelectric project. Finally, management recommendations will be given to combat climate change and keep hydroelectric generation a viable renewable resource in California. Recommendations of when California’s hydroelectric system becomes obsolete will also be addressed.
Figure 1: (Data source: U.S. Energy Information Administration, 2015) Map of all hydroelectric facilities in California. Does not include the pumped storage facilities.
Hydroelectric Generation

The United States produced over three billion-megawatt hours of electricity by the use of hydroelectric generation in 2013 (Foundation for Water & Energy Education, 2016). California has one of the largest installed capacities to create electricity with hydropower in the western region of the United States (Uria-Martinez et al., 2015). Despite a large amount of installed capacities, California is not the leader in the amount produced, it is ranked tenth (Fig. 2); Washington yields the most energy.

![Total MegaWatt hour produced in 2013 in the Western Region of the United States](image)

**Figure 2:** (Data Source National Hydropower Association, 2016) Shows the amount of hydropower produced in each state in the western region of the United States, in Mega Watt Hours in 2013.

The majority of production in California occurs in the Sierra Nevada Mountain Range along with a few projects located west of the Sierra Nevada Mountains and a small cluster in the San Gabriel Mountain Range in Southern California (Fig. 1). California’s total hydroelectric capacity is over 14 giga-watts, which is about 25% of the total electricity generation capacity for the state (Madani et al., 2014). This section will discuss how hydropower produces electricity, the stakeholders of projects, the benefits and the impacts of hydropower.
Production of Electricity

Hydropower utilizes gravity to convert potential energy into mechanical energy. The mechanical energy is then converted to electricity and later distributed to the consumers. There are three main types of hydropower systems: run of the river, pumped storage, and conventional hydropower plants (Madani et al., 2014). California currently has six pumped storage hydroelectric facilities (FERC, 2016). This paper will focus on conventional hydropower plants because they are the most widely used type of facility in California (Uria-Martinez et al., 2015).

The first system, run of the river hydroelectric plants, have little to no storage capacity. The amount of electricity produced is directly influenced by seasonal flows (U.S. Department of the Interior, 2005). The second system, pumped storage facilities utilize two reservoirs: one at a high elevation and one at a low elevation. During times the facility is producing electricity, the water is drawn from the high elevation reservoir. When energy is not being produced to supply the power grid, some energy is used to pump water from the low elevation reservoir back to the higher reservoir, with the turbine acting as the pump (U.S. Department of the Interior, 2005). The pumping is normally done at night when there is less of a demand for electricity. The third system, conventional hydropower (Fig. 3), has a large storage capacity and utilizes a network of dams, reservoirs, and canals to direct water to the powerhouse.

Figure 3: (PG&E, 2016) Diagram of the movement of water through a hydroelectric project. From lakes and reservoirs through canals to penstocks down to powerhouses and ultimately continuing downstream.
In the third system, conventional, the first step of creating electricity from falling water is to store the water at a higher elevation than the powerhouse. The powerhouse (Fig. 4A) is the place where the turbines are located. This is also the location of the transformers that send the electricity produced to the power grid.

The water that is stored in reservoirs, with the use of dams, is collected from precipitation or snowmelt runoff, depending on the location of the reservoir. Near the bottom of the dam is an intake pipe. When it is opened, water is allowed to flow downstream. Networks of canals help direct water to the powerhouse. The canals (Fig. 4B) are made of concrete and stretch miles before reaching the powerhouses.

A penstock or large pipe (Fig. 4C) is used to direct water downhill toward the powerhouse. The greater the difference in elevation between the top of the penstock and the powerhouse, the more electricity will be produced because the water will have a greater increase in velocity (USGS, 2016). As the water moves down the penstock, the velocity increases, giving the water its potential energy. The velocity of the water is able to turn the turbine and create mechanical energy. The turbine converts potential energy into mechanical energy, and the transformers convert the mechanical energy into electricity. The electricity can then be transmitted to the power grid and used by the surrounding communities.

Figure 4: (Photos taken by Sarah Carter) A: Powerhouse of the Caribou project owned and operated by Pacific Gas & Electric Company. B: Canals from the Mokelumne River hydroelectric project owned by Pacific Gas & Electric Company. C: Penstock of the Belden Powerhouse that is owned and operated by Pacific Gas & Electric Company.
Stakeholders

The major stakeholders of hydroelectric facilities in California include private owners, to public utilities, to state and federal agencies. The U.S. Bureau of Reclamation owns the large facilities in the state like the Folsom Dam and Shasta Dam (California Energy Commission, 2016); this only accounts for a small portion of the hydropower plants in the state. The majority of the hydropower facilities are owned by public utilities such as Pacific Gas & Electric Company and Southern California Edison Company (FERC, 2016). Counties and smaller companies own a small portion of facilities as well.

The owners and operators of each hydroelectric facility are not the only stakeholders. The owners hold the license, but many other outside agencies hold the owners responsible for the monitoring of special status species, stream flows, water quality, and recreation. The United States Department of Fish and Wildlife ensures that the holders of the license monitor for endangered and threatened species that could be in the project area. The California State Water Board and the National Oceanic and Atmospheric Administration ensure that there is enough water running downstream throughout the summer months. American Whitewater stakeholder is an agency that monitors the flows for recreational purposes; they want to ensure that there is enough water running downstream to provide an adequate whitewater rafting experience. Many other agencies, state, federal, or private, monitor the actions of the owner of the project and all of the agencies can have input on monitoring issues and any actions taken.

The stakeholders for each project are different and are important to note. The license only encompasses a specific area around the river and the powerhouse. The project might be owned by a public utility but the land directly around the equipment is owned by another agency, such as the U.S. Forest Service. The owners of the license must consult with each major agency before changing the daily flow, any construction or maintained that is needed, or when the relicensing of a project is needed.
Benefits of Hydropower

As a historically known renewable, clean source for energy, hydropower is not thought to have many impacts. The water that is used to spin the turbines leaves the powerhouse unchanged (U.S. Department of the Interior, 2005). Hydropower does not burn a fuel to produce air pollution like burning of coal, does not use a limited natural resource for example oil, and does not require a dangerous chemical reaction, like nuclear power (USGS, 2016).

More direct benefits of hydropower include supplementing the power grid, recreation, and monitoring of special status species (U.S. Department of the Interior, 2005). Hydropower has the ability to supplement the power grid when there is not enough electricity being produced by other methods like coal during times of peak use (U.S. Department of the Interior, 2005). Hydropower plants can respond quickly to electricity needs and allow for the stability of costs to consumers (USGS, 2016). The presence of a hydroelectric facility can improve the recreation of an area that is not normally accessible to humans as per the Federal Energy Regulatory Commission’s operation license (FERC, 2016). A condition in the license is to provide campsites, picnic areas, and trails throughout a project location (FERC, 2016). Without a hydroelectric facility present, the land could be privatized or be federal/state land that has limited use. Hydroelectric facilities provide flood control and increase drinking water storage. The infrastructure that is in place for hydropower has the capability of storing large amounts of water to prevent flooding during large storm events.

Impacts of Hydropower

Abiotic factors are defined as physical changes of the environment while biotic factors are defined by having an influence on living things. The installation of a new project has many direct impacts like ground disturbance and an increase of sedimentation of the water body. The maintenance of an existing project can influence abiotic factors (Table 1), such as dissolved oxygen, temperature, erosion, the movement of sediments downstream, and water flows (Foundation for Water & Energy Education, 2016; USGS, 2016; Ficklin et al., 2013).
Table 1: Abiotic impacts due to climate change. The historic and predicted values of dissolved oxygen, water temperature, and sediment flow compared to the thresholds of species. Sediment threshold values are unknown.

<table>
<thead>
<tr>
<th>Factor</th>
<th>Historic Levels</th>
<th>Predicted Levels by 2050</th>
<th>Minimum Thresholds for Species</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dissolved Oxygen Spring</td>
<td>11.0 mg/L</td>
<td>9.7 mg/L</td>
<td>&gt; 6.5 (mg/L)</td>
<td>Ficklin et al., 2013; Foundation for Water &amp; Energy Education, 2016</td>
</tr>
<tr>
<td>Dissolved Oxygen Summer</td>
<td>9.8 mg/L</td>
<td>8.5 mg/L</td>
<td>&gt; 6.5 (mg/L)</td>
<td>Ficklin et al., 2013</td>
</tr>
<tr>
<td>Water Temperature</td>
<td>&gt;12° C</td>
<td>17.8-25.0° C</td>
<td>&lt; 20° C</td>
<td>Ficklin et al., 2013; FERC, 2001; FERC, 2007; CA Fish and Wildlife, 2106</td>
</tr>
<tr>
<td>Sediment Spring</td>
<td>12.4 mg/L</td>
<td>6.7 mg/L</td>
<td></td>
<td>Ficklin et al., 2013</td>
</tr>
<tr>
<td>Sediment Summer</td>
<td>6.9 mg/L</td>
<td>3.5 mg/L</td>
<td></td>
<td>Ficklin et al., 2013</td>
</tr>
</tbody>
</table>

Stream temperature can be affected by hydropower facilities when little water is available to move downstream. The temperature can increase during summer months when the reservoir cannot be filled at 100 percent capacity during the winter months. The increase will occur when there is standing water. This will cause solar radiation to cause the water to warm. If the flow downstream is limited, then the stream temperature will increase; this is directly proportional to the distance the water will travel, the further the water travels, the warmer the water will get (Ficklin et al., 2009).

Sediment impacts arise when sediment gets trapped behind a dam or powerhouse (USGS, 2016). The sediment needs to be removed and placed either downstream or outside the watershed. The removal of the sediment is done manually. The removal can also cause a significant of sediment to enter the water body, if done improperly. Downstream can be starved of sediment if the barriers prevent natural movement. If this happens, there is not enough sediment to create habitat for species.

Hydroelectric facilities alter the natural flows of a river by definition. The network of dams that were created to trap and collect water upstream of a powerhouse prevents water to flow downstream. Canals and tunnels divert water from streams to either reservoirs or directly to powerhouses. When water is scarce during summer months or a dry water year, the flows that
occur are minimal. These flows are just enough water to comply with the facilities current license and keep the stream channel deep enough for aquatic species.

**Regulations**

Each hydroelectric generation project must comply with many types of regulations. This section will discuss the how the Federal Energy Regulatory Commission was created. A general overview of the relicensing process will be examined. The different agencies that are responsible for the oversight of the compliance of the current regulations will be described.

The San Bernardino Electric Company built the first commercial hydroelectric powerhouse in California near Riverside in 1887 (U.S. Bureau of Reclamation, 2016). Congress did not establish a federal committee to oversee or regulate hydropower until the Federal Power Commission in 1920. The Natural Gas Act of 1938 was established to oversee the sale and transportation of electricity and natural gas. Until the creation of the Federal Energy Regulatory Commission in 1977, the Federal Power Commission and the Natural Gas Act controlled the production and transportation of electricity produced from hydropower (FERC, 2011). The Federal Power Commission was expanded by congress to create the Federal Energy Regulatory Commission.

Currently, the Federal Energy Regulation Commission is solely responsible for issuing operation licenses to privately own or publically owned utility company hydropower projects under the Federal Power Act (Viers, 2011). Presently FERC holds 1,030 licenses across the United States (FERC, 2011). Licenses are granted for long periods of time, typically 30 to 50 years (Viers, 2011). Many federal agencies are responsible for ensuring the protection of the land, resources, and wildlife throughout the project.

With over a thousand licenses currently valid to operate a hydroelectric facility, the relicensing process is more prevalent than acquiring a new licenses. The Federal Energy Regulatory Commission can deem a license application as a non-power license, decommissioning, federal takeover, or new license (Hydropower Reform Coalition, 2005). A
non-power license can be issued temporally if the environmental quality needs to be addressed and improved; this will not change until the improvements are made (16 U.S. Code §808f). A decommissioning verdict can include decommission of all or part of a project (18 C.F.R. §2.24). The transfer of a project to federal ownership occurs when the United States provides notice at least two years before the license expires and provides a fair market value payment for the entire project (16 U.S. Code §807a).

To relicense an existing project, the new license is only awarded when the application is demonstrably superior to the existing license (18 C.F.R. §4.37). If the new license is obtained, the Federal Energy Regulatory Commission establishes a comprehensive plan of the development of the project area (Hydropower Reform Coalition, 2005). The license will always be updated when the license goes through the relicensing process in order to comply with the new laws and regulations.

In 2003, the Federal Energy Regulatory Commission developed a new process to submit a license application in order to relicense an existing project. The integrated licensing process was adopted in 2003 and it incorporates the application process and the environmental review of a project (FERC, 2011). The Federal Energy Regulatory Commission works with many federal agencies to review the environmental affects of each project area before the new license can be administered.

The federal agencies that are involved with hydropower generation and the relicensing process are the National Marine Fisheries Service, Fish and Wildlife Service, National Park Service, Bureau of Land Management, Bureau of Indian Affairs, Bureau of Reclamation, United States Geological Service, the Forest Service, U.S. Environmental Protection Agency, and the U.S. Army Corps of Engineers (Hydropower Reform Coalition, 2005). The National Marine Fisheries Service has the right to establish reasonable and prudent alternatives to prevent the take (harm, collection, or death) of a marine animal or diadromous fish (fish that migrate between salt and fresh water) that is listed under the Endangered Species Act (16 U.S. Code § 1801).
The Fish and Wildlife Service also can request a mandatory fish passage for freshwater species listed on the Endangered Species Act (Hydropower Reform Coalition, 2005). The National Park Service has no direct authority; however, there shall be no new hydroelectric projects built within a National Park except with congress approval (16 U.S. Code § 797a-c). The National Park Service’s primary role is to assist the Federal Energy Regulatory Commission in reviewing the projects comprehensive plan to ensure that the publics recreation interests are met along with any areas that river conservation can be improved (Hydropower Reform Coalition, 2005). The Bureau of Land Management is responsible for any federal lands that are not national parks, national forests, or national fish and wildlife refuges; it can recommend conditions for the projects use of this land under section 10(a) of the Federal Power Act (Hydropower Reform Coalition, 2005).

The Bureau of Reclamation is accountable for the construction, operation, and maintenance of federal hydropower dams and has input on privately owned projects when a federal dam affects the project in any way (Hydropower Reform Coalition, 2005). The U.S. Army Corps of Engineers is involved in a project when flood control is a condition of the license.

In addition to complying with the parameters outlined by the Federal Energy Regulation Commission licenses, there are many laws and regulations that each hydroelectric project needs to comply with. Section 8 of the Federal Power Act allows the National Marine Fisheries Service to require the installation of a passage for fish as a mandatory license condition in order to protect the diadromous fish (16 U.S. Code § 811). Under the Coastal Zone Management Act, the Environmental Protection Agency monitors the quality of water under the Clean Water Act (Clean Water Act § 101 and 33 U.S. Code § 1251d). As per the Clean Air Act, the Environmental Protection Agency has the authority to review all environmental documents for any hydroelectric project (Clean Air Act § 309 and U.S. Code §7609).

All of the agencies involved in the licensing and monitoring process have the right to review and comment on the studies and conditions that are presented. A balance of profitable
electric generation and environmental impacts needs to be present in the operation of each project. The majority of the licenses do not need to be relicensed until 2030 and 2040 (FERC, 2011) but for the remainder of the licenses, this modification can occur. Due to the longevity of the license, the decisions that are made for minimum flow rates, water temperature, and all other environmental factors at the time of relicensing should include the effects of climate change.

**Climate Change**

California’s hydroelectric facilities were built to handle the very diverse climates found throughout the state. These climates are classified as high land, Mediterranean, semi-arid, cool interior, and desert (Madani et al., 2014). Despite the varying weather patterns, hydro plants are located from Modoc County in Northern California to San Diego County in Southern California; hydropower can be produced anywhere there is running water.

The majority of hydroelectric facilities are located in the Sierra Nevada Watershed in the northern part of the state. This is because over 70% of the annual runoff, an average of 88 billion cubic meters, occurs in this area of the state (Madani and Lund, 2009). The production of hydroelectric power depends on the amount of water that is available to run through powerhouses to spin the turbines. Currently, the relicensing process for a hydroelectric project does not include the effects of climate change (Viers, 2011). Climate change will alter temperatures, water availability, and precipitation (Connell-Buck et al., 2011) as will be discussed in the sections below.

**Temperature**

The air temperature is predicted to increase anywhere from 3.7°C to 7.8°C, depending on human emissions (Edenhofer et al., 2014). Human emissions will increase air temperatures because when more carbon dioxide is released from processes like burning coal, more greenhouse gasses will be in the atmosphere and will not be able to escape, due to the inversion layer. The inversion layer within the atmosphere is when there is an increase of temperature with an
increase in altitude. The inversion layer is between two layers that have a decrease in temperature with increasing altitude. This does not allow the green houses gasses escape to the upper layers of the atmosphere and remain close to the Earth’s surface, which causes an increase in air temperature.

Within the Twenty-First Century, the range has been forecast to be between 1.5°C and 4.5°C (Cayan et al., 2008). Increasing air temperatures does not directly equate to water temperatures (Kadir et al., 2013), but air temperatures have been strongly correlated to stream temperatures (Ficklin et al., 2013). Air temperature is not the only factor influencing stream water temperature. The other factors that can influence the stream temperature include solar radiation, evapotranspiration, geography, groundwater inputs, dams, and land use changes (Kaushal et al., 2010). Accounting for all of the factors, Kaushal et al. (2010) concluded that long-term warming trends are occurring in the streams of the United States.

The evapotranspiration factor can cause an increase in stream water temperature (Connell-Bucket et al., 2011). Evapotranspiration is defined as the combination of evaporation of liquid water to a gaseous phase and the plant life uptake of water in the roots. Plant life releases it in the form of water vapor from structures on plant leaves. During drier years when water is already scarce, the plants will still absorb the necessary amount water for life.

Four different scenarios are possible to describe future emission levels: A2, A1, B1, and B2 (IPCC, 2001). An A2 scenario was defined in the 2001 Intergovernmental Panel on Climate Change (IPCC) Report as a very heterogeneous world. In this scenario, emissions are calculated in a world with a steadily increasing population, regionally oriented economic growth, and more fragmented, slow technological advances (IPCC, 2001). The current levels of carbon dioxide (CO2) are projected into the future with little effort to convert energy sources to renewable sources in the A2 emission scenario (IPCC, 2001). An A1 emission scenario differs from an A2 scenario because it describes a rapid increase in population with a large increase in new and more efficient technologies (IPCC, 2001). In the B1 scenario, the population growth is the same as the A1 scenario, but differs in its emphasis on a global solution to environmental sustainability and improved equality without any addition of climate initiatives (IPCC, 2001). The local and
regional protection of the environment, with a lower rate of population growth and a higher diversity of technology, describes the B2 emission scenario (IPCC, 2001).

The majority of research has focused on predictions using the A2 emission scenario (Ficklin et al., 2013; Null and Viers, 2013; Connell-Buck et al., 2011; Cayan et al., 2008; Madani et al., 2014). Using the A2 scenario emission quantities, Ficklin et al. (2013) was able to predict possible stream temperatures in the Sierra Nevada Watershed. Ficklin et al. (2013) assumes that present conditions reflect an A2 emission scenario. Figure 5 shows the stream temperatures during summer at three different times: the historical stream temperatures from 1950 to 2005, the 2050’s, and the 2080’s (Ficklin et al., 2013). The historical time period shows that the majority of the stream temperatures are between 10.1°C and 15.0°C. The 2080’s map illustrates the majority of the stream temperatures are between 22.6°C and 27.5°C with very little streams having a temperature below 10.1°C (Ficklin et al., 2013).

![Figure 5](image.png)

**Figure 5:** (Ficklin et al., 2009) This figure shows how water temperature in streams in the Sierra Nevada watershed will increase in summer months with current climate change conditions with no addition of carbon dioxide from emissions. Historic, 2050’s and 2080’s stream temperatures represented by the three maps. By the 2080’s the majority of the streams will have temperatures greater than 20.1°C.

The warmer summer water temperatures can influence how and when water is released from the lake and reservoirs. Currently, the cooler deep water is released to ensure that the downstream water is a reasonable temperature, below 20°C. This threshold is mandated to satisfy...
the regulations set by the Federal Energy Regulatory Commission. Water temperatures below 20°C ensure a suitable habitat for sensitive species like native salmon. In summer months, stream water temperature is of the most concern because during winter and spring there is enough water to keep the streams at temperatures below 10°C (Ficklin et al., 2013).

When water is released from reservoirs, the cooler, deeper water is released. The deep water is released because of stratification. When the reservoir is full or near full, there is plenty of deep cool water to release downstream. When water is scarce due to drought or climate change, the deep cool water is very limited. When the deep cool water is close to diminished, the warmer water will mix and there will be little to no stratification. Releasing warmer water is an issue because of solar radiation. Solar radiation will increase the water temperature naturally. With minimum flows, the water depth present in the streambed is low. Stream water temperature can increase depending on depth and the amount of time that it travels downstream to a different reservoir.

**Water Availability**

A water year is defined by the USGS (2016) as the 12-month time period from October 1st to September 30th of the next year. There are many different indexes used to classify water year types. The Sacramento Valley Index is used to classify four major rivers in California. The unimpaired runoff is measured from gauges located on the Sacramento River, the Feather River, the Yuba River, and the American River (Null and Viers, 2013). The Sacramento Valley Index categorizes each water year (Table 1) as wet, above normal, below normal, dry, or critically dry. These classifications are based on historical amounts of unimpaired runoff (Null and Viers, 2013).

California has very few “normal” water years and is experiencing an increase in the number of dry years and the number of sequential dry years (Viers, 2001). The number of critical water years will increase (Table 2) from 8.7% to 11.3% by 2015. This will further increase to 18.4% by the year 2050, based on A2 emissions (Null and Viers, 2013).
Table 2: (Data source: Null and Viers, 2013) Table of current water year thresholds of the Sacramento Valley Index and the number of water year type, as a percentage, based on A2 emissions for the years between 1951 and 2099.

<table>
<thead>
<tr>
<th>Water year type</th>
<th>Current classification thresholds (millions of cubic meters)</th>
<th>Number of years in each water type between 1951-2000 based on A2 emissions (%)</th>
<th>Number of years in each water type between 2001-2050 based on A2 emissions (%)</th>
<th>Number of years in each water type between 2051-2099 based on A2 emissions (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wet</td>
<td>≥11,348</td>
<td>39.3</td>
<td>36.7</td>
<td>30.6</td>
</tr>
<tr>
<td>Above normal</td>
<td>&gt;9,621 - &lt;11,348</td>
<td>20.1</td>
<td>16.7</td>
<td>12.9</td>
</tr>
<tr>
<td>Normal</td>
<td>&gt;8,018 - ≤9,621</td>
<td>23.3</td>
<td>23.3</td>
<td>18.7</td>
</tr>
<tr>
<td>Dry</td>
<td>&gt;6,661 - ≤8,018</td>
<td>7.7</td>
<td>12</td>
<td>19.4</td>
</tr>
<tr>
<td>Critical</td>
<td>≤6,661</td>
<td>8.7</td>
<td>11.3</td>
<td>18.4</td>
</tr>
</tbody>
</table>

While water is already a scarce resource in California, the amount of fresh water that is available for rivers and streams could be even more limited due to an increase of critically dry water years. Minimal water flows could be a result of a more limited water supply. The amount of runoff discharge during spring snowmelt months will significantly decrease over time (Null and Viers, 2013) and further contribute to the limited availability of water.

**Precipitation**

With California’s changing climate, the amount of annual precipitation in the future is predicted to change depending on the location in California. Current predictions range from a decrease of 26% to an increase of 18% (Connell-Buck et al., 2011). Climate change not only affects the amount of precipitation but it can also shift when and how the precipitation occurs. The shift to earlier runoff has been occurring since the 1940’s (Connell-Buck et al., 2011). The type of precipitation is also shifting from snowfall to rainfall. Presently, hydroelectric power generation in the Sierra Nevada mountain range solely relies on snowmelt (Ficklin et al., 2013).

Historically, precipitation in the form of snow would cover land in high and low elevations during the winter months. The snow pack melting would fill the storage reservoirs in spring (Freeman, 2003) to ensure that water would be available throughout the warmer summer months (Madani and Lund, 2009). With over 75% of the total precipitation happening between
November and March (Madani and Lund, 2009) either as rain or snow, rivers have maximum flows during late spring to early summer and with the minimum flows occurring in late August and early September (Dettinger and Cayan, 1994). Less runoff would be available for summer and fall flows due to the shifting of the spring runoff (Freeman, 2012).

Warming temperatures will shift the primary form of precipitation from snow to rain (Barnett et al., 2005). The snowmelt is a reliable and measurable form of precipitation while the amount and timing of the rainfall is uncertainty, which makes it increasingly difficult to manage (Freeman, 2012). Another benefit of utilizing snowmelt is that it slowly infiltrates the soils and eventually can recharge the groundwater supply (Freeman, 2012). Rainfall can be erratic and unpredictable throughout the year. Climate change will likely change the frequency and intensity of storm events in the future (Null and Viers, 2013).

The shifting of the climate from precipitation as snow in winter to more precipitation as rainfall the lakes and reservoirs will fill up during rain events if the spill gates were to remain closed (Freeman, 2003). However, the California Division of Safety of Dams mandates that the spill gates are to remain open during the winter of most of the reservoirs located in mountainous areas (Freeman, 2003). Limited rainfall outside of winter months could leave the reservoirs at record low levels if not managed correctly.

**Relicensing and Climate Change**

The relicense process currently does not account for climate change (Viers, 2011). Five years before the license expires, the holder of the license must notify the Federal Energy Regulatory Commission of their intent to file for a new license (Hydropower Reform Coalition, 2005). After intent is submitted, a series of studies must be conducted to determine the impacts of the project to the surrounding areas. This includes explaining different studies that would needed to define any effects to any and all habitat within the project area. These studies include fish habitat, water temperature, riparian habitat, visual quality, cultural resources, and many others (FERC, 2009). The effects of climate change on the hydroelectric project area are not currently included in the required studies during the relicensing process. The Federal Energy
Regulatory Commission’s relicensing requirements were designed assuming the climate would be invariable year to year (Null and Viers, 2013).

One of the first projects that attempted to include a climate change studies was the relicensing effort of the Yuba-Bear Drum Spaulding project (Viers, 2011). The Yuba-Bear Drum Spaulding hydroelectric facilities are located in Northern California. The stakeholders of the Yuba-Bear Drum Spaulding project are the Pacific Gas and Electric Company and the Nevada Irrigation Project; both companies are based out in California (FERC, 2009). The Yuba-Bear Drum Spaulding plan for impact studies was submitted in 2009. In the study plan the stakeholders requested to include a study of the effects of climate change and the potential influences on hydroelectric power generation (Viers, 2011). The stakeholders felt that it would be necessary to include the effects of climate change because they acknowledged that climate change has the impact to alter stream flows and other parameters in the new license (Viers, 2011). The Federal Energy Regulatory Commission reviewed the studies that were presented as evidence by the stakeholders and acknowledged that climate change is happening but the models that were presented to predict the affects of climate change were not accurate enough to predict a specific resource impact to the degree that the FERC license requires (FERC, 2009).

The Federal Energy Regulatory Commission, while acknowledging climate change is occurring, did not approve the addition of climate change to the proposed studies needed to renew the license. There could be many reasons for this. The reasons could include the Federal Energy Regulatory Commission needing to balance economic and political interests and the process of renewing the license that is most commonly used, Integrated Licensing Process which focuses on how hydroelectric power generation affects aquatic ecosystems downstream (Viers, 2011). Climate change will affect mostly the ecosystems upstream from hydroelectric facilities, predominantly the primary source of freshwater: snowmelt. The inherent variability of California’s climate could be another reason why climate change was rejected as a study. The historic hydrograph records were used to predict future operations in terms of water management and release schedules: the Federal Energy Regulatory Commission could have assumed that the climate change aspect of future conditions was already accounted for. This is a risky assumption because future conditions will not reflect past conditions (Viers, 2011).
If A2 conditions continue, the future of hydroelectric facilities will be in jeopardy. Climate change will alter the amount of water available, stream temperatures, and the type and amount of precipitation. There is a possibility that the effects of climate change will result in hydroelectric generation being not an affective clean energy source in the future.

Cost of Upgrading and Maintenance of a Facility

The information available on the costs of upgrading and maintaining facilities for California is limited due to the majority of the projects being owned by utility companies. This section will incorporate the costs associated with hydroelectric facilities across the United States and one company’s costs in California.

Hydroelectric facilities require a large initial investment but they have a small operating cost; costs of upgrades and maintenance of a facility is very high (USGS, 2016). Currently there are 2,198 hydroelectric facilities in the United States (Uria-Martinez et al., 2015) Of the total hydroelectric facilities in the United States, 75% of the generating capacity is produced at hydropower plants that are over 50 years old (Uria-Martinez et al., 2015). Updating the aging hydropower generation system is necessary if production is to continue into the future. In California, the ageing distribution system needs to be completely modified if it is to combat climate change (Viers, 2011).

In the last decade approximately 3.6 billion dollars have been spent to replace, repair or refurbish hydroelectric facilities through out the United States. In the more recent years, since 2005, the amount spent refurbishing, replacing and upgrading hydroelectric facilities has increased to 6 billion dollars spent in the United States (Uria-Martinez et al., 2015). For 15 projects located in the United States in 2014, the maintenance on turbines alone costs 339 million dollars (Uria-Martinez et al., 2015). The maintenance of an individual hydroelectric facility can cost millions of dollars a year: the companies that own the specific hydroelectric project pay the costs (Uria-Martinez et al., 2015).
The production and revenue of hydropower is greatly decreased in a dryer climate because there is less water to power the turbines. In California, if evapotranspiration occurs during a normal water year there is a decrease of 4.5% of production which equates to a loss of 20 million dollars a year (Connell-Bucket et al., 2011). Historically, Madani et al. (2014) found that 223,000 mega-watt hours are produced a year which is about 1726 million dollars in revenue. During a warm, dry year the decrease of production due to evapotranspiration is 6.5%, which equates to a loss of 388 million dollars a year (Connell-Bucket et al., 2011). Madani and Lund (2009) found that a classification as a dry water year would result in a loss of revenue of about 14% or 255 million dollars a year in California. The data that Mandi and Lund (2009) used to evaluate loss of revenue was from 1985 to 1988. The reduction in revenue differs due the difference in the definition of a dry year. The conditions are much dryer today than in the 1980s. The amount of revenue depends heavily on the amount of water that is available to run through powerhouses to produce electricity.

The Southern California Edison Company has 33 hydroelectric facilities that are located from Fresno to San Bernardino County in California (Kurpakus, 2015). Between the years 2013 and 2017, the projected total amount spent on all 33 hydroelectric projects combined equals $438.3 million dollars (Kurpakus, 2015). Each project is estimated to cost 13.3 million dollars annually (Kurpakus, 2015). The total amount includes spending on all aspects (Fig. 6) of all projects including: relicensing projects, electrical equipment, dams and waterways, and decommissioning (Kurpakus, 2015). The non-labor expenses for 2015 were $5.91 million for all of Southern California Edison’s projects (Kurpakus, 2015). This total included the costs of administrative fees from the Federal Energy Regulatory Commission, rent charges for any projects on federal land, and fees from other agencies: the California Department of Water Resources, State Water Resources Control Board, the U.S. Geological Survey, and the U.S. Army Corps (Kurpakus, 2015).
California’s hydroelectric plants produce some of the cheapest electricity, when environmental costs are not included. In 2015 hydropower was produced at 2 cents per kilowatt-hour produced (NHA, 2016). Table 3 shows the amount of energy consumed by the population of California, the cost of production, and the percentage of the power budget by coal, natural gas, nuclear, hydropower, and other renewable resources. Hydroelectric production is the cheapest form of energy and smallest percentage of the power budget. Natural Gas is the largest percentage of the power budget, not the most expensive to produce, and the most profitable without considering other factors like environmental, maintenance, and transmission costs.

Table 3: The costs, amount consumed, net income, and percentage of California's power budget depending on the source of the power:

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Coal</td>
<td>7.5</td>
<td>38.2</td>
<td>11,000,000,000</td>
<td>825,000,000</td>
<td>6.4%</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>6</td>
<td>2,483.20</td>
<td>729,000,000,000</td>
<td>43,740,000,000</td>
<td>44.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>9.5</td>
<td>187.2</td>
<td>54,000,000,000</td>
<td>5,130,000,000</td>
<td>8.5%</td>
</tr>
<tr>
<td>Hydropower</td>
<td>2</td>
<td>226.6</td>
<td>66,000,000,000</td>
<td>1,320,000,000</td>
<td>6.4%*</td>
</tr>
<tr>
<td>Other Natural Resources</td>
<td>19.5</td>
<td>351.2</td>
<td>103,000,000,000</td>
<td>20,085,000,000</td>
<td>12.3%</td>
</tr>
</tbody>
</table>

*includes large (5.5%) and small (0.9%) hydro-projects
Hydropower, while cheap to produce, has a large environmental, maintenance, and regulation costs associated with it. The utilization of hydropower systems might have run its course, with new techniques for collecting natural gas, solar, and wind to be the better alternatives. Maintenance costs associated with fossil fuels is 0.7 cents per kilowatt-hour produced, operation costs are 0.3 cents per kilowatt-hour produced and the fuel costs are 2.1 cents per kilowatt-hour produced (US Department of the Interior, 2005). Hydroelectric has maintenance costs of 0.6 cents per kilowatt-hour produced, 0.8 cents per kilowatt-hour produced, and no fuel costs (US Department of the Interior, 2005). While hydroelectric is a cheap form of electricity, the maintenance and environmental costs out way the upfront costs. The amount of money that is spent annually for the maintenance of the hydro projects could be spent developing cleaner and more efficient ways to produce electricity with solar, wind, coal, or natural gas.

With the aging of all hydroelectric facilities, the amount of money that will be spent on maintenance will continue to rise. New technologies may increase the efficiency of the powerhouses to create more electricity per facility, if there is enough water present to do so. The Southern California Edison Company has only 20 operating licenses, while the Pacific Gas and Electric Company owns 37 (FERC, 2016). Smaller companies may not be able to continually increase the budget of maintenance of the projects. The increase maintenance, environmental, and permitting costs will cause many small projects to become obsolete, even if hydropower is considered the cleanest option for power.

Case Studies

This section will explain two case studies. The first will be a small-scale hydroelectric project on the Kern River, and the second will be a large-scale hydroelectric project on the North Fork Feather River. Each case study will explain the location, hydrography, major source of water, and the identification the hydroelectric projects. To further understand the hydroelectric projects, the major stakeholders will be discussed and how they currently manage the projects. This section will also outline how the location and source of water plays a large part in the production of electricity. Additionally, this section will include how climate change will impact both projects and the amount of energy that could be produced.
North Fork Feather River

The North Fork Feather River is located in northern California in the Sierra Nevada Watershed. Lake Almanor is the main reservoir to the North Fork Feather River (Freeman, 2011). The North Fork Feather River (Figure 7) stretches over 100 miles from Lake Almanor to Lake Oroville (Freeman, 2010). The North Fork Feather River watershed covers 777,661.56 acres (EPA, 2016) with an average discharge of 1,930 cubic feet per second (Freeman, 2011). The North Fork Feather River is a tributary to the Sacramento River.

Figure 7: A (Made with ArcGIS) Location of the North Fork Feather River watershed. B (Made with Google Earth) Path of the North Fork Feather River within the watershed from Lake Almanor to Lake Oroville.

The elevation of Lake Almanor is 4,505 feet while the Poe dam has an elevation of only at 1,669 feet (Plumas County, 2012). The North Fork Feather River is very steep, at some points the elevation can drop up to 35 feet per mile (North Fork Feather River Planning Unit, 2007). Due to the large steps in elevation from project to project, the North Fork Feather River has been nicknamed the Stairway of Power (Fig. 8).
The North Fork Feather River watershed receives a lot of precipitation because the western facing slopes of the mountains allow the eastern moving storm events to be uplifted; this causes the air to cool and precipitation to occur (Freeman, 2011). The location of the many hydroelectric projects in the Feather River Basin is ideally located due to the collection of water from storm events in Lake Almanor (Freeman, 2011). The North Fork Feather River is susceptible to climate change due to its relatively low elevation and the presence of some rain-shadowed sub-basins: Lake Almanor and the East Branch North Fork Feather River (Freeman, 2003, 2011).

The amount of water that is discharged into Lake Oroville varies year to year. The closest USGS gauge that measures the amount of water that is drained from the watershed is located in Chico, California. The gauge measures the output daily (Fig. 9) and overtime shows the months when water is most prevalent running downstream. This gauge measures the entire watershed drainage; the specific information for the North Fork Feather River is unavailable.
Overall trends have been to have an increase in the amount of water drained in the winter and a reduction in the summer months. This is normal; the amount of water in summer has had the minimum value around 80-90 cubic feet per second in the years from 2000 to 2013 (USGS, 2016). In more recent years, 2014 and 2015, the minimum amount has started to decline slightly, to around 60 cubic feet per second (USGS, 2016). This downward trend could continue if the amount of snow packs decreases and frequency of storm events changes.

The primary source of water is snowmelt from the Sierra Nevada Mountain Range (Freeman, 20011). Snowmelt accounts for 50% of the runoff (Buer, 2003). The runoff that accumulates in Lake Almanor supplies water to the North Fork Feather River throughout the year. Snowmelt and discharge are stored in Lake Almanor and other reservoirs to be used when needed. The water supply is very limited during the hot summer months; water is manually released downstream to supply cold water to provide habitat for species and recreation.

**Stakeholders and Management**

Pacific Gas & Electric Company currently owns and operates all of the hydroelectric facilities located on this stem of the river. The North Fork Feather River accounts for about 25% of Pacific Gas & Electric Companies total annual hydropower generation (Freeman, 2003). The federal agencies that are involved are the U.S. Forest Service, U.S. Fish and Wildlife, and the National Park Service (Hydropower Reform Coalition, 2009). The state agencies that are involved are the California Department of Fish and Game and the California State Water
Resources Board. Other groups involved in the management are Plumas County, American Whitewater, Natural Heritage Institute, Friends of the River, California Outdoors, California Trout, Chico Paddleheads, Shasta Paddlers, and the California Sport Fishing Protection Agency (FERC, 2016). All of these stakeholders have different interests in the hydroelectric projects. Pacific Gas & Electric Company is concerned about the production of electricity while the different federal agencies are interested in the protection of federal lands, endangered and threatened species, and regulations.

Currently the management of the water flow downriver is such that it will provide at least the minimum flow (Table 4) that is required by the Federal Energy Regulatory Commission license when water is scarce during summer months. The current model used for dry years is to begin the summer with a large flow and step the amount up throughout the summer. If an extreme heat event is forecasted, then additional flow can be released. This allows the water supply to be conserved throughout the hot summer months.

<table>
<thead>
<tr>
<th></th>
<th>Normal and Wet Water Year (cfs)</th>
<th>Dry Water Year (cfs)</th>
<th>Critical Dry Water Year (cfs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spring Months</td>
<td>250/250</td>
<td>200/200</td>
<td>110/100</td>
</tr>
<tr>
<td>Summer and Fall Months</td>
<td>180/220</td>
<td>150/175</td>
<td>150/140</td>
</tr>
<tr>
<td>Winter Months</td>
<td>200/240</td>
<td>160/190</td>
<td>110/100</td>
</tr>
</tbody>
</table>

Pacific Gas and Electric Company ensures that all entities of the license are being met. This includes recreation flows for white water rafting and a fish population for sport fishing. Monitoring is done for all special status species if they are suspected to be present. This includes foothill yellow legged frogs, spring run Chinook salmon, winter run Chinook salmon, nesting birds, CA tiger salamanders, and western pond turtles and various plant species.

During the relicensing process for the Rock Creek-Cresta project, one of the largest issues was the decline of habitat for special status species like the foothill yellow-legged frog and native salmon species (Hydropower Reform Coalition, 2009). As per the license, the water temperature needs to be below 20 degrees Celsius to provide a cold-water habitat for the
sensitive species (FERC, 2016). To assure that the water quality remains habitual for special status species, Pacific Gas & Electric Company created a Coldwater Habitat and Fishery Mitigation and Enhancement Fund of initially five million dollars (Hydropower Reform Coalition, 2009) as a condition of the license. Within six years after the license was approved, an additional two million dollars were to be allocated to the fund (FERC, 2001).

The management of each project depends on the conditions of the operating license. Each hydroelectric project located on the North Fork Feather River has specific concerns and environmental concerns. The licenses have minimum flow rates, minimum water temperatures, and must contain plans for fish monitoring, terrestrial wildlife monitoring, vegetation and invasive weed management, and plans to enhance and maintain the roads and other facilities within the projects boundaries (FERC, 2001, 2009, 2007).

Hydroelectric Projects and Energy Production

An elaborate system of dams, canals, and powerhouses is used to produce the maximum amount of electricity as the water moves downstream. The system on the North Fork Feather River has a total of 10 powerhouses and three reservoirs (Freeman, 2011). The powerhouses include: Poe, Bucks Creek, Rock Creek, Cresta, Belden, Oak Flat, Caribou 1, Caribou 2, Butt Valley, and Hamilton Branch (Freeman, 2011). This paper will only focus on Rock Creek, Cresta, and Poe (Fig. 10). The three powerhouses consist of two projects the Poe project and the Rock Creek-Cresta project. Rock Creek and Cresta powerhouses were combined due to the closeness of proximity on the river and operate under the same license.
These powerhouses will be examined because they are all on the main section of the North Fork Feather River and do not have water diverted to the powerhouses by conduits from another source outside of Lake Almanor. The reservoirs (Fig. 11) located on the North Fork Feather River are Lake Almanor, Mountain Meadows Reservoir, and Butt Valley Reservoir. Mountain Meadows (24,8000 acre feet) and Butt Valley Reservoir (49,891 acre feet) are small in comparison to Lake Almanor (1,175,000 acre feet) and supply water to specific projects on small tributaries of the North Fork Feather River (Plumas County, 2012).
The Poe project is located furthest downstream of Lake Almanor near the city of Paradise, California. This project is comprised of the Poe powerhouse and the Poe dam. Poe dam diverts water to the powerhouse. Moving upstream, the Rock Creek-Cresta project is made up of the Rock Creek powerhouse, Rock Creek dam, Cresta powerhouse, and Cresta dam. The two licenses, Poe and Rock Creek-Cresta, have different license requirements and environmental concerns.

The Poe hydroelectric project was built in 1959 and licensed in 1953 (FERC, 2016). The original license issued by the Federal Energy Regulatory Commission in October of 1953 expired in September of 2003 (Hydropower Reform Coalition, 2016). Currently, the Poe project is being operated on a year-to-year license while an environmental assessment of the possibility of removing Big Bend Dam is being completed (Hydropower Reform Coalition, 2016). The Poe project has water quality issues that include the water temperature and the availability of gravel for spawning fish (Hydropower Reform Coalition, 2016). This project has bald eagles present that are of concern. The various fish species that are present include rainbow trout, hardhead, Sacramento pike minnow, Sacramento sucker, and the smallmouth bass (Hydropower Reform Coalition, 2016).
The Rock Creek-Cresta project was originally licensed in 1947 (FERC, 2016). The project has been operated since completion in 1950 (FERC, 2016). The original license expired in 1982 and Pacific Gas & Electric Company was not able to relicense the project until 2001 (Hydropower Reform Coalition, 2016). The original license needed to have the minimum flow requirements to be adjusted by water type; wet, dry or normal water years were used to describe water years and establish minimum flow requirements (Hydropower Reform Coalition, 2009). The current license is valid through September of 2034 (FERC, 2016). The main environmental goals of the license are to provide habitat improvements through in-stream enhancements of fish passage, spawning, and recruitment and improving the water temperature control measures (FERC, 2001). The Rock Creek-Cresta project has sedimentation and water temperature problems (Hydropower Reform Coalition, 2016). The special status species that are present include the foothill yellow legged frog (Bondi et al., 2013). Rainbow trout are present throughout this project (Hydropower Reform Coalition, 2016).

The North Fork Feather River produces a significant amount of renewable energy for the Pacific Gas and Electric Company. It is responsible for about 25% of the annual hydroelectric production (Freeman, 2003). Poe Powerhouse has a generating capacity of 142.83 Mega-Watts and the Rock Creek-Cresta project has a total combined capacity of 185 Mega-Watts (FERC, 2016). Prior to 2006, power production was on a steady increase (Fig. 12) but as the 2006-2007 El Niño ended and the 2007-2008 La Niña year began, a substantial decline in energy production occurred. California has been experiencing a drought since 2012. The drought conditions have resulted in a consecutive decline of energy production.
The Poe project is able to produce more energy than the Rock Creek-Cresta project due to water being diverted to the reservoir. Water flows from the Rock Creek project and enters the Cresta reservoir. The Cresta reservoir collects water from the Bucks facilities further upstream as well as many tributaries. This water is then diverted to the Cresta powerhouse, which feeds the Poe project. The Poe project receives more water and consequently able to produce more electricity, even though the Rock Creek-Cresta project has a larger capacity.

**Future Changes**

The decrease in low elevation snow pack has reduced the amount of hydroelectric power generated (Freeman, 2011). The future changes in the amount and type of precipitation can result in a decrease of hydropower. With the North Fork Feather River watershed losing a total of about 63% of the snow pack that feeds the system just between the years 1965 and 2010 (Freeman, 2011), the management of the water needs to be altered to combat this drop in snow pack. This change in amount of snow pack occurred over 45 years: a license can be valid for up to 50 years. With an increase of rain in the future, water might not be available in later months. Currently the floodgates are to remain open during winter storm events (Freeman, 2013). The gates should be allowed to close during the winter months to fill the reservoir, if there is no
threat of flooding. If a possibility of flooding is present, enough water could be released but still allow the reservoir to fill completely.

Air temperatures are predicted to increase as much as 6.8 degrees Fahrenheit in Plumas County (Fig. 13) by the year 2100 (Cal-Adapt, 2016) with A2 emissions. In turn, water temperatures have been steadily increasing; temperatures have increased by 6.8°F since 1962 (Freeman, 2011). The rate of temperature increase is 2-4 times faster than the majority of river systems in the Sierra Nevada Mountain Range (Freeman, 2011). Water temperatures should remain at or below 20°C during summer months until the year 2050. At that time, major changes will need to occur in the management of the North Fork Feather River.

![Observed and Projected Temperatures](image)

**Figure 13:** (Cal-Adapt, 2016) The observed and predicted air temperatures in Plumas county based on either B1, low emissions, or A2, high emissions until the year 2100. The observed, or historic, temperatures are shown from the years 1950 to 2000.

The number of dry water years is likely to continue to increase (Fig. 14). Between 1935 and 1975 there was only one dry water year while between 1976 and 2010, there were 11 dry water years (Freeman, 2011). The number of dry water years occurring between 2011 and 2050 will increase to 16 and between 2051 and 2099 the number will increase to 20 dry water years. The number of dry water years between 2011 and 2099 was calculated by using the data from Freeman, 2011 and projecting the increase using the values from Null and Viers (Appendix 1). With more dry years occurring, evapotranspiration is occurring more frequently. The amount of vegetation cover has increased since the 1970’s, which can account for some of the increased evapotranspiration. During the years 1991-2010, evapotranspiration occurred 61% more than
between the years 1971 and 1990 (Freeman, 2011). The increase in dry water years indicates that there will be less water available in the watershed.

![Number of Dry Years in the North Fork Feather River Watershed](image.png)

**Figure 14**: The number of dry water years in the North Fork Feather River Watershed. 1935-1975* and 1976-2010* is actual data observed (Freeman, 2011) while all other data is projected based on the frequency of dry water years using Null and Viers, 2013 predicted increase of percentage of dry water years.

Lake Almanor supplies the North Fork Feather River with water throughout the year. Lake Almanor has the storage capacity of 1,175,000 acre-feet (FERC, 2016). The amount of unimpaired inflow, or natural flow, into Lake Almanor during the summer and fall months has declined by about 33% since 1925 (Freeman, 2011). Snowmelt accounts for 50% of the water that fills Lake Almanor (Buer, 2003). In an A2 emissions scenario, Cal-Adapt (2016) estimates that there will be a 95.5% decline of the amount of snow in Plumas County by the year 2100 (Fig 15).

![Projected Snow Moisture](image2.png)

**Figure 15**: (Cal-Adapt, 2016) Shows the amount of snow in Plumas County with either a B1 or A2 emissions scenario from the year 1960 to 2100.
A ten-year average of the maximum and minimum water levels (Project 2015, 2016) in the lake was used to estimate future levels given the snowpack predictions (Cal-Adapt, 2016), see Appendix 2 for calculations. Once the ten-year average was calculated, the amount of water from snowmelt (50%) was calculated. Then that amount was decreased by 5, 25, or 50 percent. These increments were chosen because the minimum amount Lake Almanor was filled was 60% so a decline of 25 and 50% would result in major changes and a 5% decline was calculated to show what the best outcome could be if human emissions were reduced and the affects of climate change were lessened. The amount of water in acre-feet was calculated for each percent decline, which was then converted into a percentage of the total capacity of Lake Almanor. These calculations do not take the increased amount of rainfall into account. The amount of rainfall is very unpredictable from year to year so an average would not give an accurate prediction. The calculations assume the decline in snowmelt but do not show an increase in other sources of water.

Table 5 shows that if the snowpack has a 5% decline in 2051 Lake Almanor will be filled between 18-26% while if there were a 25% decline the lake would be filled 16-23% of the total capacity. With a 5% decline in 2100 Lake Almanor would be filled between 0.1-13% of the total capacity and if there were a 25% decline the lake would result in a 0.1% fill of capacity.

Table 5: Storage level in Lake Almanor in 2010, 2051, and 2100 at various amounts of decline of snow pack. Annual snow pack data from Cal-adapt, 2016. Lake Almanor has a capacity of 1,175,000 acre-feet (FERC, 2016).

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2051</th>
<th>2100</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum Acre Feet</td>
<td>Maximum Acre Feet</td>
<td>Maximum Acre Feet</td>
</tr>
<tr>
<td></td>
<td>954,482</td>
<td>299,472</td>
<td>147,685</td>
</tr>
<tr>
<td>% Lake Almanor Full</td>
<td>81%</td>
<td>26%</td>
<td>13%</td>
</tr>
<tr>
<td>Minimum Acre Feet</td>
<td>692,598</td>
<td>621,562</td>
<td>107,164</td>
</tr>
<tr>
<td>% Lake Almanor Full</td>
<td>58%</td>
<td>53%</td>
<td>18%</td>
</tr>
<tr>
<td>5% decline</td>
<td>856,586</td>
<td>268,757</td>
<td>18,934</td>
</tr>
<tr>
<td>25% decline</td>
<td>73%</td>
<td>23%</td>
<td>0.1%</td>
</tr>
<tr>
<td>50% decline</td>
<td>734,217</td>
<td>230,363</td>
<td>113,604</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Maximum Acre Feet</td>
<td>Minimum Acre Feet</td>
<td>Minimum Acre Feet</td>
</tr>
<tr>
<td></td>
<td>217,305</td>
<td>195,017</td>
<td>96,173</td>
</tr>
<tr>
<td>% Lake Almanor Full</td>
<td>18%</td>
<td>16%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Minimum Acre Feet</td>
<td>107,164</td>
<td>96,173</td>
<td>82,434</td>
</tr>
<tr>
<td>% Lake Almanor Full</td>
<td>1.0%</td>
<td>0.1%</td>
<td>0.1%</td>
</tr>
<tr>
<td>5% decline</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25% decline</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>50% decline</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The North Fork Feather River will be affected by climate change. With the decline in snowpack, increasing temperatures, and increase in dry water years the production of hydropower will decline. This decline will not occur until the late 2050’s. The license of the Rock Creek-Cresta project will not begin the relicensing process until 2029 with the final decision occurring before the license expires in 2034. The new license should change to incorporate climate change so the effects are not exacerbated.

Kern River

The Kern River is located in central California near the city of Bakersfield, California (Fig. 16). The Kern River is a tributary in the Tulare Lake Basin Watershed (EPA, 2016). The Kern River’s drainage area is 4,481 square miles (ECORP, 2007) of the southern portion of the Sierra Nevada Watershed. The Kern River stretches about 165 miles in length (USGS, 2016). The Kern River is at low elevation; Lake Isabella is at 2,513 feet above sea level while the furthermost downstream powerhouse, Kern Canyon, is 771 feet above sea level (EPA, 2016). Isabella Lake is the only reservoir that feeds the hydroelectric facilities downstream. The majority of the river is upstream from Lake Isabella.

The Kern River historically drained into the Buena Vista Lake and the Kern Lake (Central Valley Regional Water Quality Control Board, 2016). Buena Vista Lake is now a dry lake with two small man made lakes present, Lake Webb and Lake Evans (Central Valley Regional Water Quality Control Board, 2016). Both lakes occupy the northern area of the dry lake (Central Valley Regional Water Quality Control Board, 2016). Both lakes reside in the dried bed of Buena Vista Lake, where the Kern River historically ended. Currently, the water is diverted to the California Aquifer and used for irrigation and agriculture (USGS, 2016). Presently, Kern Lake is also a dry lakebed (Central Valley Regional Water Quality Control Board, 2016). Both lakes are dry due to irrigation diversions (Central Valley Regional Water Quality Control Board, 2016). Currently, the water is diverted to the California Aquifer and used for irrigation and agriculture (USGS, 2016).
This section will primarily focus on the conditions downstream of Lake Isabella because the majority (i.e. three of the four) of the hydroelectric projects on the river are located in this area. Lake Webb and Lake Evans are man made lakes that were built for recreational purposes. Overall, there is a declining trend in the amount of water that is moving downstream. The annual precipitation in the Kern watershed is about 13.24 inches a year (ECORP, 2007). The average annual rainfall during the winter and fall months accounts for 10.88 inches of the yearly total precipitation (USGS, 2016). The average daily discharge (Fig. 17) is 305 cubic feet per second, while the actual discharge on average is about 126 cubic feet per second (USGS, 2016).

![Figure 17](image-url) (Data source: USGS, 2016) Hydrograph of the Kern River at gauge 1189500 from 2008 to 2015 with conditional 2016 data. A steady decrease in the overall amount of water being discharge from the Kern River is occurring. The gauge is located upstream of Lake Isabella.
The source of water for the Kern River varies depending on the water year type (Table 6). During normal water years, the primary source of water is surface runoff from rainfall, groundwater is the secondary source of water, and reclaimed water is only a small amount. During a critically dry year, ground water is the primary source of water with reclaimed water being the secondary source and surface runoff form rainfall is only one percent of the total available water. The snowmelt from Mount Whitney is a small source of water of this river (EPA, 2016).

<table>
<thead>
<tr>
<th>Source of Water</th>
<th>Wet Year</th>
<th>Normal Year</th>
<th>Critically Dry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reclaimed Water</td>
<td>9%</td>
<td>12%</td>
<td>13%</td>
</tr>
<tr>
<td>Ground Water</td>
<td>10%</td>
<td>28%</td>
<td>86%</td>
</tr>
<tr>
<td>Surface Runoff (Rain)</td>
<td>81%</td>
<td>42%</td>
<td>1%</td>
</tr>
</tbody>
</table>

Table 6: (Data Source: Central Valley Water Board, 2016) Percentage of three different sources of water depending on the water year type.

The large amount of groundwater that is extracted to feed the river, naturally occurs due to the water welling up during dry conditions, due to the make up of the soils and bedrock beneath the river bed (Tulare Lake Hydrologic Region, 2004). Water from the Kern River is primarily used for ground water recharge with the rest used for irrigation and agriculture use (Central Valley Regional Water Quality Control Board, 2016). Figure 18 shows the amount of water being discharged from the watershed from January 1, 2016 to April 12, 2016 having an increasing trend. The general trend is increasing because of the time of year of the data the graph is displaying. The present discharge levels are significantly less than the projected levels based upon historic discharge data. Figure 19 shows the general decline of discharge annually at the USGS gauge number 1189500 in Santa Maria, California.
The primary source of water is rainfall that collects throughout the watershed in the Sierra Nevada Mountain Range during normal water years (Central Valley Regional Water Quality Control Board, 2016). The runoff that accumulates in Lake Isabella supplies water to the

![Graph showing daily discharge changes over time.](image)

**Figure 18:** (Data Source: USGS, 2016) The daily discharge in Santa Maria, California from January 1, 2016 to April 12, 2016. Measured at USGS gauge 11189500 SF Kern Onyx. The difference between the historic data and the present data is significant. The greatest difference occurs at the end of January and the beginning of February. Discharge is the amount of water that the gauge measures while the measured discharge is when a USGS employee measures the discharge.

![Graph showing discharge data from 2008 to 2015.](image)

**Figure 19:** (USGS, 2016) Daily discharge of the Kern River from October 1, 2007 to October 1, 2015 in Santa Maria, California. This data is from the USGS gauge number 111895000 SF KERN Onyx. The amount discharged has declined from the high in 2011.
lower Kern River throughout the year. Lake Isabella is the only reservoir that is able to store water as the Kern River is a run of the river system and there are no other lakes located on the Kern. When the water supply is very limited during the hot summer months, water is manually released downstream.

**Stakeholders and Management**

Three major stakeholders manage the Kern River: the U.S. Army Corps of Engineers, Southern California Edison Company, and Pacific Gas and Electric Company. The U.S. Army Corps of Engineers has owned and operated Isabella Dam since 1953 when it was constructed (U.S. Army Corps of Engineers, 2016). The U.S. Army Corps of Engineers manages Lake Isabella for recreation, flood management, and irrigation (U.S. Army Corps of Engineers, 2016). Southern California Edison owns and operates three powerhouses: Kern River No. 1, Kern River No. 2, and Borel Canyon (FERC, 2016). Pacific Gas and Electric Company owns the Kern Canyon project (FERC, 2016). Kern Canyon is the furthest downstream hydropower facility (Fig. 20). Southern California Edison owns one hydropower facility that is located upstream of Lake Isabella, Kern River No. 3. This section will only discuss Southern California Edison’s Borel Canyon, Kern River No. 1 and Pacific Gas and Electric’s Kern Canyon projects because they are located on the main stem of the Kern River and do not have water diverted to them from tributaries. Along with the three main stakeholders, there are many state and federal agencies that are responsible for the management of the land that is around the projects.
The agencies that are involved with these projects include many federal and state agencies and special interest groups. The federal agencies include the National Park Service and the U.S. Forest Service (FERC, 2016). The State Water Control Board monitors the water quality throughout all the projects (Hydropower Reform Coalition, 2009). American Whitewater is a private interest group that advocates for a recreation release of water every month.

American Whitewater leads trips downriver and works with the utility companies to ensure that there is an adequate flow for their activities (Hydropower Reform Coalition, 2009). The upper reaches of the Kern River are managed heavily for recreation. The flows that are required by the license are the minimum flows and the recreation flows only happen if there is adequate water in Lake Isabella. The minimum seven-day average of flows is 20-25 cubic feet per second must be present in the streambed.

All hydroelectric projects located on the Kern River are classified as run of the river systems. This means that there is no storage of water throughout the projects area (Hydropower Reform Coalition, 2016). Headwater benefits are a condition of the licenses of the Kern Canyon,
Kern No. 1, and Borel Canyon projects (FERC, 2007). Headwater benefits are a condition when a project directly benefits from other projects located upstream (FERC, 2007). Each project must pay the hydroelectric facility upstream because they are creating electricity, and profit, because the upstream facility released water. Pacific Gas & Electric Company pays headwater benefits to the Southern California Edison Company, who pays the U.S. Army Corps of Engineers for the releases from Lake Isabella.

*Hydroelectric Projects and Energy Production*

The Borel Canyon powerhouse is the first project downstream of Lake Isabella and is owned and operated by Southern California Edison Company. A new license was issued on May 17, 2006 and will not expire until April 30, 2046 (FERC, 2016). The Borel Canyon project has an authorized capacity of 12000 mega watts (FERC, 2016). Currently, this project has thermal pollution and nutrient loading water quality issues (Hydropower Reform Coalition, 2016). The special status species are located within the project area and are of main concern on the project is the elderberry longhorn beetle (Hydropower Reform Coalition, 2016). Below the powerhouse there is a 14-mile stretch that is classified as a class III whitewater run (Hydropower Reform Coalition, 2016). This prompted the new license to have a new minimum flow rate of 25-60 cubic feet per second (FERC, 2016).

Kern No. 1 project is the next project downstream. The project has a total capacity 40.20-mega watts (FERC, 2016). The current license was issued on June 16, 1998 and is valid until May 5, 2028 (Hydropower Reform Coalition, 2016) and is owned by Southern California Edison Company. There are no water quality issues with this project. There is an 11.8 mile stretch of river that is classified as III, IV, and V for whitewater rafting downstream of the hydroelectric facilities (Hydropower Reform Coalition, 2016).

Kern Canyon is located farthest downstream of Lake Isabella, near the city of Bakersfield, California and was first licensed in 1925 (FERC, 2009). Kern Canyon has the generation capacity of 11.5 mega watts (FERC, 2009). This powerhouse is responsible for 0.88% of the total hydroelectric power generated by Pacific Gas & Electric Company and it is
responsible for only 0.085% of the total of electricity that is sold by the company (FERC, 2007). Currently, the special status species that are found in the project area are not likely to affect the project. These species include the elderberry longhorn beetle, the blunt nosed leopard lizard, the California red-legged frog, the California condor, and the Bakersfield cactus (FERC, 2009). The hardhead minnow is a sensitive species that required a change in the license. An increased flow rate allows the dissolved oxygen levels to increase and the average water temperatures to decrease, creating a suitable habitat for the minnow (FERC, 2009). The minimum flows were a seven day average of 20-25 cubic feet per second, while the new minimum flow requirements are a seven day average of 50-60 cubic feet per second to ensure the habitat is suitable for the hardhead minnow (FERC, 2009). The increase of water flow decreases the generation production and on average there is a loss of revenue of 20,410 dollars a year as a result of providing the habitat for fish (FERC, 2009).

Kern Canyon has been able to continuously generate over 3,500 mega watt-hours between 2001 and 2008. Figure 21 shows the amount of net energy Kern Canyon has produced less than 3,000 mega watt-hours since 2010. In 2014 only 1,5000 mega watt-hours were produced. Due to the run of the river nature of this project, the amount of energy that is produced is solely based upon how much rainfall occurs throughout the year. As a decrease in rainfall is predicted for the area, a decline in electricity produced will be the result.

**Figure 21:** (Data Source: CA Energy Commission, 2016) The net amount of electricity produced by the Kern Canyon powerhouse on the Kern River between the years 2001 and 2014. Overall, there is a decline of amount produced since 2009. The decline in energy produced can also be attributed to the protection of the hardhead minnow in 2009 in addition to the decline of water availability.
The amount of electricity that is produced depends on the amount of water that is available in the streambed. The amount of hydropower will continue to decline with the increase of climate change affects. If the amount of energy that is produced continues to decrease at this rate, the Kern Canyon powerhouse will not be able to produce enough energy to be considered profitable.

**Future Changes**

The Kern River’s water source varies greatly based upon the type of water year. With the source of water primarily being groundwater during dry years, the ground water recharge plan will need to be improved. During normal years, the source of water is surface runoff from rainfall. The amount of rainfall (Fig. 22) has been constantly been between 8-9 inches annually. Given A2 emissions, the amount of rainfall in Kern County will be less than 7.5 inches annually (Cal-Adapt, 2016). The less rainfall that occurs will result in the stream flow will consist of groundwater and reclaimed water. The amount of ground water that is available will eventually decrease to a point that it is no longer feasible.

![Figure 22](https://example.com/figure22.png)

**Figure 22**: (Cal-Adapt, 2016) Precipitation as rainfall given either low emissions (B1) or high emissions (A2) of Kern County from 1960 to 2100.

Air temperature will increase due to climate change. With A2 emissions the temperatures in Kern County will increase by 6.3°F by the year 2100 (Cal-Adapt, 2016). Figure 23 shows how air temperatures will increase based upon low emissions (B1) and high emissions (A2).
Historically, temperatures have averaged 61.4°F; temperatures will continue to rise over the next century. With the raise in air temperatures, the water temperature will increase to above the twenty degree Celsius maximum for the seven-day average (Freeman, 2001).

![Observed and Projected Temperatures](image)

**Figure 23:** (Cal-Adapt, 2016) Increased temperatures in Kern County based on high (A2) emissions and low (B1) emissions.

During a normal water year, 42 percent of the water is from surface runoff from rainfall and during a critically dry water year only one percent of the water is from surface runoff from rainfall (Central Valley Water Board, 2016). During a critically dry water year the amount of rainfall can decrease up to 50 percent with a change that Lake Isabella could supply the river with water throughout a majority of the year.

Table 7 shows in a normal water year in the year 2100, a 5% decline in rainfall would result in Lake Isabella being 17.2-42% full and a 25% decrease would leave the lake only 15.7-38.3% full. Appendix 3 shows the calculations of the amount of water that is predicted to be in Lake Isabella with a decrease of 5 and 25 percent of rainfall in either a normal or critically dry water year.

The method of the calculations utilized the know levels of Lake Isabella from 2001 to 2010 (CA Data Exchange, 2016). A ten-year average was taken and the percentage was calculated given the capacity of Lake Isabella. The annual precipitation for Kern County was used for the year 2010 and 2100 (Cal-Adapt, 2016). Given the amount of water supplied by rain
for a dry year and a normal year, the maximum and minimum values of Lake Isabella were calculated. The maximum and minimum values were then decreased by 5 and 25 percent, in order to calculate the total capacity of the lake at the given time. These increments were chosen because the minimum ten-year average was 22%, so 25% was chosen and 5% was calculated to show what the best outcome could be if human emissions were reduced and the affects of climate change were lessened.

Table 7: Shows the amount Lake Isabella would be filled with a 5 and 25% decline in the amount of rainfall in Plumas county during normal water years and critically dry water years. During normal water years 42% of the water in lake is from runoff from rain and during critically dry years 1% of the water present is attributed from rainfall.

<table>
<thead>
<tr>
<th>Normal Water Year</th>
<th>Dry Water Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5% decline</td>
</tr>
<tr>
<td>Maximum Acre Feet</td>
<td>290,173</td>
</tr>
<tr>
<td>% Lake Isabella Full</td>
<td>51%</td>
</tr>
<tr>
<td>Minimum Acre Feet</td>
<td>119,278</td>
</tr>
<tr>
<td>% Lake Isabella Full</td>
<td>21%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2100</th>
<th>2010</th>
<th>5% decline</th>
<th>25% decline</th>
<th>25% decline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Acre Feet</td>
<td>238,008</td>
<td>217,586</td>
<td>Maximum Acre Feet</td>
<td>243,113</td>
</tr>
<tr>
<td>% Lake Isabella Full</td>
<td>42%</td>
<td>38%</td>
<td>% Lake Isabella Full</td>
<td>43%</td>
</tr>
<tr>
<td>Minimum Acre Feet</td>
<td>97,835</td>
<td>89,441</td>
<td>Minimum Acre Feet</td>
<td>99,884</td>
</tr>
<tr>
<td>% Lake Isabella Full</td>
<td>17%</td>
<td>16%</td>
<td>% Lake Isabella Full</td>
<td>18%</td>
</tr>
</tbody>
</table>

The Kern River will be impacted greatly from the affects of climate change. The amount of precipitation will decrease, the water temperatures will rise, and the amount of water will decrease. The low elevation of the system and the location in a more desert climate will amplify these affects. The future of a hydroelectric facility located on the Kern River is questionable. The amount of energy that is profitable will likely not be generated passed the year 2050 or 2060. By the year 2100, Lake Isabella will be a dry lakebed if the critically dry years continue with little to no ground water recharge and all hydropower facilities located downstream will need to be removed.
Removal of a Powerhouse

A hydroelectric project would need to be removed if the amount of energy produced is no longer profitable. Removal is also an option when there are environmental conditions that would require a large mitigation cost. This section will introduce the need for a total removal of a hydroelectric project, review a specific example on the Klamath River (located in Southern Oregon and Northern California), explain when to remove a project, and introduce some other options other than removal.

There are three different scenarios for when a hydroelectric project should be removed. The first is when there is no longer a need for the project due to a lack of water present. This is the most obvious time when removal should occur. The powerhouse can no longer produce energy to off set the cost of operation. The second is when there is a significant environmental cost to relicense. An example of this is if a fish passage needs to be installed before the Federal Energy Regulatory Commission will grant a new operating license. The cost of a new fish passage could range anywhere from 200 to 377 million dollars depending on the length of the passage (Cubed, 2006). The third time when a project should be removed is if there is a combination of a lack of production and a large mitigation cost for an environmental condition that must be met before a new license can be issued.

When a hydroelectric project is removed, there are several steps before the decommissioning can start. The owner of the project must submit a letter of interest to the Federal Energy Regulatory Commission before their current license expires. After the letter of intent is filled, an environmental review and cost analysis has to be submitted (FERC, 2016). The report must include environmental actions to be taken if the project is decommissioned or relicensed. This is done to prove that there is a need to remove the project if an environmental condition is the reason for decommission. The cost analysis must also include information for decommission and relicensing of the project. An alternate source of power must be presented to supply customers with adequate power. This could include power from solar or natural gas as long as the electricity needs are met (FERC, 2016).
The Klamath River Hydroelectric Project, owned by Pacific Corp, filed for decommissioning in 2007 (CA Energy Commission, 2007). The hydroelectric project consisted of four dams and powerhouses in Northern California and Southern Oregon, which had the generation capacity of 169 mega watts (CA Energy Commission, 2007). When the letter of intent of decommissioning the project was filed, the facilities were 90 years old (CA Energy Commission, 2007). Even though the generation capacity was 169 mega watts, the powerhouses regularly produced 42.7 mega watts annually (CA Energy Commission, 2007).

The amount of energy produced was much less than capacity because the system was acting as a run of the river type of project instead of the conventional system, with no large storage reservoirs (CA Energy Commission, 2007). When it was originally licensed, the Klamath River Project was classified as a conventional hydroelectric project. This change occurred due to the environmental effects for the native salmon species (CA Energy Commission, 2007). The change from a conventional system to a run of the river system was to allow for fish passage during spawning months. The Klamath River project accounted for two percent of the total electricity produced by Pacific Corps and one percent of the total electricity sold by the company (CA Energy Commission, 2007).

The project had two issues that prompted the removal. The first was a mitigation cost to replenish some of the 300 miles of native salmon habitat that was lost due to the hydroelectric facilities (CA Energy Commission, 2007). The second issue was water quality monitoring. Water quality devices would need to be installed to allow for adequate monitoring throughout the year. If the devices were not installed, the project would no longer be compliant under section 401 of the Clean Water Act (CA Energy Commission, 2007) and Pacific Corp would have to come up with a plan to correct the water quality issues. The cost of these improvements to the project would cost 114 million dollars more than the cost of decommission (CA Energy Commission, 2007). The 114 million was estimated in 2006, today it would cost over 134 million dollars.

The mitigation due to environmental damage from the presence of the Klamath River hydroelectric facility would cost 223-415 million dollars (CA Energy Commission, 2007). In addition to the environmental damages, a 23% decline in power production was estimated over
the 30-year life of a new license (CA Energy Commission, 2007). The power replacement aspect of the decommissioning was estimated to be between 58 and 153 million dollars over the next 30 years (CA Energy Commission, 2007). The cost of decommission of the project was estimated to be 38 to 71 million dollars (CA Energy Commission, 2007). Decommissioning the project was a cheaper option than installing a fish passage for 170-320 million dollars, mitigation for non-fish passage conditions for 70-120 million, and improving the water quality at 20-90 million dollars (Cubed, 2006; Blevin, 2007). All of the dollar amounts are given at 2006 monetary values. The Federal Energy Regulation Commission approved the decommissioning of the project.

The decommissioning of a project is the last resort option. The factors of removing the project depend on the project itself. A conventional system (Fig. 23) needs the change in power production, the amount of water available, water quality issues, and environmental issues reviewed. A conventional system is more resilient to changes because water can be collected during storm events and if at high enough elevations, snow melt can be collected also. A run of the river system (Fig. 24) is less resilient to climate change because it solely depends on precipitation to generate power.

If the owner of a project is unable to prove that decommissioning is not worth the cost to the Federal Energy Regulatory Commission, there is a different alternative. If the owner is able to relicense the project but not able to produce enough power to off set the operational cost, one option is to allow water to pass through the powerhouse and not generate any electricity whatsoever. This allows the project’s buildings and structures to remain intact and the cost of restoring the landscape to its original state is avoided. All of the environmental conditions are still required to be in-compliance by the project’s owner. An analysis of 417 hydroelectric facilities worldwide was completed and it was found that environmental reasons accounted for 39% and safety accounted for 34% of the total decommissioned hydro projects (International Water Power, 2009).

The removal of a powerhouse requires a large amount of money, but it may be the cheaper alternative to relicensing. A project must not be able to produce enough power to supply to the consumers and/or have a large environmental impact on the project area.
Decommissioning takes years and costs a large amount of money; the benefit is the potential to restore the area back to its original landscape.
Figure 24: Decision tree of when to decommission or relicense a project.
Recommendations

With a predicted increase of temperature by as much as 4.8°C and other affects of climate change in California, hydroelectric facilities not updating the management strategies will be unable to produce this form of “clean” electricity (Cayan et al., 2008). This section will focus on changing management practices to improve all aspects of a hydroelectric project, changing conditions of the license, and recommendations for both case studies.

The management of hydroelectric facilities needs to include how to combat climate change. The management strategy should include allowing higher elevation reservoirs to collect water during winter storms. This is crucial due to the shift from snow to rainfall. The collection during winter storms would ensure that the reservoirs are filled to capacity before the warm summer months, when water is very scarce. This management strategy would combat the shift in precipitation type because the operators of the dams would be able to collect the rainwater and not depend on snowmelt to fill the streambed in the summer. Snow is measurable and a predictable source of water while rain is unpredictable.

The regulation that prohibits the collection of winter storm water due to the spill gates that are to remain open in most mountainous reservoirs was written and made law by the California Department of Sam Safety and Regulation in 1995 (State of California, 1995; Freeman, 2003). One change that should be proposed is to change this outdated regulation. The regulation was written to avoid flooding in the mountain areas during large storm events. This regulation is no longer needed due to the limited number of large event occurring and the minimal amount of water present. Snowmelt was primarily filing the reservoirs in April to June supplying the river with water. The shift to less snow and more rain will allow for less water from snowmelt to fill the reservoirs in those early summer months. The risk of flooding occurred when reservoirs would slowly be filled with snowmelt and a large winter rainstorm would occur and possibly flood the reservoir. This regulation should be updated to account for current conditions and allow for rain capture when storm events occur.

Advancement in technology will have to transpire in order to track and estimate winter storms. This new technology could allow operators of hydroelectric plants to release water
before a big winter storm to avoid flooding. The collection of water during winter storms will also ensure that the lake or reservoir will not dry up during the summer months due to water scarcity. The advanced technology will ensure the predictability of depending on rainwater instead of snowmelt. The main reason climate change is not included in the relicensing process today is due to the lack of advanced technology. This technology needs to be able to accurately predict storm events and the degree that climate change will affect a small area, like the project boundary.

An increase in storage in conventional systems may offset the affects of climate change. This would only be possible if there is enough water present and the storage reservoir is capable of this. Most reservoirs are used to satisfy the recreation aspect of the operating license. This means that there are ample campgrounds and trails around the area of the reservoir. Increasing the storage capacity would be a large upfront cost; however, could result in an increase in electricity production over many years.

During the summer months, conventional hydro systems should allow enough water to flow downriver to not only meet the requirements set by the Federal Energy Regulatory Commission, but to exceed them. Larger flows would satisfy the different agencies specific needs. For example, there would be more days that would qualify as recreational flow for the American Whitewater group.

With so many different agency needs, there should be better communication between the agency and the owner of the license. The owner of a license is mandated to let all agencies review any changes or reports before they are final. This process can take months. Normally the time delay is due to budget restraints. An increase of people reviewing project documents would eliminate this issue and cause change to happen more quickly.

Due to the longevity of a license, 30-50 years, change does not occur frequently. Occasionally, a condition of a license is approved and is absolutely unrealistic. For example, one condition of the Crane Valley project, owned by Pacific Gas & Electric Company, is to conduct a fish population survey once a month during the summer months in a specific reach of a tributary of the river. This specific tributary has been dry for many years. The fish population survey still must be completed. During the fish surveys, a staff member must walk the dry riverbed and
report that there are still no fish. Conditions like these need to be taken out of the license to avoid wasting the time and money of the operating staff.

The license should be valid for shorter amounts of time, 15-25 years. The shorter license will allow for changes to occur more frequently. These changes should include flow rates that account for lower amounts of water that is available, increasing the frequency that water temperature is monitored, and to update the list of possible sensitive species that are located throughout the project area. A license of 15-25 years would allow ample time to conduct environmental impact reports and allow all agencies to review and suggest changes.

The North Fork Feather River will have a shift in the type of precipitation from snow to rainfall. The change to allow for collection during winter storms will allow for the continuation to generate electricity with hydropower. Water temperatures will be an issue by 2050 and improvements should be made now to allow for a larger amount of cold water to flow downstream if possible.

The Kern River should continue to generate electricity normally. The generation should continue until the point where little water is available and the operation costs exceed profits. This could occur as late as 2100, if normal water years occur, or as early as 2050 if dry water years continue to occur. The Kern Canyon project may be found obsolete and the removal of the system is more likely to occur than a project found on the North Fork Feather River. Due to groundwater supplying the river during dry years, the focus should be on groundwater recharge so that the aquifer does not dry out. Most of the water from the Kern River is used for irrigation for agriculture so the presence of water in this area is important.

Conventional system can be more resilient to the affects of climate change, specifically to the amount of water that will be available. Conventional systems with water from diverse sources will prove to be the most resilient, with water from rain, snow, and groundwater. Even with reservoirs to store the water, if the primary water source is from snowmelt then that specific project, for example the North Fork Feather River, will not be able to exist with the minimum amounts of water available due to climate change. Due to the ability to store large amounts of water throughout the year to supply enough water through the summer months is the primary reason that conventional systems will outlast run of the river systems.
Run of the river systems will likely become obsolete and need to be completely removed. The only option to save these projects would be to convert them to conventional systems by installing large reservoirs throughout the system. This would require many federal and state agencies to agree to allow a valley or area of land to be converted to a reservoir. The likelihood of this occurring is very small. Land is a precious resource and giving up terrestrial habitat for sensitive species to convert it to a reservoir would be in violation of the operating license and many laws associated with the Endangered Species Act.

One management change should be to develop a plan, to secure a certain amount of money each year from the owners and operators of each facility. This money would be designated to fund the maintenance and eventually the removal effort of that project. The money could be generated from the company’s profit margin each year, with a minimum amount to be allocated. The amount saved over the life of the license could fund any environmental impacts that are not foreseen with a specific percentage assigned to the removal of the project. This management change could help off set the large amount of money that is required to ensure all environmental impacts are being met. It will also allow for mitigation due to decommissioning a project to occur faster.

All hydroelectric projects are not created equal in California. Due to the highly varied climate and landscape throughout the state, each facility should be looked at individually. The management recommendations need to be tailored to specific projects. Each license has specific water quality, stream temperature, and habitat requirements that need to be individually addressed. More data is needed about future predictions on climate change in order to manage the facilities to the best of our abilities. There is always going to be a level of uncertainty due to climate change; however, each license holder needs to manage the facility with climate change in mind and alter the management accordingly.

The management of the hydroelectric projects in California needs to adapt to the affects of climate change. Without making these changes, the future of hydropower as a clean, renewable resource will diminish. The most important management change needs to address the limited amount of water available. Without water, there is no hydroelectric generation. These management changes need to occur now. The owners, federal and state agencies, and the private
organizations need to come together to alter the laws and regulations in order to keep hydroelectric generation a viable renewable power source.

Many factors affect hydroelectric production including, environmental, land rights, water rights, costs of maintenance and relicensing. With increasing maintenance and environmental costs, the future of hydroelectric generation could be limited. Before the twenty-first century, all hydroelectric facilities in California will become hard to manage and pay for. The millions to billions of dollars spent on maintenance and environmental costs could be spent wiser. The removal of all hydroelectric facilities could restore tens of thousands of acres of wild rivers and species habitat. When hydroelectric facilities are removed, the land rights should be converted from private land to a land trust so that no alteration of the landscape and commercial or residential building can occur. The land could also be converted to a different form of renewable energy. The amount of energy produced by hydropower can be supplemented by an increase in solar, wind, natural gas, or hydropower form outside of California.

More data collection and reviews of specific hydroelectric facilities needs to occur. The data that needs to be collected is how much water present is the absolute minimum before the project is considered to not be able to produce enough electricity to renew the license. Water temperature predictions as well as how to allow for cold water to flow downstream providing habitat needs to be improved. Data on how much rain fall per storm event in a specific location or watershed need to be developed. Additional information on how to reduce the costs of maintenance and improve environmental conditions needs to be greatly improved.

Hydropower facilities were not built to have an indefinite lifespan. When the facilities were built in California, the lifespan was no longer than 100 to 150 years. With utility companies utilizing a cheap form of electricity, it is hard to give up the profits even with high maintenance and environmental costs. With environmental costs reaching over 300 million for a single fish ladder and other costs for personnel to conduct species surveys, is spending this amount of money worth producing less than 7% of the states electricity budget or can this money be spent improving other technologies for solar, wind, and natural gas?
Conclusions

Hydroelectric power supplies 2.1% of California’s electricity as a clean and renewable source of energy to about two million people (PG&E, 2016; CA Energy Commission, 2016). California’s hydroelectric facilities were built between 1930s and the 1970s (Null et al., 2014). A total of 287 hydroelectric facilities located in California are licensed to operate for 30-50 years (FERC, 2016). Over 94 projects will need to be relicensed in the next thirty years, while the remainder 32 projects either were relicensed between 2009 and 2016 or will be relicensed after 2038 (FERC, 2016). The relicensing process currently does not account for the warming temperatures or the limited amount of water that will occur due to climate change.

Hydropower accounts for less than 7% of California’s power budget. With a large number of facilities, the amount of electricity produced has declined over the past ten years. In 2014, three hydroelectric facilities on the North Fork Feather River (Poe, Rock Creek, and Crest) have produced a total of 684,148-megawatt hours (CA Energy Commission, 2016). In 2006, the same facilities produced 2,321,914-megawatt hours (CA Energy Commission, 2016). On the Kern River, Kern Canyon hydroelectric facility produced 15,517-megawatt hours in 2014 and 50,817-megawatt hours in 2006 (CA Energy Commission, 2016). The lose in revenue for the North Fork Feather River is about 3 million dollars and the Kern Canyon project has lost about 300 thousand dollars.

After analyzing the two case studies, it was found that the first case study of the North Fork Feather River, a conventional system, would reach very minimum levels to no water present by the year 2051 to 2100, if the regulations of collecting winter storm water do not change. Snowmelt will no longer be an option to depend on to fill the reservoirs to feed the river through the warm summer months. As the stream temperatures will continue to rise to over 20 degrees Celsius, native species will no longer be able to inhabit the waterways. If management changes are not made, hydroelectric power generation on the North Fork Feather River will no longer exist.

The second case study, the Kern River, being a run of the river system, is less susceptible to climate change. During normal years, 42% of the water is from runoff from rainfall. A decline
in rainfall by the year 2100 of just 5%, Lake Isabella would be filled 8% less than in 2010. A decline of 25% in rainfall in 2100 would result in a 6% decline from the levels in 2010. During a critically dry water year the Kern River water supply is only 1% supplied by runoff, and 86% from groundwater (Central Valley Water Board, 2016). With a decline in rainfall, the river will rely heavily on the groundwater supply. The groundwater supply will not last with the large amounts needed to meet the demand from agriculture.

In the past ten years, the United States has spent over 3.6 billion dollars to upgrade and maintain existing hydroelectric facilities (Uria-Martinez et al., 2015). The ageing mechanics of all the hydroelectric facilities in California needs to be upgraded. Canals, dams, and the turbines will all need to be replaced. The upgrading of a single facility in California could cost upwards of 3 million dollars annually but, if it is not done, the facilities will become unusable.

The removal of a project would be necessary if the cost of operation exceeds the amount of energy produced to create a profit and/or there is a substantial environmental cost that to be paid before a new license could be issued. Possibly over 70 projects will need to be removed in the future due to lack of water. The removals will allow for the project lands to be reverted to their original landscapes. The act of removal will cost a large sum but it will be the cheaper option to relicensing.

When companies, for example Pacific Gas & Electric Company or Southern California Edison, are unable to meet the electricity demand through hydro-generation, additional power is bought from outside sources. This can include surrounding states, like Washington or Oregon to the north or Arizona to the east. The surrounding states are able to produce more hydropower due to a larger amount of precipitation. If California is unable to supply enough energy through hydroelectric generation instate, the facilities should be removed. However, the decommissioning of a project takes many years and a large sum of money. It is, in some cases, cheaper to buy outside power than it is to remove the project entirely.

In the western states, the top producers of hydroelectric power are Arizona and Washington (FERC, 2016) The majority of hydropower is produced in the New England Region of the United States (FERC, 2016). Climate change affects will be felt at these facilities also, just on a longer time scale. Instead of threat of climate change affects being felt between the years
2050 to 2100, perhaps the East Coast will begin to see drastic changes due to climate change after the year 2100.

In California the future of utilizing hydropower is limited. If climate change conditions continue to proceed given A2 emissions scenarios, all the hydropower facilities in California will need to be removed by 2100. California will need to invest the large amount of money that was spent on maintenance and environmental costs of hydroelectric facilities to a renewable source of energy that is sustainable, for example natural gas that accounts for 44.5% of the states power budget (Energy Almanac, 2015).

Worldwide the affects of climate change will affect the overall amount of power produced by hydroelectric generation. Other forms of renewable resources need to be examined and explored further. The management of hydroelectric should be altered worldwide to ensure the hydroelectric facilities would continually generate a profitable amount of electricity.
Work Cited


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Freeman, G. J. (2012). Analyzing the impact of climate change on monthly river flows in California’s Sierra Nevada and southern California cascade mountain ranges. *Western Snow Conference, 3-14*.


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Appendices
Appendix 1: Calculations For the increase of dry water years in the North Fork Feather River

1935-1975

1 dry year observed (Freeman, 2011)

1976-2010

11* dry years observed (Freeman, 2011)

The percentages used to calculate the increase of dry water years is from Null and Viers, 2013.

2011-2050

12% of 39 years=4.68
4.68+11*=15.68
=16 dry water years

2051-2099

19.4% of 48 years=9.312
9.312+11*=20.312
=20 dry water years
Appendix 2: Calculations for the Decline in Snow Pack for the North Fork Feather River

Annual snow pack with A2 emissions in Plumas County (Cal-Adapt, 2016) Numbers in orange were used to predict future levels.

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Snow Pack in Plumas County A2 emissions (in.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>36.7</td>
</tr>
<tr>
<td>1970</td>
<td>43.2</td>
</tr>
<tr>
<td>1980</td>
<td>33.4</td>
</tr>
<tr>
<td>1990</td>
<td>38.9</td>
</tr>
<tr>
<td>2000</td>
<td>29.4</td>
</tr>
<tr>
<td>2010</td>
<td>34.9</td>
</tr>
<tr>
<td>2020</td>
<td>34.6</td>
</tr>
<tr>
<td>2030</td>
<td>24.3</td>
</tr>
<tr>
<td>2040</td>
<td>30.1</td>
</tr>
<tr>
<td>2050</td>
<td>21.9</td>
</tr>
<tr>
<td>2060</td>
<td>22.8</td>
</tr>
<tr>
<td>2070</td>
<td>19.1</td>
</tr>
<tr>
<td>2080</td>
<td>18.4</td>
</tr>
<tr>
<td>2090</td>
<td>15.5</td>
</tr>
<tr>
<td>2100</td>
<td>10.8</td>
</tr>
</tbody>
</table>

Known Levels of Lake Almanor (Project 2015, 2016)

<table>
<thead>
<tr>
<th>Year</th>
<th>Maximum (af)</th>
<th>Minimum (af)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>839,813</td>
<td>662,618</td>
</tr>
<tr>
<td>2002</td>
<td>909,943</td>
<td>604,959</td>
</tr>
<tr>
<td>2003</td>
<td>1,037,316</td>
<td>705,821</td>
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<tr>
<td>2004</td>
<td>1,006,248</td>
<td>708,763</td>
</tr>
<tr>
<td>2005</td>
<td>1,019,239</td>
<td>731,407</td>
</tr>
<tr>
<td>2006</td>
<td>1,120,000</td>
<td>774,000</td>
</tr>
<tr>
<td>2007</td>
<td>945,000</td>
<td>790,000</td>
</tr>
<tr>
<td>2008</td>
<td>902,000</td>
<td>707,000</td>
</tr>
<tr>
<td>2009</td>
<td>950,000</td>
<td>702,000</td>
</tr>
<tr>
<td>2010</td>
<td>1,060,000</td>
<td>717,000</td>
</tr>
<tr>
<td>Total</td>
<td>9,789,559</td>
<td>7,103,568</td>
</tr>
</tbody>
</table>

Average per year | 978,955.9 | 710,356.8 |

% Capacity of Lake Almanor = 83.3 | 60.5

Capacity of Lake Almanor = 1175000 af
# 2010 Snow Pack Levels

Maximum lake level per year: 978955.9 acre-feet (af)  
Capacity of Lake Almanor = 1175000 af  
50% water is from snow melt

Maximum values:
Snow = 489,477.95 af  
Other sources = 489,477.95 af

<table>
<thead>
<tr>
<th>5% decline of snow</th>
<th>25% decline in snow</th>
<th>50% decline in snow</th>
</tr>
</thead>
<tbody>
<tr>
<td>(489,477.95 af)(0.05)</td>
<td>(489,477.95 af)(0.25)</td>
<td>(489,477.95 af)(0.50)</td>
</tr>
<tr>
<td>=24,473.8975 af</td>
<td>= 122,369.4875 af</td>
<td>=244,738.97 af</td>
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<td>489,477.95 af</td>
<td>489,477.95 af</td>
<td>489,477.95 af</td>
</tr>
<tr>
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<td>465,004.0525 af</td>
<td>367,108.46 af</td>
<td>244,738.97 af</td>
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<td>+489,477.95 af</td>
<td>+489,477.95 af</td>
<td>+489,477.95 af</td>
</tr>
<tr>
<td>954,482 af</td>
<td>856,586 af</td>
<td>734,217 af</td>
</tr>
<tr>
<td>81% capacity of lake</td>
<td>73% capacity of lake</td>
<td>63% capacity of lake</td>
</tr>
</tbody>
</table>

Minimum Lake level: 710356.8 af  
Capacity of Lake Almanor = 1175000 af  
50% water is runoff from rain

Maximum values:
Snow = 355,178.4 af  
Other sources = 355,178.4 af

<table>
<thead>
<tr>
<th>5% decline of snow</th>
<th>25% decline in snow</th>
<th>50% decline in snow</th>
</tr>
</thead>
<tbody>
<tr>
<td>(355,178.4 af)(0.05)</td>
<td>(355,178.4 af)(0.25)</td>
<td>(355,178.4)(0.50)</td>
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<tr>
<td>=17,758.92 af</td>
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<td>355,178.4 af</td>
<td>355,178.4 af</td>
<td>355,178.4 af</td>
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<tr>
<td>- 17,758.92 af</td>
<td>-88,794.6 af</td>
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<tr>
<td>337,419.48 af</td>
<td>266,383.8 af</td>
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<td>+355,178.4 af</td>
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<tr>
<td>69,2598 af</td>
<td>62,1562 af</td>
<td>53,2768 af</td>
</tr>
<tr>
<td>58% capacity of lake</td>
<td>53% capacity of lake</td>
<td>45% capacity of lake</td>
</tr>
</tbody>
</table>
### 2050 Snow Pack Levels

Max levels per year: \( \frac{(4,894,779.5)}{(34.9)} = 140,251.5616 \)
Min Levels: \( (140,251.5616)(21.9) = 3,071,508.885 \) af per 10 years  
307,150. = af per year

Maximum lake level: 307,150.9199 af

Capacity of Lake Almanor = 1,175,000 af  
50% water is from snow melt

Maximum values:
Snow=153,575.46 af
Other sources= 153,575.46 af

<table>
<thead>
<tr>
<th>5% decline of snow af</th>
<th>25% decline in snow af</th>
<th>50% decline in snow af</th>
</tr>
</thead>
<tbody>
<tr>
<td>(153,575.46 af)(0.05)</td>
<td>(153,575.46 af)(0.25)</td>
<td>(153,575.46 af)(0.50)</td>
</tr>
<tr>
<td>= 7,678.773 af</td>
<td>= 38,393.865 af</td>
<td>= 76,787.73 af</td>
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<tr>
<td>153,575.46 af</td>
<td>153,575.46</td>
<td>153,575.46</td>
</tr>
<tr>
<td>- 7,678.773 af</td>
<td>-38,393.865 af</td>
<td>-76,787.73 af</td>
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<tr>
<td>145,896.687 af</td>
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<td>76,787.73</td>
</tr>
<tr>
<td>+153,575.46 af</td>
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<td>+153,575.46</td>
</tr>
<tr>
<td>299,472 af</td>
<td>268,757 af</td>
<td>230,363 af</td>
</tr>
</tbody>
</table>

26% capacity of lake  23% capacity of lake  20% capacity of lake

("3.551,784 )/(34.9)=101,770.3152
(101,770.3152)(21.9)=2,228,769.903 af per 10 years  
222,876.9903 =af per year

Minimum Lake level: 222,876.9903 af

Capacity of Lake Almanor = 1,175,000 af  
50% water is runoff from rain

Maximum values:
Snow=111,438.495 af
Other sources= 111,438.495 af

<table>
<thead>
<tr>
<th>5% decline of snow af</th>
<th>25% decline in snow af</th>
<th>50% decline in snow af</th>
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</thead>
<tbody>
<tr>
<td>(111,438.495 af)(0.05)</td>
<td>(111,438.495 af)(0.25)</td>
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</tr>
<tr>
<td>= 5,571.924 af</td>
<td>= 27,859.62 af</td>
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<td>111,438.495 af</td>
<td>111,438.495</td>
<td>111,438.495</td>
</tr>
<tr>
<td>- 5,571.924 af</td>
<td>-27,859.62 af</td>
<td>-55,719.24 af</td>
</tr>
<tr>
<td>105,866.57 af</td>
<td>83,578.87 af</td>
<td>55,719.24 af</td>
</tr>
<tr>
<td>+111,438.495 af</td>
<td>+111,438.495</td>
<td>+111,438.495</td>
</tr>
<tr>
<td>217,305 af</td>
<td>195,017 af</td>
<td>167,158 af</td>
</tr>
</tbody>
</table>

18% capacity of lake  16% capacity of lake  14% capacity of lake
## 2100 Snow Pack Levels

\[
(4,894,779.5)/(34.9)=140,251.56 \\
(140,251.5616)(10.8)=1,514,716.86 \text{ af per 10 years} \\
151,471.6865 = \text{af per year}
\]

Maximum lake level: 151,471.6865 af
Capacity of Lake Almanor = 1,175,000 af  
50% water is from snow melt

### Maximum values:

- **Snow**: 75,735.84 af
- **Other sources**: 75,735.84 af

<table>
<thead>
<tr>
<th>5% decline of snow</th>
<th>25% decline in snow</th>
<th>50% decline in snow</th>
</tr>
</thead>
<tbody>
<tr>
<td>(75,735.84 af)(0.05)</td>
<td>(75,735.84 af)(0.25)</td>
<td>(75,735.84 af)(0.50)</td>
</tr>
<tr>
<td>=3,786.79 af</td>
<td>= 18,933.96 af</td>
<td>=37,867.92 af</td>
</tr>
<tr>
<td>75,735.84 af</td>
<td>75,735.84 af</td>
<td>75,735.84 af</td>
</tr>
<tr>
<td>-3,786.79 af</td>
<td>-18,933.96 af</td>
<td>-37,867.92 af</td>
</tr>
<tr>
<td>71,949.05 af</td>
<td>56,801.88 af</td>
<td>37,867.92 af</td>
</tr>
<tr>
<td>+75,735.84 af</td>
<td>+75,735.84 af</td>
<td>+75,735.84 af</td>
</tr>
<tr>
<td>147,685 af</td>
<td>132,563 af</td>
<td>113,604 af</td>
</tr>
<tr>
<td>13% capacity of lake</td>
<td>0.1% capacity of lake</td>
<td>0.1% capacity of lake</td>
</tr>
</tbody>
</table>

(3551784)/(34.9)=101,770.3152
(101770.3152)(10.8)=1,099,119.404 af per 10 years  
109,911.90404 = af per year

Minimum Lake level: 109,911.9 af
Capacity of Lake Almanor = 1,175,000 af  
50% water is runoff from rain

### Maximum values:

- **Snow**: 54,955.97 af
- **Other sources**: 54,955.97 af

<table>
<thead>
<tr>
<th>5% decline of snow</th>
<th>25% decline in snow</th>
<th>50% decline in snow</th>
</tr>
</thead>
<tbody>
<tr>
<td>(54,955.97 af)(0.05)</td>
<td>(54,955.97 af)(0.25)</td>
<td>(54,955.97)(0.50)</td>
</tr>
<tr>
<td>=2,747.798 af</td>
<td>= 13,738.992 af</td>
<td>=27,477.98 af</td>
</tr>
<tr>
<td>54,955.97 af</td>
<td>54,955.97 af</td>
<td>54,955.97 af</td>
</tr>
<tr>
<td>-2,747.798 af</td>
<td>-13,738.992 af</td>
<td>-27,477.98 af</td>
</tr>
<tr>
<td>5.2208.17 af</td>
<td>41,216.978 af</td>
<td>27,477.98 af</td>
</tr>
<tr>
<td>+54,955.97 af</td>
<td>+54,955.97 af</td>
<td>+54,955.97 af</td>
</tr>
<tr>
<td>107,164 af</td>
<td>96,173 af</td>
<td>82,434 af</td>
</tr>
<tr>
<td>0.1% capacity of lake</td>
<td>0.1% capacity of lake</td>
<td>0.1% capacity of lake</td>
</tr>
</tbody>
</table>
Appendix 3: Calculations for the Decline in Rainfall for the Kern River

Annual precipitations with A2 emissions (Cal-Adapt, 2016)
Numbers in orange were used to predict future levels.

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Precipitation (in.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>8.1</td>
</tr>
<tr>
<td>1970</td>
<td>9.1</td>
</tr>
<tr>
<td>1980</td>
<td>8.4</td>
</tr>
<tr>
<td>1990</td>
<td>7.5</td>
</tr>
<tr>
<td>2000</td>
<td>9.1</td>
</tr>
<tr>
<td>2010</td>
<td><strong>8.9</strong></td>
</tr>
<tr>
<td>2020</td>
<td>8.3</td>
</tr>
<tr>
<td>2030</td>
<td>8.9</td>
</tr>
<tr>
<td>2040</td>
<td>7.5</td>
</tr>
<tr>
<td>2050</td>
<td>7.4</td>
</tr>
<tr>
<td>2060</td>
<td>7.6</td>
</tr>
<tr>
<td>2070</td>
<td>6.5</td>
</tr>
<tr>
<td>2080</td>
<td>7.7</td>
</tr>
<tr>
<td>2090</td>
<td>7.8</td>
</tr>
<tr>
<td>2100</td>
<td><strong>7.3</strong></td>
</tr>
</tbody>
</table>

Known Levels of Lake Isabella (CA Data Exchange, 2016)

<table>
<thead>
<tr>
<th>Year</th>
<th>Maximum (af)</th>
<th>Minimum (af)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>243,563</td>
<td>99,622</td>
</tr>
<tr>
<td>2002</td>
<td>173,733</td>
<td>82,336</td>
</tr>
<tr>
<td>2003</td>
<td>303,813</td>
<td>142,021</td>
</tr>
<tr>
<td>2004</td>
<td>227,733</td>
<td>94,083</td>
</tr>
<tr>
<td>2005</td>
<td>528,885</td>
<td>130,776</td>
</tr>
<tr>
<td>2006</td>
<td>412,940</td>
<td>225,877</td>
</tr>
<tr>
<td>2007</td>
<td>240,969</td>
<td>107,179</td>
</tr>
<tr>
<td>2008</td>
<td>251,900</td>
<td>110,831</td>
</tr>
<tr>
<td>2009</td>
<td>249,178</td>
<td>102,282</td>
</tr>
<tr>
<td>2010</td>
<td>331,267</td>
<td>123,361</td>
</tr>
<tr>
<td>Total</td>
<td>2,963,981</td>
<td>1,218,368</td>
</tr>
<tr>
<td>Average per year</td>
<td>296,398.1</td>
<td>121,836.8</td>
</tr>
<tr>
<td>% Capacity of Lake</td>
<td>52.2</td>
<td>21.5</td>
</tr>
</tbody>
</table>

Capacity of Lake Isabella= 568000 af
Normal Water Year

2010 calculations:
Maximum lake level: 296,398.1 af  Capacity of Lake Isabella= 568,000 af  42% water is runoff from rain

Maximum values:
Rain= 124,487.202 af
Other sources= 171,910.898 af

\[
\begin{align*}
5\% \text{ decline of rain} &= (124,487.202 \text{ af})(0.05) \\
&= 6,224.35 \text{ af}
\end{align*}
\]
\[
\begin{align*}
25\% \text{ decline in rain} &= (124,487.202 \text{ af})(0.25) \\
&= 31,121.75 \text{ af}
\end{align*}
\]
\[
\begin{align*}
124,487.202 \text{ af} - 6,224.35 \text{ af} &= 118,262.65 \text{ af} \\
124,487.202 \text{ af} - 31,121.75 \text{ af} &= 93,365.25 \text{ af}
\end{align*}
\]
\[
\begin{align*}
118,262.65 \text{ af} + 171,910.898 \text{ af} &= 290,174 \text{ af} \\
93,365.25 \text{ af} + 171,910.898 \text{ af} &= 265,276 \text{ af}
\end{align*}
\]
51% capacity of lake  46% capacity of lake

Minimum Lake level: 121,836.8 af  Capacity of Lake Isabella= 568,000 af  42% water is runoff from rain

Maximum values:
Rain= 51,171.45 af
Other sources= 70,665.34 af

\[
\begin{align*}
5\% \text{ decline of rain} &= (51,171.45 \text{ af})(0.05) \\
&= 2,558.57 \text{ af}
\end{align*}
\]
\[
\begin{align*}
25\% \text{ decline in rain} &= (51,171.45 \text{ af})(0.25) \\
&= 12,792.86 \text{ af}
\end{align*}
\]
\[
\begin{align*}
51,171.45 \text{ af} - 2,558.57 \text{ af} &= 48,612.88 \text{ af} \\
51,171.45 \text{ af} - 12,792.86 \text{ af} &= 38,378.59 \text{ af}
\end{align*}
\]
\[
\begin{align*}
48,612.88 \text{ af} + 70,665.34 \text{ af} &= 119,278 \text{ af} \\
38,378.59 \text{ af} + 70,665.34 \text{ af} &= 109,044 \text{ af}
\end{align*}
\]
21% capacity of lake  19% capacity of lake
# Critically Dry Water Year

## 2010 calculations:

Maximum lake level: 296398.1 af

Capacity of Lake Isabella = 568000 af

1% water is runoff from rain

Maximum values:

Rain = 2,963,981 af

Other sources = 293,434.119 af

<table>
<thead>
<tr>
<th>5% decline of rain</th>
<th>25% decline in rain</th>
</tr>
</thead>
<tbody>
<tr>
<td>(2,963,981 af)(0.05)</td>
<td>(2,963,981 af)(0.25)</td>
</tr>
<tr>
<td>= 148.199 af</td>
<td>= 740.99 af</td>
</tr>
</tbody>
</table>

2,963,981 af - 148.199 af = 2,815.784 af

2,815.784 af + 293,434.119 af = 296,250.898 af

52% capacity of lake = 296,250.898 af

Minimum Lake level: 121836.8 af

Capacity of Lake Isabella = 568000 af

1% water is runoff from rain

Maximum values:

Rain = 1,218,368 af

Other sources = 120,618.432 af

<table>
<thead>
<tr>
<th>5% decline of rain</th>
<th>25% decline in rain</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1,218,368 af)(0.05)</td>
<td>(1,218,368 af)(0.25)</td>
</tr>
<tr>
<td>= 60.9184 af</td>
<td>= 304.592 af</td>
</tr>
</tbody>
</table>

1,218,368 af - 60.9184 af = 1,157,449.086 af

1,157,449.086 af + 120,618.432 af = 1,278,067.518 af

21% capacity of lake = 1,278,067.518 af
Normal Water Year
(2963981)/(8.9)=333031.57
(333031.57)(7.3)=2431130.48 af per 10 years  =243113.048 af per year

2100 calculations:
Maximum lake level: 243113.048 af  Capacity of Lake Isabella= 568000 af  42% water is runoff from rain

Maximum values:
Rain=102,107.4803 af
Other sources= 141,005.568 af

\[
\begin{align*}
\text{5% decline of rain} & \quad \text{25% decline in rain} \\
(102,107.4803 \text{ af})(0.05) & \quad (102,107.4803 \text{ af})(0.25) \\
=5105.37 \text{af} & \quad = 25,526.87 \text{af} \\
102,107.4803 \text{ af} & \quad 102,107.4803 \text{ af} \\
-5,105.37 \text{af} & \quad -25,525.87 \text{af} \\
97,002.106 \text{af} & \quad 76,580.61 \text{af} \\
118,262.84 \text{af} & \quad 76,580.61 \text{af} \\
+141,005.568 \text{af} & \quad +141,005.568 \text{af} \\
238,008 \text{af} & \quad 217,586 \text{af} \\
42\% \text{ capacity of lake} & \quad 39\% \text{ capacity of lake}
\end{align*}
\]

\[
(1218368)/(8.9)=136895.2809
(136895.2809)(7.3)=999335.55 af per 10 years  =99933.555 af per year
\]

Minimum Lake level: 99933.555 af  Capacity of Lake Isabella= 568,000 af  42% water is runoff from rain

Maximum values:
Rain=41972.09313 af  Other sources= 57961.46193 af

\[
\begin{align*}
\text{5% decline of rain} & \quad \text{25% decline in rain} \\
(41,972.09313 \text{ af})(0.05) & \quad (41,972.09313 \text{ af})(0.25) \\
=2,098.604 \text{af} & \quad =10,493.02 \text{af} \\
41,972.09313 \text{af} & \quad 41,972.09313 \text{af} \\
-2,098.604 \text{af} & \quad -10,493.02 \text{af} \\
39,873.488 \text{af} & \quad 31,479.06985 \text{af} \\
39,873.488 \text{af} & \quad 31,479.06985 \text{af} \\
+57,961.46193\text{af} & \quad +57,961.46193\text{af} \\
97,835 \text{af} & \quad 89,441 \text{af} \\
17\% \text{ capacity of lake} & \quad 16\% \text{ capacity of lake}
\end{align*}
\]
Critically Dry Water Year

\[(2963981)/(8.9)=333031.57\]
\[(333031.57)(7.3)=2431130.48\] af per 10 years =243113.048 af per year

**2100 calculations:**

Maximum lake level: 243113.0483 af  
Capacity of Lake Isabella= 568000 af  
1% water is runoff from rain

Maximum values:

Rain= **2,431.13 af**  
Other sources= **240,681.9178 af**

\[
\begin{align*}
5\% \text{ decline of rain} & \quad 25\% \text{ decline in rain} \\
(2,431.13 \text{ af})(0.05) & \quad (2,431.13 \text{ af})(0.25) \\
=121.5565 \text{ af} & \quad = 607.7825 \text{ af} \\
2,431.13 \text{ af} & \quad 2,431.13 \text{ af} \\
- 121.5565 \text{ af} & \quad -607.7825 \text{ af} \\
2,349.5745 \text{ af} & \quad 1,823.4305 \text{ af} \\
+240,681.9178 \text{ af} & \quad +240,681.9178 \text{ af} \\
243,113 \text{ af} & \quad 242,505 \text{ af} \\
43\% \text{ capacity of lake} & \quad 43\% \text{ capacity of lake}
\end{align*}
\]

\[(1218368)/(8.9)=136895.2809\]
\[(136895.2809)(7.3)=999335.55 \text{ af per 10 years} =99933.555 \text{ af per year}\]

Minimum Lake level: 99933.555 af  
Capacity of Lake Isabella= 568000 af  
1% water is runoff from rain

Maximum values:

Rain= **999.3355 af**  
Other sources= **98,934.2145 af**

\[
\begin{align*}
5\% \text{ decline of rain} & \quad 25\% \text{ decline in rain} \\
(999.3355 \text{ af})(0.05) & \quad (999.3355 \text{ af})(0.25) \\
=49.9667 \text{ af} & \quad = 249.8338 \text{ af} \\
999.3355 \text{ af} & \quad 999.3355 \text{ af} \\
- 49.9667 \text{ af} & \quad -249.8338 \text{ af} \\
949.368 \text{ af} & \quad 749.501 \text{ af} \\
949.368 \text{ af} & \quad 749.501 \text{ af} \\
+98,934.2145 \text{ af} & \quad +98,934.2145 \text{ af} \\
99,884 \text{ af} & \quad 99,684 \text{ af} \\
18\% \text{ capacity of lake} & \quad 18\% \text{ capacity of lake}
\end{align*}
\]
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