Feasibility of Retrofitting Existing Hydropower Infrastructure for Use in Renewable Energy Storage

by

Timothy Breckner Adams

B.S., University of Massachusetts Amherst (2017)

Submitted to the Department of Civil and Environmental Engineering in partial fulfillment of the requirements for the degree of Masters of Engineering in Environmental Engineering Science at the MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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Abstract

Pumped storage is the only mature grid-scale energy storage technology. Originally developed to support nuclear base load plants due to its ability to store energy on the scale of gigawatt-hours (GWh) and rapidly respond to demand fluctuations, pumped storage is recognized as a viable option to support variable renewable sources of energy such as solar and wind. However, in the United States, environmental concerns, regulatory barriers, and high capital costs have effectively prevented the building of new pumped storage facilities for the past 30 years. Instead, developers and researchers have primarily invested their time and resources into pursuing chemical storage options, including lead-acid, lithium-ion, and sodium-sulfur (Na-S) chemistries. These alternative technologies do not have the geographic limitations of pumped storage, but suffer from higher costs at grid scales, shorter lifespans, and the negative environmental impacts of mining, manufacturing, and disposing of large quantities of chemicals.

Grid-scale storage needs will increase substantially as variable resources like solar and wind supply an increasing fraction of the grid’s energy. To address this challenge, we propose a renewed focus on developing large-scale pumped storage facilities at sites with existing reservoirs. This approach avoids the environmental concerns associated with building new dams and reduces regulatory barriers by requiring minimal land-use changes. Retrofitting existing facilities in this way converts their primary purpose to storing electricity generated from other renewable sources such as solar or wind, while still enabling hydroelectricity generation to continue. Such retrofitted systems have already been built in the United States and Europe, proving that an approach of this type is feasible. In order to match the scale of the need, however, significantly more storage capacity is required. Therefore, we propose a widespread adoption of this approach, especially as a potential alternative to chemical storage.

To illustrate this concept, we explored the technical feasibility of retrofitting the Big Creek hydropower system in central California (Edison International) by carrying a preliminary technical feasibility study. The Big Creek system is composed of 6 reservoirs and currently supports about 1GW of capacity. We found that by expanding the
tunnel network and adding pump-turbines between two of these reservoirs, the Big Creek system could provide 75GWh of energy storage capacity and 5GW of power capacity. These values are large enough to enable complementary solar power to provide 5GW of baseload power in the summer, 25% of the baseload demand for the California Independent System Operator (CAISO). Existing infrastructure would remain untouched, enabling current hydropower generation to continue. Added infrastructure would include 4 tunnels 6m in diameter and approximately 24km in length each, 24 pump-turbines evenly distributed across the 4 powerhouse locations that lie between the reservoirs, additional powerhouses to store the pump-turbines, and 4 500kV transmission lines to transmit the power to either San Francisco or Los Angeles. A preliminary cost analysis for this project estimates costs between $2500-$4000/kW ($12.5-20 billion), in line with current standard estimates of pumped storage costs that demonstrate the superiority of pumped storage to chemical storage alternatives for grid-scale energy time-shifting applications.

Future research will include a more comprehensive study of the technical and economic feasibility of adding a large scale pumped storage facility to the Big Creek system. Additionally, we will expand our analysis to cover the scale of the state of California by including other existing hydropower sites.

Thesis Supervisor: Elfatih A.B. Eltahir
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Acknowledgments

I’d like to thank Fatih for his support as an advisor, teacher, and mentor. In addition to the technical knowledge I’ve been able to learn from him, I’ve been most grateful for learning how to approach a new, complex topic: Make the problem as simple as possible until you can solve it. I’ll take this lesson and many others with me long after I leave MIT.

The opportunity to visit Big Creek in October gave me a priceless visual of what I would spend the next seven months analyzing, and fulfilled a dream of mine to go to the West Coast mountains. Thanks go to Dan Golden at Southern California Edison for his role in organizing my trip, as well as to Larry Chenoweth and Andy McMillan for giving me tours of the facilities.

The Parsons community has been a welcoming place, and its collaborative, just-ask-and-I’m-there-to-help environment embodies some of my favorite parts about working with engineers. Particular thanks to Neha Mehta, for inviting me in right at the beginning; to Alex Tuel, for broadening my understanding of the world outside of Massachusetts and keeping me on my toes; to Kasia, for the moments of shared rejoicing when we got that figure to look just right; and to James Rowe, for helping me to get out of the building and into the chapel.

Though this particular program was only a year, it represents the culmination of seventeen years of education, and with it a host of teachers and mentors. Thanks in particular go to Mr. Westrate, for teaching me how to write clearly and to think critically; to Mrs. Libert, for teaching me how to speak confidently even when I didn’t feel confident; to Professor Leonard, for guiding me on the path less traveled from computer systems engineering to water resources engineering; and to Tim Fitzemeyer, for giving me the advice I needed every time, and for listening to me go on and on and on and on and on and on...

I’m learning more and more how incredible my family is. I am honored to be both an Adams and a Breckner. Grandparents, cousins, aunts and uncles have loved me, supported me emotionally and financially, and cheered me on. As for my sister and my parents—it has been an absolute joy to be back and living at home with you this year, and to see the ways in which our relationships have grown even richer than they were before. You are my closest confidants and my most committed friends. Thanks for everything.

“You may say to yourself, ‘My power and the strength of my hands have produced this wealth for me.’ But remember the LORD your God, for it is he who gives you the ability to produce wealth, and so confirms his covenant, which he swore to your ancestors, as it is today.”

I remember. Thank you, Father.
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Chapter 1

Climate change and renewable sources of electricity

This chapter provides an overview of the effects of climate change and the role that renewable sources of electricity generation can play to mitigate those effects. It describes the challenges that increasing amounts of renewables, particularly solar, can have on the electric grid by considering the case of California. Finally, it introduces how pumped hydropower storage can play a role in solving these challenges and proposes retrofitting sites with existing reservoirs, providing new pumped storage capacity without constructing new dams or requiring significant changes in land use.

1.1 Emissions scenarios and potential impacts

Climate change is having and will have a pronounced effect on the planet and human society. Global mean sea levels have risen approximately 0.19m from 1901 to 2010, with projected increases in the 21st century ranging from 0.26-0.55m for RCP2.6 and 0.45-0.82m for RCP8.5 [1]. Heatwaves, the weather events that cause the highest number of deaths in the US, have and will increase in intensity and frequency [2, 3]. Changing hydrologic regimes will increase variability and decrease precipitation in many regions, with the remaining rainfall occurring in shorter, more intense storms [4, 5].

Many of these changes are already taking place. NASA reported that 16 of the hottest years on record have occurred in the past 17 years [6]. In the United States, a year of intense hurricanes including Harvey, Irma, and Maria that collectively devastated Houston, Puerto Rico, and much of the Caribbean islands has alerted many to the severe implications of climate change.
The opportunity for mitigation still exists and remains an imperative. An increase in global mean temperature change of no more $2^\circ C$ is recognized as key to preventing the global climate from entering a catastrophic negative feedback loop of warming\[7\]. For this target to be likely achieved, the IPCC estimates that annual global CO2-equivalent emissions must decrease by approximately 40-70% from 2010 baseline values by 2050\[8\]. It is clear, then, that concerted efforts must be applied on many fronts.

### 1.2 The role of renewable sources of electricity in reducing emissions

Electricity generation is a key area in which to reduce greenhouse gas emissions. Table 1.1 shows emissions by sector in the US\[9\], with electricity generation being the largest contributor. Renewable sources of energy such as hydroelectricity, solar, wind, and geothermal, as well as nuclear power, provide an opportunity to reduce the carbon intensity of electricity\[9\]. Combined with the electrification of other sectors, such as transportation, this reduction in carbon intensity provides a significant opportunity to reduce overall carbon emissions.

A tremendous amount of effort has been expended in the past few decades to support the move towards renewable sources of energy. Government initiatives at the city, state and national levels, combined with technological innovations from industry, have enabled these technologies to significantly increase their presence in grids worldwide. Figure 1-1 shows the globally rising pace in capacity additions of wind and solar, which have received the majority of attention in the past couple of decades. In contrast, increases in hydroelectricity and nuclear technology have slowed since their

<table>
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<th>Economic Sector</th>
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<td>1941.4</td>
<td>29.5%</td>
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<td>U.S. Territories</td>
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\[9\]The carbon intensity of electricity refers to the average amount of CO2 equivalent emissions that are released for a unit of electricity to be produced.
development in the mid twentieth century, as environmental and safety concerns along with geographical constraints have hampered their continual development.

Though these increases in solar and wind generation are encouraging, they remain only a sliver of the overall electricity generation pie. Figure 1-2 on the following page shows the fraction of electricity produced from renewable sources globally. Combined, solar and wind provided only 5% of the world’s electricity in 2016. Moreover, in 1985, zero-carbon sources produced 35.6% of the world’s electricity. In 2016, that percentage dropped to 34.2%, despite absolute increases in capacity in every zero-carbon generation source. Increases in consumption due to population growth and increases in energy consumption per capita have contributed to this effect. The recent rapid increase in solar and wind capacities has helped somewhat, increasing the percentage of electricity from zero-carbon sources from a minimum of 31.7% in 2011, but the rate of increase remains quite low.

Given the severe impacts of climate change, and the importance of decarbonizing electricity consumption to mitigating those impacts, it is clear that significant effort must be invested to increase the percentage of zero-carbon generation sources on the grid globally, including wind and solar. One group that advocates for such effort is the Solutions Project [11], which presents individualized road maps for how the United States and most other countries in the world could supply 100% of their electricity

Figure 1-1: Global solar and wind capacity additions in recent decades. Data from [10].
using wind, water, and solar \[11, 12\]. Such a transition would require a concerted effort far beyond that which has been seen globally, but it is proposals like this that accurately pair the magnitude of the problem with the amount of work necessary to overcome it.

Figure 1-2: Global consumption of renewable sources of energy. Data from \[10\].
1.3 Challenges in incorporating renewables onto the grid

Though renewables such as solar, wind, and hydroelectric power still supply only a small percentage of electricity globally, in certain regions they now comprise a substantial fraction of the grid’s electricity. It is in these regions that the fundamental intermittency and variability of these resources is most clearly demonstrated. These characteristics pose significant challenges to grid operators, who at each second must balance electricity supply and demand. These challenges compound as the percentage of electricity supplied by renewables increases.

Due to their variability and intermittency, renewables are often treated as negative load. This means that at each time step, the power supplied by these sources is subtracted from the load, requiring conventional facilities such as nuclear, gas, or coal plants to meet the resulting net load. This strategy works well when renewables supply only a small amount of the grid’s energy, as the variations in renewable supply are relatively insignificant compared to the regular changes in demand throughout the day. However, as renewables increase in grid penetration, this approach leads to large fluctuations and sharp ramps in net load that conventional facilities struggle to meet.

The California grid provides a good example of the challenges faced by grid operators as solar and wind penetrations increase. Figure 1-3 on the next page shows typical seasonal net load curves in California. The net load curve shows the demand of electricity that is required by the grid’s consumers, minus generation from wind and solar. It describes the amount of power that must be supplied by other generating facilities, such as coal, nuclear, natural gas, or hydroelectricity. A typical load profile would see a more or less stable demand between midnight and 6am, followed by a steep increase in demand in the morning as customers wake up and begin to consume more power. Demand rises slowly through the day, with another peak in the early evening hours as customers go home and turn on their appliances, lights,

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6The distinction between intermittency and variability is subtle and is often not recognized. An intermittent resource is one that is not fully dependable in that it may randomly fluctuate in the amount of power it produces. A variable resource is one that does not always provide the same amount of power from one time step to the next. Our focus in this thesis is on the variability of renewables, as this relates to the need renewables have for energy time-shifting.

7In this thesis, penetration refers to the fraction of annual energy that is supplied by a given technology, e.g. solar, wind, or both combined.

8All California data comes from the California ISO, CAISO, which manages the high voltage lines in California, as well as the regional wholesale electricity market.
etc. This typical load profile, however, is not seen in Figure 1-3 due to the effect of renewables on the net load, particularly solar. In California, these curves are often referred to as “duck curves” due to their shape. The years 2014 through 2017 saw a significant build-out of solar in California, and this can be seen by a decrease
Figure 1-4: Average hourly wholesale electricity prices on the real-time market in California for Jan-Mar, 2017-2018 [19]. The effect of solar can be seen by the steep decreases in electricity prices in the middle of the day, even going negative in March 2017. These effects can cause significant strain on conventional generating facilities, which have to pay others to take their electricity.

As solar penetration continues to increase, the “belly” of the duck deepens, indicating a decrease in net load. Most conventional generating facilities operate most efficiently when providing a constant amount of power, and cannot easily reduce their output below this constant amount. Therefore, low net loads during the day result in significant strains on these conventional resources. These effects can be seen in the California market already, where electricity prices consistently went negative in March 2017 (Figure 1-4). These net loads also result in curtailment of renewable energy, where excess energy is thrown away. Higher penetrations of solar would exacerbate these issues, leading to more curtailment in the day and steeper ramps in the evening, which must be met by expensive, peaking plants which are used only for a few hours of the day and lie idle otherwise [18].
Figure 1-5: Storage can be used to transform solar into a peaking plant. Here, solar is used to charge a storage system for most of the day (blue areas), with the storage system outputting a high amount of power in a relatively short amount of time when demand is greatest.

1.4 Using storage for incorporating renewables

A variety of techniques can be used to reduce these effects of high penetrations of renewable sources like solar and wind, including grid integration, demand response, and electrification of different industries such as transportation. One of these options is to store electricity during times of excess generation, and then to discharge that electricity back into the grid during periods of excess demand. Storage’s effect then is to enable the grid operator to time-shift generation to when it is needed.

This basic principle is illustrated in Figure 1-5. Here, a PV solar plant produces power during the day and uses that power to charge a storage system (blue areas). In the late afternoon, the storage system begins to discharge energy (red areas), sending power back into the grid. A combined solar-storage system like the one described operates much like a natural gas peaking plant, providing a high amount of power for a short period during the day. Another option is demonstrated in Figure 1-6. Here, a smaller amount of power is provided consistently throughout the whole day. When solar power is being produced, only the amount above this constant value is stored.

The power of storage in both of these examples is that it enables a variable resource

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Section 2.4 describes these techniques in more detail.
Figure 1-6: Storage can also be used to transform solar into a constant source of power. Here, excess solar (blue areas) charges the storage system when it exceeds demand, while the battery discharges (red areas) when solar is not available.

like solar to act as a dispatchable resource like natural gas. Due to this ability, pairing storage and renewables like solar and wind has been a focus of an extensive number of studies. In particular, chemical batteries of various chemistries such as lead-acid, lithium-ion, and sodium-sulfur (Na-S) have received significant attention worldwide, and can perform several ancillary services that are required by variable generation sources. However, these chemical storage systems have struggled to provide grid-scale energy storage, and so represent only a tiny fraction of installed storage worldwide. In 2017, 96% of storage power capacity was provided by pumped hydroelectric storage. A pumped storage system is one where energy is stored by pumping water from a lower reservoir to an upper reservoir, converting electrical energy through the pumps into potential energy. When required, water can be let down through a turbine, producing electricity than can be fed back into the grid.

Pumped storage is a mature and established technology, being employed on a wide scale for over a century. Moreover, it is the only established energy storage technology

\footnote{A dispatchable resource is one that you can turn on or off at will.}

\footnote{Storage has two main components: energy capacity (often expressed as megawatt-hours or MWh) and power capacity (expressed as kW, MW, GW, etc.). Energy capacity refers to how much energy a storage system can store at any given time–how big the tank is. Power capacity refers to the maximum power a storage system can provide at a given time–how big the pipe is.}
at grid scales. However, it suffers from three key challenges. First, pumped storage requires an area for two reservoirs that are separated by a short distance horizontally and a large distance vertically. Relatively few of these areas exist, and many of the prime locations have already been developed. Second, if one or two dams must be built to create the reservoirs, a pumped storage facility incurs the same environmental impacts that conventional hydroelectricity does, including ecosystem degradation, damage or destruction of fish populations, and the prevention of soil from moving downstream \[21\]. Finally, financial uncertainty connected to the high capital costs and the long lead time for developing a pumped storage facility have traditionally deterred private investors, leaving the public sector to take the lead \[22\]. These barriers have hindered the development of pumped storage in much of the world over the past 30 years, particularly in the United States.

1.5 Retrofitting conventional hydropower plants to increase storage capacity

To help overcome the geographic limitations of pumped storage, as well as limit environmental impact, one can develop pumped storage facilities at sites with existing reservoirs by adding new tunnels, powerhouses, and pump-turbines. Retrofitting existing hydropower plants enables new storage capacity to be installed without constructing new dams or requiring extensive changes in land use. This mitigates the incremental environmental and social impacts of the pumped storage system. It also expands the number of potential sites where pumped storage can be utilized by maximizing the effectiveness of the best sites that have already been developed.

Using existing reservoirs to construct new pumped storage capacity is a proven technique. In California, the Helms pumped storage system was built in the 1980s using the existing Courtright and Wishon reservoirs \[23\]. At least 6 different facilities in France, Switzerland and Austria have already constructed or are in the process of constructing new pumped storage capacity at existing conventional hydroelectric facilities \[24\]. Other facility owners have expanded existing pumped storage schemes by adding new tunnels and powerhouses, such as the Veytaux II power plant owned by Alpiq and located near Lake Geneva in Switzerland \[25\].

Such projects demonstrate that retrofitting hydropower facilities at current reservoirs is not only technically possible but economically possible as well. Pumped storage and conventional hydroelectricity can and do operate side by side in these
projects, providing both generation and storage services to the grid. However, these past projects represent only incremental increases in overall pumped storage capacity. If wind and solar are to provide the majority of electricity globally, storage needs will also increase significantly.

For instance, current estimates indicate that if variable sources such as wind and solar were to supply 80% of electricity, energy storage capacities would need to equal on the order of 0.1% of total yearly energy demand \[26\]. Roughly 8500 terawatt-hours (TWh, equivalent to 1000GWh) of electricity was consumed in 2016 \[10\], so 0.1% of this value equals 8.5TWh or 8500GWh. In 2016, there was an estimated 184GW of pumped storage power capacity worldwide. Assuming a representative value of 25 hours of discharge duration \[27\], the length of time that a storage system can output at its full power capacity, this represents an energy capacity of 4600GWh. This means that supplying 80% of electricity using variable sources like wind and solar would require approximately doubling current storage capacities globally.

Such a need requires large-scale, proven techniques with the potential to be implemented widely. We propose retrofitting sites with existing reservoirs as such a technique. With 936GW of conventional hydroelectricity capacity installed in 2010 \[28\], retrofitting facilities provides a clear pathway to meeting the magnitude of the storage need of the 21st century. Other technologies, including chemical storage, can and will play a role in meeting this overall need. Without retrofitting facilities, however, the sheer scale of the challenge is likely to be insurmountable.

This thesis illustrates the application of this technique at a specific location: the Big Creek hydropower system in central California. California is an ideal area to explore this concept, having legislated ambitious renewable energy goals which mandate that 50% of electricity must come from renewable energy sources by 2030 \[29\]. As seen previously, however, the large amounts of solar installed to meet this goal have caused challenges for grid operators, who must balance supply and demand of electricity at every second of the day—challenges that storage can solve. Furthermore, California has approximately 11GW of conventional hydropower installed \[30\], potentially providing opportunities for retrofitting other locations.

1.6 Outline of the thesis

The remainder of this thesis begins with a literature review in Chapter 2, providing a deeper introduction to storage, the benefits it provides, alternatives to incorporating renewables onto the grid, and estimates of how much storage is required at high
penetrations of renewables. Chapter 3 provides an introduction to the Big Creek system, including its hydrology, role in the Upper San Joaquin watershed, and principal infrastructure. Chapter 4 contains our first-order technical feasibility assessment of retrofitting the Big Creek system to be used for large-scale pumped storage. Chapter 5 then provides a cost estimate range for the proposed 5GW, 75GWh pumped storage system at Big Creek, and compares this estimate with the recent 100MW/129MWh lithium-ion battery installed in South Australia by Tesla. Chapter 6 concludes by outlining opportunities for future analysis.
Chapter 2

Literature review

In this chapter, we provide an introduction to the principal attributes that are used to characterize energy storage, and compare energy storage technologies across these attributes. Section 2.2 describes the grid services that storage can provide. Focusing our attention on large-scale energy storage, Section 2.3 discusses the history of storage, describing the dominance of pumped storage and the growing share that lithium-ion batteries have in the non-pumped storage market. Section 2.4 presents an overview of the various techniques that are available to incorporate renewables on the grid, details the principal approaches taken in the literature to evaluate the need for storage, and reports estimates of storage needs for the California grid. Section 2.5 concludes by exploring pumped storage in more depth, including a discussion of its environmental impacts and the potential for retrofitting existing sites with existing reservoirs in California.

2.1 Basic attributes of energy storage

A wide range of storage technologies exist. Broadly, they can be classified by the type of energy they employ: chemical, mechanical, thermal, or electrical. Chemical batteries employ a wide range of chemistries for their anodes and cathodes, with the principal ones in use or development being lead-acid, lithium-ion, and sodium-sulfur (Na-S). The dominant form of mechanical storage, and indeed storage overall, is pumped storage. Other forms exist, including compressed air energy storage (CAES), which stores energy by decoupling the compression and expansion phases of conventional gas turbine electricity generation, and flywheels, which store kinetic energy in a rotating mass. Thermal storage technologies are often used to reduce refrigeration or heating costs. Alternatively, thermal storage is combined with solar generation at
solar concentrating power plants. Electrical storage systems include super capacitors or superconducting magnetic energy storage systems (SMES), and do not require the transformation of electricity to another type of energy. Detailed descriptions of each of these and other storage technologies are found repeatedly in the literature \cite{31,32,33,34} and will not be repeated here.

The principal technical attributes of a storage system are its power capacity, energy capacity, round-trip efficiency, and response time. Power capacity refers to the maximum amount of power (e.g. in units of MW) that can be discharged at any time. Power capacities for electrical energy storage range from a few kilowatts to gigawatts \cite{31}. Energy capacity refers to the maximum amount of energy that can be stored at any time (e.g. in units of MWh). Energy capacity is frequently expressed as a discharge duration, generally defined as how long a storage system can discharge at its power capacity. Discharge durations range from milliseconds to more than a day \cite{31}. The round-trip efficiency is defined as the percentage of energy that is fed back into the grid compared to the energy that was put into the storage system from the grid, with typical ranges between 70\% and 95\% \cite{35}. Finally, the response time is how quickly the storage system can respond to changes in demand. Response times range from milliseconds to minutes.

A storage system can also be described by its economic characteristics, including capital cost (expressed in \$/kW and/or \$/kWh), O&M costs (\$/MWh-yr), and lifetime (expressed either as a number of years or cycles). Capital costs are often assumed to be modular, in that power capacity and energy capacity can be sized independently and their costs summed \cite{36}. This is not always a good assumption, particularly for chemical battery storage \cite{36}. However, it is frequently used by reviews of storage systems to help facilitate economic comparisons between different technologies \cite{35,34,31,32,37,38}. Table 2.1 presents estimated values of these technical and economic attributes for a range of chemical and mechanical storage technologies.

Table 2.1 provides only one set of estimates for the technology and economic parameters of storage systems. In particular, capital cost estimates vary widely. For instance, lithium ion costs range from $175-$4000/kW and $500-$2500/kWh, and pumped storage costs are estimated between $600-4000/kW and $10-150/kWh.

\footnote{A MWh is the amount of energy that is expended by outputting 1 MW of power for an entire hour.}

\footnote{Discharge duration accounts for the generating efficiency of the storage system. Another metric that is used to characterize energy capacity but does not account for generating efficiency is the energy to power (E/P) ratio \cite{33}.}
Table 2.1: A summary of the technical and economic attributes of different storage systems. This table is summarized from one presented in [35].

<table>
<thead>
<tr>
<th></th>
<th>Lead-acid battery</th>
<th>Li-ion battery</th>
<th>NaS battery</th>
<th>VRB flow battery</th>
<th>Super capacitors</th>
<th>SMES</th>
<th>Flywheels</th>
<th>Pumped storage</th>
<th>CAES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical power output (MW)</td>
<td>1-100</td>
<td>0.1-5</td>
<td>5</td>
<td>0.01-10</td>
<td>0.1-10</td>
<td>0.1-10</td>
<td>0.1-10</td>
<td>250-1000</td>
<td>100-300</td>
</tr>
<tr>
<td>Energy storage capacity (kWh)</td>
<td>≤100</td>
<td>≤10</td>
<td>≤100</td>
<td>20-50</td>
<td>≤10</td>
<td>≤10</td>
<td>≤1-25</td>
<td>≥150</td>
<td>≥10</td>
</tr>
<tr>
<td>Discharge duration</td>
<td>Hours</td>
<td>Minutes to Hours</td>
<td>Hours</td>
<td>2-8h</td>
<td>Seconds</td>
<td>Hours</td>
<td>Seconds to minutes</td>
<td>Several hours</td>
<td>Hours</td>
</tr>
<tr>
<td>Round-trip efficiency(%)</td>
<td>70-90%</td>
<td>85-95%</td>
<td>80-90%</td>
<td>70-85%</td>
<td>90%</td>
<td>&gt;90%</td>
<td>85-95%</td>
<td>75-85%</td>
<td>45-60%</td>
</tr>
<tr>
<td>Response time</td>
<td>&lt;Seconds</td>
<td>Seconds</td>
<td>Milliseconds</td>
<td>&lt;Seconds</td>
<td>Seconds</td>
<td>&lt;Milliseconds</td>
<td>Seconds</td>
<td>&lt;Seconds</td>
<td>Minutes</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>3-10</td>
<td>10-15</td>
<td>15</td>
<td>5-20+</td>
<td>5-20</td>
<td>5-20</td>
<td>20</td>
<td>25+</td>
<td>20+</td>
</tr>
<tr>
<td>Capital cost per discharge ($/kW)</td>
<td>$300-$800</td>
<td>$400-$1000</td>
<td>$1000-$2000</td>
<td>$1200-$2000</td>
<td>$1500-$2500</td>
<td>$2000-$4000</td>
<td>$2000-$1000</td>
<td>$1000-$8000</td>
<td>$800-$1000</td>
</tr>
<tr>
<td>Capital cost per capacity ($/kWh)</td>
<td>$150-$500</td>
<td>$500-$1250</td>
<td>$125-$250</td>
<td>$150-$350</td>
<td>$300-$800</td>
<td>$1000-$2000</td>
<td>$1500-$1000</td>
<td>$100-$250</td>
<td>$50-$150</td>
</tr>
</tbody>
</table>

[34] [31] [32] [37] [38] [35] [39]. Part of this discrepancy results from rapid technological development in chemical storage. This development is expected to continue; one estimate has energy cost reductions of 50-60% from 2016 values to 2030 for all types of chemical storage [20]. Pumped storage estimates can vary significantly depending on whether the costs are associated with the construction of an entirely new site or refer to extensions of existing sites such as installing a new pump-turbine.

The low energy costs of pumped storage make it ideally suited for applications that require a large amount of energy storage in proportion to power capacity. As an example, consider a 5GW, 75GWh storage system. Assuming modular costs for energy and power and using the midpoint of the ranges provided in Table 2.1, a pumped storage system would cost approximately $26 billion. In contrast, a lithium-ion storage system of the same size would cost approximately $79 billion. These differences are compounded when the lifetimes of each system is factored in, as pumped storage can easily reach lifetimes of 50-60 years, while lithium-ion batteries are estimated to last 10-15 years.

2.2 Services provided by energy storage

Due to the range in values seen in Table 2.1, not all technologies can or are expected to perform the same function. Systems with fast response times (seconds to milliseconds) and low energy storage capacity are typically used for power quality and ancillary
services \[35\]. These services, including frequency regulation and voltage control, enable the steady distribution of electricity throughout the grid in the presence of small disturbances or supply-demand imbalances \[35, 37\]. Systems that perform these functions are designed to be able to charge and discharge within seconds to minutes, and typically do not store energy for periods longer than minutes to hours.

In contrast, bulk storage systems which can store large amounts of energy (tens to thousands of MWh) are used to time-shift electricity generation to when it is needed. This principally takes the form of energy arbitrage, which entails buying electricity when there is excess generation and prices are low during one part of the day and then selling it back during times of peak demand when prices are high\[c\]. This behavior can also be thought of as peak shaving, where the function of storage is to smooth out the peaks of electricity demand that other sources of generation need to meet. Bulk storage systems can also provide other services, including contingency reserves to hedge against the possibility of a generation facility suddenly coming off line, and even to a lesser extent power quality services like frequency regulation \[41\].

Variable generation technologies such as solar and wind require all levels of the services that energy storage offers \[42, 37\]. However, we focus in this thesis on the role that bulk storage technologies play in time-shifting generation, particularly to support solar. As discussed in Chapter 1 and seen in Figure 1-3 on page 22 increasing solar penetration leads to decreases in the net load during the middle of the day and sharp ramps to peak demand in the evening. Each of these effects can strain conventional generation facilities and, when left unchecked, reduce the value of additional solar to the grid \[15, 43\].

2.3 Storage development in the world today

Currently, pumped storage dominates energy storage worldwide. Table 2.2 shows storage capacities by energy type. Pumped storage exceeds all other technologies combined by a factor of 17. CAES, historically the only form of bulk storage other than pumped storage, is virtually nonexistent in comparison, with only two facilities

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\[c\]In the past, operating a plant to maximize energy arbitrage meant pumping water at night and selling it during the day. However, as solar penetrations have increased in California, pumped storage plants have begun to pump during the middle of the day when solar generation is highest \[40\].

\[d\]This is not to say that storage is the only option to provide these services. See discussion in Section 2.4.
Table 2.2: Global storage capacity by technology type [44].

<table>
<thead>
<tr>
<th>Storage Type</th>
<th>Power Capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumped storage</td>
<td>184.0</td>
</tr>
<tr>
<td>Electro-chemical</td>
<td>4.2</td>
</tr>
<tr>
<td>Thermal</td>
<td>4.0</td>
</tr>
<tr>
<td>Electro-mechanical</td>
<td>2.6</td>
</tr>
</tbody>
</table>

worldwide for a combined total of 400MW of capacity [44]. CAES has been hindered primarily by low round-trip efficiencies and geographic requirements, as it requires a large, essentially impermeable underground chamber to store the compressed air.

Pumped storage saw a large increase in the 1970s and 1980s, as oil prices rose and many developed nations began to pursue nuclear power for electricity generation. Nuclear provides large amounts of power, but cannot adjust its power output to meet changes in demand. Pumped storage and hydroelectricity more generally were seen as an efficient way to support the peak demand that nuclear could not. As increase in nuclear generation slowed and environmental concerns regarding pumped storage grew, development declined, particularly in Europe and the United States [24]. Recent development of new pumped storage has been primarily located in China and India, where current supplies struggle to meet peaking demand [22]. Development in these regions has also been driven by public sector involvement; this has been the case historically elsewhere as well, as the high capital costs and long lead time (6-12 years) of pumped storage projects have deterred private investors from pursuing large-scale projects [22, 45].

Of the non-pumped storage technologies, lithium-ion batteries have emerged as the dominant choice. Globally, 90% of non-pumped storage capacity announced in 2016 was lithium-ion, driven by technology cost reductions and increased manufacturing scale associated with the use of lithium-ion batteries in electric vehicles [47]. This has continued a trend that began in 2013, as lithium-ion batteries rose to become the dominant technology used for frequency regulation to support increasing solar and wind penetration [48]. While frequency regulation has been the primary use of chemical storage, with 50% of electro-chemical storage projects listing it as their primary use case [20], lithium-ion technologies are beginning to be used for energy time shifting as well. In the United States as of 2016, 4 solar plants, 13-100MW in size, have included 3-4 hour storage using lithium-ion batteries in their system design, with

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There are actually seven other facilities listed in the DOE’s Energy Storage Database, but they are demonstration facilities and are all less than 2MW in capacity.
Figure 2-1: Regional capacity additions of pumped storage, using data publicly available at [46]. Figure adapted from [22].

Battery power capacities ranging from 13-30MW [15]. While other chemical storage technologies may ultimately prove more suitable for bulk energy storage, lithium-ion batteries are the primary candidate for projects in the near future due to the manufacturing infrastructure behind them and their technological maturity [48].

2.4 Quantifying the need for storage with increasing renewables penetration

A variety of techniques exist to enable increasing penetrations of renewables[^1] of which storage is just one. For instance, increasing the area over which renewables are generated can smooth out generation by minimizing fluctuations in power output from local weather conditions. This has been well established with wind, and there is evidence it is true for solar as well [18]. To support increased wind and solar, the California ISO (CAISO) calls for increased grid integration, demand response, and electrification as well as increased storage [16]. Increasing grid integration by adding transmission lines and reducing market barriers to sell energy across borders enables excess generation to be distributed over a larger demand area [18]. Demand response refers to providing incentives for consumers to use power during times of

[^1]: Not all renewables require storage, as some renewables (e.g. biomass) are dispatchable. We are focusing on variable resources such as solar and wind.
excess generation \( [18] \). This can be thought of as the reverse of energy arbitrage, as the load curve moves to meet the generation rather than the generation curve moving to meet the load. In the near future, electrification primarily refers to a shift to electric vehicles, which can provide opportunities for demand response and reduce renewable energy curtailment.

Even with these techniques, there is a general understanding that storage is a necessary component to incorporating renewables at high penetrations. The California state legislature’s energy storage mandate recognizes this by requiring the public utilities of California to acquire a total of 1300MW of new storage by 2020\([49]\). How much energy storage is needed, however, is a more difficult question. The answer is highly location-specific, varying according to several factors, including the generation mix of the grid, the existing penetration of renewables, and the shape of the demand curve \([51]\).

There are three broad approaches to answering the question of how much storage is needed to incorporate renewables. Focusing on solar, the first is to consider how much storage is needed to make the solar energy dispatchable—that is, to enable solar energy to be sent to the grid whenever desired \([52, 53, 54]\). This approach typically focuses on the scale of a given solar plant. Storage needs vary greatly depending on the operational strategy used to dispatch the energy. A simple method for evaluating storage need in this manner can be found in Section 4.1 on page 52.

The second general approach is to consider how much storage is needed to balance generation and load at a grid scale. Renewables operate in a grid that has a mix of generating technologies and a given demand curve—these must be considered when evaluating the need for any technology. This approach analyzes the problem at a grid scale, often using optimization and simulation models to ensure that the load is met for the given solution. It relaxes the requirement that every solar (or wind) plant must be made completely dispatchable and allows for modest amounts of renewable energy curtailment, therefore resulting in a lower storage estimate than would be obtained if this requirement was held \([51, 26]\). Most of these models emphasize technical limits, though some attempt to perform economic optimization as well. Using this basic approach, Solomon et al. found that California could achieve renewable penetrations

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\(^9\)The energy mandate explicitly excludes pumped hydro storage greater than 50MW. However, Assembly Bill 33 directs utilities to consider all proposals for bulk storage \([50]\).

\(^h\)See \([51]\) for a useful summary on these types of models.

\(^i\)A significant amount of work has gone into using models of this nature to evaluate storage needs in a 100% or near 100% renewable energy generation scenario. For an example of this type of work, and the fierce disagreement in the field, see \([12, 55, 56, 57]\). For a critical review, see \([58]\).
of 85% with storage equal to 22GW of power capacity and 186GWh of energy capacity, approximately 20% of California’s average daily energy demand. Denholm and Margolis support this general conclusion by finding that a system with a flexibility factor of 80% and 8-12 hours of storage of average power demand could enable PV penetrations of up to 50% nationwide.

The third approach can be considered a refinement of the second. It explicitly acknowledges that for storage to be successful, it must fit into the grid’s economic picture. As mentioned, other techniques exist to incorporate renewables; however, each of these techniques comes with an associated cost. Furthermore, in this framework, the limit of renewable energy penetration is also economic.

One useful framework to use for this limit is the economic carrying capacity (ECC), which is the point at which the costs of adding another unit of variable generation to the grid outweigh its benefit. This concept is connected to the fact that all generation technologies, but in particular variable generation technologies, reduce in value as their penetrations increase. Denholm et al. consider how different flexibility options like the ones described above increase the ECC of solar in the California grid. They found that, after increased operational flexibility assumed to be in place by 2020, 6000MW of storage can increase the ECC of solar from 23% to 30%. Enabling greater exports increases the ECC by a similar amount. In contrast, because periods of overgeneration in California correspond to times when there is very little shiftable demand, demand response only increases economic carrying capacity from 23% to 24%.

In a similar study, Denholm et al. examined energy storage requirements for California to reach 50% solar PV penetration. They examined different flexibility scenarios, which varied according to their minimum generation level, export capacity, demand response availability and electric vehicle electrification. Required storage levels were determined by ensuring that the marginal net PV levelized cost of energy was comparable to future combined-cycle gas generators. They found that under the high flexibility scenario, no extra storage was necessary for 40% solar penetration, but 15GW of storage capacity was necessary for 50% solar penetration. Under

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3 System flexibility is defined as “the fraction below annual peak to which a conventional generation fleet may reduce output.” Flexibility factors of 60-70% are common for the US.

4 This can be seen already in California, where the wholesale power price of 1MWh of solar has decreased in value from $38.0/MWh to $23.8/MWh as solar penetration has increased from 2% to 12%.

5 The minimum generation level is the lowest value of power that could be reached by the conventional generation fleet.

6 Assuming an 8 hour discharge duration.
decreased flexibility scenarios and a higher base cost of PV, storage needs increase, up to a maximum of 10GW at 40% PV penetration and 28GW at 50% penetration.

In this thesis, we adopt the first and simplest approach described, quantifying the need for storage by determining the amount of storage necessary to make PV solar dispatchable. Specifically, in Section 4.1, we will estimate storage needs to transform a PV plant’s output to constant power, in order to mimic a base load plant. However, as noted above, a grid-scale, economic based approach is likely to provide a more realistic representation of the true demand for storage in a region.

2.5 Pumped storage in more depth

The power and energy capacity of a pumped storage plant are given respectively by the equations

\[ P = \eta_{gen} \rho g Q h_{net} \]

\[ E = \rho g h_{net} V \eta_{gen} \]

where \( \rho \) is the density of water, \( h_{net} \) is the net head between the reservoirs, \( V \) is the volume stored, \( Q \) is the flow rate of water, and \( \eta_{gen} \) is the generating efficiency.

The principal infrastructure of a pumped storage system are its reservoirs; pump-turbines with their associated motor-generators and the powerhouses that enclose them; and the tunnels and penstocks that make up the water conductors. In addition, a pumped storage system requires transmission infrastructure, including switchyards and transmission lines. Each of these components comes with an associated efficiency. Table 2.3 on the following page gives representative values for these efficiencies. Factoring in all components, modern pumped storage plants typically have a round trip efficiency of about 75%

As mentioned previously, pumped storage is the dominant source of energy storage globally, primarily due to its ability to store large amounts of energy for days, weeks, or even seasonally. Discharge durations are almost always greater than 6-8 hours and

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*Storage needs are not only affected by grid flexibility options, but by the price of solar and wind themselves. In a study that modeled the benefits provided by storage to a wind or solar plant, Braff et al. note that lower capital costs for solar and wind mean that storage costs must also be cheaper to provide a benefit compared to simply installing excess generation capacity.

*Base load is load that is always present, regardless of the time of day. The base load in California is approximately 20GW.

*A switchyard is also known as a substation.
Table 2.3: Composition of pumped storage plant cycle efficiencies. This table is a replica of Table 2-3 found in [45].

<table>
<thead>
<tr>
<th>Component</th>
<th>Indicative Value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pump cycle</strong></td>
<td></td>
</tr>
<tr>
<td>Water conductors</td>
<td>98.0-98.6</td>
</tr>
<tr>
<td>Pump</td>
<td>90.0-92.0</td>
</tr>
<tr>
<td>Motor</td>
<td>97.8-98.3</td>
</tr>
<tr>
<td>Transformer</td>
<td>99.0-99.6</td>
</tr>
<tr>
<td><strong>Overall</strong></td>
<td>85.4-88.8</td>
</tr>
<tr>
<td><strong>Generating cycle</strong></td>
<td></td>
</tr>
<tr>
<td>Water conductors</td>
<td>98.6-98.0</td>
</tr>
<tr>
<td>Turbine</td>
<td>75.0-91.0</td>
</tr>
<tr>
<td>Generator</td>
<td>97.8-98.3</td>
</tr>
<tr>
<td>Transformer</td>
<td>99.0-99.6</td>
</tr>
<tr>
<td><strong>Overall</strong></td>
<td>71.6-86.4</td>
</tr>
<tr>
<td><strong>Operational</strong></td>
<td></td>
</tr>
<tr>
<td>Losses &amp; leakage</td>
<td>98.0-99.8</td>
</tr>
</tbody>
</table>

can even exceed 20+ hours [41, 45]. These discharge durations enable pumped storage to shift demand across an entire day. Some pumped storage systems are even used for seasonal storage in regions where electricity generation is dominated by seasonal hydropower [63].

To be useful, pumped storage projects require a location with room for two reservoirs located a short distance from each other horizontally and as great a distance as possible vertically. This geographic limitation is often cited as a primary barrier for increased pumped storage development. While this limitation is real, it may be overstated. Yang and Jackson note that the U.S. Army Corps of Engineers found that the United States has a technical potential of more than 1000GW of pumped storage capacity [64, 23], in comparison with some 18GW currently licensed by the Federal Energy Regulatory Commission, FERC. Such a disparity would indicate that other variables are playing a significant role. Yang and Jackson argue that environmental impacts and the financial uncertainty associated with high capital cost projects are the primary limitations for pumped storage in the United States [64].

Many of the environmental impacts associated with pumped storage are related to the building of dams. Dams dramatically change river ecosystems and flow regimes above and below the dam, and they restrict sediment transfer and fish migration [21]. In light of this fact, most pumped storage projects in developed nations tend to avoid creating new dams altogether, adding capacity to an existing pumped storage project, developing pumped storage capacity at a conventional hydroelectric project, or using underground caverns as lower reservoirs [24, 64]. Of 42 FERC permit applications
**Licensed Pumped Storage Projects**

<table>
<thead>
<tr>
<th>State</th>
<th>Open-Loop Capacity (MW)</th>
<th>Closed-Loop Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA</td>
<td>4,243</td>
<td>365</td>
</tr>
<tr>
<td>CO</td>
<td>336</td>
<td>200</td>
</tr>
<tr>
<td>CT</td>
<td>51</td>
<td>300</td>
</tr>
<tr>
<td>GA</td>
<td>1,120</td>
<td>1,280</td>
</tr>
<tr>
<td>MA</td>
<td>1,833</td>
<td>1,221</td>
</tr>
<tr>
<td>MI</td>
<td>1,657</td>
<td>1,065</td>
</tr>
<tr>
<td>MO</td>
<td>443</td>
<td>2,722</td>
</tr>
<tr>
<td>MT</td>
<td>400</td>
<td></td>
</tr>
<tr>
<td>TX</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NY</td>
<td>1,400</td>
<td></td>
</tr>
<tr>
<td>OK</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SC/NC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>VA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL CAPACITY</td>
<td>18,376 MW</td>
<td></td>
</tr>
</tbody>
</table>

Source: FERC Staff, January 12, 2017

**Figure 2-2**: Pumped storage projects in the United States licensed by the Federal Energy Regulatory Commission (FERC). Not all of these facilities are fully operational. For example, the 1300MW Eagle Mountain closed-loop project located in Southern California began construction in 2014 and has not yet finished. Figure from [65].

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analyzed by Yang and Jackson, fewer than 25% included a proposal with a new reservoir [64].

Building a pumped storage facility at a site with existing reservoirs avoids the damage caused by new dams. However, such a facility still comes with its own environmental impacts. Excessive pumping can cause flows in reservoirs to reach critical erosion velocities, causing bottom erosion [66]. If this is the case, lining of the reservoirs may be required [27]. [63] provides a review of how the rotating pumping/discharging operation of a pumped storage plant can impact water quality and temperature, cause shoreline erosion, or impact ice cover, and how these effects can impact the reservoir ecosystem and its associated species. In their own study of increasing the pumped storage potential at existing hydroelectricity plants in southern Norway, Harby et al. restrict themselves to water level fluctuations of no more than 13 cm h\(^{-1}\). This value is consistent with studies that examine how water level fluctuations affect the stranding of salmon in rivers [67, 68], and is likely a conservative estimate for reservoirs [63].

California currently has approximately 2500MW of pumped storage capacity [61], with an extra 1300MW expected to come on-line in the next few years when the Eagle Mountain project in Southern California [65] is completed. In addition, there exist 1743MW of small hydropower capacity (typically less than 30MW) and 9119MW of large hydropower capacity [30]. Some fraction of this could be eligible for retrofitting for pumped storage use by adding new tunnels, powerhouses, and pump-turbines, without building new reservoirs. For this to be feasible, a system must have two reservoirs close enough to one another that it is economically feasible to build a pumped storage system. One potential is the Big Creek system, consisting of six main reservoirs, approximately 800MW of conventional hydropower capacity, and 200MW of pumped storage capacity. The next chapter introduces the Big Creek system, providing a foundation for the following chapters which explore the technical and economic feasibility of adding new pumped storage capacity to this existing network of reservoirs.
In this chapter, we introduce the Big Creek system, a 6 reservoir hydropower facility in central California that we propose to retrofit by adding new pumps, turbines, tunnels, and powerhouses to create new pumped storage functionality. The Big Creek system is owned and operated by Southern California Edison (SCE), one of the three main utilities in California. In Section 3.1 we introduce the main features of the Big Creek system and its history. Section 3.2 describes the uses and roles of Big Creek in the broader San Joaquin Valley. Section 3.3 describes the hydrology of the region, as well as the principal reservoirs and their water management. Sections 3.4 and 3.5 go into greater detail regarding the components of the system by describing its powerhouses, water conductors, and transmission lines. This chapter relies heavily on the Initial Information Package [69], a document provided by SCE during the Federal Regulatory Energy Commission (FERC) relicensing process of the Big Creek System.

3.1 History and Main Features

The Big Creek system is located in the Upper San Joaquin Valley in the Sierra National Forest in central California, about 100km Northeast of Fresno. It is composed of six main reservoirs: Mammoth Pool Reservoir (Mammoth), Lake Thomas A. Edison (Edison), Florence Lake (Florence), Huntington Lake (Huntington), Shaver Lake (Shaver), and Redinger Lake (Redinger). The Upper San Joaquin watershed is approximately 4000km² and varies in elevation from 90m to 4000m, while the reservoirs themselves are between 400m and 2300m in elevation. These reservoirs are connected by 9 powerhouses and their associated conduits, which in total provide 1000MW of
capacity. Due to the large elevation differences between the reservoirs, many of the powerhouses are located at small reservoirs (Dam 4, Dam 5, and Dam 6), each with their own dam but with minimal to no storage. From these small reservoirs, water is diverted again to lead to the next powerhouse. In addition to conventional hydroelectric, the Big Creek system also provides some pumped storage already via Eastwood powerhouse, a 200MW facility that uses Shaver Lake as a lower reservoir and Balsam Meadows Forebay as an upper reservoir. Figure 3-1 shows the reservoirs of the Big Creek system, as well as the powerhouses and the water conductors that link them. Figure 3-2 on the facing page shows the vertical distribution of the reservoirs and powerhouses.

Development of the Big Creek system began in the 1910s with the construction of Huntington Lake and its associated powerhouses. In the 1920s, Shaver Lake and Florence Lake were added. The 1950s saw the construction of the dams that would form Redinger Lake, Mammoth Pool Reservoir, and Thomas A. Edison Lake. In the late 1980s, Balsam Meadows Forebay and Eastwood Powerhouse were built to enable
Figure 3-2: Simplified schematic of Big Creek, highlighting the connections between the reservoirs and the powerhouses.
pumped storage capability.

3.2 Uses and role in the San Joaquin Valley

The Big Creek system’s primary purpose is to generate hydropower and, through Eastwood Powerhouse, provide pumped storage capability. However, the area also serves a recreational purpose. Located in the Sierra National forest, the reservoirs are often visited by locals and tourists for boating, fishing, and swimming, particularly in the summer months. In recognition of this fact, Southern California Edison has operational agreements in place to keep reservoir fluctuations to a minimum during the late spring and summer months at Edison Lake, Huntington Lake, Mammoth Lake, and Redinger Lake. The area is also frequented in the winter for winter sports activities such as skiing, snowshoeing, or snowmobiling.

As the Upper San Joaquin watershed provides water to the San Joaquin Valley, one of the most productive agricultural regions in the country, Big Creek provides some measure of seasonal irrigation storage to the region. This use is regulated by the Mammoth Pool Agreement, a contract with the United States Bureau of Reclamation that sets restrictions on maximum flows allowed during dry years and minimum storage requirements by the end of the water year. The role that the Big Creek system plays in irrigation storage is attenuated by Millerton Lake, a reservoir downstream of Redinger Lake that has a storage capacity of 0.64 km$^3$, almost equal to the storage capacity of the entire Big Creek system of 0.7 km$^3$. Secondly, because Big Creek’s storage capacity is small compared to the average runoff (0.7 km$^3$ compared to 2.0 km$^3$), it cannot effectively provide year-to-year storage.

3.3 Hydrology and reservoirs

The Upper San Joaquin Valley watershed receives approximately 1067 mm (42 in) of precipitation and an average of 2.1 km$^3$ of runoff per year. Over half of the precipitation occurs in January, February, and March, while most of the runoff comes from snow melt and occurs primarily from April through July. During this time, the powerhouses typically run at full capacity and operational flexibility is limited as

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$^a$Southern California Edison is the public utility that owns and operates the Big Creek system.
$^b$September 30th is the end of the water year. By this point, the vast majority of runoff has occurred until next year’s snow melt.
$^c$This value accounts for both rain and snow.
$^d$Except for dry years.
Table 3.1: Water year classifications for 1957-2016 \[70\]. Years are classified either as Wet (W), Above Normal (AN), Below Normal (BN), Dry, (D), or Critical (C). In the past 60 years, 58.4% of years were either Wet (31.7%) or Critical (26.7%), with another 18.3% classified as Dry.

<table>
<thead>
<tr>
<th>Year</th>
<th>Water Year Type</th>
<th>Year</th>
<th>Water Year Type</th>
<th>Year</th>
<th>Water Year Type</th>
<th>Year</th>
<th>Water Year Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>1957</td>
<td>BN</td>
<td>1972</td>
<td>D</td>
<td>1987</td>
<td>C</td>
<td>2002</td>
<td>D</td>
</tr>
<tr>
<td>1963</td>
<td>AN</td>
<td>1978</td>
<td>W</td>
<td>1993</td>
<td>W</td>
<td>2008</td>
<td>C</td>
</tr>
<tr>
<td>1964</td>
<td>D</td>
<td>1979</td>
<td>AN</td>
<td>1994</td>
<td>C</td>
<td>2009</td>
<td>BN</td>
</tr>
<tr>
<td>1969</td>
<td>W</td>
<td>1984</td>
<td>AN</td>
<td>1999</td>
<td>AN</td>
<td>2014</td>
<td>C</td>
</tr>
<tr>
<td>1970</td>
<td>AN</td>
<td>1985</td>
<td>D</td>
<td>2000</td>
<td>AN</td>
<td>2015</td>
<td>C</td>
</tr>
<tr>
<td>1971</td>
<td>BN</td>
<td>1986</td>
<td>W</td>
<td>2001</td>
<td>D</td>
<td>2016</td>
<td>D</td>
</tr>
</tbody>
</table>

the dams fill and excess water is spilled. In late summer, once the snow melt period ends and runoff has decreased, power generation is optimized to maximize production during peak hours of the day.

In addition to the seasonal variability mentioned above, snow melt and precipitation experience high interannual variability. The California Department of Water Resources classifies years as either Wet, Above Normal, Below Normal, Dry, or Critical. Table 3.1 shows the water year classifications for the past 60 years. 58.4% of years since 1901 were categorized as either Wet or Critical. As runoff responds rapidly in the region to changes in snow melt and precipitation, this interannual variability leads to significant changes in storage and powerhouse generation. Figure 3-3 shows box plots of monthly storage in each reservoir over the past 50 years, which illustrates the effect of this interannual variability on storage.

Though part of the Upper San Joaquin Watershed, the Big Creek system forms its own sub-basin. Figure 3-1 on page 42 shows the watersheds of each of the six

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*A water balance was conducted to calculate mean monthly fluxes at each reservoir using USGS gage data. The results, shown in Appendix A, clearly show these seasonal changes in flow.*
Figure 3-3: Boxplots of monthly mean storage for each reservoir from 1967-2015. As the scale is the same across all plots, the relative size of each reservoir can be clearly seen. Data from [71].

Main reservoirs. Ultimately, all of the water in the system flows to Redinger Lake. Mammoth Pool Reservoir, Florence Lake, and Thomas A. Edison Lake serve primarily as water storage, but provide little to no power generation directly. Of these three, only Mammoth Pool Reservoir has a diversion that goes directly to a powerhouse. Water from Thomas A. Edison Lake and Florence Lake would naturally flow down the San Joaquin River to Mammoth Pool Reservoir. However, the vast majority of the water from these reservoirs is diverted through Ward Tunnel to Huntington Lake. It is here, between Huntington, Shaver Lake, and Redinger Lake, that most of the power capacity is located. This results directly from the overall topography of the region, shown in Figure 3-4 on the next page. The steep gradients in elevation primarily occur downstream of Huntington Lake and so present the primary opportunities for hydropower generation.

Water that falls into the Big Creek system can flow through three primary “chains”: the Mammoth chain, the Huntington chain, and the Shaver chain. Each of these chains connects at Dam 6, approximately 8km upstream of Redinger Lake, where it flows through Powerhouse 3 and Powerhouse 4. Upstream of Dam 6, however, these chains represent different paths that the water can take. The Mammoth chain begins when water reaches Mammoth Pool. It then flows through Mammoth Pool Powerhouse, where it reaches Dam 6. Most of the water that flows through this chain originates in the sections of the Mammoth Pool watershed that do not overlap with
Figure 3-4: USGS elevation data for the Upper San Joaquin Watershed, where black represents low elevation (minimum = 163m) and white high elevation (maximum = 4226m). The six main reservoirs are shown in blue. Data from [71].

Table 3.2: The six main reservoirs of the Big Creek system. Watershed areas were calculated in ArcMap, while other values are from [69].

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Maximum elevation (m)</th>
<th>Watershed area (km2)</th>
<th>Storage capacity (km3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thomas A. Edison Lake</td>
<td>2329.4</td>
<td>236.5</td>
<td>0.15</td>
</tr>
<tr>
<td>Florence Lake</td>
<td>2233.4</td>
<td>447.5</td>
<td>0.08</td>
</tr>
<tr>
<td>Mammoth Pool Reservoir</td>
<td>1015.0</td>
<td>2599.1</td>
<td>0.15</td>
</tr>
<tr>
<td>Huntington Lake</td>
<td>2118.4</td>
<td>189.3</td>
<td>0.11</td>
</tr>
<tr>
<td>Shaver Lake</td>
<td>1636.8</td>
<td>76.19</td>
<td>0.17</td>
</tr>
<tr>
<td>Redinger Lake</td>
<td>427.6</td>
<td>3359.7</td>
<td>0.03</td>
</tr>
</tbody>
</table>
Table 3.3: Existing powerhouses descending downstream between Huntington and Redinger, along with their current power capacities and optimal discharges. Data from [69]

<table>
<thead>
<tr>
<th>Upper reservoir</th>
<th>Lower reservoir</th>
<th>Powerhouse</th>
<th>Gross head (m)</th>
<th>Current size (MW)</th>
<th>Optimal discharge (m$^3$s$^{-1}$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntington</td>
<td>Dam 4</td>
<td>Powerhouse 1</td>
<td>652</td>
<td>88</td>
<td>19.8</td>
</tr>
<tr>
<td>Dam 4</td>
<td>Dam 5</td>
<td>Powerhouse 2</td>
<td>569</td>
<td>66</td>
<td>17.5</td>
</tr>
<tr>
<td>Dam 5</td>
<td>Dam 6</td>
<td>Powerhouse 8</td>
<td>217</td>
<td>75</td>
<td>39.2</td>
</tr>
<tr>
<td>Dam 6</td>
<td>Redinger</td>
<td>Powerhouse 3</td>
<td>252</td>
<td>174</td>
<td>97.7</td>
</tr>
</tbody>
</table>

the watersheds of Edison and Florence. The Huntington chain starts at Huntington Lake, receives water from its own watershed as well as from Edison and Florence through Ward Tunnel, and then passes through Powerhouses 1, 2, and 8 until it reaches Dam 6. The Shaver chain also begins at Huntington, where water is diverted through the Huntington-Pitman-Shaver conduit towards Balsam Meadows Forebay. It then passes through Eastwood powerhouse and enters Shaver Lake, where it is diverted to Powerhouse 2A and joins the Huntington chain to go to Powerhouse 8 and Dam 6. Because of the connections between these chains, changes in operation in one can affect elevation levels in another.

3.4 Powerhouses and water conductors

A total of nine powerhouses provide approximately 1000MW of power capacity at Big Creek. Due to constraints in flow and interannual variability, average power produced at Big Creek ranges from 100MW to 500MW year to year. A summary of these powerhouses is presented in Table 3.3. With the exception of Eastwood, all powerhouses are conventional hydroelectric facilities, and do not provide pumping capability. All powerhouses are surface powerhouses, again with the exception of Eastwood, which is built into the mountain approximately 1500m underground.

Water conduits at Big Creek typically consist of unlined granite tunnels, constructed using tunnel boring machines. Diameters range from about 2m to 6m. These tunnels traverse most of the horizontal distance between powerhouses on a gradual slope. Over the last 10-15% of the horizontal distance, water divides into surface penstocks built with steel on a steep slope that captures most of the vertical distance between the powerhouses. These penstocks deliver water down to each of the generating units. Figure 4-7 on page 59 illustrates this behavior by showing the
Table 3.4: Descriptions of water conduits between Huntington and Redinger. Rows lower on the table refer to conduits further downstream. Data from [69].

<table>
<thead>
<tr>
<th>Name</th>
<th>Length (m)</th>
<th>Type</th>
<th>Diameter (m)</th>
<th>Number of branches</th>
<th>Optimal flow (m³s⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tunnel No. 1</td>
<td>1202</td>
<td>Unlined granite</td>
<td>3.7</td>
<td>1</td>
<td>19.8</td>
</tr>
<tr>
<td>Tunnel No. 1 Extension</td>
<td>1974</td>
<td>Steel-lined</td>
<td>2.1</td>
<td>1</td>
<td>19.8</td>
</tr>
<tr>
<td>Powerhouse 1 Penstocks</td>
<td>1325</td>
<td>Steel</td>
<td>1.4</td>
<td>4</td>
<td>19.8</td>
</tr>
<tr>
<td>Tunnel No. 2</td>
<td>6632</td>
<td>Unlined granite</td>
<td>3.7</td>
<td>1</td>
<td>17.5</td>
</tr>
<tr>
<td>Powerhouse 2 Penstocks</td>
<td>1330</td>
<td>Steel</td>
<td>1.1</td>
<td>4</td>
<td>17.5</td>
</tr>
<tr>
<td>Tunnel No. 8</td>
<td>1697</td>
<td>Unlined granite</td>
<td>6.1</td>
<td>1</td>
<td>39.2</td>
</tr>
<tr>
<td>Powerhouse 8 Penstocks</td>
<td>822</td>
<td>Steel</td>
<td>2.4</td>
<td>2</td>
<td>39.2</td>
</tr>
<tr>
<td>Tunnel No. 3</td>
<td>8592</td>
<td>Unlined granite</td>
<td>6.4</td>
<td>1</td>
<td>97.7</td>
</tr>
<tr>
<td>Powerhouse 3 Penstocks</td>
<td>422</td>
<td>Steel</td>
<td>2.3</td>
<td>4</td>
<td>97.7</td>
</tr>
</tbody>
</table>

elevation profile between Redinger and Huntington. Currently, no granite tunnels exist side-by-side; water only travels in multiple branches in the surface penstocks. Table 3.4 provides an example of the types of water conduits that compose the system by describing the conduits between Huntington and Redinger.

3.5 Transmission Lines

Two 220 kV transmission lines connect the Big Creek system to the broader electrical grid. Figure 3-5 on the following page shows the location of these transmission lines and their associated switchyards[f]. The hydropower at Big Creek was originally developed to provide power to Los Angeles, so these transmission lines run south approximately 350km (220 miles) to the city. During periods of peak generation, they operate at or near full capacity [SCE, personal correspondence].

[f] Also known as substations.
Figure 3-5: High voltage transmission lines at Big Creek.
Chapter 4

Exploring the Technical Feasibility of Retrofitting the Big Creek System for Storage

A pumped storage system is comprised of a few key pieces of infrastructure: the upper and lower reservoirs, the conduits between them such as tunnels and penstocks, pump-turbines and the powerhouses that hold them, and transmission infrastructure such as substations and transmission lines. Retrofitting a hydropower facility for pumped storage, then, entails modifications to these components, as well as adapting the operation of the facility itself. In this chapter, we examine the technical feasibility of retrofitting Big Creek by examining each of these components in turn and determining what modifications would be necessary. While we give less emphasis to changes in operation, we outline what these changes may look like throughout the analysis.

One important consideration when determining what modifications would be required is the question of battery performance and scale—how large a battery we are trying to develop, and what characteristics it should have to meet its intended purpose. Therefore, in Section 4.1 we first develop a simple model to estimate what energy-to-power (E/P) ratio is necessary to transform solar into a dispatchable source of power, with an emphasis on using solar for base load. Section 4.2 uses the length-to-head (L/H) ratio to select an upper and lower reservoir for the new pumped storage scheme, ultimately selecting Redinger Lake as the lower reservoir and Huntington Lake as the upper reservoir. Section 4.3 examines the Redinger-Huntington chain’s role in the current system by describing the current powerhouses along it and their relative power capacities and generation in relation to the entire Big Creek system.

With this context in place, Sections 4.4, 4.5, 4.6, and 4.7 explore infrastructure
and operational modifications for the reservoirs, water conductors, pump-turbines and powerhouses, and transmission infrastructure respectively. Sections 4.8 and 4.9 conclude by outlining the environmental and recreational impacts associated with these modifications, and by outlining the final design that is then used as a guide for a comparative economic analysis in the next chapter.

4.1 Establishing Battery Performance Characteristics to Support Solar

Storage is necessary to transform solar power into a dispatchable source of energy. As seen in Chapter 2, however, storage technologies vary widely in their performance characteristics, particularly in their energy and power capacity costs. What kind of battery does solar require? In this section, we answer this question by sizing a battery to equally charge and discharge on a typical summer day under a variety of different operational regimes. We find that an E/P ratio of 15.4 is necessary to transform the output from a solar plant into a constant source of power that is suitable for base loads.

Solar experiences variability at a variety of different time scales, ranging from minutes to yearly. Though each of these sources of variability can impact the ease with which solar can be converted into dispatchable power with storage, not all are equally important. Variability on the time scale of minutes is small compared to wind, and is minimized by aggregating generation across multiple plants over a large geographic area. Yearly variability is minimal as seen in Figure 4-1 and can generally be ignored. Hourly, daily, and monthly variability have more significant impacts. Figure 4-2 shows monthly and daily variations in solar irradiance for a point about 100km northeast of Los Angeles. As can be seen, solar irradiance fluctuates seasonally by a factor of more than 3. These fluctuations, coupled with seasonal changes in demand, change the shape of the net load curve as seen in Figure 1-3 on page 22.

The greatest variability experienced by solar, however, is on the hourly timescale via its diurnal cycle, as illustrated in Figure 4-3 on page 55. It is this variability that provides the greatest challenge to grid operators for increased solar penetration, as it leads to the low net loads during the day and sharp ramps in the evening that are challenging for conventional facilities to adapt to. For the remainder of our analysis, we focus on the use of storage to minimize the impact of this diurnal cycle. In

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*aFor instance, even though solar irradiance increases in the summer, the high increase in AC use minimizes or eradicates the dip in net load in the middle of the day that is seen in other months.*
Figure 4-1: Mean global horizontal irradiance (GHI) for each year at two different points in California. GHI is the total amount of shortwave radiation received from above by a surface horizontal to the ground, and is often used to estimate energy generation potential for solar PV plants. Point A refers to a latitude/longitude of (34.49, -117.54), approximately 100km northeast of Los Angeles; Point B refers to (36.49, -119.82), approximately 30km south of Fresno. Data from [72].

In particular, we will emphasize storage necessary to make solar power dispatchable on a daily basis.

The exact performance characteristics of a battery that is used to make solar dispatchable will vary depending on the desired output profile from the combined PV-battery plant. In particular, the power and energy characteristics of the battery will vary significantly. To arrive at an estimate of the performance characteristics required, we sized a battery for each of three different output profiles: a base load plant, which provides a constant amount of power across the entire day; a peaking plant, which provides a large amount of power between the hours of 5 and 9PM; and a smoothed output plant, which provides a constant amount of power for the middle
Figure 4-2: Monthly and daily variability in solar irradiance. Data from [72].

16 hours of the day (5AM-9PM)\textsuperscript{b} We simplified the analysis by using the following assumptions:

- Solar power generation is 0 from midnight to 7AM, follows a sinusoidal curve from 7AM-7PM, and is 0 again from 7PM to midnight\textsuperscript{c} Power generation peaks at 100MW\textsuperscript{d} This assumption approximates a 100MW nameplate capacity PV solar plant’s generation for a clear day in the summer\textsuperscript{f}

- Discharge and charging efficiency are 85%, for a round trip efficiency of 72.25%.

\textsuperscript{b}This approach does not incorporate the economic value that is provided by this storage, but rather assumes \textit{a priori} a given output profile. See [36] for an example of optimizing the size of a battery to maximize the economic value that is provided to a solar plant.

\textsuperscript{c}[54] considers how storage requirements change with increasing forecast error.

\textsuperscript{d}100MW is taken as the nameplate capacity of a typical utility PV plant in California, see Figures 4-4 on page 56 and 4-5 on page 57.

\textsuperscript{e}As noted previously, we are explicitly focusing on hourly variability and are therefore ignoring daily and seasonal variability. See [52] and [53] for studies which consider how changes in solar irradiance on daily and monthly timescales impact storage requirements.
figure 4-3: Hourly variability in solar irradiance. Data from [72].

Most modern pumped storage facilities range between 75-80% round trip efficiency [27].

- The battery is capable of adjusting its power output/input instantaneously.
- At the end of the day, the amount of energy stored in the battery is the same as at the beginning of the day.
- The battery is sufficiently full at the beginning of the day so that it can discharge even if the sun has not yet risen. That is, if needed, one can take out a loan of energy at the beginning of the day and get paid later in the day.
- The maximum power capacity that the combined PV-battery plant can guarantee is the power capacity of the battery.

To size the batteries for each output profile, we found the power capacity (equivalent to the constant amount of power supplied) that best balanced the energy stored
and discharged over an entire day. Solar power produced in excess of the immediate demand is stored, while times of excess demand are met by discharging the battery.

The results of our analysis are shown in Figure 4-6 on page 58. For each graph, the value $P$ corresponds to the power capacity of the battery, while $E$ corresponds to the energy capacity. The results are unit-invariant, and depend on the unit of the PV plant the battery is paired to. For instance, if a 100MW PV plant is desired to operate as a baseload plant, it would require a battery with a power capacity of 26MW and an energy capacity of 400MWh.

The desired output profile has a significant effect on the power and energy capacity requirements of the battery, with power and energy capacity values varying by a factor of 5 and 2, respectively. These differences can be captured by the $E/P$ ratio, roughly the number of hours that a battery would be capable of discharging at full capacity. From left to right in Figure 4-6 on page 58, these three different cases have $E/P$ ratios of 15.4, 4.3, and 6.7, respectively. No one battery technology is ideally suited to all of these use cases. In this work, we focus on the base load plant operation,

\[ E \geq P \quad \text{and} \quad \eta < 1 \]
Figure 4-5: Cumulative distribution function of solar plant capacity in California, showing the percentage of nameplate capacity provided by plants smaller than a given capacity. For example, plants with capacities of 100MW or less supply 40% of the overall nameplate capacity. Data from [73] which has a relatively high E/P ratio, emphasizing the need for storing energy over a greater amount of time. This is a use case where PHS excels due its low energy cost and relatively higher power costs. In a grid of the future, one could imagine solar and PHS combined to provide this base load power, while other battery technologies could be used to provide peaking plant needs. Note that, due to the peaking nature of solar’s natural generation, using it for a base load means that on a day when the solar plant is reaching its nameplate capacity, the amount of constant power that can be produced across the whole day is only about 25% of the nameplate capacity.

### 4.2 Selecting an Upper and Lower Reservoir

A pumped storage system needs an upper and lower reservoir. The Big Creek system has 6 reservoirs, and each could potentially be used. To screen potential options, we used the length to head ratio (L/H), which divides the horizontal distance between reservoirs by the vertical distance or head separating them. This ratio serves as a
Figure 4-6: Results of our battery sizing algorithm. The ultimate battery characteristics vary significantly depending on the desired operation of the combined PV-battery plant.

rough cost-to-benefit ratio, as greater lengths correspond to greater friction losses and more tunneling costs, and larger heads refer to more power produced. In general, L/H ratios rarely exceed 10 \[74\], although there are some existing plants in the US with L/H ratios slightly above 10 \[27\]. These include Helms, a pumped storage plant less than 30km from Big Creek with a L/H ratio of 12.5.

Table 4.1: Length to head ratios for various lower and upper reservoir combinations. Data from \[69\].

<table>
<thead>
<tr>
<th>Chain</th>
<th>Length (m)</th>
<th>Head (m)</th>
<th>L/H Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Redinger-Huntington</td>
<td>24000</td>
<td>1690</td>
<td>14.2</td>
</tr>
<tr>
<td>Redinger-Florence</td>
<td>43400</td>
<td>1850</td>
<td>23.5</td>
</tr>
<tr>
<td>Redinger-Mammoth</td>
<td>22800</td>
<td>587</td>
<td>38.8</td>
</tr>
<tr>
<td>Redinger-Shaver</td>
<td>17900</td>
<td>1209</td>
<td>14.8</td>
</tr>
<tr>
<td>Shaver-Huntington</td>
<td>14000</td>
<td>480</td>
<td>29.2</td>
</tr>
<tr>
<td>Shaver-Florence</td>
<td>34600</td>
<td>640</td>
<td>54.1</td>
</tr>
</tbody>
</table>

Table 4.1 shows the L/H ratios for several potential chains in the Big Creek system. Each chain is denoted by its lower reservoir followed by its upper reservoir. It can be seen that chains incorporating the back country reservoirs (e.g. Mammoth
and Florence) have L/H ratios significantly exceeding 10-12. Of the options in Table 4.1, only Redinger-Huntington and Redinger-Shaver approach reasonable values. We chose to focus our analysis on the Redinger-Huntington chain. This is the main chain of the Big Creek system, with a total of 4 powerhouses (Powerhouses 1, 2, 8, and 3) spread throughout.

### 4.3 The Redinger-Huntington Chain and Its Role in the Big Creek System

The Redinger-Huntington chain is composed of 4 powerhouses over a total length of 24km and head drop of 1690m. The elevation profile is provided visually in Figure 4-7. Huntington and Redinger are the only large reservoirs along this profile, but several smaller dams exist to divert water to the next powerhouse on the chain, each with close to zero storage capacity. The L/H ratios for the powerhouses in the chain vary widely, from 6.9 to 36.1.

![Elevation Profile for Redinger-Huntington Chain](image)

Figure 4-7: The Redinger-Huntington chain is composed of 4 different powerhouses, with varying L/H ratios. Data from [69].

<table>
<thead>
<tr>
<th>Upper reservoir</th>
<th>Lower reservoir</th>
<th>Powerhouse</th>
<th>L/H ratio</th>
<th>Optimal flow ($m^3/s$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntington</td>
<td>Dam 4</td>
<td>Powerhouse 1</td>
<td>6.90</td>
<td>19.8</td>
</tr>
<tr>
<td>Dam 4</td>
<td>Dam 5</td>
<td>Powerhouse 2</td>
<td>13.9</td>
<td>17.5</td>
</tr>
<tr>
<td>Dam 5</td>
<td>Dam 6</td>
<td>Powerhouse 8</td>
<td>11.5</td>
<td>39.2</td>
</tr>
<tr>
<td>Dam 6</td>
<td>Redinger</td>
<td>Powerhouse 3</td>
<td>36.1</td>
<td>97.7</td>
</tr>
</tbody>
</table>

Table 4.2: Length to head (L/H) ratios for the Redinger-Huntington chain, which has an overall L/H ratio of 14.2. The low value for Huntington to Dam 4 balances out the high value for Dam 6 to Redinger. Data from [69].
The powerhouses in the Redinger-Huntington were the first ones built at Big Creek. Supplying about 40% of Big Creek’s power capacity, these powerhouses provide more than 50% of the power generation, as they are given priority during times of low flow. Table 4.3 shows the power capacities of each of the powerhouses at Big Creek, while Figure 4-8 shows how the Redinger-Huntington chain’s power generation compares to those of the other powerhouses.

Table 4.3: Power capacities of powerhouses at Big Creek. The Redinger-Huntington chain supplies about 40% of the power capacity available. Data from [69].

<table>
<thead>
<tr>
<th>Redinger-Huntington powerhouses</th>
<th>Other powerhouses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Powerhouse 1 88.5MW</td>
<td>Eastwood 200MW</td>
</tr>
<tr>
<td>Powerhouse 2 66.5MW</td>
<td>Powerhouse 2A 75MW</td>
</tr>
<tr>
<td>Powerhouse 8 75MW</td>
<td>Mammoth Pool 190MW</td>
</tr>
<tr>
<td>Powerhouse 3 174.5MW</td>
<td>Powerhouse 4 100MW</td>
</tr>
<tr>
<td></td>
<td>Portal 10.5MW</td>
</tr>
<tr>
<td><strong>Total:</strong> 404.5MW</td>
<td><strong>Total:</strong> 575.5MW</td>
</tr>
</tbody>
</table>

Figure 4-8: Average power produced by the Redinger-Huntington chain and all other powerhouses at Big Creek. Though the Redinger-Huntington chain supplies only 40% of the power capacity, it provides approximately 50% of the power generation. (Data: EIA)

Such comparisons highlight the importance of this chain to the overall system,
but can belie the connections between the Redinger-Huntington chain and its counterparts. As one moves further downstream, this chain connects with the Shaver and Mammoth chains at Dam 5 and 6 respectively. As a result, tunnel capacities increase downstream, from a low of 17.5 m$^3$ s$^{-1}$ to a high of 97.7 m$^3$ s$^{-1}$. These connections mean that changes in operation in one chain affect the other chains. Operating the Huntington and Shaver chains at maximum capacity means that the Mammoth chain cannot also run at maximum capacity without creating spill at Redinger and Dam 6; similarly, changing flows in the Huntington and Shaver chains disproportionately will change the reservoir levels at Huntington, Shaver, and Redinger Lake [69].

These complex interrelations mean that any changes to the operation of one chain must be carefully modeled to understand their effects on the system as a whole. However, by adding new tunnels and powerhouses side-by-side to existing infrastructure, such changes can largely be avoided. The system can be operated as it currently is, except that in addition there is a daily flux of water back and forth between Redinger and Huntington. As shall be seen in Section 4.5, this results in a reduction of available storage capacity in Huntington, but otherwise leaves the current system unchanged.

### 4.4 Examining the Reservoirs

The amount of energy that can be stored in any two reservoirs is determined by

$$ E = \rho g h_{net} V \eta_{gen} $$

where $\rho$ is the density of water, $g$ is the acceleration due to gravity, $h_{net}$ is the net head between the reservoirs, $V$ is the volume stored, and $\eta_{gen}$ is the generating efficiency. We choose a value of 85% for $\eta_{gen}$ in line with the high end of efficiencies of existing pumped storage plants in the United States [27]. We also assume that 3% of our gross head is lost to friction. In our 85% generating efficiency number, we do not explicitly consider transmission losses from Big Creek to the consumer (e.g. San Francisco), which can range from 1-10% depending on the transmission lines used. See Section 4.7 for a more extended discussion on transmission line losses.

Figure 4-9 shows volume vs. energy for the Redinger-Huntington chain, assuming 3% head loss and a range of efficiencies. When considering what volume of water is available for pumping, we use 0.02 km$^3$ as an upper limit. This value comes from examining Redinger’s exceedance curve (Figure 4-12 on page 65), which shows the percentage of time in the period of record that the storage in Redinger Lake exceeded
Figure 4-9: Energy storage potential between Redinger and Huntington, assuming 85% generating efficiency and 3% head loss due to friction.\[27\].
a given value. It can be seen that Redinger always has 0.01km$^3$ water in it. We will not attempt to pump this water, therefore restricting ourselves to the remaining 0.02km$^3$. While it may be possible to increase Redinger’s capacity by raising the height of its dam, the extent to which this is feasible is dependent on the dam’s construction and the nearby topography, and would require flooding more land. Despite this limit, the Redinger-Huntington chain is capable of storing up to 75GWh using 0.02km$^3$ of water with an 85% generating efficiency. This is primarily due to the large head difference (1690m) between the two reservoirs.

Using the E/P ratio of 15.4 that we derived as necessary to transform solar into a base load power plant, 75 GWh is enough energy storage to support a power capacity of 4.87GW (approximately 5GW). Figure 4-10 demonstrates that current base loads in California are 20GW. Therefore, if the Redinger-Huntington chain was used to provide 5GW of power capacity, this would be enough storage to enable solar to provide 25% of CAISO’s base load. Note that, according to our results found in Section 4.1, this would require approximately $5 \times 4 = 20$GW of PV nameplate capacity in the summer. Because nameplate capacity refers to the peak power output of a PV panel, and due to seasonal variations in solar irradiance that significantly reduce solar irradiance from this peak in winter months, significantly more PV nameplate capacity would be required in the winter/late fall (approximately 3-4 times more) to provide the same 5GW of base load power. This is a function of solar’s relatively low capacity factor$^k$ compared to conventional generation facilities.

With the 0.02km$^3$ value as an upper limit, we can examine the elevation storage curves in Figure 4-11 on the next page for both Redinger and Huntington to estimate expected reservoir elevation changes on a given day. To achieve the 75GWh of storage associated with 0.02km$^3$ of water, Huntington would require an elevation change of approximately 4 meters. The exception to this is when Huntington drops below 0.03km$^3$, where a decrease in capacity of 0.02km$^3$ could result in a 15-20m drop in elevation.

Redinger is a significantly smaller reservoir and is set in a narrow gorge, so changes in capacity result in larger elevation changes. From a nearly full capacity of 0.03km$^3$, a drop in volume of 0.02km$^3$ at Redinger would result in an elevation decrease of

---

$^9$For comparison, there was 9.867 GW of combined utility scale solar PV and solar thermal capacity installed in California by 2016. [http://www.energy.ca.gov/renewables/tracking_progress/documents/installed_capacity.pdf](http://www.energy.ca.gov/renewables/tracking_progress/documents/installed_capacity.pdf)

$^k$“Capacity factor” is defined as the average power that is generated by a generating facility over some period of time divided by the power that would be generated if the plant was operating at its rated capacity during that whole time.
Figure 4-10: Average seasonal loads from 2014-2017. The base load is 20GW, as seen by the fact that the load curves never drop below this amount. Data from [14].

Figure 4-11: Capacity curves for Redinger and Huntington. Data courtesy of Southern California Edison.
about 14m. Daily changes of reservoir elevation on the order of 6-14m would represent a significant departure from current operations, which emphasize minimizing fluctuations during the summer months to support recreational use [69]. Regarding the structural integrity of the dam at Redinger, it is possible that the constant drying and wetting caused by this change in elevation would accelerate deterioration. It is also possible that these elevation changes could cause erosion of the reservoir banks and beds [66, 63, 27]. These possibilities, as well as other potential environmental and recreational impacts, are discussed further in Section 4.8 on page 83.

As California’s hydrology is characterized by significant interannual variability, we would want to ensure that there is always or nearly always sufficient water available to operate our pumped storage system. To do so, we sum the volume of water used for pumping with the minimum reservoir volumes in both Redinger and Huntington. Mathematically,

\[ V_{\text{min}, \text{cum}} = V_{\text{pump}} + V_{\text{min, Redinger}} + V_{\text{min, Huntington}} \]

The volume exceedance graph for Redinger in Figure 4-12 implies that Redinger must have a volume of 0.01km\(^3\) at all times. For establishing a minimum volume for Huntington, we turn instead to the storage curve in Figure 4-11. At volumes below 0.025km\(^3\), elevation decreases significantly faster than at higher volumes. By setting 0.025km\(^3\) as the minimum volume, a change in volume of 0.02km\(^3\) would result in elevation changes of no more than 6m. Assuming a pumping volume of 0.02km\(^3\) results in the minimum required water volume equal to
Figure 4-13: Cumulative storage in Redinger and Huntington (monthly means). The red line is the minimum amount of water that is needed to operate our 4.9GW pumped storage facility. The blue line is the maximum amount of water that can be in the reservoirs, to allow volume to pump water into. For 98% of months, sufficient water is available in the reservoirs to operate the facility. Approximately 40% of months lie above the maximum amount of water that is allowed. Data from [71].

\[ V_{\text{min,cum}} = 0.02 + 0.01 + 0.025 = 0.055\text{km}^3 \]

Figure 4-13 shows box plots of mean monthly cumulative storage in Redinger and Huntington over a period of 56 years. The red line shows \( V_{\text{min,cum}} = 0.055\text{km}^3 \), and all months that fall above this line have enough water for the pumped storage system to operate. In all, 97.8% of months and 97.4% of days have a mean storage greater than 0.055\text{km}^3. It can be concluded, then, that lack of availability is not likely to play a significant role in determining the feasibility of a pumped storage system between Redinger and Huntington.

While water availability is important, too much water can also be a problem. Namely, a pumped storage systems needs enough storage capacity such that there is space available to pump or discharge water into. The small sizes of these reservoirs
Figure 4-14: Boxplots showing monthly mean storage in Redinger and Huntington. Redinger is often full or close to full due its position as the lowest reservoir in the system. Huntington fills almost every July and August. Data from [71].

compared to the flows received combined with the period of high flows in the late spring and summer that corresponds to the period of snow melt, means that for many months, Redinger and Huntington are at or near full capacity. The blue line in Figure 4-13 on the facing page indicates a value of 0.121km$^3$, 0.02km$^3$ below the maximum cumulative capacity of the two reservoirs. 44.1% of months and 45.7% of days from 1965-2016 lie above this line, primarily during the summer and early fall months, but also occasionally during the late fall and winter months. Figure 4-14 shows mean monthly storage for each reservoir.

There appear to be two primary reasons for the reservoirs filling up so frequently. The first is due to the flow exceeding tunnel capacities. As part of a water balance conducted on the system, mean monthly fluxes were calculated at each reservoir from 1986 to 2016. During the months of May and June, the mean inflow received by Redinger is greater than the outflow tunnel capacity of approximately 100m$^3$ s$^{-1}$, resulting in the reservoir filling and ultimately spilling. Mean monthly fluxes at Huntington do not exceed tunnel capacities. However, these mean monthly fluxes obscure the significant variability that exists between dry and wet years.

The second reason for the reservoirs filling is not technical, but operational. Both Redinger and Huntington are kept at as high an elevation as possible during the

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1The Big Creek system receives 2.1km$^3$ of water annually. All of this water flows into Redinger (capacity of 0.032km$^3$), and a substantial fraction flows into Huntington (capacity 0.128km$^3$).

2See Appendix A for the full water balance.
late spring and summer months to aid recreation. In addition, maintaining Redinger elevations high provides additional head to Powerhouse 4.

When the available volume for storing water drops below that which is being pumped up and down, the operation of the pumped storage facility must also be adapted. No change in operation is necessary when Redinger, the lower reservoir, lacks sufficient storage. Any excess water would simply spill over, exactly as it does now, leaving a full reservoir available for pumping when needed. Pumping water up into Huntington when it lacks the storage, however, is a waste of energy, akin to pumping water into a bucket that is already full. Therefore, whenever Huntington exceeds a storage of 0.09km³, the amount of water pumped up should be limited so that only the amount needed to fill the reservoir is pumped.

For this “water battery,” pumping is the equivalent of charging the battery. Restricting pumping therefore means that there is (solar) power being generated that is not able to be stored. In the summer, this excess power coincides with periods of high AC use, which can likely absorb some or most of it. Alternatively, this solar could be sold for cheaper power or curtailed if no other options exist. Periods when solar would have to be curtailed could also be predicted, and could be good opportunities to perform needed maintenance at the solar plant.

Finally, it can be noted that setting $V_{pump} = 0.02km^3$ means that there is an effective 0.02km³ reduction in storage capacity in the system as a whole. Figure 4-15 on the facing page shows the cumulative mean monthly storage in the Big Creek system from 1970 to 2015. By comparing the magnitudes of water stored to the 0.02km³ value, it can be seen that this reduction in storage capacity does not significantly impact Big Creek’s secondary use for seasonal storage of water.

### 4.5 Examining the Water Conductors

In order to enable the Redinger-Huntington chain to provide pumped storage facility as well as its current functionality of hydropower generation, new tunnels will need to be added. In this section, we estimate the size and number of tunnels that are required in order to meet a given power capacity, up to 5GW. We also consider how the extra discharge capacity that these tunnels offer could be used to capture water that is currently spilled during the late spring and early summer months.

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$k$This 0.09 figure comes from subtracting $V_{pump}$ from 0.11km³, the maximum amount of water stored in Huntington since 1925.
Figure 4-15: Cumulative storage in the entire Big Creek system (monthly means). Due to its small size compared to the storage in the entire system, the 0.02km$^3$ reduction in storage that our 4.9GW facility requires will not significantly affect Big Creek’s use for seasonal storage.
4.5.1 Derivation of tunnel diameter and number

The Darcy-Weisbach friction formula gives the friction loss $h$ across a length of pipe $L$ with diameter $D$, given a velocity $u^2$ and a Darcy friction factor $\lambda$:

$$h_f = \frac{\lambda L u^2}{2gD}$$

Rewriting velocity in terms of $Q$ and $D$:

$$u = \frac{Q}{A} = \frac{4Q}{\pi D^2}$$

Then substituting the expression for $u$ into the equation for $h_f$:

$$h_f = \frac{\lambda L \left( \frac{4Q}{\pi D^2} \right)^2}{2gD}$$

Solving for $D$:

$$D = \left( \frac{8\lambda L Q^2}{\pi^2 h_f g} \right)^{\frac{1}{5}}$$

Given estimates for $\lambda$, $h_f$, and $L$, we can use this equation to determine the diameter required for a particular discharge. Further assuming a generating efficiency $\eta_{gen} = 0.85$ [45], we can relate discharge with a power output according to

$$P = \eta_{gen} \rho g Q h_{net}$$

We assume a friction factor $\lambda = 0.025$, approximating the values of 0.015-0.044 which are given for unlined granite tunnels of diameters 2.5-10m created by a boring machine [75]. Waterway losses are assumed to be 3% of the difference in head between Huntington and Redinger (50.7m) [27]. Tunnels are assumed to be of equal length to existing tunnels, so $L = 24000m$. This, combined with the constant friction factor, implies that the entire conduit is made of unlined granite tunnels—a reasonable approximation except for the penstocks, which are built out of steel. Penstocks are also typically of smaller diameter, branching off to each respective turbine. These details are omitted in this analysis.

The analysis above is suitable for a single tunnel. We can also perform a similar analysis for multiple tunnels in parallel. In this case, the total discharge can be written as a function of the $k$ tunnels

$$Q = Q_1 + Q_2 + \ldots + Q_k = \frac{\pi}{4} \left( D_1^2 u_1 + D_2^2 u_2 + \ldots + D_k^2 u_k \right)$$
We assume that the tunnels have equivalent diameters and areas, lengths, and friction factors. These assumptions imply that velocities are also equivalent. Therefore, the equation for the total discharge simplifies to

\[ Q = \frac{\pi}{4} k D^2 u \]

Solving for \( u \) gives

\[ u = \frac{4Q}{\pi k D^2} \]

Which, when plugging into our previous equation for \( h_f \) and solving for \( D \) gives

\[ D = \left( \frac{8\lambda L Q^2}{k^2 \pi^2 h_f g} \right)^{\frac{1}{5}} \]

### 4.5.2 Results of tunnel derivation and potential to harness spills

The results of the previous section are shown in Figure 4-16 on the next page and Figure 4-17 on page 73. Figure 4-16 plots tunnel diameter vs. power capacity. Because area is proportional to the square of diameter, doubling the number of tunnels does not lead to a reduction in diameter size by a factor of two. As construction costs are more sensitive to tunnel length than tunnel diameter, the general principle is that the larger the tunnel size that can be safely built, the cheaper overall construction costs will be. This principle is reinforced by the fact that, in reality, friction factors increase as tunnel diameter decreases, although because we assume a constant friction factor, this effect does not show in our results.

Current tunnel sizes on the Redinger-Huntington chain range from 2m to 6.5m, increasing downstream as the chain joins with the Shaver and Mammoth chains. This increase implies that economic or water availability considerations governed the sizing of the tunnels, rather than geotechnical limits. However, in selecting a tunnel size, we assume that there were good reasons for restricting tunnel maximums to less than 6.5m, which could include water hammer, hydraulic jacking, or faults in the rock itself [75]. We therefore set our tunnel diameter to 6m, which, when referencing Figure 4-16, means that 4 tunnels are necessary to provide 5GW of power capacity.

Figure 4-17, which plots tunnel discharge capacity vs. power capacity, shows that to achieve this 5GW power capacity, the tunnel discharge capacity must be equal to 350m³ s⁻¹. Given that the current tunnel capacities on the Redinger-Huntington
Figure 4-16: Tunnel diameters required for different power capacities.
Figure 4-17: Discharge required for different power capacities. The red lines represent the range of current tunnel capacities along the Redinger-Huntington chain.
Figure 4-18: Spills that could be harnessed if tunnel capacities were expanded.

Chain range from $17\,m^3\,s^{-1}$ to $100\,m^3\,s^{-1}$, this represents a significant increase in capacity, and would lend itself to the idea that it is likely several tunnels will need to be built side by side. However, this additional tunnel capacity presents an opportunity to harness the energy potential of water that is currently spilled over the dams during periods of high flow. To estimate an upper bound for this potential, we gathered daily mean flow data from stream gages immediately below each of the main dams. Figure 4-18 shows the location of these gages, with box plots showing the distribution of flows above the minimum stream requirements (estimated at $3\,m^3\,s^{-1}$ everywhere). The spills below Huntington, from Pitman Creek, Below Dam 5, and Below Dam 6 can each be utilized by some or all of the new infrastructure we propose to build. These excess flows were assumed to be used for hydropower, up to a max of $350\,m^3\,s^{-1}$.

The power generation potential varied for each gage according to the elevation from which it became available to the extra tunnel capacity in the Redinger-Huntington chain.

The results of this analysis is shown in Figure 4-19, which shows the increase in average power in a year that could be achieved if these spills were harnessed. It can be seen that the spill potential varies significantly year to year, a result of the interannual variability of California’s climate. In wet years, however, harnessing spills could increase average power generated by approximately 15-20%. Though this value
Figure 4-19: Additional power that could be generated from spills. This power is represented as an average power across the entire year—however, it is concentrated during months of high flow, typically late spring and early summer.

is reported as an increase in average power over the whole year, the actual generation is focused in those months when the majority of spills occur.

Of course, if some or all of the new tunnel capacity is being used for spills, it cannot simultaneously be used for pumping. A more thorough analysis would compare the economic benefit of harnessing these spills against the benefit of using the tunnels for storage.

4.6 Examining the Pump-turbines and Powerhouses

For a single powerhouse, power generation is given by the equation

\[ P = \eta_{gen} \rho g Q h_{net} \]

For multiple plants in series, which each have the same discharge \( Q \) but different net heads, the equation becomes

\[ P = \eta_{gen} \rho g Q h_{net} \]

\[ \text{Particularly May and June.} \]
Figure 4-20: Average power produced across the entire Big Creek System. Data from [73].
Table 4.4: Required power capacities at each stage if the Redinger-Huntington chain is to provide 4.9GW of power.

<table>
<thead>
<tr>
<th>Upper reservoir</th>
<th>Lower reservoir</th>
<th>Powerhouse</th>
<th>Gross head (m)</th>
<th>Required capacity (MW)</th>
<th>Current size (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntington</td>
<td>Dam 4</td>
<td>Powerhouse 1</td>
<td>652</td>
<td>1890</td>
<td>88</td>
</tr>
<tr>
<td>Dam 4</td>
<td>Dam 5</td>
<td>Powerhouse 2</td>
<td>569</td>
<td>1650</td>
<td>66</td>
</tr>
<tr>
<td>Dam 5</td>
<td>Dam 6</td>
<td>Powerhouse 8</td>
<td>217</td>
<td>630</td>
<td>75</td>
</tr>
<tr>
<td>Dam 6</td>
<td>Redinger</td>
<td>Powerhouse 3</td>
<td>252</td>
<td>730</td>
<td>174</td>
</tr>
</tbody>
</table>

\[ P = \sum_i \eta_{gen} \rho g Q h_{net,i} \]

This fact bears relevance to the system at Big Creek because the Redinger-Huntington chain consists of 4 separate powerhouses, each with varying heads. Because Dams 4, 5, and 6 have little to no storage, these 4 powerhouses must operate as a single unit, in that the discharge at each must be the same. Therefore, the power capacities at each stage must vary proportionally to the head. Table 4.4 summarizes this information at each stage.

At a first order, we would like to estimate the number and physical size of units required at each powerhouse. To do so, we use the current pumped storage facility at Big Creek, Eastwood, as a model. Eastwood utilizes a combined pump-turbine rather than a separate pump and turbine side-by-side. Combining the pump and turbine into one system uses less space than the alternative, which reduces powerhouse size and therefore saves on structure costs. Our general approach is to take the pump-turbine and powerhouse at Eastwood and scale it up to the discharge required for 5GW.

Pumps-turbines are designed for a specific head and discharge capacity. A particular pump-turbine has a certain range of discharges (sometimes very narrow) that can be achieved at a reasonable efficiency. The system at Eastwood uses a Francis-type, vertical shaft, hydraulic reaction pump-turbine, which provides 200MW of power at 393m head. It is designed to operate at 62 m\(^3\) s\(^{-1}\) while generating and 43 m\(^3\) s\(^{-1}\) when pumping. Francis-type pump-turbines can be designed to operate from 40m to 700m, which encompasses the range of heads on the Redinger-Huntington chain.

\(^{\text{m}}\) These dams are the intermediate dams between Redinger and Huntington, that serve as places to divert water to the next powerhouse.

\(^{\text{n}}\) The differences in generating and pumping discharges can be accounted for by fixing the amount of power that is generated and discharged, and then multiplying this value by 85%, the approximate generating and pumping efficiency. This occurs because the 200MW generator is also used as a 200MW motor. This effect was accounted for in Section 4.1 when we established the battery performance characteristics required to make solar dispatchable, since we explicitly set a generating and discharge efficiency of 85%. 

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However, they will vary in their discharge capacities and sizes.

For now, we ignore these distinctions, and assume that a pump-turbine of the same size as the one at Eastwood can provide a good efficiency at the same level of discharge at the varying heads seen at each powerhouse along the Redinger-Huntington chain (215m, 252m, 570m, and 652m). In this case, each of the 4 locations requires the same number of turbines, equal to approximately 6 units. In the same line, we assume that the area required for each turbine is approximately equal to the area of the Eastwood powerhouse of 1400m\(^2\). Therefore, at each of the 4 locations, we require 6 turbines \(\times 1400\text{m}^2\text{ turbine}^{-1} = 8400\text{m}^2 < 0.01\text{km}^2\) of land area.

4.7 Examining Transmission Infrastructure and Co-Location with Solar

Transmission lines are necessary components of any electric grid. In general, their function is to transmit power from the generation source to the load. With a storage system, transmission lines are also necessary to transmit power from generation source to the storage system (i.e. Big Creek), and from the storage system to the load. Minimizing these distances minimizes transmission losses and reduces capital costs associated with building the transmission lines.

4.7.1 Estimating the required number and voltage of transmission lines

The population of California is clustered around two major load centers, San Francisco and Los Angeles, which are located 290km (180 miles) and 354km (220 miles) from Big Creek respectively. Most of the power that is generated in California flows to one of these two areas. This can be seen in Figure 4-21 on the facing page, which shows high voltage transmission lines in California. Big Creek was originally developed to provide power for Los Angeles, which can be seen by the 230kV transmission lines that begin in the watershed and then head south. However, due to its location between these load centers, Big Creek could serve as a storage system for either Los Angeles or San Francisco.

\(^a\)Because discharges are equal.
\(^b\)\(350 / 62 = 5.6\)
\(^c\)The Eastwood powerhouse is an underground powerhouse, with a cavern 24.4m wide, 57.3m long, and 46.6m high.
\(^d\)A fraction of the transmitted power that is lost due to resistance in the conductor.
Figure 4-21: California transmission lines.
To estimate how many transmission lines are required to transmit 5GW of power, we use Figure 4-22 on the next page [77], which relates a transmission line’s load capability to its length. This figure relates line load to surge impedance loading (SIL), which is the point where net reactive power on the line is zero. For a 500kV line, the SIL is equal to 885MW. At a line length of 220 miles, sufficient to travel from Big Creek to Los Angeles, the line load capability would be 1.2 times the SIL, or 1060MW. At a line length of 180 miles, the distance between Big Creek and San Francisco, the line load capability is 1.4 times the SIL, or 1240MW. This means that to transmit 5GW of power to Los Angeles would require approximately five 500kV transmission lines, while four 500kV transmission lines would be required to transmit the same amount of power to San Francisco.

The AEP estimates that these 500kV lines experience losses of approximately 1.3% every 100 miles under a load of 1000MW [78]. These losses were not factored in when we evaluated the performance characteristics of a battery to make solar dispatchable in Section 4.1, but the small amount of losses mean that they are unlikely to affect our results significantly. The change would be greater if we used 345kV lines instead, which experience losses of approximately 4.2% every 100 miles at 1000MW [78].

4.7.2 The potential to co-locate solar and storage near Big Creek

A 500kV transmission line costs approximately $2.3-3.5 million dollars per mile [79]. Therefore, we want to minimize constructing these lines as much as possible. Given that our storage location is fixed, keeping generation as close as possible to the storage and on the same path as the transmission lines that lead to the load is the most effective way of accomplishing this. Co-locating generation and storage also minimizes transmission line losses.

Figure 4-23 on page 82 shows data from the National Renewable Energy Lab [72] that estimates solar generation potential in Southern California. In the Central Valley near Big Creek, solar generation potential is approximately 5.9kWh per m² per day (annual average) in the San Joaquin Valley, about 10% less than the 6.6kWh per m² per day in the Mojave Desert. Figure 4-23 reflects this fact, showing current solar plants installed in California. Most solar plants have been developed in the Mojave desert—however, there are also several that have been built in the Central Valley near Big Creek.

To arrive at an estimate of the amount of land that would be required to provide
Figure 4-23: Solar potential near Big Creek. Solar potential data from the NREL [72], while plant data is from the EIA [73].
Table 4.5: Solar plants used to develop an empirical benchmark of nameplate capacity per square kilometer.

<table>
<thead>
<tr>
<th>Plant name</th>
<th>EIA plant code</th>
<th>Nameplate capacity (MW)</th>
<th>Estimated area (km²)</th>
<th>Capacity per km²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Henrietta Solar Plant</td>
<td>58975</td>
<td>102.0</td>
<td>2.14</td>
<td>47.6</td>
</tr>
<tr>
<td>RE Tranquility</td>
<td>59939</td>
<td>200.0</td>
<td>14.2</td>
<td>14.0</td>
</tr>
<tr>
<td>North Star Solar</td>
<td>58713</td>
<td>62.5</td>
<td>1.81</td>
<td>34.5</td>
</tr>
<tr>
<td>RE Kansas South</td>
<td>58148</td>
<td>20.0</td>
<td>0.71</td>
<td>28.2</td>
</tr>
<tr>
<td>RE Kansas Solar</td>
<td>58985</td>
<td>20.0</td>
<td>0.68</td>
<td>29.4</td>
</tr>
</tbody>
</table>

A given amount of solar resource, we used EIA data to identify 5 utility solar plants in the Central Valley, along with their nameplate capacity. Each of these solar plants was approximately 112km (70 miles) from Big Creek. Using Google Earth, we identified the area these plants took, and divided the nameplate capacity by this area. Figure 4-24 on the next page shows the locations of the solar plants we used, while Table 4.5 shows the estimated areas. We approximated these results by assuming 25MW of nameplate capacity could be obtained per square kilometer of land area used.

We noted in Section 4.1 that a 5GW battery at Big Creek would need 20GW or more of nameplate capacity of solar in order to provide 5GW of base load power. At 25MW nameplate capacity per square kilometer, 20GW of solar would equate to 800km² of land area required. This is approximately a quarter of the Big Creek watershed, and a little more than twice the area of Fresno (the nearest city).

To the best of our knowledge, the current solar plants near Big Creek seem to be on retired agricultural land. Future work could explore the potential for expansion of solar in the Central Valley, or elsewhere near Big Creek, and evaluate whether achieving 20GW or greater of solar nameplate capacity in this region is economically feasible.

### 4.8 Environmental and Recreational Impacts

The principal environmental impacts of the proposed system result from the change in operation of the reservoirs at Huntington and Redinger. If 5GW of power capacity is installed, Huntington and Redinger will experience daily fluctuations of 4-6m and 14m, respectively. These fluctuations, coupled with the changes in flow velocities

---

*This value could be closer to 60-80GW in the winter. See discussion in Section 4.1 especially Figure 4-2 on page 54.*
Solar plants used to estimate nameplate capacity per kilometer squared outlined in red.

Figure 4-24: Solar plants in red were used to develop an empirical benchmark of nameplate capacity per square kilometer.
that accompany them, could impact fish populations and reservoir ecosystems [63].

More significantly, there is the potential for significant erosion of the river banks and potentially the bottom sediment [66, 27]. If this is the case, lining the reservoirs may be required [27].

There are reasons to believe that these environmental impacts can be managed. First, the Bath County pumped storage facility in West Virginia experiences fluctuations of 18m and 32m in its lower and upper reservoir respectively, although it is unclear at what time scale these fluctuations occur [80]. Second, soil development in the Sierra Nevada where Big Creek is situated is generally poor, with minimal clay content and dissolved-solids content between 25 to 200 parts per million. In addition, most of the soils in the substrate in the Sierra Nevada are medium to coarse-grained sands and large boulders, rather than clay [69]. Regardless, potential erosion on the banks is an important area for future work.

In addition to its environmental impacts, daily fluctuations in reservoir elevation on the order of 4-14m also impact recreation. Southern California Edison has operational agreements as part of their FERC license to keep reservoir elevations as high as possible with minimum fluctuation at both Redinger and Huntington [69]. At Redinger, these agreements are in effect in from June through September, while at Huntington, they are in effect from May through September.

Land required for transmission lines and powerhouses also comes with its associated environmental impact, although these impacts can be minimized by co-locating new infrastructure with existing infrastructure, or by building new powerhouses underground if it is technically and economically feasible to do so.

The impacts described above are real and non-trivial. However, they are incremental impacts on a watershed that has already been developed for the past century. There are no incremental impacts related to building a dam, as no new dams would be built. The environmental and recreational impacts caused by this plan must be compared to that of developing a similar pumped storage facility on an entirely new watershed, or, equivalently, to the impacts of mining, creating, and disposing of the materials required for chemical battery storage at grid scales. Though additional work would be needed to quantify the relative impacts caused by each of these options, it seems clear that retrofitting existing hydropower facilities to be used for pumped storage causes significantly fewer impacts than the alternatives.
4.9 Design Selected for Economic Analysis

In summary, we have found that for the Big Creek system to provide a battery with a power capacity of 5GW and 75GWh of energy, the following infrastructure modifications are required:

• 4 unlined granite tunnels in parallel of 6m diameter each, approximately 24km in length, to be connected to penstocks which will feed into the powerhouses and turbines. These tunnels will be capable of handling $350\text{m}^3\text{s}^{-1}$ of discharge.

• Approximately 6 additional turbines and associated powerhouses at each current powerhouse location, for a total of 24 new turbines, which will occupy a total of approximately 33600m$^2$.

• 4 500kV transmission lines, which will extend approximately 200 miles to San Francisco or LA, along with their accompanying switchyards.

In addition, it is possible that the reservoirs would need to be lined to prevent erosion. It is also assumed that at least 20GW of solar will be located near Big Creek, most likely in or near the Central Valley, occupying approximately 800km$^2$ of land.
Chapter 5

Cost estimate of retrofitting the Redinger-Huntington chain and comparative economic analysis

A proposal of any infrastructure project is incomplete without some estimation of its associated economic cost and a comparison with its alternatives. In this chapter, we address this need by arriving at an overnight capital cost estimate for transforming the Redinger-Huntington chain into a pumped storage system. We begin in Section 5.1 by providing current overnight capital cost estimates for a variety of generation and storage technologies. In Section 5.2, we explain the method and assumptions used to arrive at our cost estimate, guided extensively by a set of reports published by the Electric Power Research Institute, EPRI [81, 82, 83]. These reports guide the reader in designing the basic layout of the pumped storage facility, and then provide cost curves for the different system components. Section 5.3 presents the results of this analysis, and compares it with the estimates seen for pumped storage and other technologies already presented in Section 5.1.

Note that throughout this chapter, we use overnight capital cost as our primary metric for comparing different technologies. Other factors, including O&M costs, technology lifespan, fuel costs, and efficiencies all play important roles in evaluating technologies. Future work could explore these additional factors in the specific context of Big Creek and California’s grid to evaluate the best storage technology, in line with the extensive work that has already been done in this area.

---

\[a\] Overnight capital costs are defined as the cost of construction assuming no costs for financing.

\[b\] Operation and management.

\[c\] In particular, see [84, 34, 85].
Table 5.1: Capital cost estimates for a variety of generation and storage technology types. Values are in 2016 USD unless reported otherwise. Data from [39, 87].

<table>
<thead>
<tr>
<th>Technology</th>
<th>Nominal Capacity (MW)</th>
<th>Overnight Capital Cost ($/kW)</th>
<th>Fixed O&amp;M ($/kW-yr)</th>
<th>Variable O&amp;M ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Natural Gas Combined Cycle</td>
<td>429</td>
<td>1104</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>Advanced Nuclear</td>
<td>2234</td>
<td>5945</td>
<td>100.28</td>
<td>2.3</td>
</tr>
<tr>
<td>Onshore Wind</td>
<td>100</td>
<td>1877</td>
<td>39.7</td>
<td>0</td>
</tr>
<tr>
<td>Photovoltaic–Tracking</td>
<td>150</td>
<td>2534</td>
<td>21.8</td>
<td>0</td>
</tr>
<tr>
<td>Conventional Hydroelectric</td>
<td>500</td>
<td>3123</td>
<td>14.13</td>
<td>0</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>250</td>
<td>5626</td>
<td>18</td>
<td>0</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>4</td>
<td>2813</td>
<td>40</td>
<td>8</td>
</tr>
</tbody>
</table>

5.1 Existing overnight capital cost estimates for generation and storage

Generation and storage technologies vary widely in their capital costs, lifetimes, and performance characteristics. Table 5.1 shows capital cost estimates from the EIA, used in their energy modeling initiatives [87, 39]. In 2016, natural gas had the lowest capital cost of the generating technologies at $1104/kW, although fuel costs can reduce this gap over time. A utility-scale PV solar plant is estimated at $2534/kW, a significant drop from its estimated cost of $5,390/kW in 2013, but still 2.5 times higher than natural gas. Of particular note is the difference in capital cost between a greenfield pumped storage site and battery storage. Chemical batteries, in general, tend to have lower power costs and higher energy costs than pumped storage, lending themselves more towards peak shaving than time-shifting energy generation. The 2011 EPRI report [82] estimated historical pumped storage costs at approximately $500-$2500/kW, significantly lower values than the $5626/kW seen in Table 5.1. This distinction may be due to a variety of factors. It is likely that the primary factor is that the EIA assumes a greenfield installation, and most of the prime locations for pumped storage have already been used, although increased regulatory costs may also play a role.

As noted previously in Chapter 2, lithium-ion batteries are the dominant mode of chemical storage. Several power and energy costs available in the literature are provided in Table 5.2 on the facing page. As with most estimates for chemical battery storage technologies, different technologies vary significantly in their capacity factors—the ratio of the average amount of power actually generated to the nameplate capacity of the plant. The estimated capacity factors in 2016 for nuclear, conventional hydropower, wind, and grid scale PV solar were 92.3%, 38.2%, 34.5%, and 25.1% respectively [86].

This is equal $1.1 billion dollars for 1 GW of capacity.
Table 5.2: Various cost estimates for lithium-ion batteries.

<table>
<thead>
<tr>
<th>Reference</th>
<th>Year Published</th>
<th>Power Cost ($/kW)</th>
<th>Energy Cost ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schoenung and Hassenzahl</td>
<td>2003</td>
<td>175</td>
<td>500</td>
</tr>
<tr>
<td>Chen et al. [31]</td>
<td>2009</td>
<td>1200-4000</td>
<td>600-2500</td>
</tr>
<tr>
<td>Evans et al. [32]</td>
<td>2012</td>
<td>4000</td>
<td>2500</td>
</tr>
<tr>
<td>Sundararagavan [37]</td>
<td>2012</td>
<td>1500</td>
<td>1500</td>
</tr>
<tr>
<td>Castillo and Gayme [35]</td>
<td>2014</td>
<td>400-1000</td>
<td>500-1500</td>
</tr>
<tr>
<td>Hill et al. [89]</td>
<td>2014</td>
<td>4000</td>
<td>2500</td>
</tr>
</tbody>
</table>

costs, these vary widely, from $175-$4000/kW and $500-$2500/kWh. Actual cost data is difficult to find, as grid-scale chemical storage is still in its infancy. However, one potential estimate is Tesla’s 100MW/129MWh battery that was built in South Australia in 2017. Estimates of capital costs range from $50-$200 million [88], which would lead to an estimate of 500-2000 $/kW and 387-1550 $/kWh. These estimates do not modularize energy and power costs, as no cost breakdown is available.

These per kW and per kWh costs can be used to estimate the cost of a facility of a given power and energy capacity. For example, using the midpoint estimates of the Tesla Australian battery ($1250/kW and $968/kWh) for a facility of 4.9GW and 75GW, the same size as the proposed system at Big Creek, the total capital cost would equal $6.1 billion or $72.6 billion, depending on whether the cost is estimated using power capacity or energy capacity. As the system would need to meet both requirements, the higher cost should be used. This estimate of $72.6 billion is similar to that presented in Section 2.1.

5.2 Estimating the capital cost of retrofitting the Redinger-Huntington chain

To estimate the overnight capital costs associated with retrofitting the Redinger-Huntington chain, we followed the methodology set out in a series of reports by the Electric Power Research Institute (EPRI). The first, the *Pumped-Storage Planning and Evaluation Guide* [81], was written in 1990 and provides a means for planners to arrive at an initial estimate for a new pumped storage system with limited information. Using cost data from other pumped storage plants built in the United States, EPRI developed a series of cost curves that estimate component costs based on a

\[T\]his large difference in estimated cost is one of the primary reasons why chemical batteries have such difficulty storing energy on a grid scale.
few key parameters: power capacity (MW), energy capacity (MWh), length (ft), and head (ft). The user of the EPRI report is provided with the choice of several basic designs\(^g\) and the calculation of a few secondary parameters such as tunnel diameter and penstock length. Using the primary and secondary parameters combined with the cost curves enables the user to arrive at a direct cost estimate. Two values are then multiplied to this direct cost to arrive at the total cost estimate. The first is a contingency multiplier, which accounts for unforeseen difficulties leading to higher costs, as well as costs associated with small components not directly included in the direct cost estimate. The second multiplier is associated with “engineering management”, which can be thought of as all of the indirect costs associated with building the pumped storage facility, including project administration and regulatory and legal costs. Mathematically, the general procedure could be represented as

\[
C_{\text{total}} = \left( \sum_i P_i C_{\text{unit},i} m_{\text{contigency},i} \right) m_{\text{indirect}}
\]

Here, \(C_{\text{total}}\) is the total cost. It is calculated by summing the component costs \(\sum_i P_i C_{\text{unit},i} m_{\text{contigency},i}\), where \(P_i\) is a parameter like power capacity or length, \(C_{\text{unit},i}\) is the cost of the component \(i\) per unit of the parameter, and \(m_{\text{contigency},i}\) is the contingency associated with that component.\(^h\) This summed value is the direct cost of the system, and is multiplied by \(m_{\text{indirect}}\) to arrive at the total cost.

As an example of this method, consider Table 5.3, which provides a subset of the components whose costs were estimated. To estimate the costs associated with building the power plant structure, the user selects the capacity of the power plant (1890MW). Cost curves are provided for generating units with either 80MW, 120MW, 225MW, or 350MW capacity. For each of these capacities, a different cost curve is given for 2, 3, 4, or 6 units. The closest estimate of the desired 1890MW capacity from a combination of these values is obtained from using six 350MW units (2100MW); therefore, this cost curve is chosen. The cost curve itself is a function of head, so the user simply reads the value which corresponds to a head of 2139ft—in this case, $30/kW. Multiplying $30/kW by 1890MW obtains a cost of $56.7 million.

Estimating tunnel costs is similar. Different cost curves are provided for half mile, one mile, two mile, and four mile tunnel lengths; in the case of the tunnel shown in

---

\(^g\)For instance, using a surface powerhouse vs. an underground powerhouse, or using penstock tunnels vs. surface penstocks.

\(^h\)For instance, to estimate pump-turbine costs, one would multiply the power capacity in kW to the cost in dollars per kW to arrive at a cost in dollars. Multiplying this by the contingency would arrive at a final estimate for pump-turbine costs.
Table 5.3: An example of the method and assumptions used to estimate capital costs.

<table>
<thead>
<tr>
<th>Component name</th>
<th>Capacity (MW)</th>
<th>MW per unit</th>
<th>Number of units</th>
<th>Head (ft)</th>
<th>Length (ft)</th>
<th>Cost curve value</th>
<th>Cost (millions 1998 USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Powerplant structures</td>
<td>1890</td>
<td>350</td>
<td>6</td>
<td>2139</td>
<td></td>
<td>$30/kW</td>
<td>56.7</td>
</tr>
<tr>
<td>Power station equipment</td>
<td>1890</td>
<td>350</td>
<td>6</td>
<td>2139</td>
<td></td>
<td>$105/kW</td>
<td>198</td>
</tr>
<tr>
<td>Upper reservoir intake</td>
<td>4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$4.1 million/intake</td>
<td>16.4</td>
</tr>
<tr>
<td>Tunnels</td>
<td>4</td>
<td>14132</td>
<td></td>
<td></td>
<td></td>
<td>$2800/ft</td>
<td>1582</td>
</tr>
<tr>
<td>Penstock tunnels</td>
<td>6</td>
<td>2139</td>
<td>642</td>
<td></td>
<td></td>
<td>$7500/ft</td>
<td>28.8</td>
</tr>
<tr>
<td>Vertical shaft</td>
<td>4</td>
<td>2139</td>
<td>2139</td>
<td></td>
<td></td>
<td>$3800/ft</td>
<td>32.5</td>
</tr>
</tbody>
</table>

Table 5.4: Escalation factors from the 2011 EPRI report [82], used to convert 1988 USD [81] to 2010 USD.

<table>
<thead>
<tr>
<th>Cost Type</th>
<th>EPRI Figures</th>
<th>Low</th>
<th>Average</th>
<th>High</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Station, Civil</td>
<td>6-8, 6-9</td>
<td>2.5</td>
<td>2.75</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Intakes</td>
<td>6-12</td>
<td>2</td>
<td>2.5</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Surface Penstocks</td>
<td>6-16</td>
<td>2</td>
<td>2.5</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Vertical Shaft</td>
<td>6-14</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Horizontal Power Tunnels</td>
<td>6-13</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Steel-Lined Tunnels (Penstock Tunnels)</td>
<td>6-16</td>
<td>3</td>
<td>3.5</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Electro-Mechanical Works, Single Speed</td>
<td>6-17, 6-18</td>
<td>2</td>
<td>2.38</td>
<td>2.75</td>
<td></td>
</tr>
<tr>
<td>Electro-Mechanical Works, Variable Speed</td>
<td>6-17, 6-18</td>
<td>2.7</td>
<td>3.2</td>
<td>3.7</td>
<td></td>
</tr>
<tr>
<td>Switchyard</td>
<td>6-20</td>
<td>2</td>
<td>2.5</td>
<td>3</td>
<td></td>
</tr>
</tbody>
</table>

Table 5.3: the two mile cost curve was selected. The cost curve is a function of diameter; in this case, we assume a 6m (20ft) diameter. The value is then read off the cost curve as $2800 per linear foot of tunnel. Multiplying $2800/ft by the length of the tunnel as well as by the number of tunnels side by side gives a value of $1582 million.

The estimates in the 1990 EPRI report are given in 1988 USD. The second report, *Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements* [82], was written in 2011 and escalates these costs to 2010 USD, using several standard civil engineering cost indices, discussions and quotes from equipment manufacturers and vendors/contractors, and cost data from recently approved projects. These escalation factors can be seen in Table 5.4. In addition, this report updated the engineering management/indirect cost multiplier $m_{indirect}$ to 1.25 for normal projects and 1.3 for complex projects. The lower value was used in our analysis.

Table 5.5 shows the key parameters for this analysis on the Redinger-Huntington
Table 5.5: Key parameters used for estimating costs according to the methodology in the 1990 EPRI report [8]. Though values here are presented in metric units for consistency, the EPRI report uses English units.

<table>
<thead>
<tr>
<th>Upper reservoir</th>
<th>Lower reservoir</th>
<th>Gross head (m)</th>
<th>Current tunnel length (m)</th>
<th>Current penstock length (m)</th>
<th>Required capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntington</td>
<td>Dam 4</td>
<td>652</td>
<td>3180</td>
<td>1325</td>
<td>1890</td>
</tr>
<tr>
<td>Dam 4</td>
<td>Dam 5</td>
<td>569</td>
<td>6632</td>
<td>1280</td>
<td>1650</td>
</tr>
<tr>
<td>Dam 5</td>
<td>Dam 6</td>
<td>217</td>
<td>1698</td>
<td>822</td>
<td>630</td>
</tr>
<tr>
<td>Dam 6</td>
<td>Redinger</td>
<td>252</td>
<td>8593</td>
<td>422</td>
<td>730</td>
</tr>
</tbody>
</table>

Four different powerhouse locations are included, each with their own upper and lower reservoirs. For the purpose of the EPRI report, which assumes only one upper and lower reservoir, these powerhouse locations are separate facilities. To accommodate this, we arrived at a cost estimate for each facility independently and then summed them to arrive at a total cost for the entire Redinger-Huntington chain. The power capacity values assume a total power capacity of 4.9GW.

The cost curves provided by EPRI 1900 were designed to be applicable within a length/head (L/H) ratio of 4-12, heads lower than 670m, and power capacities lower than 2100MW. The four sections that form the Redinger-Huntington chain fall within these ranges, except for the section between Dam 4 and Dam 5 and the section between Dam 6 and Redinger, which have L/H ratios of 13.9 and 36.1, respectively.

Lacking a better method for estimating cost, we proceeded with the analysis regardless.

We deviated slightly from the method outlined in the 1990 EPRI report. The report provides a method to estimate the number of tunnels required and their associated diameter; to ensure our tunnel sizes were in range with the current system’s, we used our calculations from Section 4.5 and chose either 8 tunnels at 4.5m (15ft) diameter, or 4 tunnels at 6m (20ft). Access tunnel costs were neglected, although this is unlikely to significantly affect our results. Transmission line costs were estimated at

---

1. Although the energy capacity associated with the proposed system at Redinger-Huntington is 75GWh, this value does not affect our cost estimate, as it is only used to estimate dam costs. In our case, no new dams are built, so these costs are equal to zero.
2. This 4.9GW value was chosen because it is closer to the exact 4.87GW of power capacity that complements Redinger-Huntington’s 75GWh of energy storage potential, assuming an energy/power ratio of 15.4. See Section 4.1 for a derivation of this ratio.
3. See Table 4.3 on page 59.
Table 5.6: Assumptions in each scenario that deviate from the base case. Scenarios are shown on the columns, while assumptions are shown on the rows

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>Variable speed (VS)</th>
<th>Adverse conditions</th>
<th>Small units</th>
<th>Eight tunnels</th>
<th>Surface penstocks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable speed</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Adverse conditions</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small units</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>8 tunnels</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Surface penstocks</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

about $2 billion, but were not included in the total costs.[7] Finally, we set dam costs to equal zero, as no new dams would need to be built on the Redinger-Huntington chain.

To understand how changes in our assumptions would affect final cost, we analyzed several different scenarios with varying assumptions. Our base case scenario used a basic configuration corresponding to Alternative D in the 1990 EPRI report [81]. This consists of an upper connected to a horizontal intake, low pressure tunnel, vertical shaft, and a high pressure tunnel. The low pressure tunnel branches into steel-lined penstock tunnels, which each feed into a different generating unit in a surface powerhouse. 4 tunnels of 6m (20ft) diameter were used along the entire chain. This means that at each upper reservoir, 4 horizontal intakes lead into 4 low/high pressure tunnels and 4 shafts. The number of penstock tunnels was set equal to the number of generating units at a particular powerhouse. The 1990 EPRI report provides cost curves for “average” and “adverse” conditions for both tunnels and powerhouse civil costs; average conditions were assumed. 350MW units in the two upstream high head sections[9] and 225MW units in the two downstream low head sections[10]. Cost curves are provided for generating units of sizes 80MW, 120MW, 225MW, and 350MW, so these values were chosen to aid analysis. Single speed pump-turbines were used, although variable speed pump-turbines are used in other scenarios. A surge chamber was included for each of the four sections, directly upstream of the vertical shaft. 4 switchyards, one for each section, as well as road access was also included. Table 5.6 shows which of these assumptions were modified in the other scenarios explored.

[7] Transmission lines will certainly need to be built if pumped storage capacity is installed at Big Creek. Helms, the 1000MW pumped storage plant located less than 50km south of Big Creek, already is limited in its pumping operations by transmission congestion in the Fresno area [10].

[9] Between Huntington and Dam 4, and between Dam 4 and Dam 5.

[10] Between Dam 5 and Dam 6, and between Dam 6 and Redinger.
Table 5.7: Contingency multipliers for civil works above and below ground. Standard values come from the 2011 EPRI report [82], while low values are calculated by subtracting 0.1 from the standard values. In the case that the knowledge acquired from having already built the existing Big Creek system at this location means that contingencies could be minimized, it is possible that the low values could be used.

<table>
<thead>
<tr>
<th></th>
<th>Above ground &amp; Electrical-Mechanical</th>
<th>Underground</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard</td>
<td>1.25</td>
<td>1.35</td>
</tr>
<tr>
<td>Low</td>
<td>1.15</td>
<td>1.25</td>
</tr>
</tbody>
</table>

The 2011 EPRI report provides a set of contingency multipliers. These are shown in Table 5.7. An additional, lower set of contingency multipliers were also used, the rationale being that as Big Creek is a well-known system, unforeseen costs could be expected to be smaller here than at a greenfield site.

5.3 Results of Redinger-Huntington capital cost estimation and comparison with existing estimates

Figures 5-1 on the next page and 5-2 on the facing page show the results of our cost estimation outlined in the previous section. For each scenario, 6 values are shown, which correspond to each possible combination of the two contingency assumptions and the three escalation factor assumptions outlined in Section 5.2. Costs vary from a minimum of $11 billion (equivalent to $2200/kW or $146/kWh) to a maximum of $34 ($6734/kW, $440/kWh). Transmission line or right of ways costs were not included; however, transmission line costs were estimated at approximately $2 billion.

In all cases, capital costs vary significantly with the escalation factors; a more detailed cost analysis should seek to minimize this uncertainty for a given design. Of the assumptions made, our results are most sensitive to using penstock tunnels vs. surface penstocks, which increase the price by about $2000/kW on their own. Surface penstocks are used in the current design; however, most recent pumped storage plants, particularly those with long water conductors, use penstock tunnels. If this could be done at Big Creek, the range of costs in our scenarios drops to $11-$23 billion. In comparison, a lithium-ion battery system similar to the Tesla battery built in South Australian would cost approximately $76 billion.

Figure 5-3 on page 96 shows the breakdown of costs by type for the Variable Speed
Figure 5-1: Capital cost estimates for a 5GW, 75GWh pumped-storage system at Big Creek between Redinger and Huntington. $/kW estimates are obtained by dividing the capital cost by 4.9GW. Values are in 2018 USD—the consumer price index was used to escalate values from 2010 USD to 2018 USD.

Figure 5-2: Capital cost estimates for a 5GW, 75GWh pumped-storage system at Big Creek between Redinger and Huntington. $/kW estimates are obtained by dividing the capital cost by 75GWh. Values are in 2018 USD—the consumer price index was used to escalate values from 2010 USD to 2018 USD.
Table 5.8: Breakdown of costs by type for the Variable Speed scenario, compared with a similar breakdown found in [90]. Access costs and indirect costs from Figure 5-3 are bundled together into Engineering management.

<table>
<thead>
<tr>
<th></th>
<th>O’Connor et al.</th>
<th>Variable speed scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering management</td>
<td>11.7%</td>
<td>21.4%</td>
</tr>
<tr>
<td>Electrical infrastructure</td>
<td>6.3%</td>
<td>1.8%</td>
</tr>
<tr>
<td>Electro-mechanical equipment</td>
<td>35.0%</td>
<td>21.1%</td>
</tr>
<tr>
<td>Civil works</td>
<td>47.1%</td>
<td>55.6%</td>
</tr>
</tbody>
</table>

Figure 5-3: Distribution of costs for the Variable Speed scenario, using medium escalation factors and standard contingency assumptions. Total cost is 12 billion 2018 USD. “Transmission” refers to switchyard costs; transmission line (approximately $2 billion) or right of way costs are not included.

scenario, using standard contingency assumptions and medium escalation factors. Though the exact distribution varies by scenario, this scenario is both representative of the overall breakdown and may be the closest of the scenarios explored to a system that may actually be built. Table 5.8 compares this breakdown with one found in O’Connor et al. [90]. Civil works comprises 55% of the overall costs. This relatively higher proportion is primarily due to the high length to head ratio of our system (14.2), which drives up tunnel costs.

Breaking down the civil works costs further in Figure 5-4 on the facing page, it can be seen that tunnel costs compose 60% of the overall civil works costs. Put another way, tunnel costs compose 30% of the overall system costs. The cost curves in the 1990 EPRI report assume that these tunnels are built using a drill and blast method.
Figure 5-4: Distribution of civil works costs for the Variable Speed scenario, using medium escalation factors and standard contingency assumptions. Tunnels make up the majority of the cost.

However, in the case of very long tunnels like those seen on the Redinger-Huntington chain, it is more common for tunnels to be built using tunnel boring machines (TBM), as it is often cheaper to do so [81]. The current tunnels at Big Creek were also built using the TBM method. TBM tunnel costs are difficult to estimate due to the nature of the technology [9] and we were unable to find any quantitative estimates. Future work could focus on estimating these tunnel costs at Big Creek, as any reduction of these costs would make a meaningful contribution to the overall system cost.

\[\text{Tunnel boring machines are often custom built, and can cost up to $80 million [91]. [92] provides estimates of tunnel costs, but does not include tunnels built with tunnel boring machines.}\]
Chapter 6

Future Work

This thesis has proposed a renewed focus on adding pumped storage capacity at sites with existing reservoirs. There is much opportunity for future work to refine and extend the analysis performed so far. In addition to exploring the potential reach of this proposal, the Big Creek system can continue to serve as a useful example for the broader proposal of retrofitting existing sites at large scales. Here, we highlight four key opportunities for future research:

1. Exploring the technical potential of retrofitting existing reservoirs in California, the United States, and across the world,
2. Modeling the operation of a pumped storage facility at Big Creek and its associated impacts,
3. Quantifying the benefits that would be provided to the California grid with an expanded pumped storage facility at Big Creek,
4. Reducing the uncertainty of our cost estimates for adding new pumped storage capacity at Big Creek.

6.1 Exploring the technical potential of retrofitting

California currently has approximately 11GW of both large and small conventional hydropower capacity [30]. Some fraction of this capacity could potentially be retrofitted into pumped storage without creating new dams. For this to be the case, two reservoirs with a meaningful head difference must be sufficiently close to one another so that a pumped storage plant could be economically built. Alternatively, an underground cavern could be used for the lower reservoir. A length-to-head ratio of
approximately 10-12 could be used as a screening tool to evaluate potential sites [27, 74]. In the case of screening sites with two above ground lakes/reservoirs that meet this criteria, a GIS-based approach is likely the most effective, using Oak Ridge National Laboratory’s database of existing hydropower assets in the United States [93] with USGS elevation data [94]. This same approach could be extended to other regions of the world.

6.2 Modeling plant operation and its impacts

Our work explored a massive pumped storage system at Big Creek, with 5GW of power capacity and 75GWh of energy capacity. This system, if installed, would be 2GW larger than the largest pumped storage system in the world today [80]. Such a proposition requires detailed modeling to understand how it might operate and the impacts of those operations on the energy and environmental systems it is a part of. An understanding of these impacts would enable comparisons with alternative technologies such as chemical storage. These alternatives are themselves opportunities for future work; a comparison of relative environmental impact must necessarily include an understanding of how the mining, manufacturing, and disposal of the materials used to create chemical storage impacts the environment.

To understand the impacts of operations at Big Creek, the first step would be to develop a simulation model using historical inflow data into Redinger and Huntington that estimates hourly pumping and discharge operations of the system. For simplicity, the model could assume that the design currently described (5GW/75GWh) is fully utilized every day of the year, to the extent possible. Such a model’s output could provide insight into how water and storage availability as described in Section 4.4 would impact operations, including fluctuations in reservoir elevations throughout the year. It would also provide insight into the potential for maximizing hydropower generation by utilizing current spills, and how that hydropower generation would be distributed through the year.

With the insight provided by this first model, a more detailed simulation model could examine the environmental impacts of these reservoir fluctuations. In particular, this model should analyze the impact of pumped storage operation on flow velocities in the reservoirs. This would enable a comparison with the critical erosion velocities that would cause bottom erosion in each reservoir [66]. These results would be dependent on the discharge or pumping capacity, the bathymetry and water levels of the reservoirs, and the specific location of discharge or pumping in the reservoir.
The critical erosion velocities are dependent on the sediments found in the reservoirs themselves; obtaining information about these sediments may require field work.

Finally, another model could explore the connection between Big Creek and the rest of the California grid. Helms, the 1GW pumped storage system located less than 50km away from Big Creek, is already limited in its operations by transmission line congestion near Fresno [40]. The purpose of this model then would be to quantify the need for new transmission line needs if new pumped storage capacity was to be added at Big Creek, and how this relates to seasonal variations in power generation from current spills or nearby solar plants.

The results of each of these models would provide insight into the design of new pumped storage capacity at Big Creek by imposing realistic constraints on the system. It is likely that such work would indicate that our 5GW, 75GWWh system would need to be reduced in size.

6.3 Quantifying the net benefit of storage

Our current economic analysis looked only at capital costs of the Big Creek system in comparison with other storage technologies. A simple extension of this work could examine overall life-cycle costs, which more accurately reflect the cost of a storage system [34]. However, in order to evaluate the true economic feasibility of a storage system, its benefits must be compared to its costs. Therefore, quantifying the economic benefit associated with new pumped storage capacity at Big Creek is a key next step for our work. This benefit could then be compared to those of other technologies.

The benefit of a pumped storage system is primarily related to the following:

1. The opportunity for energy arbitrage, where energy is bought at low prices and sold at high prices,

2. Its ability to provide capacity credit, i.e. to supply capacity that can meet peak loads,

3. Its ability to provide frequency regulation, if variable speed turbines are installed.

The opportunity and need for these services varies seasonally due to changes in solar generation potential and changes in demand (primarily AC use). We explicitly ignored these variations in our work, focusing solely on the diurnal cycle of solar.
Taking into account variability at these longer time scales is an important next step in understanding the benefits of pumped storage.

In addition to depending on seasonal effects, the value of these benefits changes under different renewable energy scenarios. For example, [95] performed an extensive, multi-year study to quantify the value of pumped storage in the United States under different renewable energy scenarios. They found that revenues from energy arbitrage increased from $3.9/kW-yr to $43.4/kW-yr when renewable penetrations increase from 14% to 33%. In a similar vein, [96] found frequency regulation was more valuable than energy arbitrage by a factor of two.

The type of renewable energy penetration (wind vs. solar) also impacts the value of storage. In particular, increasing solar penetration changes the net load shape, resulting in a shorter duration peak. As solar penetration increases, then, this peak requires shorter duration, higher power capacity storage, changing the relative benefits of pumped storage compared to other technologies such as chemical batteries [97, 43]. Decreasing capital costs of solar generation facilities also affects the cost/benefit ratio of storage, potentially incentivizing an overbuilding of generation capacity rather than using storage to increase the value of existing generation capacity [36].

In summary, then, future work in this area could include quantifying the benefits provided by new pumped storage capacity at Big Creek and examining how these benefits change under different solar penetrations. Comparing pumped storage benefits with those provided by chemical battery storage and new solar capacity is also critical.

### 6.4 Reducing cost estimate uncertainty

Our initial cost estimate ranged from $11 to $34 billion\(^a\). Key reasons for this range are the uncertainty surrounding the exact design of the new infrastructure and uncertainty regarding what escalation factors to use when converting from 1988 USD to current USD. A more clearly defined design could narrow this cost estimate range. This would include clearly defining tunnel sizes and lengths\(^b\), whether surface or underground power stations are used, and the number and type of pump-turbines and generating units at each stage of the Redinger-Huntington chain. To accomplish this, further work is needed to understand the geotechnical and structural limits at Big Creek. In addition, discussions with contractors and consultants to obtain price

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\(^a\)Or $11–$23 billion, if it is assumed that penstock tunnels are used instead of surface penstocks.

\(^b\)This would also enable us to arrive at a better estimate for our friction factor.
quotes for the different infrastructure components could help to reduce uncertainty surrounding prices in current USD.
Appendix A

Big Creek Water Balance

A.1 Introduction and Background

As the percentage of electricity that is supplied by solar power grows on the grid, there grows an increasing mismatch between when energy is produced and when it is needed. Energy storage is one solution to this problem, but massive amounts of energy would be needed to support a high penetration of solar power onto the grid. For California, several studies have explored the possibility of solar power supplying 50% or more of California’s electricity \[59\, 62\], and have concluded that between 150-250GWh of energy storage would be required. Pumped storage is one potential solution to this challenge, but environmental motivations and site limitations prevent new dams from being built which may help to supply this storage. Converting existing hydropower facilities to be used for massive pumped hydro storage could provide the benefits of energy storage without the negative environmental costs of new dams.

This report presents a monthly water balance for the six reservoirs in the Big Creek System, a hydropower facility in the Upper San Joaquin watershed in Central California. The watershed, approximately 4000km$^2$, varies in elevation from 90m to 4000m, with the reservoirs themselves between 400m and 2300m. These six reservoirs—Thomas A. Edison Lake, Florence Lake, Mammoth Pool Reservoir, Huntington Lake, Shaver Lake, and Redinger Lake—combined with their powerhouses produce about 1000MW of dependable power to the electric grid in California. An average of 2km$^3$ of runoff flows through the system each year, although year-to-year values deviate far from this mean, as over 50% of years are either critically dry or wet. Most of this runoff occurs in May to July in the form of snow melt. Summer storms account for only about 3% of precipitation \[98\].

The goals of this report are to (1) understand current water management, includ-
ing the main fluxes throughout the system and how these fluxes change seasonally, and (2) estimate evaporation and groundwater seepage losses, if possible. Section A.2 details the methods and data that were used to conduct the water balance, while section A.3 presents the results.

A.2 Methods

We performed monthly and yearly water balances for each of the 6 reservoirs in the Upper San Joaquin watershed using a standard conservation of mass equation:

\[
\frac{dS}{dt} = I + P - O - \epsilon
\]

where

- \( \frac{dS}{dt} \) is the change in storage of the reservoir over the time period
- \( I \) is the inflow from rivers or diversions
- \( P \) is the direct precipitation onto the reservoir
- \( O \) is the outflow to rivers downstream, or diversions e.g. to powerhouses or other reservoirs
- \( \epsilon \) is the resulting error, and is expressed as a negative to highlight the fact that this term encapsulates both evaporation and seepage losses from the reservoir

A.2.1 Data and Period Analyzed

Southern California Edison, the operator of these reservoirs, has a long, consistent record of reservoir storage, dating back as far as 1925 for some of the older reservoirs. Outflows were in general well provided by stream gages, although a key outflow from Huntington Lake was lacking from 1986-2015. Precipitation was estimated using either NOAA station data [99, 100] where available for the entire period, or the CRU 4.1 dataset [101, 102], a gridded dataset from 1901-2016 based on observations. See Tables A.2 on the next page and A.3 on page 119 for the list of gages and weather stations used.

While inputs from diversions were well-accounted for by USGS stream gages, river inflows were typically minimal or nonexistent, except in the case of powerhouses that flowed into reservoirs. An area based method was used to estimate inflows, described
Table A.1: Analysis periods chosen for each reservoir.

<table>
<thead>
<tr>
<th>Reservoir Name</th>
<th>Analysis Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edison</td>
<td>1954-2016</td>
</tr>
<tr>
<td>Florence</td>
<td>1925-1980</td>
</tr>
<tr>
<td>Mammoth</td>
<td>1980-2016</td>
</tr>
<tr>
<td>Huntington</td>
<td>1986-2016</td>
</tr>
<tr>
<td>Shaver</td>
<td>1989-2016</td>
</tr>
<tr>
<td>Redinger</td>
<td>1986-2016</td>
</tr>
</tbody>
</table>

Table A.2: NOAA weather stations used

<table>
<thead>
<tr>
<th>Station Name</th>
<th>Station Number</th>
<th>Period of Record</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Auberry 2 NW, CA US</td>
<td>USC00040379</td>
<td>1915/07/27 to 2017/09/30</td>
<td>Used at Redinger.</td>
</tr>
<tr>
<td>Big Creek Powerhouse 1,  CA US</td>
<td>USC00044176</td>
<td>1915/06/01 to 2017/12/08</td>
<td>Used at Shaver. Gap in data between 1989 and 1999.</td>
</tr>
<tr>
<td>Huntington Lake, CA US</td>
<td>USC00044176</td>
<td>1915/06/01 to 2011/12/08</td>
<td>Used at Shaver and Huntington</td>
</tr>
</tbody>
</table>

in Section [A.2.2] This estimation includes overland flow on regions near the reservoirs that would flow into them directly, without first reaching a river channel.

The periods analyzed were guided primarily by where outflow data was available. See Table [A.1] for a summary of analysis periods for each reservoir. Most reservoirs had good records extending from the mid 80s to September 30th, 2016, the end of the 2016 water year. Because one of the primary goals of this analysis was to understand current water management, we focused on this time period. The notable exception to this was Florence Lake, as its downstream gage on the South Fork San Joaquin River was discontinued in 1980. we therefore chose to conduct a water balance on Florence when this gage was in use, from 1925 to 1980.

A.2.2 Estimating Inflows Using The Area Method

Most or all of the inflows lacked stream gages for the periods analyzed. To overcome this, we used an area-based method, where the inflow is estimated by using a ratio between the watershed of the desired point and a reference gage:

\[ Q_{\text{point}} = Q_{\text{reference}} \times \frac{A_{\text{point}}}{A_{\text{reference}}} \]
This method is often used in hydrology to estimate gage data \(^{103}\), and was used by Southern California Edison’s Combined Aquatics Working Group (CAWG) during their relicensing process in the early 2000s to estimate unimpaired inflows \(^{98}\). In addition to the precedent established by the CAWG, we chose this method because of its ability to account for snow melt timing and conversion to discharge, assuming the reference gage has similar precipitation rates and temperature to the watershed of the desired point.

Watersheds were computed in ArcGIS using elevation data from the USGS \(^{94}\) at a 1/3rd arc second (10m) resolution (see Figure A-1 for elevation data). First, sinks were filled to ensure a sensible stream network was calculated. A flow direction raster was generated using a steepest descent algorithm, giving the direction of flow from each pixel. A flow accumulation raster was then produced to estimate the contributing area to any point in the stream channel. 24 stream gages and 6 reservoirs were overlaid on the stream channel, and their watersheds determined using the flow direction and flow accumulation rasters.

Figure A-2 shows the watersheds of the 6 reservoirs, along with those of Pitman...
Creek (west, green) and Bear Creek (east, green). Pitman Creek and Bear Creek were selected as reference watersheds because they are the only two gages with unimpaired watersheds and consistent data during the period of analysis. Edison and Florence used Bear Creek, while Shaver, Huntington, and Redinger used Pitman Creek as their references.

For Mammoth Pool, using just one reference gage proved ineffective. Instead, in line with [98], we used Bear Creek as a reference gage for 1126km$^2$ of Mammoth’s watershed and Pitman Creek for the other 1476km$^2$. The physical argument for this is two fold. The first is one of elevation. Bear Creek’s watershed lies mainly between 3000-4000m, while Pitman Creek’s sits between 2000-3000m. Mammoth Pool’s watershed has significant portions at both of these elevations and these changes in elevation affect snow melting patterns. The second lies in the existence of Kaiser Ridge, a 3000m ridge that separates Florence and Edison from Mammoth and Huntington. This ridge creates a rain shadow, causing storms approaching from the west to dump most of their precipitation on the west slopes [69]. Pitman Creek, like a portion of Mammoth Pool’s watershed, lies to the west of Kaiser Ridge, while Bear Creek lies to the east.

### A.2.3 Specific Reservoir Equations

This section defines the specific gages and equations that were used for each reservoir. They are written to solve for $\epsilon$, as this was the only unknown term after inflows were estimated. Many inflows were estimated using an area-based method (see section A.2.2).

USGS gages and NOAA stations are referred to by their site number. Precipitation estimates using CRU data are denoted as $P_{CRU}$. The reservoirs Edison, Florence, Mammoth, Huntington, Shaver, and Redinger are denoted by the first letter of their name in the subscript. For changes in storage, changes were first calculated on a daily basis, and then on a monthly or yearly as required.

**Edison**

$$\epsilon_E = I_{est,E} + P_{CRU,E} - USGS_{11231500} - \frac{dS_E}{dt}$$

$I_{est,E}$ was estimated using the Bear Creek gage (site number 11230500).
Figure A-2: Watersheds of the 6 main reservoirs and the 2 reference gages used to estimate inflows (green). Note that Mammoth’s watershed (pink) is overlapped by Edison, Florence, and Bear Creek (northwest, green), while Redinger’s watershed (gray) is overlapped by every other watershed shown.
Florence

\[ \epsilon_F = I_{est,F} + P_{CRU,F} - USGS_{1233000} - USGS_{1229500} - \frac{dS_F}{dt} \]

\( I_{est,F} \) was estimated using the Bear Creek gage (site number 11230500).

Mammoth Pool

\[ \epsilon_M = I_{est,M} + P_{CRU,M} - USGS_{12335100} - USGS_{1234760} - \frac{dS_M}{dt} \]

\( I_{est,M} \) was estimated using both the Bear Creek gage (site number 11230500) and the Pitman Creek gage (site number 11237500). See section A.2.2 for details.

Huntington

\[ \epsilon_H = I_{est,M} + USGS_{12335500} + NOAA_{USC00044176} - UGS_{1238100} - UGS_{1237000} - (UGS_{1238250} - UGS_{1237600}) - \frac{dS_H}{dt} \]

\( I_{est,H} \) was estimated using the Pitman Creek gage (site number 11230500), as the input gage used is a diversion carrying water from Florence and Edison, but does not include water from Huntington’s own watershed. The NOAA station was located next to the lake. Outflows through the Huntington-Pitman-Shaver conduit, which supply the majority of water to Shaver Lake, were not measured during the time period analyzed (1986-2016), and were estimated by subtracting the difference of flows at Eastwood Powerhouse (USGS 11238250) and North Fork Stevensen Creek Diversion (USGS 11237600).

Shaver

\[ \epsilon_S = I_{est,S} + UGS_{1239300} + UGS_{1238250} + NOAA_{multiple} - UGS_{1238400} - UGS_{1241500} - \frac{dS_S}{dt} \]

\( I_{est,S} \) was estimated using the Pitman Creek gage (site number 11230500), to estimate the contribution of approximately 25km\(^2\) that were not accounted for using the other two input gages. Two NOAA stations were used to estimate precipitation. The first and closest (USC00040755) was used from 1999-02-01 to 2010-04-30, the
Figure A-3: NOAA stations used to estimate precipitation at Shaver Lake and Huntington. The distance from Shaver to the nearest gage is approximately 10km.

entire period for which it had data in our analysis period. When required to fill in the analysis period (1989-2016), the farther station was used (USC00044176).

Redinger

\[ \epsilon_R = I_{\text{est},R} + \text{USGS}_{11241800} + \text{USGS}_{11238600} + \text{USGS}_{11241500} + \text{NOAA}_{\text{USC00040379}} - \text{USGS}_{11246530} - \text{USGS}_{11242000} - \frac{dS_R}{dt} \]

\[ I_{\text{est},R} \] was estimated using the Pitman Creek gage (site number 11230500), to estimate the contribution of roughly 220km\(^2\) that were not accounted for using the other two input gages (Figure A-4). The NOAA station was located outside of Auberry California at a distance of approximately 9km.

A.3 Results and Discussion

Figures A-5 through A-11 show the monthly means of the fluxes in and out of each reservoir over the analysis period. One can see that the area-based method for estimating inflows was largely effective in representing the seasonal cycle of inflows, but had a tendency to underestimate magnitude. It proved most effective at Edison
Figure A-4: Stream gages (black) and weather station (yellow) stations used at Redinger Lake. Powerhouse gages are not shown. Note the portion of the watershed shown in gray not covered by any stream gage.

(Figure A-5) and Florence (Figure A-6), regions close to and of similar elevation and area to Bear Creek. At Mammoth Pool, the inflow estimation produced a peak in the error in May, followed by consistent underestimation of inflows throughout the rest of the year. This performance still exceeded an attempt that just used the Bear Creek watershed as a reference, which shifted the inflow peak to June and July when the outflows were already decreasing (see Appendix, Figure A-12).

The underestimation of inflows makes it difficult to estimate evaporation using the water balance approach taken. However, it is likely that evaporation plays a small role in this system. Figure A-8 shows the monthly water balance for Shaver Lake, with CRU potential evaporation estimates in red. Shaver Lake is the only reservoir for which error is always positive, which is what we would expect if inflows have been correctly estimated. Even so, evaporation accounts for only a small portion of the error. The rest may be accounted for by gaps or errors in the data. Figure A-17 shows a yearly water balance for Shaver, where spikes in the error can be attributed to abnormal lows in the output data.

While data for outflows was in general readily available, this was not the case at Huntington Lake. The Huntington-Pitman-Shaver conduit brings most of the flow that enters Shaver Lake. It receives water both from Huntington Lake and the Pitman Creek Diversion. Data on the Pitman Creek Diversion is available through our period of analysis, but the gages at the inlet and outlet of the conduit that
Figure A-5: Monthly means of fluxes at Edison Lake over the analysis period.

Figure A-6: Monthly means of fluxes at Florence Lake over the analysis period.
Figure A-7: Monthly means of fluxes at Mammoth Pool over the analysis period.

Figure A-8: Monthly means of fluxes at Shaver Lake over the analysis period, with CRU potential evaporation shown in red.
measured the contribution of Huntington Lake were discontinued in the early 1980s. To overcome this, the gage at Eastwood Powerhouse was used as a proxy for inflows from Huntington. Figure A-10 shows these different fluxes. Eastwood Powerhouse consistently exceeds the flow in the conduit, particularly in later months. Comparing to Figure A-9, this can be seen to drive the observed negative error that would arise from either an underestimation in inflows or an overestimation of outflows.

Figure A-9: Monthly means of fluxes at Huntington Lake over the analysis period.
Figure A-10: Fluxes along the Huntington-Pitman-Shaver conduit. Only Eastwood Powerhouse and the Pitman Creek Shaft had data for the analysis period.

Figure A-11: Monthly means of fluxes at Redinger Lake over the analysis period.
A.4 Conclusion

A monthly water balance was conducted for 6 reservoirs in the Big Creek System. Inflows were estimated using an area-based method, while outflows were provided by stream gages. The area-based estimation method produced reasonable seasonal curves, but consistently underestimated inflows, to the point where it was not possible to estimate evaporation or seepage using a water balance method. Diversions within the system dominate natural flows, to the extent that gaps in data (as in the case of Huntington) dominate the observed error. An investigation of CRU potential evaporation estimates suggest that evaporative losses are low compared to the fluxes in the system, although the steep changes in elevation over the grid cell limits the confidence that can be placed in these estimates.

A.5 Additional Figures and Tables
<table>
<thead>
<tr>
<th>Station Name</th>
<th>Station Number</th>
<th>Period of Record</th>
<th>Gage Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Florence Lake</td>
<td>11229600</td>
<td>1925/11/02 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Lake Thomas A. Edison</td>
<td>11231000</td>
<td>1954/10/12 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Mammoth Pool Reservoir</td>
<td>11234700</td>
<td>1959/10/17 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Huntington Lake</td>
<td>11236000</td>
<td>1926/10/01 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Shaver Lake</td>
<td>11239500</td>
<td>1927/01/11 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Redinger Lake</td>
<td>11241950</td>
<td>1965/10/01 to 2016/09/30</td>
<td>Storage</td>
</tr>
<tr>
<td>Powerhouse 3</td>
<td>11241800</td>
<td>1980/10/01 to 2016/09/30</td>
<td>Flow</td>
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<tr>
<td>San Joaquin River below Dam 6</td>
<td>11238600</td>
<td>1973/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>(above Stev. Cr.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stevenson Creek below Shaver Lake</td>
<td>11241500</td>
<td>1925/06/09 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>Powerhouse 4</td>
<td>11246530</td>
<td>1980/10/01 to 2016/09/30</td>
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<td>San Joaquin River above Willow Creek</td>
<td>11242000</td>
<td>1951/03/07 to 2016/09/30</td>
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<td>No. Fk. Stevenson Creek above Shaver Lake</td>
<td>11239300</td>
<td>1989/01/25 to 2016/09/30</td>
<td>Flow</td>
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<td>Eastwood Powerhouse</td>
<td>11238250</td>
<td>1987/10/01 to 2016/09/30</td>
<td>Flow</td>
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<tr>
<td>Powerhouse 2A</td>
<td>11238400</td>
<td>1980/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>Mammoth Pool Powerhouse</td>
<td>11235100</td>
<td>1980/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>San Joaquin River above Shakeflat Creek</td>
<td>11234760</td>
<td>1959/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>Portal Powerhouse</td>
<td>11235500</td>
<td>1927/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>Powerhouse 1</td>
<td>11238100</td>
<td>1980/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>Big Creek below Huntington Lake</td>
<td>11237000</td>
<td>1925/06/09 to 2016/09/30</td>
<td>Flow</td>
</tr>
<tr>
<td>South Fork San Joaquin River Near Florence Lake</td>
<td>11230000</td>
<td>1925/06/09 to 1980/09/29</td>
<td>Flow</td>
</tr>
<tr>
<td>Ward Tunnel at Intake at Florence Lake</td>
<td>11229500</td>
<td>1925/06/29 to 2016/09/30</td>
<td>Flow</td>
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<tr>
<td>Mono Creek below Lake T. A. Edison</td>
<td>11231500</td>
<td>1925/06/09 to 2016/09/30</td>
<td>Flow</td>
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<tr>
<td>Bear Creek near Lake Edison</td>
<td>11230500</td>
<td>1925/01/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
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<td>Pitman Creek below Tamarack Creek</td>
<td>11237500</td>
<td>1927/12/01 to 2016/09/30</td>
<td>Flow</td>
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<tr>
<td>Huntington-Shaver Conduit Outlet</td>
<td>11239000</td>
<td>1928/10/19 to 1985/07/24</td>
<td>Flow</td>
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<tr>
<td>Near Shaver Lake</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pitman Creek Shaft below Tamarack Creek near Big Creek</td>
<td>11237600</td>
<td>1986/10/01 to 2016/09/30</td>
<td>Flow</td>
</tr>
</tbody>
</table>
Figure A-12: Yearly water balance at Mammoth Lake, using only Bear Creek as a reference watershed.

Figure A-13: Yearly water balance at Edison Lake over the analysis period.
Figure A-14: Yearly water balance at Florence Lake over the analysis period.

Figure A-15: Yearly water balance at Mammoth Pool over the analysis period.
Figure A-16: Yearly water balance at Huntington Lake over the analysis period.

Figure A-17: Yearly water balance at Shaver Lake over the analysis period.
Figure A-18: Yearly water balance at Redinger Lake over the analysis period.


