THE IMPACT OF THE LOSS OF ELECTRIC GENERATION AT GLEN CANYON DAM
Overview of Study Findings

Background

The vast Colorado River system of dams, reservoirs, and diversions is facing an unprecedented water supply crisis. The 1922 Colorado River Compact, the legal foundation of this water system, was based on flawed assumptions that seriously overestimated Colorado River flow, underestimated public demand, and could not have foreseen the impacts of climate change. As a result, more water is allocated today than actually flows in the river. This water deficit is projected to increase significantly in the years ahead.[1]

The two main Colorado River reservoirs, Lake Powell, behind Glen Canyon Dam (GCD), and Lake Mead, behind Hoover Dam, are symptomatic of this crisis. These reservoirs have been hovering around half-full for the past decade. Studies have concluded that they are unlikely to both ever fill again, and could go dry within the next decade.[2] The stakes are high because the Colorado River supplies water to 40 million people and 4.5 million acres of agricultural lands.

GCD was authorized in 1956 as a part of the Colorado River Storage Project (CRSP). The primary purpose of the dam is to store excess water in Lake Powell for the upper basin states of Wyoming, Colorado, Utah, and New Mexico, which can be released, as needed, to Lake Mead downstream. A secondary purpose of the dam is to generate hydroelectricity, which is used to help fund operation of the Colorado River water delivery system and is sold at a discount to selected contractors[3]. As river flows continue to decline, Colorado River managers are increasingly concerned about maintaining Lake Powell to elevations that allow hydropower generation.

Some conservationists have questioned the benefits of attempts to preserve the status quo, and propose instead, fundamental changes in the management of the Colorado River system. For example, Glen Canyon Institute (GCI) has put forward the Fill Mead First (FMF) plan which would change the operation of GCD, allowing water to fill Lake Mead reservoir downstream before impounding it in Lake Powell. Others, such as former Commissioner of Reclamation, Daniel Beard, call for decommissioning and tearing down GCD, and permanently draining Lake Powell. These advocates contend that their plans could conserve large amounts of water now lost to seepage from Lake Powell, promote the restoration of Grand Canyon ecosystems, and allow the recovery of once-flooded portions of Glen Canyon.

Colorado River system managers are critical of such proposals because they argue that they would violate the Colorado River Compact. They also warn that these plans would jeopardize or eliminate hydroelectric power generation at GCD. They claim that this would cause spikes in

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[1] http://www.usbr.gov/lc/region/programs/crbstudy/finalreport/Executive%20Summary/CRBS_Executive_Summary_FINAL.pdf

[2] https://scripps.ucsd.edu/news/2487

[3] Theses contractors include publicly owned electric utilities, municipalities, irrigation districts, military bases, and native American tribes

endangered Colorado River fish species[4]. These contentions, however, are not well documented and questions have been raised about their accuracy.

Establishing an understanding of the economic impacts of a potential loss of electric generation at GCD is vitally important. Water managers and policy makers are now making far-reaching decisions on the management of the Colorado River, including how to allocate water between Lake Powell and Lake Mead. They need the best possible information on which to base these decisions.

The Glen Canyon Dam Hydropower Studies

In an effort to gain a greater understanding of these issues, Power Consulting, Inc. conducted a detailed analysis of the economic impacts to ratepayers in the region if Glen Canyon Dam (GCD) were to cease generating hydroelectric power. This research was reviewed by an independent panel of distinguished economists: David Marcus, Gail Blattenberger, and Spencer Phillips[5].

The study was done in three phases:

- Phase I, focuses on the economic value of current production of the electricity at GCD as well as the impact that not generating that electricity at GCD would have on the electric grid and on the regional economy;
- Phase II, focuses on the impact of the loss of GCD electric generation on the people and entities who directly or indirectly contract through the CRSP and Western Area Power Administration (Western) to receive their electricity.
- Addendum to Phase II, focuses on the financial costs and offsetting benefits if GCD were no longer able to generate hydropower.

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[4] Oritz, K. Western Slope is Refusing to Divert More Water to Front Range. New Channel 5 Grand Junction, Montrose, Glenwood Springs. Accessed 10.29.2015. https://web.archive.org/web/20140715021756/http:/www.krextv.com/story/western-slope-is-refusing-to-divert-more-water-to-front-range-20140711 and Harvey, N. To protect hydropower, utilities will pay Colorado River water users to conserve. High Country News. 8.4.2014. Accessed on 10.29.2015 https://www.hcn.org/blogs/goat/doi-and-utilities-partner-to-stave-off-colorado-river-power-woes and U.S. Bureau of Reclamation. Flow Regimes and Glen Canyon. Accessed on 10.29.2015. http://www.creda.org/Documents/Messaging2.pdf

[5] **David Marcus**, an independent energy consultant with union, government, and NGO clients

Gail Blattenberger, Ph.D., Professor Emerita at the economics Department of the University of Utah with fields in Econometrics and Environmental Economics

Spencer Phillips, Ph.D., principal of Key-Log Economics, LLC; lecturer at University of Virginia Department of Economics and Batten School of Leadership & Public Policy; and adjunct faculty, Goucher College graduate program in environmental studies.

Phase I

GCD is the largest single electricity producer in the Colorado River Storage Project (CRSP), a system of hydroelectric power plants in the Upper Colorado basin. GCD functions as both a base load electric generating facility and a peaking facility. Electricity produced in the CRSP is marketed by the Western Area Power Administration (Western) to publicly owned electric utilities, Native American Tribes, Federal agencies, and electric generating cooperatives at cost-based, as opposed to market, prices. Should GCD go offline, any price increase for these customers would be the difference between their contracts with WAPA and market rate prices.

The analysis concentrates on the economic value of current production of the electricity at GCD as well as the impact that not generating that electricity at GCD would have on the electric grid and on the regional economy. A major objective is to determine the economic value of GCD in a contemporary market. Another objective is to assess the capacity available in the region to offset the broad impact of shutting down energy production at GCD.

The study concludes that the amount and value of electric energy generated at GCD is significant. However, it represents only a small fraction of regional electric production, can be easily replaced if lost, and has been declining for two decades. Specifically:

- The average annual value of the GCD electric energy is $153.3 million. This value is less than one half of one percent of the close to $31 billion in sales value from electric generation in the Western Electricity Coordinating Council (WECC), which includes GCD power.
- The economic value of the peak electric generating capacity of GCD is marginal, less than $47.8 million per year. In the contemporary market however, the actual value is much lower, due to the existence of excess capacity reserves in the region.
- The base load electricity produced at GCD could be easily replaced by currently operable generators. WECC estimates of excess reserve margins through 2024 total more than 56 times the effective electric capacity of GCD.
- Since 1996, GCD electric generation has been reduced by about a third and the capacity of GCD is reduced by more than half because of generation restrictions implemented to mitigate environmental impacts in the Grand Canyon, coupled with low reservoir elevations at Lake Powell. Any impacts due to the termination of GCD production must be weighed against the significant electric capacity that has already been lost, with no negative effects on the grid.

Phase II

This study examines the potential increased cost of electricity on the ~3.2 million customers that receive *some* of their electricity from GCD at a below-market price. The analysis divides the customers into 526 groups based on which utility they buy electricity from and the class of electric consumer that they are in. It assesses the average amount of GCD electricity that each of these groups consume, looks at the customers that are affected the most, and determines what the electricity is being used for.

The analysis concludes that the total economic value lost as a result of GCD no longer being used for electric generation would be significant. However, the increase in electric costs would be widely spread over the 3.2 million end-user customers. As a result, average electricity cost increases per year would be $0.96 for residential customers, $7.04 for commercial customers, and $75.77 for industrial customers. Less than one half of one percent of residential customers would experience cost increases of more than a $1 a month. The highest average residential increase would be $2.59 per month.

A small subset of customers receive all of their electricity from the CRSP — mostly sovereign nations, governments or government-owned or run enterprises. These customers could face a 2.5- to 2.7-fold increase if GCD electricity generation were lost. The largest electricity cost increase for these non-utility contractors would be borne by the Navajo Tribal Utility Authority (NTUA). It would have an annual electricity cost increase of approximately $1.3 million.

It is important to understand that non-utility contractors' electricity cost increases are not directly passed onto individual households but are, instead, borne entirely by the non-utility contractor. Residential customers who receive electricity from the NTUA would incur an annual cost increase of $1.83, the commercial customers would incur an annual increase of $20.89, and the industrial customers would incur an annual increase of $452.93. The NTUA owns four large casinos, ten shopping centers, a large number of businesses, a museum, a parks and recreation department, an arts and crafts enterprise, and numerous tribal government and social centers. The Navajo nation is home to 250,000 residents, and generated a net $81 million dollars from their 3 casinos in New Mexico alone in 2014.

Addendum

The Addendum to Phase II estimates the economic impacts and potential cost savings of implementing GCI's Fill Mead First (FMF) proposal to transfer water from Lake Powell to Lake Mead. FMF would lower Lake Powell, increasing the volume and pool elevation of Lake Mead, resulting in increased generating capability at Hoover Dam. The process of filling Lake Mead is broken into three phases of elevation: minimum power pool, dead pool, and natural river elevation. This study estimates transfer rates of water from Lake Powell to Lake Mead for the three potential FMF pool elevations.

A water balance model was constructed for the two reservoirs based on historical inflow and release data, estimates of monthly evaporative loss, and reasonable flow rates through the Grand Canyon. This highly simplified model was used to estimate the potential increase in pool elevation at Lake Mead over time.

The study identifies two types of potential cost savings associated with the FMF scenarios: 1) current costs associated with operating Glen Canyon Dam, and 2) costs associated with the loss of potential earnings.

Current costs associated with operating Glen Canyon Dam include:

- Operations and maintenance for the Glen Canyon Dam, which are shared between Western Area Power Administration and the Bureau of Reclamation

- Compliance with the requirements of the U.S. Fish and Wildlife Service and Endangered Species Act to protect endangered species
- Funding of the Glen Canyon Dam Adaptive Management Program, which studies the effects of dam operations on the Grand Canyon and can recommend changes in dam operations

Costs associated with the loss of potential earnings include:

- Hoover Dam hydropower revenue lost due to the low water levels at Lake Mead
- Value of water lost to Lake Powell seepage into the reservoir banks

Results are displayed in Table 1 below.

TOTAL ANNUAL COSTS AND POTENTIAL SAVINGS ASSOCIATED WITH GLEN CANYON DAM OPERATIONS

Current Costs Associated with Operating Glen Canyon Dam

Cost Category	**Cost/year**
Dam operation	$22,585,265
Compliance with USFWS and ESA	$1,900,000
GC Dam Adaptive Management Program	$10,472,367
TOTAL ANNUAL COST	**$34,957,632**

Costs Associated with Loss of Potential Earnings

Potential Earnings Loss Category	**Loss**
Foregone Hoover Dam hydropower	$11,787,080
Water lost to Lake Powell seepage	$28,057,286
TOTAL ANNUAL LOSS	**$39,844,366**
TOTAL POTENTIAL SINGLE-YEAR SAVINGS	***$74,801,998***

This study estimated that the implementation of the Fill Mead First proposal could result in total single-year cost savings of $74.8 million. This represents a savings equivalent to 49 percent of the total $153.3 million average annual value of electric power generated at GCD.

Summary of Findings

The study concludes that, if Glen Canyon Dam stopped generating hydropower, it would have a negligible impact on the western power grid, would raise electric rates by an average of 8 cents per month for residential customers of hydropower, and could save tens of millions of dollars each year in taxpayer subsidies and water lost to system inefficiencies.

- The average annual value of Glen Canyon Dam's electric energy represents less than one half of one percent of the sales value from electric generation in the western grid, and that the grid could readily absorb the loss of hydropower from the dam.

- The total impacts would be an increase of $16.31 million in electricity costs for consumers of Glen Canyon Dam power, but because they would be spread among 3.2 million customers, the individual impacts would be small in the vast majority of cases.

- The average annual value of the GCD electric energy is $153.3 million. This value is less than one half of one percent of the close to $31 billion in sales value from electric generation in the Western Electricity Coordinating Council (WECC).

- Average yearly cost increases would be $.08 per month for residential customers, $.59 per month for commercial customers, and $6.16 per month for industrial customers of Glen Canyon Dam electricity.

- A discontinuation of Glen Canyon Dam operations could have offsetting benefits of approximately $74.8 million annually, including savings of $34.9 million in management costs and potential earnings of as much as $39.8 million annually due to increased hydropower at Hoover Dam and conservation of water that would otherwise have seeped into the banks of Lake Powell.

The Impact of the Loss of Electric Generation at Glen Canyon Dam

A Report Prepared for the

Glen Canyon Institute

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Executive Summary

1. Why we are writing this report: The change in the operational goals of Glen Canyon Dam from its original design goals

Glen Canyon Dam (GCD) was authorized by Congress as part of the Colorado River Storage Project in 1956. The stated purpose of GCD was "to initiate the comprehensive development of the water resources of the Upper Colorado River Basin, for the purposes, among others, of regulating the flow of the Colorado River, storing water for beneficial consumptive use, making it possible for the States of the Upper Basin to utilize, consistently with the provisions of the Colorado River Compact, the apportionments made to and among them in the Colorado River Compact and the Upper Colorado River Basin Compact, respectively, providing for the reclamation of arid and semiarid land, for the control of floods, and for the generation of hydroelectric power".[1] Seven years later GCD was completed and the blocked flows of the Colorado River began flooding Glen Canyon, creating Lake Powell and starting a process of sedimentation of Glen Canyon. In 1966 GCD generators began producing electricity at full capacity and by 1980 Lake Powell hit maximum pool elevation. In more recent years due to long term changes in winter precipitation rates in the Upper Colorado Basin, the pool elevation of Lake Powell has dropped and without greatly increased inflow rates, the pool elevation will not hit maximum again.

In the past three decades the operation of GCD has adapted from a generating facility that was primarily used to accommodate loads during peak hours to a generating facility with limited peaking ability. This change is due primarily to restrictions on the flow rates out of the dam as well as restrictions on the rate of change of the flow rate. These restrictions were enacted to balance the electric generating capabilities of the dam with the ecological impacts that are inherent in river flow engineering. As resource management directives changed, continual assessments of the potential effects, both ecological and economic, of different operational scenarios were conducted. Currently, the operational scenarios that are being studied range from scenarios that maximize the value of electricity that is generated to water release rates that would mimic natural sedimentation rates in the Grand Canyon, downstream of the dam to water release rates that would benefit native fish populations, among many other scenarios. Most scenarios under consideration for new rules and restrictions on the operation of GCD attempt to maximize the value of electricity that is generated while still trying to balance the ecological impacts of the dam.

[1] Colorado River Storage Project – Authority to Construct, Operate, and Maintain, Chapter 203 – Public Law 485, enacted by the U.S. Senate and House of Representatives, April 11, 1956

This report analyzes both the economic impact of stopping energy generation at GCD on the Western United States[2] as well as the ability of the current resources on the electric grid to compensate for the loss of energy generation at GCD.

2. The focus of our analysis

Our analysis focuses on the economic value of current production of the electricity at GCD as well as the impact that *not* generating that electricity at GCD would have on the electric grid and on the regional economy. We do *not* use the original planned capacity of the dam to calculate the economic value of GCD as it is unrealistic to assume that the production of electricity will ever consistently reach the original engineering goals for electric generation. We are also *not* attempting to analyze future variations in electric rates or changes in climate that would certainly change the economic value of GCD. Our focus in this report is to determine the economic value of GCD in a contemporary market by analyzing electric production from GCD and the value of that electricity at the time that it was sold. Further, we analyze the capacity available in the region to offset the broad impact of shutting down energy production at GCD.

3. The value of GCD and how that fits into the Western Electricity Coordinating Council (WECC) regional picture

GCD is the largest single electricity producer in the Colorado River Storage Project (CRSP), a system of hydroelectric power plants in the Upper Colorado basin. Electricity produced in the CRSP is marketed by the Western Area Power Administration (Western) to publicly owned electric utilities, Native American Tribes, Federal agencies, and electric generating cooperatives at cost-based as opposed to market prices. Nonetheless, the economic value of GCD is essentially determined by the market price of the electricity at the time it is sold.

The amount of total electricity available at any time on the electric grid has two facets. (1) Enough electricity is generated continually to maintain a minimum "base load." This base load electric generation fluctuates daily and seasonally to allow for average changes in electric consumption.[3] This means that a portion of the electric generating facilities on the grid need to run continually.[4] (2) In addition to this base load, demand for electricity fluctuates moment by moment as does generation from intermittent generators

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[2] Specifically, this report focuses on the states that are part of the Western Electricity Coordinating Council (WECC). These states are within two census regions: the Mountain and contiguous Pacific census regions. The 11 states in these regions are: California, Oregon, Washington, Idaho, Montana, Nevada, Wyoming, Utah, Colorado, Arizona, and New Mexico.

[3] Typically, there is more demand for electricity during the day than at night, more demand on weekdays than weekends, more demand during the summer and winter than in the fall and spring, etc.

[4] In practice, it is not possible for a single electric generator to run continually as they must be off-line from time to time for maintenance. Also, some generators are not designed to operate for extended periods; if they are overused, they incur excessive wear.

such as wind and solar sources in unpredictable ways. This high frequency fluctuation of both demand and supply requires variable "peaking" generation. Electricity generation needs to quickly ramp up and down to maintain the balance between electric load and electric generation during these peaking events. So, for a stable electric grid there needs to be a combination of generators that are run at a constant rate and generators that can quickly increase and decrease their amount of total electric generation. This can be achieved either by ramping up the rate at which online generators are producing electricity or by bringing additional generators online to supply the needed electricity. GCD is used as both a base load generator and as a peaking facility, thus our analysis of the economic impact of the loss of electric generation at GCD accounts for both of these facets.

a. The current value of GCD is an insignificant percentage of the total economic value of the power that is generated in the Mountain and Pacific Contiguous Census Regions

We used 5 years of hourly electricity generation data from GCD[5] and daily market electricity prices from the Palo Verde hub[6] to calculate the economic value of the electric energy from GCD. By multiplying the electric generation (in megawatt hours) by the market electricity prices (in dollars per megawatt hour), we found the value of the dam for each hour of the five year time series. We then summed the hourly values over various time scales from days to years to examine temporal variations in the value of GCD's electric energy over the five years and the cause for any large changes in value. We found that, on annual timescales, the value of the electricity generated at GCD ranged from \$124.7 million per year to \$220.1 million per year. The source of this \$95.4 million per year variation was *not* due to large fluctuations in the market value of electricity, but was due to the annual variation in the amount of precipitation in the Upper Colorado Basin. We analyzed data from 106 weather stations that have collected hourly precipitation levels and determined that the 5 year average precipitation over the basin is representative of the thirty-year average precipitation between 1981 and 2010.[7] During the 5 years of our analysis, the average market price of electricity was \$37.10 per megawatt hour with a standard deviation of \$8.57 per megawatt hour and no statistically significant trend in price changes. There were three short (1-2 days) periods of very high electricity prices; however, prices were fairly stable over the 5 years of our analysis. The

[5] Water year 2010-2014; a water year spans the time between October 1st of one year and September 31st of the next year. For example, water year 2014 was from October 1st 2013 through September 31st 2014. The electric generation data comes from Katrina Grantz who is a Hydraulic Engineer at GCD for the Bureau of Reclamation.
[6] Palo Verde is physically the closest hub to GCD that the EIA regularly reports on and this was the convention of David Marcus (2009) *Glen Canyon Dam Releases – Economic Considerations.* The Palo Verde transmission hub wholesale prices are used in part to calculate the Dow Jones Palo Verde Electricity Price Indexes.
[7] Of the five water years analyzed in this report, two years were close to the 30 year average total precipitation levels, two years were below the 30 year average precipitation, and one year was well above the 30 average precipitation level. The mean precipitation of these 5 water years is very close to the 30 year mean precipitation. Both of these averages have the signal of the drought in the region.

combination of fairly stable electricity prices and precipitation rates throughout the Upper Colorado Basin, which are representative of the longer-term average, allow us to use the five water years[8] analyzed herein as an accurate time period to determine the recent annual economic value of GCD.

The average annual value of the GCD electric energy is $153.3 million. This value is less than one half of one percent of the close to $31 billion[9] in sales value from electric generation in the Western Electricity Coordinating Council (WECC). To put this in perspective, if the total revenue from electric generation in the WECC were represented by the height of the Glen Canyon Dam (705 feet), the value of GCD would be the height of a three and a half foot child standing next to it.[10]

b. In the short-term, there is little to no value associated with the electric generating capacity of GCD

Recall that GCD functions as both a base load electric generating facility as well as a peaking facility. The economic value of the peak electric generating capacity of GCD is marginal, less than $47.8 million per year.[11] This *maximum* value of the electric generating capacity of GCD is equivalent to the levelized cost[12] of constructing an electric generator that would *only* replace the peaking functionality of GCD. It is more likely that the value of the electric generating capacity of GCD is much less than this maximum value due to the existence of capacity reserves in the region significantly in excess of those prudently required to meet unexpected contingencies. Excess capacity reserves are likely to continue into the future as a side effect of the development of renewable resources to displace coal generation.

[8] The "water year" used in the Western U.S. runs from October 1 through the following September 30.
[9] This is the total revenue adjusted by the average percentage of revenue from transmission and service fees charged by WECC sub-regions in 2012, resulting in revenue from electric generation ONLY, as described in section III-1 of this document. The total revenue is the annual sum of Total Electric Industry revenue from states within the Mountain and contiguous Pacific census regions reported on EIA-861 form. Data downloaded from http://www.eia.gov/electricity/data/state/revenue_annual.xls on 2/6/2015.
[10] We are comparing the market value of GCD generation to the sales value of electric generation across the WECC region. The sales value of electric generation is not necessarily determined by market pricing. Regulatory commissions set the prices charged by investor-owned utilities on a cost of service basis that could be below or above the prevailing prices in regional electric markets. If regulators and the managers of government-owned electric generators price their electricity below market value, then we are overstating the relative importance of GCD generation. If regulators or government managers let electric generators get out of control and authorize electric prices above the market price, we are understating the relative importance of GCD generation.
[11] Section II-3-d, this report.
[12] "Levelizing" a lump sum capital costs consists of calculating a monthly or annual payment that over the life of the project would have the same present value as that lump sum cost. A monthly mortgage or car payment is the levelized payment associated with the capital cost of the home or car.

4. The current electric grid can absorb the loss of GCD

As we stated above, replacing the electricity generated at GCD requires replacing both base load electric generation as well as peak load electric generation. Before the recession of 2008, demand for electricity had been steadily increasing since the early 1980s.[13] Planned construction of power plants just before the recession was based on this steady increase in demand. However, demand fell during the recession, leaving excess electricity-producing capability on the grid. Currently, there are enough operating electric generators online to accommodate the loss of electricity at GCD for the foreseeable future. In addition, renewable resources are being rapidly developed throughout the WECC, and particularly in California, to reduce carbon dioxide emissions. Because the development of these resources is adding generation resources faster than the rate at which post-recession demand is growing, there is likely to continue to be more capacity than the minimum needed for reliability for the indefinite future.

Within the 11 states that make up the majority of the WECC in the U.S.,[14] there are 513[15] electric generating facilities that report running generators with a nameplate capacity[16] of more than 1 MW.[17] The annual electric energy production of generators in the region in 2013 was approximately two-thirds of their potential maximum electric energy production. The difference between the potential maximum electricity generation and actual electricity generation at natural gas fired combined cycle generators[18] in the region in 2013 was 190 million megawatt hours[19], over 46 times the 4.08 million megawatt hours of electricity produced at GCD annually. It is apparent, then, that the base load electricity produced at GCD could be easily replaced by currently operating generators. The capacity of GCD is also replaceable with WECC estimates of excess reserve margins through 2024 of more than 56 times[20] the effective electric capacity of GCD.

We close by pointing out that GCD has been losing electric production and capacity since the implementation of the 1996 ROD. These generating restrictions coupled with

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[13] Figure 15-3 of the National Renewable Energy Laboratory 2012 Renewable Electricity Futures Study; Volume 3: End-Use Electricity Demand. Downloaded on 2/17/2015 at: http://www.nrel.gov/docs/fy12osti/52409-3.pdf

[14] WECC also includes the Canadian Provinces of British Columbia and Alberta as well as the Mexican state of Baja California Norte.

[15] Data from EIA-860 Schedule 3, 'Generator Data' (Operable Units Only) downloaded from http://www.eia.gov/electricity/data/eia860/index.html and EIA-923 Monthly Gerneing Unit Net Generation Time Series File, 2013; downloaded from http://www.eia.gov/electricity/data/eia923/index.html

[17] Data from EIA-923 Monthly Generating Unit Net Generation Time Series File, 2013 December; Sources EIA-923 and EIA-860 Reports. Downloaded from: http://www.eia.gov/electricity/data/eia923/index.html

[18] We assume that electric production that is suitable for replacing GCD will come primarily from combined cycle natural gas fired generators.

[19] Summer capacity from EIA-860 Data (2012) accessed at: http://www.eia.gov/electricity/data/eia860/index.html accessed on 1/15/2015. The potential capacity factor for main generator type from: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm accessed on 1/28/2015. Summed summer capacity for each plant is multiplied by the potential capacity factor for main generator type (prime mover) for each power plant.

[20] Calculations are detailed in the main body of the text.

low reservoir elevations at Lake Powell have combined to reduce electric generation by about a third and reduce the capacity of GCD by more than half. Those are losses that have already been incurred by the grid without incident. If GCD was to stop producing power altogether the same size impacts could be expected in the future with a lower loss of electric capacity compared to what has been already lost and a higher loss of electric energy, twice what has been lost thus far.

Table of Contents

I. History of Glen Canyon Dam

In the early 20th century there was rapid population growth in the Southwestern United States. The largest source of water for the region is the Colorado River with a drainage basin that spans over 150 million acres in 7 states (Colorado, New Mexico, Utah, Wyoming, Arizona, Nevada, and California) as well as small parts of Sonora and Baja California in Mexico. The water demands from the rapid population growth in cities like Las Vegas, Los Angeles, Phoenix, and San Diego in conjunction with millions of acres of irrigated crop land in the region put a large amount of stress on the limited water resources of the Colorado River. In response to this stress, a series of laws and congressional rules have been enacted over the last 90 years in an attempt to equitably share the Colorado River water resources among an ever growing population. This includes the implementation of large water projects, such as the building of the Hoover and Glen Canyon Dams that were designed to ease the stress on the water resources in the region but also allowed for further growth into previously uninhabitable areas. Today, in accordance with these rules, more than 70 percent of the water in the Colorado River is diverted for irrigation[21] and the river often does not reach the Gulf of California.

In 1922, Congress enacted the Colorado River Compact, which is considered to be the cornerstone of the all-encompassing "Law of the River," to help quell the growing tensions that were mounting regarding use of the Colorado River. This compact divided the seven basin states into an Upper Division (Colorado, New Mexico, Utah, and Wyoming) and a Lower Division (Arizona, Nevada, and California). With the explosive growth of the Lower Division, the Upper Division wanted to secure their right to the Colorado River and the Lower Division wanted a guaranteed annual volume of water to secure their own growth. Initially each division was allocated the right to develop 7.5 million acre-feet of water annually and the Lower Division was given an additional 1 million acre-feet for consumptive use.[22]

With the Boulder Canyon Protection Act of 1928 Congress ratified the 1922 Colorado River Compact, authorized the construction of the Hoover Dam, and established the Secretary of the Interior as the "Water Master" of the Lower Division. Congress also established a special "Colorado Dam Fund" to be controlled by the Secretary of the Interior.[23] Thus, with this act, Congress established the governance and the funding necessary for the construction of the Hoover Dam as well as the specific allocation of water to each state in the Lower Division. The Upper Colorado Basin Compact of 1948

[21] The Colorado River Runs Dry. Sarah Zielinsk. Smithsonian Magazine. October, 2010. http://www.smithsonianmag.com/science-nature/the-colorado-river-runs-dry-61427169/?no-ist
[22] Colorado River Compact. 1922 http://www.usbr.gov/lc/region/g1000/pdfiles/crcompct.pdf and Colorado River Law and Policy: Frequently asked Questions. March, 2011. http://www.waterpolicy.info/projects/CRGI/materials/Colorado%20River%20FAQ%20v1.pdf and The Law of the River. Bureau of Reclamation. http://www.usbr.gov/lc/region/g1000/lawofrvr.html
[23] Boulder River Canyon Project Act. H.R. 5773. 1928. http://www.usbr.gov/lc/region/g1000/pdfiles/bcpact.pdf

established each of the upper states' share of the water allocated to the Upper Basin states. It also established the Upper Colorado River Commission to manage the Upper Colorado River Basin water resources. The Upper Colorado River Commission consists of a representative commissioner from each state within the Upper Basin as well as a representative from the national government.[24] On April 11, 1956, Congress authorized the Colorado River Storage Plan ("CRSP"), which set forth a basin-wide plan that included the Glen Canyon, Curecanti, Navajo, and Flaming Gorge dams.

Construction on the Glen Canyon Dam began in 1956; the dam was completed in 1963 and began producing power at full capacity by 1966. It took 17 years for Lake Powell to fill to full capacity with a pool elevation of 3,700 feet. In 1977 the Bureau of Reclamation ("BOR") transferred the marketing and transmission of the power created at Glen Canyon Dam to the Western Area Power Administration ("WAPA" or "Western") through the Department of Energy Organization Act of 1977,[25] where it remains today.

Since 1956, numerous other Congressional acts dedicated various amounts of water to different interested parties. These Acts include the Colorado Basin Act which gave Arizona water rights that are defined as junior to the water rights of California as well as multiple treaties with Mexico which guarantee water volume and water quality of the Colorado River as it flows out of the United States. Between 1963 and 1992 the BOR and Western operated hydroelectric generating facilities at the Glen Canyon Dam in accordance with the Law of the River without restrictions on flow rates or timing of the release of water. The operations included flood control measures; however, water releases were generally timed to provide the maximum amount of generating capability when the electricity was needed and most valuable (on-peak).

With the passage of the Grand Canyon Protection Act of 1992, flood control and hydroelectric generation were no longer the primary considerations for the water that passed through the Glen Canyon Dam. This Act specifically notes that the management of Glen Canyon Dam should be operated "to protect, mitigate adverse impacts to, and improve the values for which Grand Canyon National Park and Glen Canyon National Recreation Area were established."[26] This Act also set up specific rules for the minimum, maximum, and ramp rates for the flow of the Colorado through Glen Canyon Dam. Effectively, this Act limited the way that the water within Lake Powell could be used. Previously, the water was kept in storage during off-peak hours and the hydro-generation potential was used during on-peak hours to maximize the economic value of the generated electricity without regard for the pre-dam flow rates through the Grand Canyon. The 1996 Record of Decision (ROD) for the operation of Glen Canyon Dam following the Final Environmental Impact Statement (EIS) established an Adaptive Management Program (AMP) to study the impact of various flow rates on the Grand Canyon. Under the Grand Canyon Protection Act and the Adaptive Management Program, the Glen Canyon Dam has been managed so that fish habitat, temperature of

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[24] Upper Colorado River Basin Compact of 1948.
http://www.usbr.gov/lc/region/g1000/pdfiles/ucbsnact.pdf
[25] http://www.gcdamp.gov/keyresc/hydropower.html
[26] http://ltempeis.anl.gov/eis/why/index.cfm
Ibid

the river, movement of sediment, cultural resources, and water level for navigation through the Grand Canyon take precedence over economic value of power generation.

A Long Term Experimental and Management Plan (LTEMP) EIS will be released in 2015. The LTEMP will lay out the new rules for the operation of the Glen Canyon Dam using the last 18 years of experiments and data to develop a plan for the next 15 to 20 years. There are seven different scenarios that are being considered in the EIS that will govern the power producing ability and flow rates of the Colorado River through the Glen Canyon Dam.[27] The scenario analyzed in this report is *not* one of the seven currently being considered. We analyze a scenario in which Glen Canyon Dam generates zero hydropower, and flow rates of the Colorado River through the Glen Canyon Dam are returned to levels as close to pre-dam as possible. Under this scenario, we consider the economic implications of a total loss of hydro generating capability from the Glen Canyon Dam as well as the potential economic impacts of this loss. The first part of this report is a quantification of the economic value of the generation of power at the Glen Canyon Dam during the last five water years. We further put that value into the broader regional context to evaluate the impact of losing this electric power resource.

II. Economic value of the operation from GCD under current restrictions

1. Electric Energy versus Electric Capacity

In addition to providing electric energy (e.g. kilowatt hours, kWh) over any given time period, the ability of an electric generating unit to help meet *peak* demands on the electric grid is also valuable. Customer's electric loads vary across the day and year. In addition, the output of the electric generating facilities available to meet those loads can vary too. That is especially true of variable generation resources such as solar and wind electric generation. In addition, the efficiency of conventional fuel-using electric generators can also vary with ambient air temperature and source water temperature. Finally electric generators can have unplanned shutdowns due to any number of mechanical or environmental factors.

At all times customers' demands for electricity have to be kept in balance with the electric power attached to the grid to keep the electricity delivery system stable and functional. To keep this balance across every minute of every day, there has to be sufficient electric power sources attached to the grid to meet peak demands and maintain balance in the face of considerable uncertainty. The uncertainty comes from

[27] http://ltempeis.anl.gov/

the timing and size of customer demand as well as to the availability of electric power from variable power sources and from each of the other attached electric generators.

The ability of an electric generator to contribute to meeting this uncertain peak demand is called its electric *capacity* and is measured in kilowatts (kW) or megawatts (MW, 1000 kW).[28] Capacity is a measure of the instantaneous power production of a generator, and maximum capacity is a measure of the maximum power production capability of the generator.[29] The energy produced *over time* as a result of the generator operating, on the other hand, is measured by the sum of that cumulative generation. As a result electric energy has a time unit to it, kilowatt *hours* or megawatt *hours*. Typically, a customer's *peak* electric load during a given time period like a month, a season, or a year is used to measure the customer's responsibility for electric generation facilities having to standby to periodically meet that peak demand. The instantaneous peak output of an electric generator is termed its "capacity." This is different from the *average* demand or energy load that the customer puts on the system across a month or year.

When a generator is online and supplying electricity to the grid, it often does not run at its nameplate capacity. There are many reasons that generators do not run at nameplate capacity all of the time. For GCD, restriction of water release rates keeps GCD from running at its maximum rate in all but a very few hours per year, and limits on annual water releases would keep it from running at its maximum rate all year even if there were no release rate restrictions. Reductions in electric consumption can lead the more expensive generating units to be ramped down or idled. Also low pool elevation can reduce the generating capacity of a hydroelectric unit. Coal and natural gas fired power plants are often run below nameplate capacity because cheaper energy is available or the generators may not be designed to run continuously at nameplate capacity. Whatever the reason that a generator is not running at nameplate capacity, the fact that it is not running at nameplate capacity can mean that there is a potential for more electric energy to be produced at any given time. Indeed, the electric grid is designed to have a portion of the total energy potential of the entire fleet of generators connected to the grid available to meet spikes in demand or to replace the loss of electric generating capacity when an unplanned reduction in generation from a facility occurs. The

[28] The ability to almost instantaneously, within a minute or so, adjust to keep loads and resources in balance has traditionally been treated as a separate "service" of an electric generator and labeled as one of the "ancillary services" some electric generators can provide in addition to energy and capacity. There are two such ancillary services associated with generators that are capable of relatively quickly adjusting the electric power they bring to the grid. Adjusting, usually automatically, to fluctuations in electric demand and supply to keep them instantaneously in balance is call *regulation* service. In addition to this minute-by-minute balancing, there is also need for electric generators that can ramp up and down from hour to hour as customer loads on the system rise and fall over the day. This *load following* ability is also a valuable service that more flexible electric generators can provide. The electric power production of some electric generators, such as coal and nuclear fueled generators, cannot be safely and efficiently adjusted in this way. Other generators, such as natural gas fueled combined cycle plants or combustion turbines, can adjust their electric power production without damaging the plant or becoming grossly inefficient. Hydroelectric resources with significant storage can also provide regulation and load following services if their water releases are not tightly constrained by regulations to protect other river values.

[29] The maximum capacity for which a generator was designed is often called its "nameplate" capacity. The actual maximum capacity can vary slightly from the nameplate capacity, and be either above it or below it. For simplicity, the terms "maximum capacity" and nameplate capacity" are used interchangeably below.

availability of this potential capacity can prevent blackouts due to sudden imbalances between electric supply and electric demand. Here we will refer to the *difference* between the average amounts of electric energy that a generator produces over a given amount of time and the average amount of electric energy that the generator *could* produce if it were to run at available nameplate capacity as the *residual energy potential*.

2. Value of electric energy generation from GCD

The market value of electric energy generated at Glen Canyon Dam (GCD) fluctuates yearly, seasonally, and daily. That market value of the electricity generated from GCD over any given time period is determined by the volume of the electricity generated and the current market price of electricity, which is largely based on the demand for the electricity. Regulations imposed by the Federal Energy Regulatory Commission (FERC), Glen Canyon Dam Environmental Impact Statement Record of Decision (ROD)[30], the Grand Canyon Protection Act of 1992[31], and a ROD defining coordinated operations of Lake Powell and Lake Mead[32] constrain the total power generation and flow rates through GCD. Power generation at GCD varies daily within the constraints imposed by FERC and the RODs. The RODs are based on Environmental Impact Statements (EIS) which consider water supply, environmental protection (including beach and habitat-building, ensuring fish habitat especially for Humpback Chub, and flood control), hydropower production (which is partially determined by hydrology and fluctuations of electricity prices and demand[33]), and recreation (including fishing, reservoir related recreation, and downstream activities).

GCD is the largest component of a system of power generating reservoirs that make up the CRSP. Electricity generated from CRSP is marketed through Western, a power marketing administration within the U.S. Department of Energy. Western is tasked with marketing and transmitting wholesale electricity from multi-use water projects.[34] Specifically; electricity generated by CRSP is sold at below-market prices to publicly owned electric utilities, Native American Tribes, Federal agencies, and electric distribution cooperatives. Excesses and deficiencies in generation from CRSP are sold and bought at wholesale market prices.[35] Put another way, when there is not enough

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[30] Record of decision operation of Glen Canyon dam final environmental impact statement https://www.usbr.gov/uc/rm/amp/pdfs/sp_appndxG_ROD.pdf

[31] Reclamation Projects Authorization and Adjustment Act of 1992, Title XVIII – Grand Canyon Protection http://www.usbr.gov/uc/legal/gcpa1992.html

[32] Record of Decision Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead
http://www.usbr.gov/lc/region/programs/strategies/RecordofDecision.pdf

[33] Marcus, D., (2009), *Glen Canyon Dam Releases – Economic Considerations*, http://www.grandcanyontrust.org/documents/gc_damEconomics.pdf

[34] Information taken directly from http://ww2.wapa.gov/sites/Western/about/Pages/default.aspx, Western's web page.

[35] Marcus, D., (2009), *Glen Canyon Dam Releases – Economic Considerations*, http://www.grandcanyontrust.org/documents/gc_damEconomics.pdf

energy for the CRSP to meet their contractual obligations, they have to go into the market to make up for those deficiencies and meet their customers' energy demands.

Western imposes generation scheduling guidelines on GCD that are based on ROD guidelines and customer loads. Within these constraints, GCD generation scheduling attempts to produce the minimum allowable amount of power (firm load) during off-peak hours, when energy prices are lowest, and the maximum amount of power during on-peak hours, when energy prices are at a premium[36].

To estimate the current market value of GCD operations, we investigated the last five *water years*[37] of power generation. This time series begins on October 1, 2009 and ends on September 30, 2014. This time span is inclusive of the water years (WY) 2010-2014. Electric generation from GCD can be priced on an hourly basis, representing the total megawatt hours (MWh). For each non-holiday weekday, trade prices are reported by the U.S. Energy Information Administration.[38] Reported trade prices for the produced electricity are valid for one or more days following the trade date.[39] The report has three price values: (1) absolute high price for the period, (2) absolute low price for the period, and (3) weighted mean price (the quantity of the sum of each transaction's price multiplied by its volume of energy divided by the total volume of energy transacted that day). All three of these prices are inclusive of all of the power stations which sell at the Palo Verde[40] hub as well as all of the trades made during the time period; thus the low and high prices represent the maximum possible range of pricing for the GCD electricity that is produced each day. We calculate the economic value of GCD over the past 5 water years by multiplying hourly energy generation of GCD by each of the three different energy price time series.[41] (1) In order to find the minimum economic value we multiply the 24 hours of energy generation for each day by the low price for the day. (2) To find the maximum economic value of GCD we multiply the hourly data by the high price for the day. (3) We assume that the reported weighted average price is valid for the electricity sold from GCD and multiply the weighted average price by the 24 hours of energy generation for each day. The difference between (1) and (2) is the maximum

[36] Poch, L.A., D.J. Graziano, T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, (2013), *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2012*

[37] A water year begins on October 1st the year before the water year indicates, and lasts until September 30th of the water year.

[38] http://www.eia.gov/electricity/wholesale/

[39] Trade prices dated on Thursdays were used for Friday (they are forward prices) Saturday and Sunday trades since there are no values for Sat and Sun; holidays are dealt with similarly. Friday dated trade prices were used for Monday, Monday for Tuesday, etc.

[40] Palo Verde is the closest electricity trading hub to Glen Canyon Dam.

[41] In addition to these three metrics of economic value, we also calculated the economic value of GCD with the assumption that all electricity produced during the 16 on-peak hours of the day is sold at the high daily trade price and that all electricity produced during the 8 off-peak hours of the day is sold at the low daily trade price. This method is adapted from the report *Glen Canyon Dam Releases – Economic Considerations* by David Marcus released in 2009. The difference between calculated value of GCD using the daily weighted average price index and the on-peak/off-peak calculated price is $1.7 million, roughly 1 percent of the total economic value of GCD. We choose to use the weighted average price index from the Palo Verde hub to value GCD because it is a more accurate estimate of the average price of the electricity throughout the day.

range in our calculations of the economic value of the GCD. This range is only 7 percent of the market value (Table 1).

The five water years analyzed herein show that the economic value of GCD is time dependent, ranging from $124.7 million per year to $220.1 million per year with an average 5 year value of $153.3 million per year. In water year 2011 the economic value of GCD was $220.1 million, which was $61.2 million – $95.4 million *higher* than the other years investigated in this analysis; this high single year economic value is directly related to the relatively high electric generating *flow* through the dam, *not* exceptionally high electricity prices or demand during WY2011.[42] The high GCD electric energy generation in WY2011 is due to a relatively high winter snowpack in the Upper Colorado River Basin (the input basin for Lake Powell) and the rules for equalization of Lake Powell and Lake Mead.[43] Average weekly and yearly results of our calculations are shown in Figure 1.

Figure 1.

[42] The mean annual value for the weighted average electricity trading price per megawatt hour for the 5 water years analyzed herein was $40.23 in WY2010, $36.64 in WY2011, $30.08 in WY2012, $35.91 in WY2013, and $42.66 in WY2014.

[43] Record of Decision Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead, (2007)

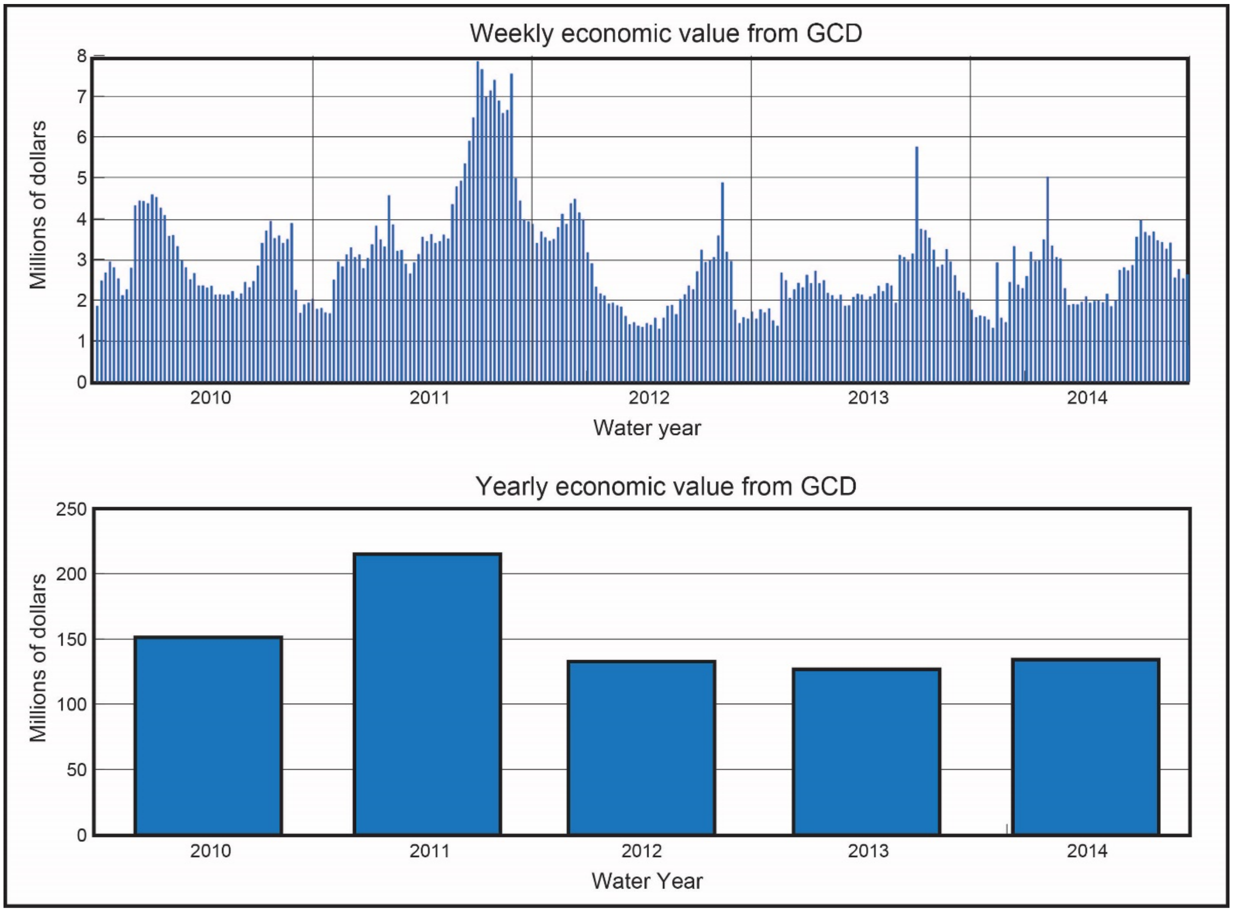

Figure 1 shows weekly and yearly economic value of GCD based on hourly power generation at GCD and daily market price of electricity at Palo Verde trading hub. [44]

Table1.[45]

Water Year	Total Electricity Generated (Million MWh)	Weighted Average Price Economic Value (Million $)	Low price Economic Value (Million $)	High Price Economic Value (Million $)	On/Off-peak Economic Value (Million $)	Range in Calculated Value (percent of value)
WY2010	3.7	158.9	154.1	165.0	161.2	6.90%
WY2011	5.72	220.1	212.2	229.5	222.6	7.90%
WY2012	4.32	132.7	128.9	136.4	133.7	5.70%
WY2013	3.51	124.7	120.8	128.7	126.0	6.30%
WY2014	3.12	129.9	125.7	134.7	131.5	7.00%
5 Year Average	4.08	153.3	148.3	158.9	155.0	7.00%

Table 1 shows electricity generation and its market value for GCD.

44 http://www.eia.gov/electricity/wholesale/
45 All prices are in 2012 dollars.

Energy prices are highly variable over long time scales. To determine if our time scale is representative of long term power generation, we analyzed the water input into Lake Powell based on total winter and summer precipitation over the Upper Colorado River Basin. We collected data from 106 Snow Telemetry (SNOTEL[46]) sites within the Upper Colorado River Basin with continuous records between WY1981 and WY2014 and calculated both the average snowpack levels (measured in Snow Water Equivalent (SWE)) as well as the total annual precipitation across all 106 SNOTEL sites for each water year. We also calculated the five year average snowpack levels and total precipitation and compared the 5 year average across the 106 sites to the 30 year average for those sites (WY1981-WY2010). The results of our analysis (Figure 2) reveal that during WY2011, the Upper Colorado River basin received 42% more snowfall and 24% more total precipitation than the 5 year average. This above average precipitation led to a 50 ft. increase in Lake Powell pond elevation. Because of the increased input of precipitation into Lake Powell during WY2011, there was a corresponding increase in the amount of water that went through the power generating facility at the Glen Canyon Dam. The 2007 ROD clearly defines the rules of equalization between Lake Powell and Lake Mead. Because Lake Powell's elevation went up dramatically, Lake Powell was obligated to release large volumes of water to balance the water budget between Lake Powell and Lake Mead.

According to the 2007 ROD:[47]

> "…equalization or balancing of storage in Lake Powell and Lake Mead shall be achieved as nearly as is practicable by the end of each Water Year."

Therefore the high input to Lake Powel led to more water being released through the generators at GCD, creating more electricity and a higher annual market value for WY2011.[48] Figure 2 shows that the average snowfall and precipitation from WY2010 to WY2014 is very close to the 30 year average across the Upper Colorado Basin. This indicates that, although the water input to Lake Powell in WY2011 is significantly higher than the other four years included in this analysis, the average precipitation from WY2010 to WY2014 is representative of historical values. Thus, under current operating restrictions and electricity prices, the market value of GCD electric energy ($153.3

[46] SNOTEL data is used here because snowpack and precipitation data, unlike gauged stream flow data, is representative of the entire basin including ungauged streams. It is also the data source for planned release of water. Data source: Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/snow/

[47] Record of Decision Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead, (2007).

[48] Except in unusually circumstances, all water releases from GCD pass through the generators. In some of the "experiments" with managing sedimentation in the Grand Canyon or unusually high water inflows water can be "dumped" without passing through the generators.

million per year[49]) calculated herein is an appropriate annual value for near-term historical valuation of the electric energy generation at GCD.[50]

Figure 2.

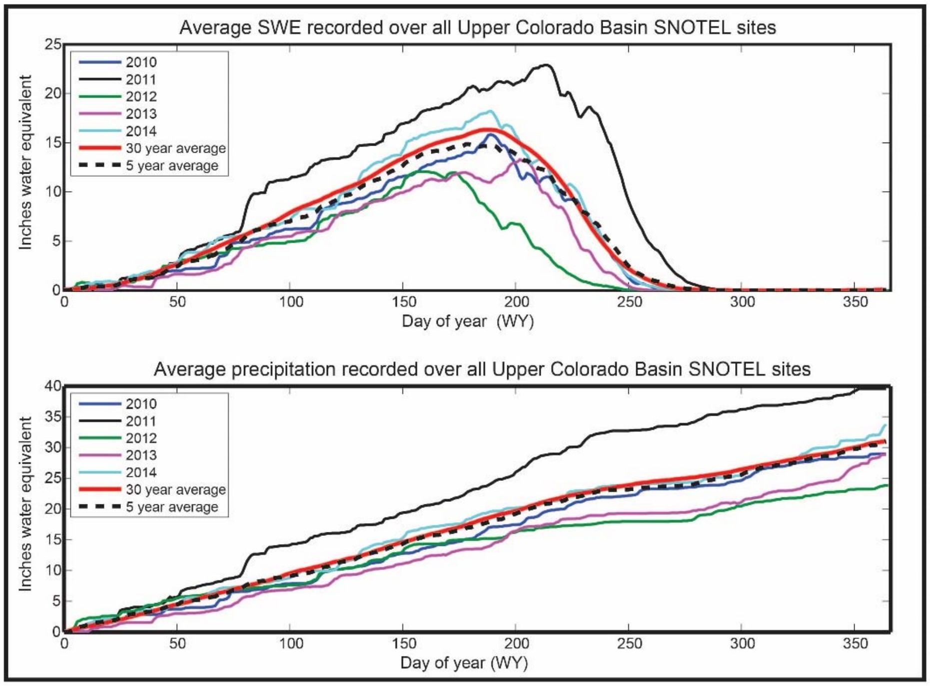

Figure 2 shows the average SWE and total precipitation for all SNOTEL sites in the Upper Colorado Basin for WY2010 – WY2014. Note that the 5 year average SWE and precipitation values closely follow the 30 year average. Both plots show inches of water versus day of year (DOY) where DOY equal to 1 is on October 1st.

a. The Net Cost of the Electric Energy Lost If Generation at GCD Ceases

We have valued the electric energy produced by GCD using the market value of that electricity, hour-by-hour, at the Palo Verde electricity trading hub. However, if electric generation were to cease at GCD, the variable costs associated with generating that electricity at GCD would also be avoided. The cost of not having GCD available to

[49] The range of values calculated from daily high and low prices are: $157.4 M to $147.0 M, respectively. This is less than a 6.6% total variation in the calculation. Official definition of the low, high, and weighted average daily prices used in the calculations herein can be obtained on the U.S. Energy Information Administration website: http://www.eia.gov/electricity/wholesale/ (accessed 1/2/2015).

[50] It is also important to note that if water year 2011 had been average, the five year average input into the upper basin would be below the 30 year average. It is also important to note that electricity prices have been relatively low recently. Given the rise in natural gas fired electricity partly due to the recent glut of natural gas on the market and the past volatility in natural gas prices, we do not pretend to know the future prices for electricity. We are merely trying to show that this value is close to the 30 year average for precipitation in the basin and is valued at current electric prices.

produce electric energy is the cost *advantage* that GCD had in producing electricity. The primary economic advantage of a hydroelectric resource is its zero fuel costs. The potential energy associated with the vertical “head” created by the dam provides the “fuel.” The use of the generators to produce electric energy, however, has some costs associated with it. The variable *operation and maintenance* (O&M) costs associated with that generation are what can be avoided if electric generation at GCD is abandoned.

As mentioned above, the electricity produced at GCD is marketed by Western. GCD is one of several electric generation facilities grouped within the Salt Lake City Area-Integrated Project (SLCA/IP). Western calculates the electricity that customers pay for that whole group of projects. In preparation for a rate adjustment in 2010, Western calculated the annual costs associated with those generating facilities. The annual O&M costs incurred by BOR, the operator of the hydroelectric facilities, were estimated to be $29.6 million going forward. Some of the electricity sold to Western customers, however, came from purchasing power from other generators. In addition, Western made money on some of its market electricity sales to other utilities. When these costs and revenues associated with the SLC/IP are summed up they come to $30.9 million. The annual energy sales from SLC/IP were projected to be 5.17 million MWh over the rate case study period. That is, the electric generating O&M costs associated with GCD and the other electric generating facilities that are part of SLC/IP came to $5.97 per MWh.[51] Table 2 below summarizes this calculation.[52] With the annual O&M costs in mind, the five year weighted average value of the energy from GCD of $153.3 million per year, is a conservative estimate.

Table 2.

Electric Generation Costs for Rate Making: Sal Lake City Area-Integrated Project			
2007 FY, 2009 Work Plan for years 2009-2025			
Bureau of Reclamation Hydro O&M	$	29,611,000	Cost of operating the hydroelectric units
Energy Sales (MWH)	$	5,170,879	This is an avg. of 2009-2025. It includes purchase/sales
Cost per MWH	$	5.73	This needs to be adjusted for net costs of purchase/sales
Purchased Power Costs	$	8,866,000	
Offsetting Rev: Merchant Function	$	(7,620,000)	
Net Impact of Purchased Power	$	1,246,000	
Total Energy Costs with Purchase/Sale	$	30,857,000	
Generation/Purchase/Sale Cost per MWH	$	5.97	
Source: Brochure for the Proposed Rates: SLCA/IP Firm Power, Western Area Power Administration, January 2008			

[51] Some of these O&M costs are likely to be “fixed” in the sense that they do not vary with the level of generation, i.e. some maintenance activities on the dam are undertaken whether or not electricity is generated. In that sense the $5.97/MWh is an overestimate of the variable costs of generation. Only Bureau of Reclamation O&M costs are included because the Western costs are associated not with generation but with operating the transmission grid that allows it to move the electricity to customers. Sources: “Brochure for Proposed Rates: SLCA/IP Firm Power, CRSP Transmission, and Ancillary Service Rates, “Western Area Power Administration, January 2008, Table 3, p. 5. http://www.wapa.gov/crsp/ratescrsp/documents/ratebrochureFY2009forediting.pdf

[52] Glen Canyon Dam dominates the set of the 11 hydroelectric generating facilities managed together as the Salt Lake City Area Integrated Project. GCD’s design capacity is 1,320 MW or 73 percent of the total of 1,819 MW in the entire integrated projects. The O&M costs we have calculated are for all 11 of the hydroelectric projects, not just for GCD. However, they primarily reflect the costs associated with GCD.

Table 2 shows the electric generating O&M costs associated with GCD and the other electric generating facilities that are part of SLC/IP.

3. The Value of the Electric Capacity Provided by the Glen Canyon Dam

At the time of system peak demand, the utility has to have access to a combination of electric generators that together are able to meet that peak demand, the timing and size of which is uncertain. In addition, the utility needs to maintain a reasonable reserve of electric generation capacity to deal with unexpected contingencies such as generator failure or unexpectedly high demand.

Depending on the amount of under-utilized or unutilized capacity connected to the grid, the cost of providing the needed capacity can be very low or quite high. The *maximum* long run cost of additional capacity is the cost associated with building a generating facility that is intended solely to provide capacity to keep demand and supply in balance at time of peak load. Typically that would be a natural-gas-fueled simple cycle combustion turbine (SCCT). That technology has the lowest investment cost and fixed operation and maintenance costs. A SCCT is also thermally one of the least efficient technologies for producing electric energy, burning more fuel than other generation technologies to produce a given amount of electric energy. In addition, natural gas prices have been volatile in the past, potentially making the per unit fuel costs for a SCCT relatively high. As a result, the cost of electric *energy* from a SCCT could be quite high.

If the SCCT is expected to operate only for a few hundred hours a year, those high energy costs may be acceptable. If the facility is expected to operate for a substantial portion of the year as a source of off-peak electric *energy* as well as *capacity*, then a technology with somewhat higher fixed costs but lower operating cost may be more economic. For instance, a natural-gas-fueled combined cycle combustion turbine (CCCT) that uses the waste heat from a combustion turbine to make steam and turn an additional generator may be more economic. The higher fixed cost of the CCCT, however, would have been incurred not to provide more electric capacity but to reduce the fuel costs of operating it to produce electric energy over extended periods of time, and those higher fixed costs should be considered energy, not capacity, costs.

a. Western and BOR Estimates of the Value of GCD Electric Capacity

The actual incremental cost of additional electric capacity depends on the portfolio of electric generators already connected to the regional grid as well as the characteristics of the electric load on that electric delivery system. Only by modeling the addition of different generating units to that system and the economic dispatch of that fleet of generators to meet expected loads can the incremental cost of capacity be determined. However, the upper limit of that capacity cost can be approximated by using the fixed costs associated with adding a SCCT to the system.

This is the approach that the Western used to develop an estimated cost of additional electric capacity on its system. [53] The BOR adopted that incremental capacity cost to value the electric capacity provided by the generators at the Glen Canyon Dam (GCD) in 2007.[54] The BOR and Western, however, characterized the source of this estimated value of electric capacity differently. The BOR described the estimated capacity value as "based upon the alternative market cost of capacity."[55] Western, however, was more explicit: "For valuing capacity, Western obtained a cost of constructing a new combined cycle [combustion turbine] natural gas power plant. That capacity was valued at the cost of replacing that GCD capacity at the cost incurred by some SLCA/IP customer utilities who had recently constructed facilities that provide load following capacity. These electric generator construction costs were collected in order to get information regarding the construction cost per megawatt of a recently built facility that provided electric services similar to the GCD power plant."[56]

Western's statement that its estimate of the value of electric capacity was based on the "market cost of capacity," might be interpreted to suggest that there was an active market for electric capacity just as there is for electric energy at, for instance, the Palo Verde hub and many other electric markets across the United States. But, in general, that is not the case. As the actual approach that Western took to estimate the value of electric capacity indicates, electric utilities typically invest in building their own electric generating facilities to provide the capacity they need or enter into bilateral long run power purchase agreements with another utility to obtain that capacity.

Despite the differences in the description of the source of the estimated value of electric capacity, both BOR and Western report a capacity value of $6.32 per kilowatt month in 2007 dollars.[57] In 2010, Argonne National Laboratory (Argonne) estimated the economic cost associated with various operational restrictions at Glen Canyon Dam for Western.[58] Among the costs associated with those operational restrictions was the loss of electric capacity at GCD. Argonne drew on the previous work done by Western in the Shortage Criteria EIS discussed above to obtain this value. Argonne expressed that value of capacity in 2009 dollars as $6.90 per kW mo.[59]

Western, while presenting these estimates of the value of the electric capacity GCD provided, pointed out that "[t]his value is higher than the average cost of capacity from existing facilities on the system…" This higher value was used because "[o]ver the 53-year study period, available capacity from existing sources will not be adequate to serve

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[53] "Analysis of Power and Energy Impacts to Glen Canyon Dam, Shortage Criteria EIS," S. Clayton Palmer, et al., July 30, 2007 Update for FEIS, prepared for the Bureau of Reclamation. Appendix O to the Shortage Criteria EIS.
[54] Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lakes Powell and Mead, Final Environmental Impact Statement, November 2007, p. 4-253.
[55] Op. cit. Colorado River Interim Guidelines, November 2007, p. 4-523.
[56] Op. cit. Appendix O, Shortage Criteria EIS, pp. O-16-17.
[57] Ibid
[58] "Ex Post Power Economic analysis of Record of Decision Operational Restrictions at Glen Canyon Dam," T.D. Veselka, et al, ANL/DIS-10-6, July 2010.
[59] Ibid. p. 63. That shift from 2007 to 2009 dollars raised the estimated value of capacity by about 9 percent

growing loads." [60] That is, Western was taking a relatively conservative long-run future view, rather than focusing on what the value of electric capacity was currently in the region served by GCD.

Western's decision to use the construction costs of a combined cycle instead of a simple cycle combustion turbine is questionable if it is just the cost of capacity that is being estimated. Using the costs "of a recently built facility that provides electric services similar to the GCD power plant" is appropriate only if you are trying to estimate the costs of all of the electric services a particular generator can provide, not just one: electric capacity. GCD also produces electric energy at very low cost as well as ancillary services such as minute-by-minute regulation and load following. What is relevant to valuing the capacity of GCD is only the portion of the costs associated solely with the electric capacity GCD provides.

Typically, increased investment costs are incurred to improve the efficiency with which fuel is used to produce electric energy. A SCCT has quite low fixed costs but higher energy (fuel) costs. A CCCT involves significantly higher fixed investment costs but significantly reduces the per-unit cost of the electric energy that is obtained from the combustion of the natural gas. A coal-fired generator faces still higher fixed investment costs so that it can burn what is typically a much lower cost fuel. But coal-fired electric generators cannot be quickly cycled up and down without reducing their efficiency and increasing the annual maintenance costs or shortening the life of the units. Hydroelectric facilities often incur very high fixed investment costs in order to eliminate the need to purchase fuel altogether. Clearly there is a tradeoff between high fixed investment costs and the variable costs of generation. Some of the fixed costs are incurred to reduce fuel costs and need to be considered energy-related, not capacity-related, because lower fuel costs were part of the economic logic of incurring those additional fixed costs. Table 3 below shows this pattern of levelized fixed costs per MWh of generation and variable energy costs moving in opposite directions as one shifts from more fuel efficient to less fuel efficient generating technologies.

Table 3.

Levelized Cost per MWH of Generation over Plant Life				
Plant Type	Capital Cost	Fixed O&M	Total Fixed Costs	Variable O&M Including Fuel
Conventional Coal	$60.00	$4.20	$64.20	$30.30
Advanced NG Combined Cycle	$16.07	$2.05	$18.12	$45.50
Advanced NG Combustion Turbine	$9.64	$0.95	$10.59	$70.30

Source: US EIA Average Levelized Cost of Energy, 2012 $/MWh for plants entering service in 2019 Annual Energy Outlook 2014. Modified to show fixed cost values using identical capacity factors.

Table 3 looks at the levelized cost per MWh of generation over the life of different electric generating plants.

[60] Op. Cit. Appendix O, BOR 2007 Shortage Criteria EIS, p. O-17.

b. A Contemporary Estimate of the Value of Electric Capacity

The levelized cost of alternative electric generation technologies provided by the Energy Information Agency of the U.S. Department of Energy in its development of the *2014 Annual Energy Outlook*[61] can be used to provide an estimate of the upper limit of the electric capacity value of GCD using contemporary costs associated with a natural gas simple-cycle combustion turbine. The EIA levelized costs were stated on the basis of levelized costs *per MWh* of electric generation. We have converted the fixed costs of the Advanced Natural Gas Combustion Turbine (fixed investment cost and fixed O&M costs) from a *MWh* base to a *kW* basis using the EIA's assumed capacity factor for the combustion turbine.[62] This was then converted to a kW month basis for comparison with the Western estimate of the capacity value of GCD by dividing by 12 months. The resulting value of electric capacity is $6.57 per kW month in 2012 dollars for a SCCT generating plant constructed in 2019. See Table 4. Note that this cost per kW month is close to the BOR and Western cost of $6.32 per kW month discussed above.

Table 4.

Calculation of "Capacity Cost" Using Fixed Costs of Advanced CT "Capacity Cost" is the Fixed capital O&M costs per kW-mo of capacity			
Levelized Fixed Capital Cost	$/MWh	$	27.30
Levelized Fixed O&M Cost	$/MWh	$	2.70
Total Levelized Fixed Costs	$/MWh	$	30.00
MWH used by EIA levelized $/MWH calculation	MWh		2,628
Fixed Costs per MW-yr	$	$	78,840
Fixed Costs per kW-yr	$	$	78.84
Fixed Costs per kW-mo Capacity	**$/kW-mo**	**$**	**6.57**

Cost of installation in 2019 stated in 2012$s

Source: US EIA Average Levelized Cost of Energy for plants entering service in 2019.

Table 4 shows the upper limit of the fixed cost of capacity.

c. The Electric Capacity of GCD under Current Operating Restrictions

This estimated value of capacity needs to be applied to the electric generating capacity of the GCD. The original total sustained operating capacity (nameplate capacity) of GCD was 1,320 MW.[63] This was the generating capacity of all of the generators when Lake Powell was at full pool and there were no limitations on the rate at which water could be discharged through the turbines and there were no limitations on the rate at which generation could be ramped up or down. That is, the GDC capacity measure of 1,320 MW assumed there were no constraints on the operation of the GCD electric generators

[61] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014. Release date: April 17, 2014. http://www.eia.gov/forecasts/aeo/electricity_generation.cfm
[62] The capacity factor was used to convert this levelized cost per MWh to simply the annual levelized fixed costs per MW of capacity. These then were divided by the months in the year to get those levelized costs expressed in terms of megawatt months.
[63] The instantaneous maximum output was about 1,356 MW. Ex Post Power Economic Analysis of Record of Decision Operational Restrictions at Glen Canyon Dam, Argonne National Laboratory, ANL/DIS-10-6, T.D. Veselka et al. July 2010, p. 2.

to avoid environmental damage such as physical and biological impacts on riverine systems downstream on the Colorado River including Grand Canyon National Park. Also, of course, Lake Powell would have to be at full pool and the water inflows would have to be sufficient to maintain this level of discharge through the turbines across the peak periods.

In the early 1990s there were increasing environmental concerns about the impact of water releases at GCD when those water releases were guided only by water delivery commitments and the market value of electricity. Those concerns led to the first environmental limitations on GCD water releases. In 1992 the Grand Canyon Protection Act was passed by the U.S. Congress. It mandated consideration of the impacts of GCD water releases "on the values for which Grand Canyon National Park and Glen Canyon National Recreation Areas were established, including, but not limited to natural and cultural resources and visitor use."[64] The Department of Interior was mandated to prepare an Environmental Impact Statement on the operation of GCD and alternative water release restrictions. Based on the findings, conclusions, and recommendations made in that study, new criteria and plans for the operation of GCD were to be adopted. The Record of Decision from that GCD environmental impact analysis was issued in 1996 and a flow restriction regime was adopted in 1997 that limited both the operational range of water releases and the rate that water releases were permitted to change over time.[65]

These limitations of daily water releases and the ramping up and down of water releases significantly reduced the ability of GCD to follow loads and meet peak demands. That is, it reduced the electric capacity of GCD. As an Argonne study of the impact of those operating restrictions between 1997 and 2005 put it:[66]

> The operational restrictions affect the economic benefits of the hydropower resource in two ways. First, the loss of operable capability must eventually be replaced. Second, the hydropower energy cannot be used to its fullest extent to reduce the need for generation from expensive peaking units. Maximum flow restrictions reduce Glen Canyon's operating capacity by approximately 36%, and ramp rate limitations decrease [Western's] ability to follow firm loads.

That analysis isolated the impact of the restrictions on GCD water releases on the electric energy and electric capacity values associated with those releases. For the 2000-2005 period, the average annual reduction in capacity at GCD was about 385 MW, worth about $32 million per year when the capacity is valued at $82.80 per kW year in 2009 dollars.[67] The implied full capacity of GCD without any restrictions on water releases but actual reservoir levels and water flows was 1,069 MW. With the 1996 Record of Decision restrictions on the operation of GCD in place, its capacity level averaged 684 MW over the 1997-2005 period.[68] That is the source of the 36 percent

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[64] Grand Canyon Protection Act of 1992, Section 1802(a).
[65] Ibid.
[66] Ibid, p. 19
[67] Ibid. Comparison of Figures 4.47 and 4.46 and valuation at $82.80 per kW year (p. 63).
[68] Ibid. Author's calculation.

reduction in capacity mentioned above. That 684 MW of electric capacity at GCD with the current restrictions on water releases is only about half of the 1,320 MW of "sustainable" electric capacity if there were no restrictions on the operation of GCD and the reservoir was at full pool.

In 2007, Western released long-run estimates of the generating capacity of the GCD across a study period from 2008 through 2060.[69] The estimated GCD capacity included all of the restriction placed on the operation of the dam as of 2007. Based on the pattern of hourly spot market prices as of 2004 and using water flows from 100 past water years, Western calculated the water release pattern that maximized the economic value of the electric output, subject to all the constraints of GCD operations. The mean capacity of GCD was estimated in that study to be 606 MW. The median capacity was 546 MW. The estimated GCD capacity ranged from 451 MW (low water years such as the recent past, 90 percent historical exceedance) to 839 MW (high water years, 10 percent historical exceedance).[70]

d. The Economic Value of the GCD Electric Capacity

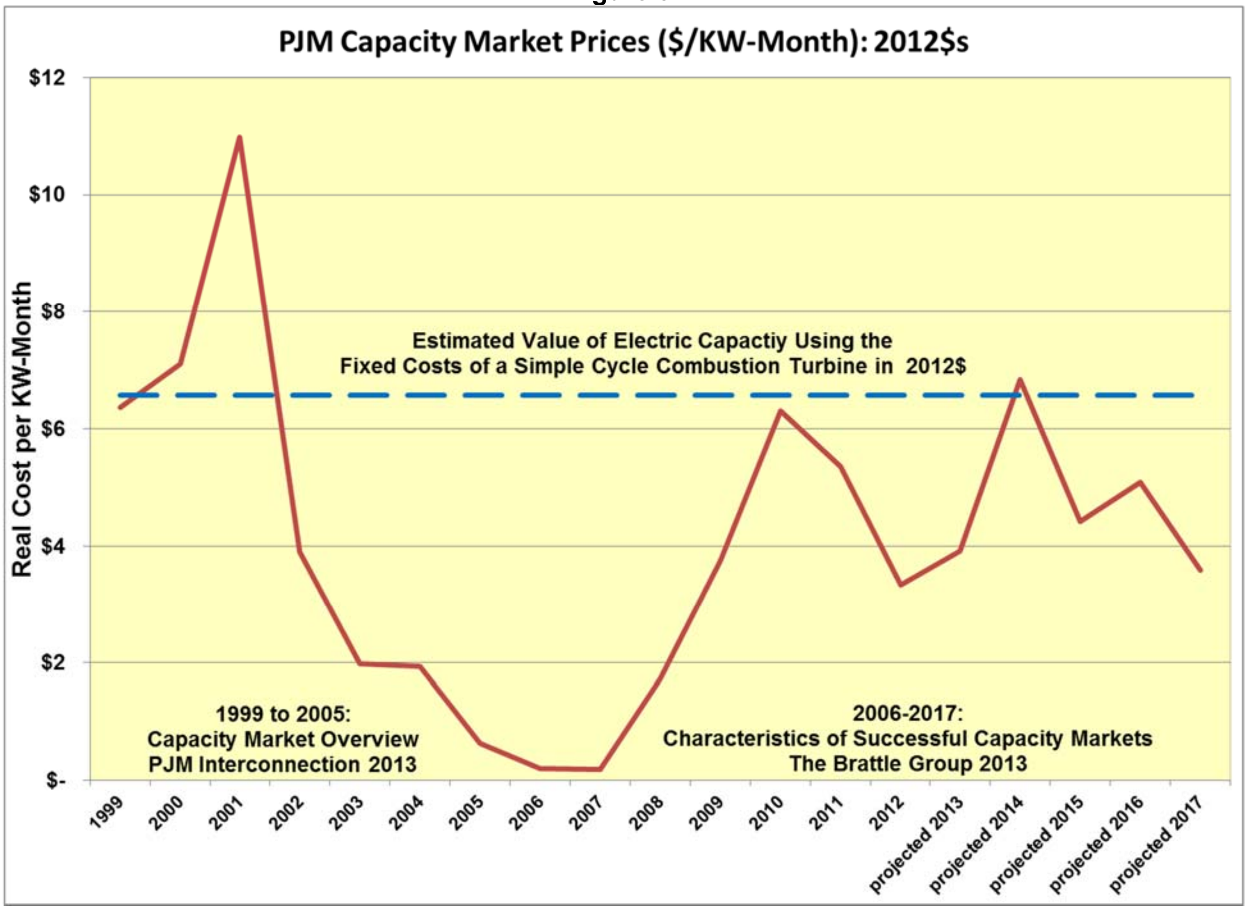
In the near term, the economic loss associated with GCD electric capacity not being available would be relatively low because there is significant excess electric capacity available in the region (WECC). When supply exceeds demand one can expect competitive electric markets to drive the value of electric capacity down well below its replacement cost. That can be seen in the PJM Interconnection capacity market. PJM is the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in parts of 13 states from North Carolina to Pennsylvania and from Pennsylvania to northern Illinois. PJM has operated a capacity market for its member utilities since 1999. At times the market value of electric capacity has been at or above our replacement cost estimate of about $79 per kW-year or about $6.60 per kW month. For many other years, excess capacity on the interconnected systems reduced the market value of capacity to near zero. In more recent years and in the projected near future, the market value of capacity has fluctuated between a value close to our estimated replacement cost and a value about half the replacement cost that we have estimated. See Figure 3 below.

In the longer term, as discussed above, the economic loss associated with the GCD electric capacity not being available may be as high as the levelized cost of building a natural gas fueled combustion turbine. Such a generator is unlikely to actually be built because a CCCT would provide the same ability to meet peak demands and follow loads while also providing electric energy at a lower cost because of a CCCT's higher fuel efficiency. Most of the projected fossil-fuel-burning electric generation planned or under construction in the region will be CCCTs. These generators can be operated as base-load generators providing electric energy throughout much of the year. They can

[69] "Analysis of Power and Energy Impacts of Glen Canyon Dam," Shortage Criteria FEIS, July 30, 2007. WAPA carried out the study for the BOR. It became Appendix O of the Shortage FEIS.
[70] Ibid. Table 7, no action alternative.

also ramp up and down relatively quickly to follow load, just as GCD was able to do before water release restrictions were imposed on it to protect other river values.

Figure 3.



Sources: "PJM Capacity Market Overview," Andrew Ott, PJM Senior Vice President, February 26, 2013, Long-Term Resource Adequacy Summit, p.3. http://www.caiso.com/Documents/Presentation-AndyOtt_PJM.pdf ; "Characteristics of Successful Capacity Markets,", J. Pfeifenberger and K. Spees, The Brattle Group, APEx Conference 2013, October 31, 2013, p. 20.
http://www.brattle.com/system/publications/pdfs/000/004/951/original/Characteristics_of_Successful_Capacity_Markets_Pfeifenberger_Spees_Oct_2013.pdf?1383246105
Nominal prices were converted to real 2012$ using the Producers Price Index.
Figure 3 shows the SCCT fixed costs for an online date of 2019 stated in 2012 dollars. See Table 3 above for more detail.

It is possible that in the future, in the pursuit of an optimal portfolio of electric generating facilities, the WECC region could continue to have generating capacity in excess of what is necessary to meet peak load and satisfy prudent reserve requirements, just as it does today. The continuing development of renewable resources for their energy output, in particular, could lead to installed capacity well above that needed purely for reliability. If that is the case, the economic loss associated with not having the electric capacity of

GCD available will remain low.[71] Facilities simply dedicated to meeting peak load while providing little electric energy may not be needed. On the other hand, as more and more intermittent renewable resources are added to the electric system, more firm electric capacity may have to be added to support those intermittent resources, and the cost of electric capacity might rise towards the levelized construction cost of a simple cycle combustion turbine. It is unclear at this point in the ongoing changes in the regional electric system exactly what the future cost of electric capacity is likely to be.

As discussed above, the *maximum* cost of ultimately replacing the electric capacity provided by GCD can be estimated using the levelized cost of constructing an electric generator that would only provide electric power at the time of peak demand. That would be the fixed costs associated with a natural gas fueled simple cycle combustion turbine. Table 3 above provided the Energy Information Administration's estimate of those costs in 2012 dollars: $6.57 per kW month or $78.84 per kW-yr. This capacity cost is consistent with electric capacity values that both Western and BOR have used for the value of GCD's electric capacity.

Also above we have discussed Western's long run estimates of the electric capacity that GCD can provide given the restrictions that have been placed on maximum and minimum water releases and maximum rates of change in those water releases to protect other river values. The mean capacity estimated for GCD was 606 MW.[72] The *maximum* annual value of that capacity *if and when* the region moves beyond its current surplus electric capacity status and becomes capacity constrained would be $47.8 million per year in 2012 dollars.

III. The Impact on the Regional Grid of Losing GCD Electric Generation

To put this assessment of the economic value of GCD in context, we compared the average electric generation from GCD to the rest of the region within the United States covered by WECC. The WECC covers Oregon, Washington, Nevada, Idaho, Arizona, Utah, Colorado, Wyoming, British Colombia, and Alberta; most of Montana and New Mexico; as well as parts of South Dakota, Texas and northern Baja California. There are two Census regions that encompass most of the WECC area within the contiguous United States, the Mountain and contiguous Pacific regions which together include 11 states: Washington, Oregon, California, Idaho, Nevada, Arizona, Utah, Montana,

[71] Electric systems can be energy constrained rather than capacity constrained. For instance, an electric system that had large quantities of hydroelectric generation with significant storage may have substantial generation capacity, in excess of its average energy production, so that during seasons of high water flow more of the water can be run through the generators. That could make the system capacity surplus, primarily constrained by the electric energy associated with annual water flows.

[72] This ignores the potential increased generating capacity at Hoover Dam due to the increase in the storage function of that hydroelectric facility due to the elimination of storage at GCD. In addition, there may be less water lost due to evaporation with the elimination of storage behind GCD, also boosting the vertical depth of Lake Mead storage. Any such increases in capacity at Hoover Dam would reduce the economic cost associated with eliminating generation at GCD.

Wyoming, Colorado, and New Mexico. This is essentially the WECC without Mexico and Canada, which for our purposes is a more helpful regional area to use for comparison. In 2012 (the most recent year of available data), there were over 26.6 million households in the Mountain and contiguous Pacific regions each using an average of 8.982 MWh of electricity, resulting in a total residential consumption of more than 239 million MWh annually,[73] which is about 17% of the national electricity consumption for 2012.[74] Over the five water years examined herein, GCD produced 4.08 million MWh annually, which is roughly enough electricity to power 455,000 homes for one year (1.71% of the households in the Mountain and contiguous Pacific regions).

1. The Size of the Impact on the Regional Grid

The revenue from retail sales of electricity in the Mountain and the contiguous Pacific census regions was $69.14 billion in 2010[75], $69.20 billion in 2011[76], and $69.30 billion in 2012.[77] This includes all transmission and service fees. Table 5 shows the 2012 retail electricity prices by service category[78] for the four WECC sub-regions[79] as well as the average of the values for the four sub-regions.[80] The percent of revenue from retail sales of electricity that are derived solely from the generation of electricity in the WECC region is an average of 45% of the total price of electricity. So, in 2012 revenue from generation of electricity in the Mountain and contiguous Pacific census regions was close to $31 billion. With respect to the overall electricity sales in the two census regions, the $153.3 million per year[81] market value associated with GCD electricity sales represents only 0.5 percent of the market value of electric generation in the Mountain and Pacific census regions. In other words, the region produces electric revenue about 200 times the market value of the energy that comes from GCD alone. If we add the *maximum* cost associated with replacing the electric capacity of GCD that is associated with peaking to the economic value of GCD ($47.8 million)[82], the value of GCD is still just 0.65 percent of the revenue generated in 2012 by electric generation in the Mountain and contiguous

[73] Based on electricity consumption data published by U.S. Energy Information Administration. Accessed on 1/12/2015 at: http://www.eia.gov/electricity/sales_revenue_price/xls/table5_a.xls
[74] Based on national electricity consumption data published by U.S. Energy Information Administration. Accessed on 1/28/2015 at: http://www.eia.gov/electricity/annual/xls/epa_01_02.xlsx
[75] In 2012 dollars
[76] In 2012 dollars
[77] This is the annual sum of Total Electric Industry revenue from states within the Mountain and contiguous Pacific census regions reported on EIA-861 form. Data downloaded from http://www.eia.gov/electricity/data/state/revenue_annual.xls on 2/6/2015.
[78] From the EIA Annual Energy Outlook for 2014 released on May 7, 2014, data downloaded on 2/11/15 from http://www.eia.gov/forecasts/aeo/data.cfm#enrenfuel
[79] Western Electricity Coordinating Council / Rockies, Western Electricity Coordinating Council / Northwest, Western Electricity Coordinating Council / California, and Western Electricity Coordinating Council / Southwest
[80] Weighted average based on total electricity sales and price for each sub-region
[81] Table 1, column 3 above.
[82] Page 18 above.

Pacific census regions. In this context, GCD electric generation has almost no impact on the revenue of the WECC electric grid as a whole.[83]

Table 5.

Prices by Service Category 2012 (cents per kWh)	WECC sub-region Rockies	Northwest	California	Southwest	All of WECC
Generation	5.35	2.99	5.27	6.25	4.67
Transmission	0.67	0.93	1.58	0.76	1.12
Distribution	3.29	3.57	6.68	2.77	4.59
Total Price	9.31	7.49	13.53	9.77	10.38
Electricity Sales (billion kWh)	60.53	227.02	252.07	120.88	660.5
Percent of Revenue from Generation	57.5	39.9	39	64	45

Table 5 shows the price of electricity by service category for WECC sub-regions and weighted average price for WECC. The prices are the weighted average price across all sectors (Residential, Commercial, Industrial, and Transportation).[84]

2. Grid stability without GCD

A central issue to this report is the relative importance of the power generation provided by GCD to the greater stability of the regional electric grid and the viability of supplementing the electricity lost in a scenario where Lake Powell is drained below a level where power production at GCD is possible. There are two aspects of power generation that are relevant to this issue: The ability to generate the electric energy over time that customers demand and the ability to always be ready to meet customer's peak power demands. To determine if it is possible to replace the electric energy generated by GCD from the current generators on the grid, we calculated the residual energy producing ability[85] of all of the power plants in the region for the most recent year for which data was available (2013). The absolute maximum amount of annual electric energy that can be produced by a single generator (potential electric output) is determined by the energy producing ability[86] of the generator across the year multiplied by the maximum annual capacity factor.[87] The capacity factor is a measure of the

[83] This, of course, is largely due to the huge size of the Western interconnected grid. GCD is the source of hundreds of millions of dollars worth of electricity. In the second phase of this project, we will focus on local impacts as opposed to broad regional impacts.
[84] Data from: http://www.eia.gov/beta/aeo/; Electric Power Projections by Electricity Market Module Region; Rockies, Northwest, California, and Southwest.
[85] Summer capacity minus the total annual electric generation adjusted for electric consumption required for power plant operation. See equation 1 below.
[86] The absolute maximum amount of electricity that the generator can produce during an hour of operation, summer and winter capacity, may be different. Summer capacity, since it is generally the more conservative of the two, is used herein.
[87] This is the percentage of time during a year that the generator can be run; this takes maintenance and wear into account. This is **not** the actual capacity factor for the generator, which is the time that the

percentage of the year that the generator can be expected to run. Electric generating facilities cannot run continuously throughout the year and must be ramped down at some point during the year to have regularly scheduled maintenance and other shut downs associated with how reliably each generating unit has performed in the past. Some generating facilities, like conventional combustion turbines, are simply too expensive to run all of the time due to their high fuel costs. Although they may be available to run much more often than they do, it would not make economic sense to run them as a base load electric generator. We are interested in the ability of the regional generating infrastructure to generate residual energy. Thus we use the potential electric output at summer nameplate capacity multiplied by the capacity factor for each generator, multiplied by the number of hours per year, and then subtract the actual net generation to calculate the residual energy potential (Equation 1).

$$\begin{aligned} &\mathit{Residual\ Energy\ Potential} \\ &\qquad = (\mathit{Summer\ Nameplate\ Capacity} * \mathit{Capacity\ Factor} * \mathit{hours\ in\ the\ year}) \\ &\qquad - \mathit{Actual\ Net\ Generation} \end{aligned}$$

In this region, there are 529 power plants that reported generating more than 1 MW of electricity in 2013 (Table 6 below).[88] This includes 133 natural gas power plants, 104 hydroelectric power plants (including GCD), 41 coal fired plants, 21 geothermal power plants, 3 nuclear plants, and 227 “other”[89] power plants (Figure 5). Of these 529 power plants, 53 generated more electricity in 2013 than GCD. This includes 19 coal fired power plants, 18 natural gas power plants, 12 hydroelectric plants, 3 nuclear plants, and one geothermal complex of plants (Table 7). Due to the dual base load and peaking capabilities of GCD, not all forms of electricity production are a viable option for replacing GCD electricity production. Substantially increased electric power generation will not come from existing nuclear plants which produced 100.5%[90] of their calculated potential summer capacity in 2013 (Table 7). Hydroelectric power generation facilities have limitations of power generation such as river flow restrictions as well as natural limits and inconsistencies in regional precipitation and pool elevation. With near zero variable generating cots, renewable generation is generally run as much as is physically feasible, and additional generation from *existing* renewable generators in response to GCD retirement could not reasonably be expected. Also, solar and wind generation are

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generator was actually run during a particular year. Capacity factor estimates (87% for a combined cycle plant) are from EIA forecast of potential energy generation: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[88] Data from U.S. Department of Energy, The Energy Information Administration (EIA), EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2013 December, http://www.eia.gov/electricity/data/eia923/, accessed on 1/15/2015.

[89] “other” power plants include Petroleum, Wind, Solar, Biomass, and Pumped Storage power plants.

[90] They are able to produce more than 100% for 2 possible reasons: (1) the summer capacity limits the amount of energy they can produce in the summer when the ambient temperature limits the generating capacity of the generator and (2) the maintenance downtime was less than the estimated capacity factor used by the EIA in We are choosing to use the summer capacity of the generators as a conservative estimate of total generating capacity.

highly variable and may need to be paired with power generation with high ramp rates to keep supply and demand in balance. Further, it is important to consider multiple sources of power generation as substitutes for GCD since the stability of the electric grid is partially dependent on diversity. With these limitations in mind, we analyzed all of the electric power plants within the Mountain and contiguous Pacific Regions to evaluate the potential for existing generators to replace the electric energy and capacity currently being provided by GCD.

Table 6.[91]

Plant Type	Number of Plants	Total Generation 2013 (million MWh)	Available Energy Potential[92] (million MWh)	Residual Energy Potential 2013 (million MWh)	Percent of Total Generation 2013
Nuclear[93]	3	57.9	57.6	-0.3	100.5
Hydro	104	137.2	195.2	58	70.3
Coal	41	206.8	239.6	327.5	86.3
Natural Gas - total	133	199.2	426.9	227.7	46.7
Natural Gas - Combined Cycle	85	178.9	373.8	194.8	47.9
Geothermal	21	10.2	13.9	3.6	73.8
Other[94]	227	56.2	68.6	12.4	81.9
Total	529	667.5	1001.7	334.2	66.6

Table 6 shows 2013 electric generation data for all Pacific Contiguous and Mountain census regions power plants. Summer Capacity is meant to show a year round value for a conservative maximum output of the plant. All values are rounded to nearest decimal place, thus there are apparent rounding errors.

Table 7.

[91] Data from U.S. Department of Energy, The Energy Information Administration (EIA), EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2013 December, http://www.eia.gov/electricity/data/eia923/, accessed on 1/15/2015.

[92] Available energy potential is the summed summer capacity for each plant multiplied by the potential capacity factor for main generator type (prime mover) for each power plant. Summer capacity from EIA-860 Data (2012) accessed at: http://www.eia.gov/electricity/data/eia860/index.html accessed on 1/15/2015. The potential capacity factor for main generator type from: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm accessed on 1/28/2015.

[93] Nuclear power plants in this region are all operating above the potential capacity factor listed at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm accessed on 1/28/15.

[94] Including electrical production form solar, wind, biomass, pumped storage, and 'other'

Plant Type	Number of Plants	Total Generation 2013 (million MWh)	Available Summer Capacity (million MWh)	Residual Capacity 2013 (million MWh)	Percent of Capacity 2013
Nuclear	3	57.9	57.6	-0.3	100.5
Hydro	12	86.9	105.7	18.8	82.2
Coal	19	173.8	192.6	18.8	90.2
Natural Gas	18	80.6	131.4	50.7	61.4
Geothermal	1	4.8	6.2	1.4	77.1
Total	53	404	493.5	89.4	81.9

Table 7 shows 2013 electric generation data for Pacific Contiguous and Mountain census regions power plants that produced more electricity than GCD in 2013. All values are rounded to nearest decimal place, thus there are apparent rounding errors.[95]

Figure 4.

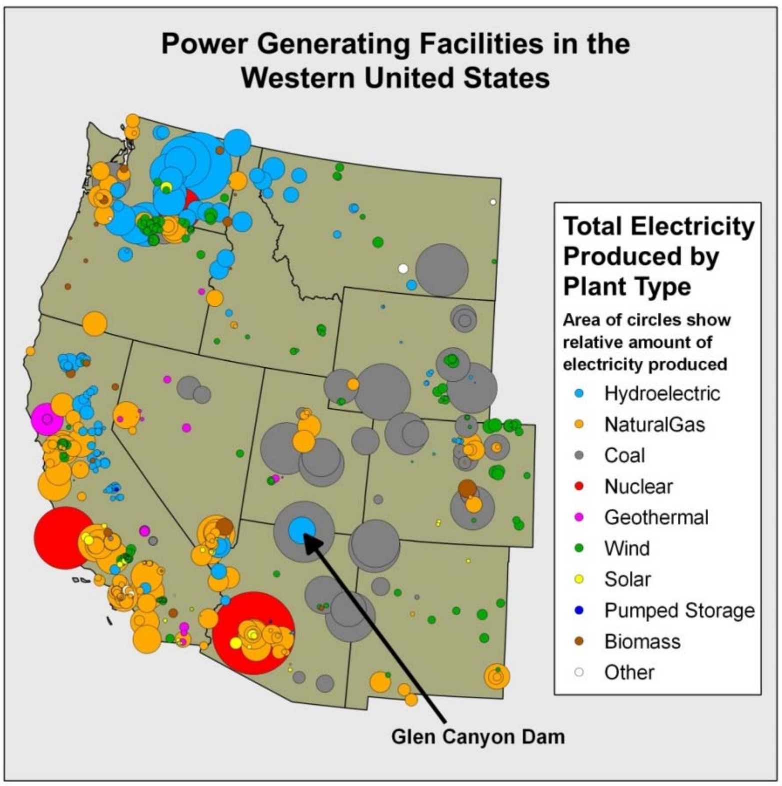

Figure 4 shows power plants in the Pacific Contiguous and Mountain census regions. Area of circles show relative electricity generated in 2013.[96]

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[95] Data from U.S. Department of Energy, The Energy Information Administration (EIA), EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2013 December, http://www.eia.gov/electricity/data/eia923/ , accessed on 1/15/2015

[96] Data from U.S. Department of Energy, The Energy Information Administration (EIA), EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2013 December,

a. Coal fired power plants

Despite its high environmental cost, coal is a stable source of electricity that could be used to supplement part or all of the base load generation of GCD by running those existing plants more hours of the year. The total annual residual energy potential of the 41 coal-fired power plants in 2013 was over 32 million megawatt hours, or over 7.8 times the average power production of GCD. If we look only at the 19 coal fired power plants in the region that produced more electricity than GCD in 2013, we find that they ran at 90.2% of the potential electric output in 2013; a 2.2% increase would provide enough electricity to compensate for GCD electricity and still allow for a 7% (13.5 million MWh) margin of available electricity generation from coal-fired power plants. Even though the existing coal-fired power plants would be able to supply enough base load electricity to make up for GCD, with long start-up times and slow ramp rates, coal fired power plants do not make good peaking facilities; other sources of electricity must be used to accommodate the peaking generation of GCD. Coal-fired generation also has significant emissions problems that may make more intensive use of these plants problematic.

b. Natural gas power plants

Recall that there are two main types of natural gas fired power plants, (1) SCCT and (2) CCCT. There are 133 natural gas fired electric power plants in the region with a combined residual energy potential of more than 225 million MWh in 2013, or 55 times the annual power generation of GCD. This estimate includes both SCCT and CCCT generators. Both of these technologies can be started quickly to accommodate peaking, however SCCT generators have low energy conversion efficiencies (20% - 35%),[97] low capacity factors (30%),[98] and are not suitable for baseload electric generation. Because of their low energy conversion efficiencies the SCCT are not suitable for base load generation because the fuel costs are simply too high for them to be run except for peaking purposes. CCCT generators, on the other hand, have a potential capacity factor of 87%[99] and can be used as both base-load generators as well as peaking facilities, therefore the residual energy potential of combined cycle generators is a more appropriate substitute for GCD electricity generation. The 2013 annual residual energy potential from natural gas fired combined cycle generators alone was more than 190 million MWh, or 46 times the annual power generation of GCD.

c. Total residual energy potential from all power generation sources

Our calculations show that there was more than 222 million MWh of potentially available residual energy potential from coal and CCCT power plants in the Pacific Contiguous

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http://www.eia.gov/electricity/data/eia923/, accessed on 1/15/2015 and Power Plant shape file downloaded from http://www.eia.gov/maps/layer_info-m.cfm on 1/10/2015

[97] http://energy.gov/fe/how-gas-turbine-power-plants-work

[98] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm accessed on 1/28/2015.

[99] Ibid

and Mountain census regions in 2013. This is over 33% of the total electricity produced from all sources in the region. With this potential electric output it is certainly possible to currently replace all of the base load power generation expected from GCD without having to build any new electric generating facilities. This analysis, however, only takes into account the annual average electric output of generators and does not take into account single peaking events which may require a larger percentage of generators to run at nameplate capacity during a peaking event.

3. Electric Capacity Balance on the Western Regional Grid

To this point, we have examined the average electric generation over a year and have reported electric production and consumption as total MWh. Recall that the ability of an electric generator to contribute to meeting uncertain peak demand is its electric *capacity* and is measured in kilowatts (kW) or megawatts (MW). The unused, available capacity on the grid is called the resource reserve margin. WECC forecasts of anticipated resource reserve margin[100] (ARRM) between 2015 and 2024 show that there will be an annual reserve margin of at least 33,855 MW each year (Table 8). The range of anticipated summer resource reserve margin stated in the WECC report is 20.00%-31.11% for 2024 and 2016, respectively. This range of resource reserve margins is significantly higher than the 14.7% Building Block reserve margin (BBM) reported in the 2014 WECC Power Supply Assessment. The BBM considers contingency reserves, regulating reserves, additional forced outages reserves, and temperature adders.[101] This reserve margin, then, is the metric that WECC uses in assessing the minimum reserves for the regional power grid; anything below the BBM is considered deficient, anything above the BBM is considered surplus.

Table 8.

WECC: Class 3 – Demand and Capacity - Summer	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated Capacity Resources (MW)	196,453	199,767	201,897	202,638	204,065	205,308	204,841	204,110	203,199	203,169
Excess capacity (MW)	42,499	46,234	46,025	44,412	43,720	43,208	41,095	38,695	36,024	33,855
ARRM (%)	27.6	30.11	29.53	28.07	27.27	26.64	25.1	23.39	21.55	20

Table 8 shows the annual anticipated resource reserve margin for 2015-2024.

[100] 2014 Western Electricity Coordinating Council (WECC) Power Supply Assessment, schedule 3A – Demand and Capacity - Summer, WECC Total, https://www.wecc.biz/ReliabilityAssessment
[101] Fully defined by the WECC in the 2011 Power Supply Assessment Report, accessed on 2/5/15 at: https://www.wecc.biz/Reliability/2011_PowerSuppyAssessment.pdf

As pointed out above, currently there is not a shortage of capacity on the regional interconnected grid that would require that a new natural gas fueled generator be built to replace lost GCD electric capacity. The cost of purchasing electric capacity on regional electric markets is well below the levelized cost of building new generating capacity. It is only in the future that new generation may be needed to offset the loss of GCD electric capacity. In that sense the cost of additional electric capacity we have discussed above are significant over-estimates of the current capacity value of GCD.

The stability of the interconnected electric grid of which GCD is a part is managed by WECC. WECC is one of the regional reliability organizations that are responsible under federal law for the reliability of the North American interconnected electric grid. WECC monitors the electric system that stretches from the Canadian provinces of British Columbia and Alberta to northwest Mexico and from the Rocky Mountains to the Pacific coast.

WECC's *2014 Power Supply Assessment* [102] studied the adequacy of the electric generating resource in the Western states to meet projected peak electric demands within the interconnected region. WECC's geographic region is broken into nine sub-regions. GCD is located in the Desert Southwest sub-region that consists of the states of Arizona and New Mexico as well as southern Nevada. WECC sets minimum reserve recommendations, "reference" or "target" reserve requirements[103], for each sub-region. It seeks to assure that there are reserves to cover contingencies, allow load following and fluctuating generation from intermittent resources such as wind and solar generation, and cover generation forced outages and loads during extreme weather.

In these assessments of the adequacy of the capacity of the electric system to meet future system peak loads, NERC is very cautious about projections of future new electric generators. It categorizes future generation additions by the likelihood that they will actually come on line by a certain date. The most certain future generation capacity is the sum of existing generation (adjusted for retirements and inoperable plants) plus plants that are almost certain to come on line (e.g. currently under active construction). It is only these "certain" additions to (or retirements from) generation that are considered in the following discussions of "excess" electric capacity reserves projected in the WECC region. Other potential additions to generating capacity that are somewhat likely to be added to the system include those that have received regulatory approval or are about to undergo regulatory review. These are *not* included in the following discussion of reserve margins. Of course, if market conditions supported additional generating units one could project conceptually how much and what type of generation would be added.[104] Thus the reserve margins discussed below are the minimum reserve margins

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[102] WECC, September 2014.
[103] The National Electric Reliability Corporation (NERC) to which WECC belongs does not have the authority to specify the reserve margins or other mandatory standards for adequacy for the eight reliability coordinating councils.
[104] The 2014 Annual Energy Outlook (U.S. EIA) projects considerable new electric generation capacity being added between 2013 and 2040. 351,000 MW of new capacity will be brought on line to replace 97,000 of existing capacity that will be retired and to serve growing load under EIA's Reference Case (p. MT-17) About three-quarters of this is expected to be fueled by natural gas. Thus, NERC's focus on only

that are expected going forward given projected electric demand and only those additional generators almost certain to be on line in the near future.

Recall that the BBM for WECC as a whole in the 2015-2024 *Power Supply Assessment* was 14.7 percent of projected net peak demand on the system. For 2015, however, the actual reserve margin over projected peak summer loads was 27 percent. That reserve margin was projected to be 25 percent in 2018 and about 19 percent in 2022. That is, the electric generating capacity that would be available just based on existing and new generation considered "certain" was more than sufficient to meet peak loads plus the target reserves.[105]

For the whole WECC region the "excess" reserves over the "target reserve margin" was projected to be about 22,000 MW of capacity in 2016 and 10,500 MW in 2021, after which the excess reserves declined to 2,200 MW in 2024 (Table 8). Recall that the effective electric capacity of GCD is about 600 MW. The "excess" reserves on the WECC system could easily accommodate the loss of the electric capacity of GCD. GCD capacity currently serves loads in Arizona, Utah, southern Nevada, and Southern California all of which are linked by substantial transmission lines that would allowed the movement of electric capacity from surplus regions in WECC to the regions currently served by GCD electric capacity.[106] In 2015 the total electric capacity available to meet peak summer loads on the WECC system were projected to total 196,000 MW.[107] GCD's approximately 600 MW of electric capacity contributed about three-tenths of one percent to that total electric capacity of the region.

The WECC reliability area faces significant adjustments in generating resources over the next ten years. By 2023 coal-fired generating capacity on the WECC interconnected system was projected to decline by 1,000 MW. Natural gas fueled generating capacity was projected to increase by almost 11,000 MW, while the solar and wind electric generation that was expected to be available at time of peak load was projected to add over another 11,000 MW of capacity. [108] The 600 MW of electric capacity associated with GCD is a relatively modest part of the projected changes in regional electric capacity over the next ten years.

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those plants currently under construction understates the actual electric capacity that is likely to be added to the national grid.

[105] WECC, 2014 Power Supply Assessment, PSA datasheets, Schedule 3A, Demand and Capacity-Summer, WECC Total, https://www.wecc.biz/ReliabilityAssessment .

[106] Op. cit. 2014 Power Supply Assessment, Appendix A—Zonal Topology Diagrams, Figure 1.

[107] Op. cit. WECC 2014 Power Supply Assessment, Demand and Capacity spreadsheet, Schedule 3A, line 13.

[108] Op. cit. NERC 2013 Long-Term Reliability Assessment, p. 159. The planning period was 2014 to 2023. NERC classifies the more certain future resource as "existing and planned." Planned resources include those resources included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve. This includes potential resources that may not be under construction or have gained regulatory approval.

4. Putting the Loss of the Remaining Electric Generating Potential at GCD in a Regional Context

The main conclusion of this report, that ceasing to use the GCD for electric generation would have only a very small impact on the larger electrically-interconnected region (WECC), should not be surprising. Since the early 1990s increasingly strict constraints have been imposed on the operation of GCD for electric production in order to protect other river values damaged by the operation of GCD for electricity production. Previous to the 1996 ROD permanently adopting a series of restrictions, GCD was expected to generate 6,010 gigawatt hours of electric energy and have a summer electric power capacity of 1,315 MW.[109]

As we discussed above, water flows into Lake Powell during the 2010-2014 water years and low reservoir elevations have limited electric energy production at GCD. Given that the average inflows during this time period approximately reflected the average in terms of water flows over a 30-year history at GCD, partially because 2011 was a very high inflow year, the average GCD electric energy production is unlikely to be higher than what was attained in the 2010 to 2014 water year period. This is at least due, in part, to the ROD Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead[110] which mandate that reservoir elevations must be equalized. Lake Powell is not allowed to hold water back so that they can generate more energy and keep its pool elevation high while Lake Mead continues to have a lower pool elevation. During the 2010-2014 time period, annual generation averaged 4,075,673 MWh, about a third less than the generation that would be possible at full pool and with no restrictions on the timing of water releases. See Table 9 below.

Table 9.

[109] Table IV-26, p. 300, Operation of Glen Canyon Dam, FEIS, March 1995, U.S. Department of Interior and Bureau of Reclamation
[110] http://www.usbr.gov/lc/region/programs/strategies/RecordofDecision.pdf

Annual GCD Electric Generation 2010-2014 WY (MWh)			
Water Year	Electric Generation	Avg. Electric Generation w/o Restriction and Full Pool	Actual Generation as a % of Full Pool Generation
2010	3,700,878	6,010,000	62%
2011	5,724,099	6,010,000	95%
2012	4,323,668	6,010,000	72%
2013	3,509,857	6,010,000	58%
2014	3,119,863	6,010,000	52%
Average	4,075,673	6,010,000	68%

Table 9 source: Bureau of Reclamation, GCD electric generation. Average electric Energy potential at GCD without restrictions on releases and at full pool is from the 1995 FEIS on Operation of Glen Canyon Dam, Table IV-26, p. 300. U.S. Department of Interior and Bureau of Reclamation.

As we have pointed out above, the summer electric capacity of GCD is now projected to average 606 MW, only 46 percent of the unconstrained 1,320 MW level. That is, 54 percent of the electric power capacity of GCD will no longer be available.[111]

This means that in the recent past the interconnected electric grid (WECC) and the customers of the SLCA/IP that markets the GCD electricity have already adjusted to the loss of over half of the electric capacity and a third of the electric energy associated with GCD. Those impacts have already been accommodated. The abandonment of electric generation at GCD altogether would have about the same-sized impact as has already been experienced with respect to capacity. On the other hand the loss of electric energy would be about twice what has been experienced thus far due to the drought and a greater emphasis protecting or rehabilitating the lower Colorado. The sub-WECC regional analysis and the impact of the loss of the electric energy and capacity that has already happened as well as the total loss of all of the electricity from GCD will be part of the next phase of this analysis. In that next phase we will seek to analyze these impacts on the specific customers that receive power from GCD and look at the grid impacts of this loss on a much smaller regional scale.

[111] "Analysis of Power and Energy Impacts of Glen Canyon Dam," Shortage Criteria FEIS, July 30, 2007. WAPA carried out the study for the BOR. It became Appendix O of the Shortage FEIS. Table 7.

IV. Conclusion

Rapid population growth in the Desert Southwest in the second half of the twentieth century put stress on the water resources of the Colorado River. A series of congressional acts and large scale water projects established the rules for the allocation of the Colorado River and put restrictions on how dams could modify the flow of the River. As a result the Glen Canyon Dam (GCD) is no longer managed exclusively for electric generation. Concern over a broad range of environmental impacts also constrains the operation of GCD for electric production. This report analyzed the impact of a broader restriction on the operation of GCD: ending the use of GCD for electric generation.

In this report we have focused on ***regional*** impacts on the interconnected grid of ceasing electric generation at GCD. That regional impact is important given that all electric users rely on that interconnected generation and transmission system. However, taking that regional perspective introduces a much larger set of electric generators as well as a much larger set of electric customers. As a result, it is possible that if GCD no longer is the source of electric generation, some local areas and groups of customers might face relatively intense negative impacts that are not visible from the larger regional perspective. For that reason, the analysis of the impact of ending electric generation at GCD needs to be broken into two phases. The first phase, on which this report focuses, provides the larger ***regional*** perspective. Phase II of this analysis will focus on the existing local customers who benefit from having access to the relatively low priced hydroelectric power that GCD currently provides, albeit, at a lower level of generation than in the past.

The analysis found in the main body of this first phase, regional, report supports the following set of conclusions:

i Averaged over the five water years 2010 through 2014, the electric energy produced by GCD had a market value of about $153 million per year. While that is obviously a large monetary value, the annual total sales revenue associated with the production and sale of electric energy within the Western Electric Coordinating Council (WECC) region was about $30 billion. The market value of GCD electric energy generation was about one-half of one percent of that $30 billion value of regional generation. (See section II and section II of this report)

ii The interconnected regional grid has significant additional electric energy generation potential. If we just focus on the additional electric energy generating potential of regional natural-gas-fired combined cycle combustion turbines, that currently unused generation ability is 46 times the generation coming from GCD. (Section III, page 25 in this report.)

iii GCD also provides peaking capacity when customer loads rise to daily or yearly peaks. The WECC region, however, currently has peaking capacity far beyond what is required to meet contingencies and is expected to continue to have excess electric capacity reserves for many years to come. The excess capacity reserve margins in 2024 in the WECC region are projected to be 56 times the current effective peaking capacity of the GCD. (See section III, table 8, page 26 in this report.)

iv *If* it were necessary to build new electric generation to replace the current peaking capacity of GCD, the maximum it would cost would be about $48 million per year. The actual value of the GCD's peaking capacity is much lower than this because of the surplus supply of electric capacity in the region. (See section II, page 18 of this report)

v If the current market value of GCD electric energy is combined with the maximum cost of replacing the GCD peaking capacity, that combined cost would represent about 0.65 percent of the total electric generation revenues in the region. (See section II, page 20 of this report)

vi The regional grid can clearly cope with the loss of the existing electric generation at GCD without disruption. Over the last two decades, over half of the peaking capacity at GCD has already been lost to restrictions of water releases and drought. About a third of its electric energy generation has also already been lost. This did not lead to instability on the regional electric grid or economic disruption across the region. Ending the remaining generation at GCD would involve a slightly smaller reduction in regional peaking capacity than what has already been experienced. The electric energy loss would be about double the amount already lost due to environmental restrictions and drought. (See section III, page 29 of this report)

In the next phase of this project we will look at the impacts of the loss of electric generation at GCD on a smaller area, that is served by the Western Area Power Authority's Salt Lake City Area Integrated Project (SLCA-IP). That area is served by 11 hydroelectric projects, but almost three-quarters of the power marketed by it comes from the electricity produced at the Glen Canyon Dam. That is the area that is most reliant on Glen Canyon Dam generation and most at risk to be disproportionately affected.

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The Impact of the Loss of Electric Generation at Glen Canyon Dam, Phase II: Financial Impacts on Existing Electric Consumers

A Report Prepared for the

Glen Canyon Institute

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Executive Summary

This project was initiated to quantitatively analyze the impact of the loss of Glen Canyon Dam (GCD) on the regional and local electric grid as well as to analyze the impact at an individual customer level. Numerous different media outlets have claimed that the impact of the loss of GCD would be catastrophic to the customers that currently get at least some of their electricity from GCD. In this phase of our report, we focus on the impact of the loss of GCD electric generation on the people who directly or indirectly contract through the Colorado River Storage Project (CRSP) and Western Area Power Administration (Western)[1] to receive their electricity.

To examine the potential increased cost of electricity on the approximately 3.2 million customers that receive a percentage of their electricity from GCD at a below market price, we divide the customers into 526 groups based on which utility they buy electricity from and the class of electric consumer that they are in.[2] The results of our analysis are based on the average amount of GCD electricity that each of the 526 groups consume. We also look at the customers that are affected the most, and we determine what the electricity is being used for. This allows us to put the loss of GCD electricity into a societal context and determine if there are certain groups that would be unduly affected by the electricity cost increases.

When we considered the impact on all utility customers together, we found that the loss of power generation at GCD would result in modest electricity cost increases in the residential ($0.96 per year), commercial ($7.04 per year), and industrial ($75.77 per year). However, since each utility receives a different percentage of their total electricity from GCD, there are some end-use customers that are affected more than others. The highest average electric cost increase for residential class consumers is $31.13 per year ($2.59 per month) for customers of the Ak-Chin Electric Utility Authority. The two commercial class customers[3] that purchase electricity from the Colorado River Commission of Nevada would have the highest electricity cost increases, just over $19,000 annually. There is one customer that purchases power as an industrial class customer from the Provo City Corporation (Provo Power); this customer would have an electric cost increase of almost $155,000 annually. This is roughly 2% of the current amount that the

[1] CRSP is one of five regions within the Western Area Power Administration.

[2] The four classes of consumers that are considered here are the three utility customer classes: residential, commercial, and industrial, as well as non-utility customers that receive their electricity directly from CRSP.

[3] There are a total of 7 customers that are served by the Colorado River Commission of Nevada. These customers include Boulder City, the Southern Nevada Water Authority, the industries comprising the Basic Management Industrial Complex (the home of Timet, which supplies nearly one fifth of the world's titanium supply and was acquired by Precision Castparts in 2013), Lincoln County Power District No.1, Overton Power District No.5, NV Energy, and Valley Electric Association; the $19,000 annual cost increase for electricity represents much less than one tenth of one percent of the revenue for each of these customers except Lincoln County Power District No.1 (which is 0.76%).
http://www.watereducation.org/sites/main/files/file-attachments/crcn_brochurejason_theriot.pdf
http://budget.nv.gov/uploadedFiles/budgetnvgov/content/StateBudget/TaxpayersReport/FY_15_Cities/Boulder%20City%202015%20budget.pdf
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EIA-861 2012 data (table 10) http://www.eia.gov/electricity/data/eia861/zip/f8612012.zip

customer paid for the very large amount of electricity consumed in 2012 (137,512 MWh).[4] It is clear that the large impact on this single user is largely due to the amount of electricity that it consumes.

Non-utility, largely government, contractors for CRSP electricity are the class of customer that would realize the highest electricity cost increase from the loss of GCD electricity generation. The average electricity cost increase is $115,029 per customer for this class of governments and government enterprises. These government organizations do *not* resell the electricity that they purchase from CRSP. This class includes federal, state, and tribal government entities and enterprises they run. Since this class uses the electricity purchased from CRSP directly, the increased electricity cost that each of these customers would potentially incur is directly related to the size of the allocation of CRSP electricity that they receive.[5]

The largest electricity cost increase for non-utility contractors would be borne by the Navajo Tribal Utility Authority.[6] It would have an electricity cost increase of approximately $1.3 million. Again, this increase in electricity cost is due to the large size of their annual electricity allocation from CRSP. Over the period of this study that allocation has been a little over 101,691 MWh, or roughly 2.5% of the average annual electricity generated at the GCD. This electricity is used to run tribally owned businesses and public services which include: a large public works and services department that serves some 250,000 members living on the reservation;[7] four large casinos; ten shopping centers; one museum; a parks and recreation department; a large number of businesses; and numerous tribal government and social centers.[8] Currently, the Navajo Tribal Utility Authority purchases over $3 million of electricity from the CRSP. As a result, the increase in the cost of electricity is approximately 43%. However, the 2014 Net Win[9] for the three Navajo casinos in New Mexico alone was over $81 million[10] making the $1.3 million electricity cost increase just 1.6% of the Net Win from New Mexico gaming, and well under 1.6% as a share of all tribal business revenue. It is important to understand that non-utility contractors' electricity cost increases are not directly passed onto individual households but are, instead, borne entirely by the non-utility contractor, usually a government or a government owned or run enterprise.

It is clear from the analysis presented in this report that the total economic value lost as a result of GCD no longer being used for electric generation would be substantial. However, the resulting increase in the cost of electricity would be widely spread over a very large number, 3.2 million, end-user customers. The large majority of the residential end-user customers will not be overly burdened by the average increase in the cost of electricity. The average monthly increase in cost of electricity across all residential customers would be about eight cents per month, with less

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[4] This is roughly equal to 3% of the annual generation at GCD. Source: EIA-861 2012 data (table 8 Industrial) http://www.eia.gov/electricity/data/eia861/zip/f8612012.zip. We believe that this customer is Brigham Young University based on the extremely high electrical consumption which is over 20% of the total electricity sold by Provo Power.

[5] This differs from the electricity cost impact on the three utility end-user classes, since their impact is related to the total amount of electricity which the utility contractor purchases for distribution, the number of customers within the class who purchase the electricity from the utility contractor, as well as the total allocation of CSRP electricity that the utility contractor is allotted.

[6] The Navajo Tribal Utility Authority receives two separate electricity allocations; one for utility resale, the other for non-utility direct tribal use.

[7] http://www.navajo-nsn.gov/history.htm

[8] http://navajogaming.com/discover-navajo

[9] The 'Net Win' is the amount wagered minus the amount paid out in cash and non-cash prizes on gaming machines minus state and tribal regulatory fees.

[10] http://isletapueblopolitics.com/2015/02/28/nm-releases-4th-quarter-net-win-from-indian-casinos/ accessed on 10/28/2015.

than one half of one percent of residential customers seeing more than a $1 monthly increase in cost. However for a small subset of CRSP contractors who receive all of their electricity from the CRSP, could face a 2.5 to 2.7 fold increase; this is the difference between the market price and the CRSP price.[11] Among residential customers, however, such impacts would not happen since the largest percentage of electricity any utility receives from CRSP is less than 49% of the total electricity consumed by that utility.[12] Although those contractors who are completely dependent on CRSP for electricity represent only a small subset of the electric consumers relying on GCD, the size of the impact on this small minority of customers is likely to be of concern to them.

[11] This is the ratio of the average market rate paid for supplemental electricity by CRSP to the CRSP composite rate offered to contractors over the time period of this study. Thus, any contractor that finds that the cost of electricity is greater from CRSP than other sources will not pay the CRSP cost; they will change where they get electricity from first.

[12] The City of Truth or Consequences which accounts for less than 0.35% of all of the residential customers served by the CRSP, receives about 48.5% of their electricity from the CRSP.

I. The impact of GCD electricity generation on consumers

The impetus for quantitatively looking at the impact of the loss of electrical generation at Glen Canyon Dam (GCD) was media reports that greatly exaggerated the impact of GCD generation on local and regional electric rates. In multiple different news stories there were claims that a very large rate increase (as much as a fivefold increase) in electrical power prices to an unknown number of customers living in a nebulously defined region would result if electric generation ceased at GCD.[13] In Phase I of this report we examine the potential impact of the loss of GCD generation on the larger regional electrical grid and GCD's place in that grid. Phase I of this report shows that the larger regional grid would have no problem absorbing the loss of GCD as an electric generation resource. In Phase II of this report, we look at the impact of the loss of GCD's electric generation on the people who contract through the Colorado River Storage Project (CRSP) and Western Area Power Administration (Western)[14] to receive some of their electricity from GCD.

Recall from Phase I of this report that the electricity produced by the GCD is sent to users in the Upper Basin who sign five year contracts for CRSP power. Remember also that the CRSP markets electricity that is generated at 6 different hydro generating entities, not just GCD.[15] The CRSP bundles the electricity from the 6 hydro generating entities and markets them together. Thus, the loss of electric generation at GCD does not mean the complete loss of CRSP electrical production since the remaining CRSP facilities will continue to operate and provide electricity to the CRSP customers in the absence of GCD generation. However, GCD is by far the largest of these CRSP hydroelectric facilities: Between 2009 and 2013 GCD generated an average of about 78% of the CRSP electricity.

Through the CRSP contracts, GCD provides electricity to publically-owned electric utilities that serve 2.75 million residential customers, 392,000 commercial customers, and 39,200 industrial customers. Over 170 electric utilities, municipalities, and irrigation districts receive power from CRSP. In addition, CRSP provides electric power to 53 Native American tribes.[16] Given this extensive integration of GCD electric production into the regional economy, there is understandable concern about the potential impacts on these customers if GCD ceases to be used to generate electricity. Some commentators have projected very large economic impacts,

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[13] Oritz, K. Western Slope is Refusing to Divert More Water to Front Range. New Channel 5 Grand Junction, Montrose, Glenwood Springs. Accessed 10.29.2015. https://web.archive.org/web/20140715021756/http:/www.krextv.com/story/western-slope-is-refusing-to-divert-more-water-to-front-range-20140711 and Harvey, N. To protect hydropower, utilities will pay Colorado River water users to conserve. High Country News. 8.4.2014. Accessed on 10.29.2015 https://www.hcn.org/blogs/goat/doi-and-utilities-partner-to-stave-off-colorado-river-power-woes and U.S. Bureau of Reclamation. Flow Regimes and Glen Canyon. Accessed on 10.29.2015. http://www.creda.org/Documents/Messaging2.pdf

[14] CRSP is one of five regions within the Western Area Power Administration.

[15] Blue Mesa, Crystal, Frontenelle, Flaming Gorge, Glen Canyon, and Morrow Point

[16] See Appendix A of this report for the total utility customers served by CRSP. The other information comes from CRSP: "Who Is CRSP?" August 2012 CRSP presentation to the Glen Canyon Adaptive Management Working Group, Lyn Jeka, CRSP Manager, Western Area Power Administration, p.9.. http://www.wapa.gov/crsp/customerscrsp/default.htm .

asserting that the cost of electricity to the existing customers for GCD could see their electricity costs rise as much as five-fold.[17]

This report investigates this concern about the likely size of the economic impact of the loss of GCD as a source of electricity on the customers who currently rely at least partially on GCD to serve their electric needs.

The CRSP generates and sells electricity to a small group of customers (contractors) under contracts that can be modified once every five years. The CRSP markets electricity at a reduced rate compared to market wholesale prices: The CRSP price was approximately 38% of the average market rate in 2013.[18] The contractors are contractually obligated to buy a certain amount of the electricity that is produced by the CRSP during the five-year term of their agreement. The CRSP is obligated to provide the electricity at a rate that is proposed by Western and approved by the Federal Energy Regulatory Commission (FERC).[19] If the CRSP generates less than the contractually specified amount of electricity, Western must supplement the shortfall of electricity by purchasing the remaining electricity at the current market rate. Thus, the five-year fixed CRSP rate includes the cost of generating at and transmitting the electricity from the CRSP hydroelectric projects plus an estimate of the amount of electricity that will need to be bought from the wholesale market at a forecast price. If the CRSP dams produce a surplus of electricity, each contractor is offered a share of that surplus in accordance with the contractor's percentage of the total allocation. If the forecast price and amount of electricity create a situation wherein the CRSP loses money on the sale of electricity, Western can either increase the rate charged for the electricity or decrease the amount of electricity provided to each contractor. In the event of a rate change contractors "can opt out of their contracts if they don't like the rate change."[20] This means that the maximum that contractors who purchase electricity from Western would pay for electricity is the market price.

CRSP allocates electricity to 139 contractors[21] including 53 Native American tribal entities, nine Federal military installations, two State Universities, one Department of Energy facility, 66 utilities, and seven utility cooperatives (which have a total of 111 member utilities and one water conservation district).Typically, CRSP is just one of the sources of electric supply for each of these utilities. Thus 177 utilities incorporate CRSP's reduced-rate electricity generated at GCD into their electricity supply and rates and 66 non-utility organizations directly use electricity from GCD. The 177 utilities market the electricity to commercial, residential, and industrial

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[17] "The Bathtub Ring: Implications of Low Water Levels in Lake Mead on Water Supply, Hydropower, Recreation, and the Environment," Ning Jiang et al., 2015, Master's Group Project, Bren School of Environmental Science and Management, University of California, Santa Barbara, p. 2. http://www.esm.ucsb.edu/research/2015Group_Projects/documents/The_Bathtub_Ring_Final_Report_2015_05.pdf and Harvey, N. To protect hydropower, utilities will pay Colorado River water users to conserve. High Country News. 8.4.2014. Accessed on 10.29.2015 https://www.hcn.org/blogs/goat/doi-and-utilities-partner-to-stave-off-colorado-river-power-woes

[18] https://www.wapa.gov/regions/CRSP/OpsMaint/Documents/MonthlyOnandOffpeakPrices10-15-15.pdf

[19] http://www.usbr.gov/uc/power/progact/UCownop.html and https://www.federalregister.gov/articles/2014/12/09/2014-28866/colorado-river-storage-project-rate-order-no-wapa-169

[20] https://www.wapa.gov/PowerMarketing/Pages/rates.aspx

[21] These numbers are from the seasonal allocation summary documents, they differ slightly from the list of 143 contractors provided directly on the CRSP customer web page. https://www.wapa.gov/regions/CRSP/PowerMarketing/Documents/TribalAllocationTable(2009andAfter).pdf https://www.wapa.gov/regions/CRSP/PowerMarketing/Documents/FY2009andafterseasonalsummary.pdf

consumers. The electricity is used in many different applications: to power cities,[22] military bases,[23] and universities.[24] The electricity is also used to power industrial facilities[25] and casinos.[26]

The end-user consumers of CRSP electricity will not be equally affected by a loss of GCD electricity; each contractor receives a different amount of electricity from the CRSP, and this electricity represents a different percentage of the total electricity consumed or sold by each contractor. The contractors also receive electricity from other suppliers at a market rate. Thus, for the utility contractors, the end-user rate is partially based on the percentage of electricity that the utility contractor receives from the CRSP at the federally subsidized rate. In our modeling, we take into account the electricity that each consumer is currently getting from the CRSP as well as the electricity that they are currently receiving from other sources. By looking at the rates that end-user consumers are currently paying for their electricity along with the percentage of electricity that the contractor receives from the CRSP, we determine the rate that the utility would have to charge if GCD did not produce power. With that information, we are able to determine the total change in the rate that each end-user customer would likely pay for electricity and the likely increase in the total cost of electricity to each end-user customer on an annual and monthly basis.

Appendix D details the methods used to determine the impacts for each end-user customer, with equations and assumptions explicitly provided. Here it is enough to understand that the loss of GCD electricity to each CRSP customer is replaced by the same amount of electricity purchased at the market rate. It is important to keep in mind that although GCD makes up the majority of CRSP power, of the roughly 3.1 million end-user customers that get their electricity in part from CRSP, no more than 66 get 100% of their electricity from GCD[27] and roughly 2.8 million end-user customers get less than 10% of their electricity from the CRSP.[28] Further, each CRSP customer will still receive the approximately 22% of the electricity that comes from CRSP non-GCD hydroelectric facilities at the well-below market CRSP rate.[29]

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[22] i.e. Holden, UT and Fredonia, AZ
[23] i.e. the Tooele Army Depot and Yuma Proving Ground
[24] i.e. The University of Utah and Utah State University
[25] i.e. Anheuser Busch and the Cargill beef processing facility in Morgan County, CO
[26] Please see appendix C for the complete list of casinos.
[27] Because we are looking at rate impacts, for our calculations we conservatively assume that the non-utility contractors get 100% of their electricity from CRSP.
[28] 1.2 million of the customers get less than 1% of their electricity from the CRSP.
http://www.eia.gov/electricity/data/eia861/zip/f8612012.zip residential, commercial, industrial data.
https://www.wapa.gov/regions/CRSP/PowerMarketing/Documents/TribalAllocationTable(2009andAfter).pdf
https://www.wapa.gov/regions/CRSP/PowerMarketing/Documents/FY2009andafterseasonalsummary.pdf
[29] From the other 5 dams in the CRSP.

II. Overall Impacts

The total impacts would be an increase of $16.31 million in electricity costs for the CRSP consumers. The impacts are split between non-utility contractors ($7.94 million) and utility contractors ($8.38 million). Amongst the utility contractors this impact is nearly split evenly between the different major use classes with the residential class seeing a $2.65 million increase, the commercial class seeing a $2.76 million increase, and the industrial class seeing a $2.97 million dollar increase.

Although the total cost increases may appear fairly large due to the loss of GCD generation, the individual customer impacts are generally fairly small. For the residential customers the average yearly impacts are $0.96 or eight cents per month; for the commercial customers the average yearly impacts are $7.04 or $.59 per month; and for the industrial customers the average yearly impacts are $75.77 or $6.16 per month. (See Table 1).

Table 1.

Average Customer Impacts for the Loss of GCD

	Yearly	Monthly
Residential	$0.96	$0.08
Commercial	$7.04	$0.59
Industrial	$75.77	$6.16

In general the electricity that is produced at GCD goes to cities, utilities, and tribes within the Upper Basin states. Within the different customer classes, the impact of the loss of GCD electric generation is muted because the non-utility contractors receive most of their electricity from non-CRSP sources and pay for this electricity at a market rate. In the following sections we discuss the end-user customers that have the highest calculated potential rate impacts. We seek to understand why different end-user customers are impacted in different ways, and we investigate what the electricity is being used for. This allows us to have some context for understanding the potential individual economic impacts.

1. Residential

As noted in Table 1, the average yearly increase in electric costs for the residential class end-user is $0.96. The largest of the annual residential per customer impacts are to the fewer than 300 residential customers of the Ak-Chin Electric Utility Authority ($31.13 per customer per year), the approximately 3,500 residential customers of the City of Truth and Consequences ($20.10 per customer per year), and the approximately 3,500 residential customers of the Page Utility Enterprises ($19.89 per customer per year). Table 2 shows the ten largest individual residential impacts of the loss of GCD electric generation on a yearly and monthly basis; note that the highest average monthly bill increase in the residential sector is $2.59, and that these ten most-impacted utilities have a total of fewer than 13,000 customers. The distribution of impacts, of course, will not be the same for each end-user customer because each customer uses different amounts of electricity.

Table 2.

	The 10 Largest Individual Residential Impacts for the Loss of GCD			
		Yearly	Monthly	# of Customers
1	Ak-Chin Electric Utility Authority	$31.13	$2.59	293
2	City of Truth or Consequences	$20.10	$1.68	3,502
3	Page Utility Enterprises	$19.89	$1.66	3,517
4	Flowell Electric Assn, Inc	$14.99	$1.25	188
5	Nephi City Corporation	$13.09	$1.09	1,884
6	City of Manti	$13.02	$1.09	1,281
7	City of Holyoke	$12.89	$1.07	947
8	Salem City Corporation	$12.77	$1.06	1,680
9	Levan Town Corporation	$11.66	$0.97	315
10	Ocotillo Water Conserv. Dist.	$11.51	$0.96	20

Source: Appendix A.

2. Commercial

As we noted in Table 1, the average yearly increase in electric costs for the commercial class is $7.04. The three largest annual impacts per customer on the commercial class from the loss of GCD electricity would be for the customers of the Colorado River Commission of Nevada ($19,188 per customer per year), the Garkane Power Association Inc. ($567 per customer per year), and Ak-Chin Electric Utility Authority ($487 per customer per year). Table 3 shows the ten largest individual commercial impacts of the loss of GCD electricity on a yearly and monthly basis.

The high average monthly increase for the Colorado River Commission of Nevada is due to the fact that the customers purchase very large amounts of electricity every year. Thus, even though the Colorado River Commission of Nevada only receives 6 percent of their total electricity from the CRSP, the total impact on the *average* monthly bill is high. However, the Colorado River Commission of Nevada is a state agency that is in charge of managing all of Nevada's water and electricity from the Colorado River. The Commission had total assets of $127 million and made electric purchases of more than $21 million in 2014 according to the Comprehensive Annual Financial Report of the Colorado River Commission of Nevada.[30] The yearly increase of a little more than $19,000 would represent less than one tenth of a one percent increase in the cost of electric purchases in 2014. Further Nevada has the ability to draw electricity from both the Upper and Lower Basin of the Colorado River; this could further mute the impact of rate increases to the Commission.[31]

[30] Comprehensive Annual Financial Report of the Colorado River Commission of Nevada. Pages 19 and 25. http://crc.nv.gov/docs/AFR/crc_afr_2014.pdf

[31] If the water in Lake Powell were to be fed into Lake Mead then there would be a large increase in the generating capacity of Hoover. This could partially offset some of the loss of electricity to the state of Nevada.

Table 3.

The 10 Largest Individual Commercial Impacts for the Loss of GCD			
		Yearly	Monthly
1	Colorado River Comm of Nevada	$19,188.24	$1,599.02
2	Garkane Power Association Inc.	$567.46	$47.29
3	Ak-Chin Electric Utility Authority	$487.01	$40.58
4	City of Truth or Consequences	$136.98	$11.41
5	Page Utility Enterprises	$106.15	$8.85
6	Ocotillo Water Conserv. Dist.	$100.74	$8.39
7	Nephi City Corporation	$98.95	$8.25
8	Provo City Corp	$95.02	$7.92
9	Electrical Dist No5 Pinal Cnty	$82.30	$6.86
10	Spanish Fork City Corporation	$81.04	$6.75

3. Industrial

As we noted in Table 1, the average yearly increase in electric costs for the industrial class is $75.77. Table 4 shows the ten largest impacts from the loss of GCD electricity on the industrial class. Because there are far fewer industrial customers, with much larger electric demands, the impacts on this class of customer are far larger per customer than for either the residential or commercial classes. However, the list of industrial class customers is generally populated by fairly large municipalities with utilities like The Provo City Corporation,[32] which is owned by the city of Provo, Utah. Provo Utah, in 2014, had a population of 114,801 people.[33] Like most metropolitan cities, the city of Provo provides electricity to all of its various public departments including its fire department, police department, courthouse, waste treatment facilities, water utility, airport, etc. While $154,963 is a large amount of money to have to absorb for any entity, the total Provo City revenues were $174 million in 2014.[34] The loss of GCD's cheap electricity to the city of Provo represents less than one-tenth of one percent of 2014 city revenues. Other industrial class customers also benefit, either directly or indirectly,[35] from the reduced electric rates from access to GCD electric generation. This includes the Anheuser-Busch Fort Collins Brewery which is over 1 million square feet in area, serves 11 states entirely (as well as portions of 6 other states), and shipments include approximately 225 trucks daily and 30 rail cars weekly.[36]

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[32] The Provo City Corporation is run by the Municipal Council which is a group of elected city officials that help manage the city.
[33] State and County Quick Facts from the U.S. Census Bureau. Provo, Utah. 2014. http://quickfacts.census.gov/qfd/states/49/4962470.html
[34]Popular Annual Financial Report for the Fiscal Year Ended June 30, 2013. Provo, Utah. http://www.provo.org/Home/ShowDocument?id=2947
[35] The utilities that market electricity in Fort Collins are members of cooperatives that are listed as contractors for GCD power by CRSP, thus part of the rate structure includes GCD electricity.
[36] http://www.anheuser-busch.com/s/uploads/2013-Fact-Sheet-FCL.pdf

Table 4.

	The 10 Largest Individual Industrial Impacts for the Loss of GCD		
		Yearly	Monthly
1	Provo City Corp	$154,963	$12,914
2	Los Alamos County	$49,191	$4,099
3	Brigham City Corporation	$41,661	$3,472
4	Springer Electric C	$20,223	$1,685
5	Garkane Power Association Inc.	$17,546	$1,462
6	City of Fort Morgan	$16,115	$1,343
7	Moon Lake Electric Assn Inc	$14,070	$1,172
8	Fort Collins	$12,618	$1,051
9	Dixie Escalante R E A, Inc	$9,022	$752
10	Colorado River Comm of Nevada	$8,477	$706

4. Native American Tribes

The average impact of the loss of GCD electric generation to the Native American tribes that use the electricity from GCD is $98,619 per tribe. This number may appear quite large, and in some cases it is. What must be considered when evaluating the size of this impact is what the electricity is being used for and what revenue streams the different tribes have to cover this calculated increase in electricity costs. All of the tribes that are being considered in this list are non-utility contractors. That means that the tribal governments or tribally-owned organizations are purchasing the electricity but are not distributing it to individual tribal members or private organizations. For instance: A tribal member who personally owns a business would not be subject to an increase in electric payments because their business is not owned by the tribe and was not receiving any of the GCD electricity from the tribe. These impacts on tribal non-utility contractors would be felt by the Tribe as a whole not by individual tribal members.

With the exception of the Hopi Tribe in northeastern Arizona, all of the tribes on the list of the tribes with the 10 largest tribal impacts (Table 5, below) from the loss of GCD electricity have large tribally-owned casinos as well as other large tourist facilities like resorts, golf courses, conference centers, etc. located on their reservations. So, although the tribes would incur a substantial increase in their calculated monthly electric payments, they also have very large and profitable businesses to help pay the new electric rates that are closer to market value. For a complete list of tribal impacts see appendices B and C. Appendix B provides the calculated impact and appendix C provides some context for each tribe to be viewed in.

Table 5.

The 10 Largest Individual Tribal Impacts for the Loss of GCD			
		Yearly	Monthly
1	Navajo Tribal Utility Authority (tribal)	$1,300,024	$108,335
2	Salt River Pima-Maricopa Indian Community	$844,516	$70,376
3	Gila River Indian Community	$781,368	$65,114
4	White Mountain Apache Tribe	$339,369	$28,281
5	Colorado River Indian Tribes	$277,638	$23,137
6	San Carlos Apache Tribe	$227,236	$18,936
7	Hopi Tribe	$158,647	$13,221
8	Ft. McDowell Mojave-Apache Indian Community	$132,354	$11,029
9	Yavapai Apache Nation	$95,953	$7,996
10	Pascua Yaqui Tribe	$67,223	$5,602

Because these estimated increases in electricity costs to tribal organizations and enterprises are likely to be the most troubling of our modeled impacts, we will take a closer look at some of the tribes that may initially appear to be disproportionately impacted.

a. The Navajo Tribal Utility Authority

The Navajo Tribal Utility Authority (NTUA) was the first and continues to be the single largest tribally owned utility in the U.S.[37] Since 1959 NTUA has supplied the Reservation with electricity, water, natural gas, wastewater collection and treatment, and solar power. They have an electric customer base of more than 36,000, a wastewater customer base of more than 13,000, and almost 8,000 natural gas customers.[38] It is important to note that the $1.3 million annual increase in electricity costs that the NTUA would incur as a result of the loss of GCD power generation are not costs associated with providing electricity to its electric end-user customers. We have already calculated and discussed that impact on NTUA end-use customers: The residential customers who receive electricity from the NTUA would incur an annual cost increase of $1.83, the commercial customers would incur an annual increase of $20.89, and the industrial customers would incur an annual increase of $452.93. Here we are evaluating only the increase in the cost of electricity that the NTUA would incur as the tribal entity that owns and runs tribal businesses and facilities.

Aside from the large public works and services department that the NTUA has, the NTUA also owns four large casinos, ten shopping centers, a large number of businesses, a museum, a parks and recreation department, an arts and crafts enterprise, and numerous tribal government and social centers very much like any large municipality.[39] The Navajo have more than 300,000 enrolled members with some 250,000 living on the Navajo Reservation,[40] making it one of the

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[37] Western Area Power Administration. Tribal Authority Process Case Studies: The Conversion of On-reservation Electric Utilities to Tribal Ownership and Operation. 2010. http://apps1.eere.energy.gov/tribalenergy/pdfs/tribal_authority.pdf

[38] http://www.ntua.com/aboutus.html and http://www.navajo-nsn.gov/history.htm

[39] http://navajogaming.com/discover-navajo and

[40] In 2011 the Tribe's census office had their enrollment pegged at 300,048. http://navajotimes.com/news/2011/0711/070711census.php#.VhgewPIVhBc the Navajo Nation Government website has the number at a slightly lower 250,000. http://www.navajo-nsn.gov/history.htm

largest if not the largest Native American tribe in the U.S.[41] Clearly the Navajo have a very large, robust, and thriving sovereign economy that is similar to that of any large municipality that would face a similar change in the cost of electricity. Finally it should be noted, and is discussed in much greater detail in appendix C, that the Navajo had a Net Win just from their three New Mexico casinos of more than $81 million in 2014,[42] plus an unspecified amount from a fourth casino in Arizona which opened in 2013 east of Flagstaff.[43]

b. Salt River Pima-Maricopa Indian Community

The second largest calculated impact on non-utility tribal entities would be incurred by the Salt River Pima-Maricopa Indian Community (SRPMIC) located in the metropolitan Phoenix area. As Table 5 shows, they would incur almost $845,000 annually in increased electricity costs associated with the loss of GCD power generation. The two tribes that make up the SRPMIC, the Pima and the Maricopa, together have a tribal enrollment of over 9,000.[44] The SRPMIC "proudly owns and operates several successful enterprises including Talking Stick Golf Club, Talking Stick Resort, Salt River Fields,[45] Salt River Devco,[46] Casino Arizona, Salt River Sand and Rock, Phoenix Cement, Saddleback Communications, Salt River Financial Services, and Salt River Landfill."[47] Among those facilities the Salt Rivers Fields has 13 baseball fields covering 140 acres including a large covered facility that is home to the Arizona Diamondbacks and Colorado Rockies Spring Training.[48] The Talking Stick Resort is a sprawling resort, golf course, and casino with over 100,000 square feet of gaming, dining, and entertainment including five unique restaurants and the "Southwest's largest collection of contemporary native American art."[49] Thus, the SRPMIC own a myriad of very large and diverse tourist-oriented businesses that account for the large electric demand of the Tribes. These businesses would need to pay for the potential increase in electricity cost if GCD did not generate electricity.

c. Gila River Indian Community

The Gila River Indian Community (GRIC) Reservation in Arizona had a population of 11,712 residents in 2010.[50] The GRIC has a host of tribally owned enterprises: "The GRIC is a rural area with a number of improved residential sites, 3 industrial developments, large scale farming operations, 1 standalone casino, 2 casino/resorts, world class golf, a resort/spa, large upscale shopping, a motorsports park, other attractions, wild land/urban interfaces and numerous archaeological sites of cultural/spiritual significance."[51] Since the GRIC is located 34

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[41] There is some controversy as to who has more members between the Navajo and the Cherokee. Because of the different blood quantum requirements of the two tribes there is no clear cut standard for which tribe is larger.

[42] http://isletapueblopolitics.com/2015/02/28/nm-releases-4th-quarter-net-win-from-indian-casinos/

[43] The Twin Arrows Casino, with over 1000 slot machines, employing 600 people. http://www.azindiangaming.org/wp-content/uploads/2015/10/The-Economic-Impact-of-Tribal-Gaming-in-Arizona-2014.pdf

[44]About the Salt River Pima-Maricopa Indian Community. http://www.srpmic-nsn.gov/community/

[45] Salt River Fields is a stadium complex which hosts festivals, concerts, and is the location for spring training for both the Arizona Dimondbacks and Colorado Rockies professional baseball teams.

[46] Salt River Devco is an asset management and commercial development company.

[47] Ibid. and http://www.srpmic-nsn.gov/enterprises/

[48] http://www.saltriverfields.com/spring-training-tickets/2015-Schedule.aspx

[49] http://www.srpmic-nsn.gov/enterprises/gaming.asp

[50] 2010 Census of Population. Demographic Profile Data. http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=DEC_10_DP_DPDP1&prodType=table

[51] http://www.gilariver.org/index.php/enterprises

miles south of the Phoenix Sky Harbor International Airport, they have the ability to draw a large number of tourists to their world class establishments.

The GRIC also has an extensive public works department,[52] a Tribal Government,[53] a Tribal Education Department that provides education and childcare from the daycare level through high school,[54] as well as all of the services that one generally associates with a municipality.[55] Although the GRIC will incur a cost increase of $781,000, their large tourist draw from the greater Phoenix area and beyond should help offset this loss. Indeed, the large energy consumption of the GRIC is primarily due to the large number of tourist-related businesses on their reservation.

d. Hopi

Although the Hopi would incur the 6th largest impact on the list ($13,220 monthly electric cost increase), the Hopi are the only tribe in our list of the top 10 largest impacts that does not have a casino or other large tourist-related electric energy needs. This places them in a unique situation for non-utility tribal end users. The Hopi have one relatively small hotel that is attached to their Cultural Center, a new Hopi Health Center, and an Elderly Assisted Living Center.[56] Aside from these facilities it is likely that the Hopi are supplying energy to a number of different Hopi run businesses and tribal facilities,[57] but we have been unable to verify which businesses or facilities on the Hopi Reservation are specifically tribally owned. The Hopi Reservation encompasses more that 1.5 million acres and is made up of 12 villages on three mesas.[58] According to the 2010 census, the Hopi Tribe had 7,185 members living on the Reservation.[59] About 54% of the Hopi that are employed work for the "government" according to the 2010 census based American Community Survey.[60] Since the majority (79 percent) of those "government" workers work for "local government" and because the Hopi are a sovereign nation, we assume that they are working for the Hopi Tribe directly. This would suggest that the government has some relatively robust facilities to which they are supplying electricity. Since they cannot resell their share of this electricity to another entity, the Hopi Tribe is consuming all of this power. It is the Hopi Tribal operations that will incur the increase in electric costs of about $159,000 annually. The Hopi are relatively unique in that they are actively attempting to keep their Reservation as traditional as possible. The Hopi have not welcomed casinos or large tourist related establishments onto their Reservation. Where some of the other tribes' higher electricity costs may be absorbed by the large and profitable tourist businesses they run, the Hopi Tribal services

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52 http://www.gilariver.org/index.php/departments--programs/tribal-development-services
53 http://www.gilariver.org/index.php/government
54 http://www.gilariver.org/index.php/departments--programs/administrative-support
55 http://www.gilariver.org/
56 http://www.hopiculturalcenter.com/reservations/ and https://www.ihs.gov/Phoenix/index.cfm/healthcarefacilities/hopi/ and http://www.owp.com/hopi-tribe-elderly-assited-living#.Vhv8ovlVhBc
57 There is a large list of different Hopi run government offices, but none of them are described in any detail on their various websites. http://www.hopi-nsn.gov/contact/
58 http://www.hopi-nsn.gov/
59 http://www.census.gov/2010census/ and http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=DEC_10_DP_DPDP1&prodType=table
60 Demographic Analysis of the Hopi Tribe using 2010 Census and 2010 American Community Survey Estimates. Completed by the Arizona Rural Policy Institute Page 60. http://azcia.gov/Documents/Links/DemoProfiles/Hopi%20Tribe.pdf

will incur most of the impact of the increase in electric costs associated with the loss of GCD electric generation.

III. Possible Mitigation of the Increased Cost of Electricity

Recall that the electricity that is produced from the CRSP is currently sold to its customer base at a price substantially below electric market prices. This is the result of one of the largest engineering feats of all time in the United States, the building of the GCD. The hydroelectric power from federal dams has turned out to be much cheaper than the electricity now generated by fossil-fueled electric generators for many reasons including:[61]

- The Federal Government's access to many of the best hydroelectric sites,
- the use of U.S. Treasury funds at very low fixed interest rates,
- the use of a fifty-year amortization period over which some of the CRSP projects' investment costs have already been paid off so that only the variable costs of operating the hydroelectric generation need to be recovered in rates,
- the ability to allocate some of the costs associated with federal multipurpose dams to other, non-electric-power, functions, and
- the legal requirement that the electricity produced at federal dams be sold at the lowest price possible consistent with sound business principles and the payment of operation and maintenance expenses, purchase power and wheeling expenses, replacements and power investments with interest, and other costs assigned to the electric power generation function. The price at which Western sells the electricity is not a commercial or market price and does not include a "profit" for investors and operators of the hydroelectric facilities.

The end result is a CRSP customer cost per unit of energy that is a little more than one-third of the market rate for electricity in the region. Since this is effectively federally subsidized electricity sold to particular customers at a dramatically lowered non-market price, it is not clear how federal agencies as directed by Congress would adjust their electric marketing programs if GCD were to cease generating electricity for environmental and basic engineering reasons in the face of lower long-run Colorado River flows. Past legislation authorized the distribution of this low cost federal electricity to particular beneficiaries, for the GCD, for the benefit of the Upper Basin states. New legislation that modified the purpose of Glen Canyon Dam to end its use for electric production could also seek to mitigate the impacts of that change on the GCD's existing beneficiaries.

Regardless, it is clear that the highest amount that any entity would have to pay for electricity is the current market rate since contractors can opt out of their contracts if they do not like a rate change proposed by Western.[62] This directly contradicts the assertions in a recent study that as

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[61] Bureau of Reclamation Hydropower Program, "Federal Rate and Repayment" and "Power Repayment Studies," http://www.usbr.gov/power/data/role_rpt.html#rate , accessed October 24, 2015.

[62] "Using flexible provisions in our power sales contracts, Western adjusts power rates through a public process. Customers can opt out of their contracts if they don't like the rate change." from https://www.wapa.gov/PowerMarketing/Pages/rates.aspx

water levels fall in Lake Mead, the operations costs for the dam are directly transferred to the contractors for the power and that the contractors will be forced to pay up to 5 times the price contractors paid when Lake Mead was at full pool.[63] This claim is unfounded and is directly contradicted by Western.[64]

One option for muting the increased cost of electricity due to GCD not generating power could come from allowing the water currently stored in Lake Powell to flow into Lake Mead and be stored there instead. That would increase the elevation of Lake Mead and the amount of electricity produced by each unit of water that flows through the generators. Under this scenario, the potential increase in electricity generation at Hoover Dam is approximately 673,000 MWh of power production per year,[65] or roughly 17% of the current five-year average power production at GCD. This enhanced electricity production could be used to mitigate the effects of the loss of power production at GCD on electricity rates on the most vulnerable end-user customers who are currently getting electricity from GCD. It seems likely that there are regulatory and legislative changes that would be required to both end electric generation at GCD and facilitate retaining some of the benefits that GCD was intended to provide to residents of the Upper Basin states. Such mitigating legislative and regulatory changes, however, lie beyond the purpose of this analysis and report.

IV. Conclusion

From the analysis presented here, it is clear that the potential price increase of electricity due to the loss of electrical generation at the GCD is small for most end-user customers of the CRSP. Recall that the average residential impact for the loss of GCD is $.08 per month, for the commercial customer it is $.59 per month, and for the industrial customer it is $6.16 per month. Most of the end-users of GCD electricity are in a position where paying market value for electricity will not impose an undue hardship. In fact, there are only 3 end-user customers that could be in a position wherein they could be adversely affected by paying market prices for electricity, the Hopi Tribe, the Pueblo of Zuni, and the Ramah Navajo Chapter. The result of a loss of electrical generation at the GCD would not lead to the end-users of the electricity paying full market value for the electricity; rather they would pay a price for electricity that is closer to market value. The price that they would pay would still be less than market value because it would be partially offset by the remaining CRSP facilities besides GCD.

It is important to remember that the largest potential cost increases for electricity are for those entities that consume the most power. As we have shown in detail, the customers that use the most power are municipalities and large commercial entities that have very large operating costs in general. The cost increases need to be viewed against the size of their electrical usage and what the electricity is being used for to determine the impact. It is also of note to remember that the market price for electricity is paid by tens of millions of customers across the western United

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63 "The Bathtub Ring: Implications of Low Water Levels in Lake Mead on Water Supply, Hydropower, Recreation, and the Environment," Ning Jiang et al., 2015, Master's Group Project, Bren School of Environmental Science and Management, University of California, Santa Barbara, p. 2. http://www.esm.ucsb.edu/research/2015Group_Projects/documents/The_Bathtub_Ring_Final_Report_2015_05.pdf

64 Ibid. "Using flexible provisions in our power sales contracts, Western adjusts power rates through a public process. Customers can opt out of their contracts if they don't like the rate change."

65 Calculations and assumptions are detailed in Appendix E.

States and that the highest rate that consumers who purchase CSRP electricity will pay for electricity is that market price.

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Appendices

Appendix A: Annual Rate Increase for Retail Customers of Electric Utilities Receiving GCD Electricity

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Average	**$0.96**	**$6.94**	**$75.79**	2,745,635	391,670	39,191
Ak-Chin Electric Utility Authority	$31.13	$487.01	$50.16	293	82	21
Anza Electric Coop Inc.	$0.00	$0.00	-	4158	314	-
Duncan Valley Elec Coop, Inc.	$0.00	$0.00	$0.00	1891	286	156
Graham County Electric Coop Inc.	$0.00	$0.00	$0.01	7752	815	425
Mohave Electric Cooperative	$0.00	-	$0.25	35171	-	22
Sulphur Springs Valley E C Inc.	$0.00	$0.00	$0.81	41091	9710	4
Trico Electric Cooperative Inc.	$0.00	$0.01	$0.04	38780	2102	44
Town of Holly	$0.01	$0.02	$0.02	410	150	14
City of La Junta	$0.01	$0.01	$0.73	2588	1663	56
City of Lamar	$0.01	$0.06	$0.04	6176	1857	108
City of Springfield	$0.01	$0.10	$6.31	93590	16475	44
City of Trinidad	$0.01	$0.05	-	3984	688	-

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
City of Las Animas	$0.01	$0.04	$0.01	1364	553	34
Raton Public Service Company	$1.13	$3.39	$72.73	3675	595	31
City of Aspen	$1.16	$4.43	-	1899	1023	-
City of Aztec	$3.33	$31.22	-	2824	454	-
Bridger Valley Elec. Assn., Inc.	$6.00	$27.52	$218.01	5262	1012	156
Brigham City Corporation	$7.13	$49.31	$41 660.74	6643	927	1
Colorado River Indian Irr. Proj.	$0.14	$0.81	$0.41	4032	675	74
City of Center	$10.24	$28.67	$209.74	838	168	45
Central Valley Elec Coop, Inc.	$0.07	$0.08	$0.91	5180	5447	3475
Colorado River Comm. of Nevada	-	$19 188.24	$8 477.22	-	2	5
City of Colorado Springs	$0.11	$0.69	$19.88	180928	21854	1374
City of Delta	$1.18	$4.07	$85.80	2245	546	50
Dixie Escalante REA, Inc.	$8.06	$33.05	$9 021.94	13831	1905	2
Electrical Dist. No. 2 Pinal County	$2.50	$35.15	$609.37	3719	933	18

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Electrical Dist. No. 3 Pinal County	$0.22	$0.71	$10.50	19826	3371	314
Electrical Dist. No. 4 Pinal County	$3.73	$24.01	$71.73	1018	178	327
Elec District No. 5 Maricopa Cnty.	-	-	$2 477.86	-	-	6
Electrical Dist. No. 5 Pinal Cnty.	$7.03	$82.30	$139.48	156	50	140
Electrical Dist. No. 6 Pinal Cnty.	-	-	$1 012.89	-	-	96
Electrical Dist. No. 7 Maricopa	-	-	$570.66	-	-	91
Farmers Electric Coop, Inc.	$0.11	$0.72	$1.66	9764	1678	1530
City of Farmington	$0.44	$2.42	$3 564.44	34240	9837	7
Town of Fleming	$1.16	$4.37	-	183	37	-
Flowell Electric Assn, Inc.	$14.99	$26.08	$165.52	188	103	163
City of Fort Morgan	$2.29	$36.46	$16 115.10	5285	805	1
Town of Frederick	$0.00	$0.00	-	3453	695	-
City of Gallup	$0.36	$5.55	-	8509	1812	-

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Garkane Power Association Inc.	$9.45	$39.32	$17 545.73	10 520	2 168	1
City of Glenwood Springs	$0.25	$2.11	-	4779	1331	-
Grand Valley Power	$0.14	$0.44	$1.12	14127	2176	114
City of Gunnison	$11.27	$75.96	-	3348	815	-
Town of Haxtun	$7.93	$18.45	-	522	129	-
City of Helper	$2.64	$15.23	-	1020	45	-
Holy Cross Electric Assn, Inc.	$0.21	$0.87	$102.94	45196	9635	9
City of Holyoke	$12.89	$48.12	-	947	256	-
Intermountain Rural Elec. Assn.	$0.07	$0.34	$11.85	130075	11982	77
Lea County Electric Coop	$0.05	$0.47	$77.72	8331	7248	20
Los Alamos County	$0.01	$0.10	$543.31	7792	854	1
Maricopa County M W C Dist. #1	-	-	$403.42	-	-	220
City of Mesa	$0.31	$2.25	-	13257	2454	-
Moon Lake Electric Assn Inc.	$5.62	$34.55	$14 069.78	13537	4561	20

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Mt Wheeler Power, Inc.	$3.51	$5.47	$225.18	5218	1769	451
Navajo Tribal Utility Authority	$1.83	$20.89	$452.93	36217	4179	148
Navopache Electric Coop, Inc.	$0.38	$2.19	$18.90	36206	3825	78
Town of Oak Creek	$4.79	$19.30	-	598	68	-
Ocotillo Water Conserv. Dist.	$11.51	$100.74	-	20	68	-
City of Estes Park	$2.89	$12.95	-	8222	2059	-
City of Fort Collins	$3.38	$26.74	$12 617.51	59406	7788	15
City of Longmont	$3.74	$55.03	$4 725.81	34474	2629	11
City of Loveland	$3.54	$10.15	$421.18	29267	3875	357
Price Municipal Corporation	$0.51	$6.60	-	4456	628	-
Roosevelt County Electric Cooperative	$0.85	$1.03	$5.58	3745	988	1593
Roosevelt Irrigation District	-	-	$357.30	-	-	220
City of Safford	$0.29	$1.87	$1.01	3435	582	15
Salt River Project	$0.02	$0.17	$111.44	867846	95325	46

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
City of San Carlos	$0.05	$0.37	$64.80	11361	2079	4
Town of Thatcher	$0.72	$3.82	$0.99	967	248	65
Tohono O'Odham Utility Authority	$1.00	$9.88	$448.78	3007	665	1
City of Torrington	$0.33	$1.88	$30.52	3159	685	52
Chimney Rock PPD	$1.62	$3.86	$5.52	1975	295	834
Midwest Electric Member Corp	$1.52	$5.04	$16.75	3161	1149	1961
Northwest Rural Public Power Dist.	$2.19	$0.99	$14.35	1409	1290	683
Panhandle Rural Electric Member Assn.	$2.33	$1.41	$13.79	1791	1111	838
Roosevelt Public Power Dist.	$2.05	$1.34	$6.54	2075	514	586
Wheat Belt Public Power Dist.	$1.46	$7.68	$19.08	3200	722	993
Delta Montrose Electric Assn.	$1.28	$3.13	$194.87	28745	3389	212
Empire Electric	$1.11	$2.87	$313.37	13104	2473	217

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Gunnison County Electric Assn.	$1.08	$3.45	$129.82	8937	1430	8
La Plata Electric	$1.18	$6.17	$334.62	34266	6237	197
San Miguel Power	$1.32	$5.12	$2.17	10594	2416	55
White River Electric	$1.12	$10.02	$2 120.57	2485	739	60
Highline Electric Assn.	$1.44	$5.45	$18.81	5681	1528	3188
K C Electric Association	$1.76	$4.54	$22.38	3244	2335	721
Morgan County Rural Electric Assn.	$1.70	$8.03	$7.84	4818	1381	1553
Mountain Parks Electric	$1.13	$4.78	$319.49	16449	3195	13
Mountain View Electric	$1.53	$6.84	$1 059.37	42181	3599	15
Poudre Valley	$1.61	$8.72	$91.70	31917	3849	666
San Isabel Electric	$1.05	$3.17	$1 179.39	20826	2649	28
San Luis Valley REC, Inc.	$1.08	$5.37	$5.86	8612	1014	2620
Sangre De Cristo Elec Assn Inc.	$0.95	$4.62	-	10756	965	-
Southeast Colorado Power Assn	$1.17	$6.95	$8.56	7618	1133	1409
United Power	$1.52	$7.95	$50.02	60608	8857	636

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Y-W Electric Assn. Inc.	$1.37	$5.71	$16.61	5007	1373	2538
Central New Mexico Electric Coop	$1.03	$6.08	$52.37	15879	1362	227
Columbus Electric Coop	$0.94	$3.43	$41.48	3961	1133	164
Continental Divide Electric Coop Inc.	$1.00	$6.43	$2 389.33	20580	3162	11
Jemez Mountains Electric Coop	$0.93	$5.45	$1 825.84	27229	3776	4
Kit Carson Electric Coop	$0.79	$4.16	$592.38	24309	3677	10
Mora-San Miguel Electric Coop	$0.74	$6.53	$322.38	10575	274	1
Northern Rio Arriba Electric Coop Inc.	$0.85	$1.95	$25.98	3677	529	83
Otero County Electric Coop Inc.	$0.83	$4.75	-	15359	3075	-
Sierra Electric Coop	$0.89	$4.12	-	3595	573	-
Socorro Electric Coop	$0.88	$6.36	$101.61	11296	1605	52
Southwestern Electric Coop Inc.	$1.02	$5.62	$140.82	1446	304	536
Springer Electric Coop	$0.83	$4.51	$20 223.12	2455	540	2

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Big Horn Rural Electric Coop	$1.35	$8.36	$42.57	2892	496	251
Carbon Power & Light	$1.15	$8.66	$228.41	5415	727	49
Garland Light & Power Company	$1.65	$9.56	$5.28	1809	38	76
High Plains Power Inc.	$1.70	$22.88	$240.14	11848	442	465
High West Energy	$1.62	$21.46	$9.69	6782	99	2538
Niobrara Electric Assn., Inc.	$1.31	$2.17	$16.70	1403	1309	143
Wheatland Rural Elec Assn., Inc.	$1.54	$1.37	$18.25	2188	993	481
Wyrulec Company	$1.29	$10.14	$128.47	3446	1397	1
City of Truth or Consequences	$20.10	$136.98	-	3502	645	-
Beaver City Corporation	$0.74	$5.08	$44.71	1455	375	3
City of Blanding	$0.97	$5.02	-	1347	289	-
City of Bountiful	$1.13	$7.93	$4 298.44	15295	1354	1
City of Enterprise	$1.11	$4.83	$26.39	858	80	4
City of Ephraim	$0.97	$8.04	$80.96	1641	222	2

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Fredonia City	$1.00	$4.38	-	664	78	-
City of Gallup	$0.66	$10.32	-	8509	1812	-
Town of Holden	$0.87	$1.17	-	211	8	-
Hurricane Power Committee	$1.10	$14.09	-	5422	400	-
Hyrum City Corporation	$0.85	$14.53	$4 182.88	2340	168	1
City of Idaho Falls	$1.37	$7.74	$1 365.50	22449	3705	7
Kanosh Town Corporation	$0.80	$2.84	-	241	6	-
Kaysville City Corporation	$1.27	$6.66	$133.68	7929	716	1
Lassen Municipal Utility District	$0.88	$1.87	$8.34	9124	2872	122
Lehi City Corporation	$1.13	$6.94	-	14146	1412	-
City of Logan	$0.65	$9.73	$1 429.30	16130	1955	11
Los Alamos County	$0.82	$9.10	$49 191.32	7792	854	1
Lower Valley Energy Inc.	$2.12	$4.08	$44.92	19900	6125	197
Meadow Town Corporation	$0.80	$3.31	$5.35	159	13	3
Monroe City	$0.86	$4.87	-	1012	98	-
City of Morgan City	$0.79	$3.20	-	1350	267	-

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
MT. Pleasant City	$0.71	$2.49	-	2104	231	-
City of Murray	$0.93	$9.06	$4 782.10	13977	3186	1
Northern Wasco County PUD	$1.67	$4.47	$191.13	9198	431	226
Oak City	$1.09	$2.79	$2.91	259	10	2
Town of Paragonah	$0.72	-	-	265	-	-
Parowan City Corporation	$0.97	$3.98	-	1519	80	-
Payson City Corporation	$0.89	$9.80	$566.68	5404	441	5
Plumas-Sierra Rural Electric Coop	$0.95	$2.36	$84.71	6928	736	98
Price Municipal Corporation	$0.63	$8.19	-	4456	628	-
Santa Clara City	$1.74	$6.14	-	1936	118	-
Strawberry Electric Serv. Dist.	$1.41	$1.63	$13.60	2708	438	37
Spring City Corporation	$0.75	$0.78	-	501	23	-
City of Springville	$0.95	$9.47	$4 170.14	9486	992	2
City of St George	$1.32	$2.45	$38.94	22859	3836	715
Truckee Donner PUD	$0.72	$5.04	-	11692	1491	-

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
City of Washington	$1.09	$9.05	$35.37	5578	444	1
Page Utility Enterprises	$19.89	$106.15	-	3517	1007	-
Levan Town Corporation	$11.66	$34.51	$397.12	315	11	3
City of Manti	$13.02	$38.88	-	1281	86	-
Nephi City Corporation	$13.09	$98.95	-	1884	310	-
Provo City Corp	$9.12	$95.02	$154 963.17	30433	4786	1
Salem City Corporation	$12.77	$80.88	$896.72	1680	144	1
Spanish Fork City Corporation	$10.29	$81.04	$4 925.07	9372	1084	10
Wellton-Mohawk Irrigation District	$0.02	$0.10	$0.36	2768	996	52
Willwood Light and Power Company	$6.11	-	-	48	-	-
City of Wray	$1.86	$9.88	-	976	291	-
City of Cody	$0.67	$6.68	-	5780	1292	-
City of Powell	$0.87	$1.69	$41.31	2506	456	71
City of Pine Bluffs	$0.85	$7.81	-	630	57	-
Fort Laramie	$0.91	-	-	171	-	-
Town of Guernsey	$0.84	$3.45	$28.51	560	73	3

Utility Contractor or Utilities within Coop	Electricity cost increase: annual per customer ($)			Number of customers		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
Town of Lingle	$0.97	$4.52	-	225	37	-
Town of Lusk	$0.81	$1.87	$29.64	908	172	27
Town of Wheatland	$0.95	$1.63	$18.34	1709	289	89
Yampa Valley Electric Assn.	$0.21	$0.88	$212.70	21670	4663	17
City of Yuma	$3.37	$21.98	-	1252	307	-
Total	$415.51	$21,807.37	$401,369.42	2,745,635	391,670	39,191
Average	$0.96	$6.94	$75.79	2,745,635	391,670	39,191

Appendix B: Non-Utility GCD Customers' Annual Rate Increase

Non-Utility Contractor (all commercial sector)	Rate increase: annual per customer ($)	Contractor type
Alamo Navajo Chapter	$10,909	Tribal
Cannon Air Force Base	$84,643	Military
Canoncito Navajo Chapter	$8,031	Tribal
Chandler Heights Citrus Irrigation District	$18,470	Irrigation District
Cocopah Indian Tribe	$66,912	Tribal
Colorado River Indian Tribes	$277,638	Tribal
Confederated Tribes of the Goshute Reservation	$2,929	Tribal
Defense Depot Ogden	$162,172	Military
Department of Energy Albuquerque Operations Office	$1,085,931	Federal
Duckwater Shoshone Tribe	$3,903	Tribal
Ely Shoshone Tribe	$5,979	Tribal
Fort Mojave Indian Tribe	$15,913	Tribal
Ft. McDowell Mojave-Apache Indian Community	$132,354	Tribal
Gila River Indian Community	$781,368	Tribal
Havasupai Tribe	$12,545	Tribal
Hill Air Force Base	$215,682	Military
Holloman Air Force Base	$122,695	Military
Hopi Tribe	$158,647	Tribal
Hualapai Tribe	$35,397	Tribal
Jicarilla Apache Tribe	$37,861	Tribal
Kirtland Air Force Base	$215,682	Military
Las Vegas Paiute Tribe	$35,493	Tribal
Luke Air Force Base	$83,171	Military
Mescalero Apache Tribe	$56,400	Tribal
Nambe Pueblo	$3,560	Tribal
Navajo Tribal Utility Authority (tribal)	$1,300,024	Tribal
Paiute Indian Tribe of Utah	$8,958	Tribal
Pascua Yaqui Tribe	$67,223	Tribal
Picuris Pueblo	$2,755	Tribal
Pueblo De Cochiti	$11,787	Tribal
Pueblo Depot Activity Department of the Army	$143,543	Military
Pueblo of Acoma	$23,802	Tribal
Pueblo of Isleta	$63,335	Tribal
Pueblo of Jemez	$13,778	Tribal
Pueblo of Laguna	$42,902	Tribal
Pueblo of Pojoaque	$13,806	Tribal

Non-Utility Contractor (all commercial sector)	Rate increase: annual per customer ($)	Contractor type
Alamo Navajo Chapter	$10,909	Tribal
Pueblo of San Felipe	$21,595	Tribal
Pueblo of San Ildefonso	$3,645	Tribal
Pueblo of San Juan	$17,263	Tribal
Pueblo of Sandia	$50,367	Tribal
Pueblo of Santa Clara	$13,773	Tribal
Pueblo of Santo Domingo	$25,526	Tribal
Pueblo of Taos	$16,213	Tribal
Pueblo of Tesuque	$35,148	Tribal
Pueblo of Zia	$4,407	Tribal
Pueblo of Zuni	$63,419	Tribal
Quechan Indian Tribe	$35,627	Tribal
Queen Creek Water Conservancy District	$49,547	Irrigation District
Ramah Navajo Chapter	$20,523	Tribal
Roosevelt Water Conservation District	$104,839	Irrigation District
Salt River Pima-Maricopa Indian Community	$844,516	Tribal
San Carlos Apache Tribe	$227,236	Tribal
San Tan Irrigation District	$23,172	Irrigation District
Santa Ana Pueblo	$24,913	Tribal
Skull Valley Band of Goshute Indians	$862	Tribal
Southern Ute Indian Tribe	$65,948	Tribal
Tonto Apache Tribe	$20,962	Tribal
Tooele Army Depot	$67,102	Military
University of Utah	$201,709	State
Utah Associated Municipal Power Systems (CUWCD)	$10,613	Irrigation District
Utah State University	$70,124	State
Ute Indian Tribe	$33,083	Tribal
Ute Mountain Ute Tribe	$28,277	Tribal
White Mountain Apache Tribe	$339,369	Tribal
Wind River Reservation	$27,991	Tribal
Yavapai Apache Nation	$95,953	Tribal
Yavapai Prescott Indian Tribe	$44,198	Tribal
Yomba Shoshone Tribe	$1,775	Tribal
Yuma Proving Grounds	$21,081	Military
Total	$7,936,972	
Average	$115,029	

Appendix C: Brief description of the tribal GCD customers with significant impacts.

In this appendix we further investigate all of the different tribes that would see an annual impact of *at least $15,000* (rounded to the nearest thousand[66]) as a result of the loss of electricity generation at Glen Canyon Dam. Most of the tribes on this list have at least one casino on their land, but not all of them do. We are attempting to determine where each different tribe is consuming their energy. Since each of these tribes is a non-utility end user, they are using the energy that they get from GCD as a single entity rather than reselling that electricity to other end-users.[67] For example: If the Tribe operates one or more large casinos, then those casinos are likely to be consuming a large amount of the Tribe's electricity. Since we do not have a breakdown of each individual tribe's energy consumption, we attempt here to look at the commercial businesses and infrastructure that each tribe has. This is a first approximation of where the tribes likely are using the electricity. For many tribes, their largest single energy use appears to be in their casinos. For other tribes their single largest energy draws appear to be tribally run utilities like a water plant, a sewage treatment plant, or a medical facility.

Since casinos have been a very large source of revenue for tribes in the Upper Basin states much of this list is focused on casinos. Although data on tribal profits for each individual casino does not appear to be readily available, in New Mexico we can look at the Net Win from each casino. Net win is used as a relative view of how well each casino is doing and the revenues that the casino is generating. Because electronic gaming machines are the largest source of gaming revenue and generally have the highest net win for casinos, we assume that there is a correlation between net win and energy consumption. Since we cannot look at the actual energy consumption of each casino, we are simply using this as a first approximation of how a tribe's share of CRSP electricity is being used in their New Mexico casinos. The information in Appendix C provides those first approximations. It, however, is not meant to be used quantitatively.

"Net Win is the total amount of money wagered in Class III Games *MINUS*:

1. Money paid to patrons as winnings from Class III Games.
2. Costs of non-cash prizes paid to patrons from gaming machines.
3. $116,000 per year. Tribe reimburses the State its costs to enforce the Gaming Compact. This amount increases 5% annually.
4. $275,000 per year as tribal regulatory costs. This amount increases 3% annually.

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[66] For a complete list see appendix A.

[67] The NTUA has both a tribal and non-tribal entity in our list. This is because they both serve their customer base with the power that they receive and provide for their own needs as an end user. We have separated the power that they receive into these two different categories.

“Net Win” is not the “Net Profit” from a casino since there are many other costs associated with operating a casino. It is more like the “gross revenues” to the tribe from the casino.

Tribes must pay a percentage of their Net Win to the State based on the following chart.”[68]

Annual Net Win July 1 -June 30:	2007 – 2015	2015 – 2030	2030 -2037
Under $15 Million:	3% of the first $5 Million, & 9.50% on the rest	3% of the first $5 Million, & 9.50% on the rest	3% of the first $5 Million, & 9.50% on the rest
$15 – $50 Million:	9.25%	10.00%	10.25%
More than $50 Million:	9.75%	10.00%	10.75%

Table C1 shows the Net Win totals of the 13 largest casinos in New Mexico. The purpose of presenting this list is to show the relative size of some of the casinos that are owned by tribes that would be impacted by the loss of the power that comes from Glen Canyon Dam. It should also be noted that not all of the tribes in this table have a potential cost increase of at least $15,000 annually from the loss of GCD, so they do not appear in the detailed descriptions below.[69]

[68] http://isletapueblopolitics.com/2015/02/28/nm-releases-4th-quarter-net-win-from-indian-casinos/
[69] The Pojoaque and the Santa Clara bot report Net Win but their impact is less than $15,000 annually.

Table C1.

	2014 New Mexico Casino Net Win Totals	
1	Sandia	$155,889,432
2	Isleta	$91,178,566
3	Laguna	$88,452,663
4	Navajo	$81,131,668
5	Santa Ana	$75,065,365
6	Mescalero	$65,778,870
7	Pojoaque	$60,784,099
8	Santa Clara	$12,068,707
9	Acoma	$10,796,712
10	Tesuque	$20,676,044
11	San FelipeOhkayOwingeh	$4,597,098
12	Taos	$9,681,339
13	Jicarilla	$6,570,268
	Total	$682,670,831

Source: http://isletapueblopolitics.com/2015/02/28/nm-releases-4th-quarter-net-win-from-indian-casinos/

Since not all of the tribes that are impacted have casinos in New Mexico, we cannot determine the net win for individual casinos, in other states, as they are not obligated to report them. However, in Arizona we can look at the tribal employment in tribally owned casinos as well as Tribal Gaming Revenue. In 2014 Arizona Tribal Gaming Employment was 14,836 ranking just below Forestry, Fishing, and Related Activities according to the U.S. Bureau of Economic Analysis sector characterizations.[70] In fact tribal gaming in Arizona had revenues of $1.81 billion dollars in 2014.[71] Although we do not have a breakdown of the individual tribal earnings or a similarly descriptive metric such as Net Win in New Mexico, it is clear that tribal gaming is a very large revenue generator for the tribes.

Below we present an alphabetical list of the tribes that we estimated would incur *at least an annual $15,000* electricity cost increase (rounded to the nearest thousand) associated with the loss of GCD electric generation.

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[70]Taylor, J. The Economic Impact of Tribal Gaming in Arizona, 2014. Table 4. Page 9. http://www.azindiangaming.org/wp-content/uploads/2015/10/The-Economic-Impact-of-Tribal-Gaming-in-Arizona-2014.pdf
[71] Ibid. Figure 2. Page 10.

Cocopah Indian Tribe: $67,000

Own a golf course on their land, an RV resort, a speedway, a bowling alley, and casino/resort/conference center.

Colorado River Indian Tribes: $278,000

"The BlueWater Resort & Casino is a state-of-the-art gaming resort, including more than 200 hotel rooms with views of the Colorado River. The resort includes a casino with more than 450 slot machines, Keno, Blackjack and many other gaming opportunities. It also has several restaurants, a conference center and a multi-screen movie theater. Major national acts perform frequently at the resort's amphitheater. The BlueWater Resort & Casino is a great launching point for enjoyment of recreation opportunities on the Colorado River. The resort has a 160-dock marina, and is just one of dozens of locations where those interested in river recreation can enjoy what the Colorado River has to offer. " http://www.crit-nsn.gov/crit_contents/tourism/

Fort Mojave Indian Tribe: $16,000

The Fort Mojave Indian Tribe owns their own utility to serve their customers (http://www.ahamacav.com/). Since there is only one end user we assume that the power goes to the tribal facilities. They also have a golf resort (http://www.mojavegolf.com/), a casino (http://www.avicasino.com/)/resort, and a new health clinic (http://mojaveindiantribe.com/health-department/).

Fort McDowell Yavapai Nation: $132,000

The Fort McDowell Yavapai Nation have the Fort McDowell Casino (http://www.fortmcdowellcasino.com/home.php), the We-Ko-Pa Conference Center, golf club, and Resort (http://www.wekoparesortandconferencecenter.com/ and http://wekopa.com/), the Poco Diablo Resort (http://www.pocodiablo.com/), and the Eagle View RV Resort (http://www.eagleviewrvresort.com/).

Gila River Indian Community (GRIC): $781,000

The GRIC owns and operates three casinos (Vee Quiva, Wild Horse Pass, and Lone Butte). http://www.wingilariver.com/. They also operate two golf courses (Toka Sticks and Whirlwood), an equestrian center, a sand and gravel corporation, multiple restaurants, a spa, and numerous other commercial enterprises. http://www.gilariver.org/index.php/enterprises

Hopi Tribe: $159,000

The Hopi provide a fairly large list of different member services. http://www.hopi-nsn.gov/ However, we do not know how they use their energy except for their own Tribal use. They have one lodging center at the Cultural Center. The Hopi are discussed in more detail in the main body of this report. http://www.hopiculturalcenter.com/reservations/index.html

Hualapai Tribe: $35,000

The Hualapai Tribe does not have a casino or a large resort but they do have the "Hualapai Lodge" with 60 rooms as well as "Grand Canyon West" which is a large facility with a glass skywalk above the Grand Canyon (4,00 feet above it). http://www.grandcanyonwest.com/grand-canyon-west.html

Jicarilla Apache: $38,000

The Jicarilla Apache operate two casinos in Northern New Mexico; The Apache Nugget and the Wildhorse Casino. The Wildhorse Casino has an event center, a hotel, restaurant, and a bar. The Apache Nugget casino has a fuel station, convenient store, car wash, RV parking, and a restaurant. http://www.apachenugget.com/

As noted above in table C1 the Jicarilla Apache had a net win of more than $6 million in 2014.

Las Vegas Paiute Tribe: $35,000

The Las Vegas Paiute Tribe owns and operates three large golf courses outside of Las Vegas, Nevada. The Snow Mountain, Sun Mountain, and Wolf golf courses offer "magnificent, championship golf" designed by Pete Dye. http://www.lvpaiutegolf.com/

Navajo Tribal Authority: $1,300,000

The Navajo Tribal Authority are discussed in some detail in the main body of this report. The Navajo Tribal Authority run a very large public works department much like any municipality. They also run four casinos (Twin Arrows, Fire Rock, Flowing Water, and Northern Edge). Each of the casinos has lodging associated with it as well as dining and a host of different amenities and activities. http://navajogaming.com/casinos and http://navajogaming.com/discover-navajo .

The Navajo had a Net Win of more than $81 million dollars in 2014 (see table C1).

Mescalero Apache Tribe: $56,000

The Mescalero Apache Tribe owns and operates the "Inn of the Mountain Gods" resort and casino. This is a large casino/resort/golf course. The resort has multiple dining establishments, a spa, private ski area, a convention center, a hotel with multiple luxury suite options, and a host of other activities associated with their resort. http://innofthemountaingods.com/

As noted above in table C1 the Mescalero Apache had a Net Win of almost $66 million in 2014.

Pascua Yaqui Tribe: $67,000

The Pascua Yaqui Tribe owns and operates the Casino Del Sol Resort. The resort has a golf course, conference center, hotel, casinos, restaurants, a gas station, and a smoke shop etc. http://www.casinodelsolresort.com/about-us

Pueblo of Acoma: $24,000

The Pueblo of Acoma runs the Sky City hotel and casino. Sky City has a hotel, a casino, multiple restaurants, multiple bars (the Vino 102 and the Sky Lounge), a RV park, a shopping center, a travel center, a cultural center, and a concert venue among other facilities. http://www.skycity.com/alpha.html

As noted in table C1 above the Pueblo of Acoma had a Net Win of almost $11 million in 2014.

Pueblo of Isleta: $63,000

The own and operate Isleta Resort Casino, Eagle Golf Course and Isleta Lakes Recreational Complex. http://www.isleta.com/ As noted in table 1 above the Isleta had a Net Win of more than $91 million in 2014.

Pueblo of Laguna: $43,000

The Pueblo Laguna own three casinos (the Dancing Eagle, Route 66 Casino, and Casino Xpress) and numerous other businesses that are wholly owned subsidiaries of the tribe (Route 66 has a 154 room hotel, there are seven different restaurants/bars, 4 different "travel center" gas stations). http://lagunadevcorp.com/casino-gaming.aspx and http://lagunadevcorp.com/retail.aspx and http://lagunadevcorp.com/hotel.aspx and http://lagunadevcorp.com/food-beverage.aspx and http://lagunadevcorp.com/

As noted in table 1 above the Pueblo of Laguna had a Net Win of more than $88 million in 2014.

Pueblo of San Felipe: $22,000

"The pueblo has relatively few shops and amenities, but visitors can enjoy traditional foods, dancing, jewelry and other traditional crafts during the pueblo's annual arts and crafts show held in October. A modern-day attraction is the tribal-owned Casino Hollywood, quite visible from I-25, day or night… The tribe also operates a gas station, restaurant, gift shop and motor sports track across from the casino." www.sanfelipecasino.com and https://www.newmexico.org/san-felipe-pueblo/

As noted in table C1 above the Pueblo of San Felipe had a Net Win of more than $4.5 million in 2014.

Pueblo of San Juan: $17,000

The tribe owns the OhKay Casino and the Oke-Oweenge Crafts Cooperative, which showcases Redware pottery, weaving, painting, and other artwork from the eight northern pueblos. The OhKay Casino has the Harvest Buffet, the Coyote Cantina, the Coffee Spot, the Silver Eagle Lounge events center, and a hotel. http://ohkay.com/

Pueblo of Sandia: $50,000

They have a tribal government that operates Sandia Casino, Bien Mur Indian Market Center, Sandia Lakes Recreation Area, and the Albuquerque Golf Resort. The Sandia Resort and

Casino has a spa, a large events center, a hotel, and multiple different restaurants and bars. http://www.sandiacasino.com/?_vsrefdom=sandia-ppc&gclid=Cj0KEQjwvo6wBRCG3Zv92ZSLIIYBEiQA5PLVAiwwyldJ9QeT0sowWYGjSQSD79qGeemoeAq29OQy300aAp7N8P8HAQ

As noted in table C1 above the Sandia had a Net Win of more than $155 million in 2014.

Pueblo of Santo Domingo: $26,000

The Pueblo of Santo Domingo does not have a tribal gaming establishment. The Santo Domingo have an emergency medical station, a tribal utility authority, a housing authority, a water resource department, the Kew fitness center, a tribal court, an early childhood learning center, a senior center, a library, and a planning department. The Pueblo of Santo Domingo is similar to the Hopi tribe, which was discussed in more detail in the main body of this report, since, like the Hopi, they have not embraced tribal gaming. They live on a dry reservation and do not allow cameras or any kind of recording device while on their lands. They are a very traditional tribe. The roughly $26,000 of potential electricity rate increases would impact the tribe as a whole. http://santodomingotribe.org/

Pueblo of Taos: $16,000

The Pueblo of Taos runs the Taos Mountain Casino. It is billed it as the "largest small casino in New Mexico." The casino boasts the Red Diamond Restaurant, a smoke shop, and the Hotel Don Fernando de Taos. http://www.taosmountaincasino.com.

Although the casino may be "small" their Net Win, from table C1 above, was almost $10 million in 2014.

Pueblo of Tesuque: $35,000

Although the Pueblo itself is relatively small, the Camel Rock Casino that the Tesuque operate is relatively large. It boasts the Rock Showroom which is a 10,000 square foot event center, a casino in operation 7 days a week that only closes for four hours a day, and the Pueblo Artist Café and the Oasis Snack Bar. http://www.camelrockcasino.com/

As shown in table C1 above, the Pueblo of Tesuque had a Net Win in 2014 of almost $21 million.

Pueblo of Zuni: $63,000

Like the Hopi, discussed in detail in the main body of this report, the Pueblo of Zuni does not have a casino. The Zuni have the Zuni Rental Enterprise (a house rental agency), the Pueblo of Zuni Home Health Care Agency, and A: shiwi A: wan Museum and Heritage Center. They also have a Tribal court system, an education and career development center, Zuni Entrepreneurial Enterprises, and a host of other Tribal facilities. Since they do not have a casino that draws tourist dollars to their Pueblo it is possible that the Zuni tribe as a whole will more acutely feel the impact of increased electric rates with the loss of GCD generation. http://www.ashiwi.org/ and http://www.ashiwi.org/Links.aspx

Quechan Indian Tribe: $36,000

The Quechan operate the Paradise Casino and bingo hall as well as a number of RV parks. The Casino has the Pipa Events Center, the Ocotilla Bar, the Sidewinder Bar and Grill, a bingo hall, and a 166 room luxury hotel. http://www.paradise-casinos.com/

Ramah Navajo Chapter: $21,000

Like the Hopi, discussed in more detail in the main body of this report, the Ramah Navajo Chapter does not have a casino. The Ramah Navajo Chapter have an office of grants and contracts, a business and property/procurement office, the Ramah Navajo Utility Authority, a police department, and a host of other facilities like any small town or small sovereign nation. Since they do not have a casino or another tribally owned large tourist draw the Ramah Navajo Chapter may more acutely feel the loss of GCD generation and the below market rate power that comes from the GCD. http://ramahnavajo.org/home.html

Salt River Pima-Maricopa Indian Community: $845,000

The Salt River Pima-Maricopa Indian Community owns the Talking Stick Resort and Spa and Casino Arizona. Both are large casinos. The Talking Stick Resort also boasts the Talking Stick Golf Course and an events center and spa. The Salt River Pima-Maricopa also own Salt River Fields which is home to spring training for the Colorado Rockies and the Arizona Diamondbacks. For more information on the Salt River Pima-Maricopa see the main body of this report.

http://www.srpmic-nsn.gov/enterprises/gaming.asp and http://www.saltriverfields.com/facility-rental.aspx

San Carlos Apache: $227,000

The San Carlos have the Apache Gold Casino/Resort. The resort boasts the Apache Stronghold Golf Club, the Apache Prime Steakhouse, the Black River Grill, SNAX, the Point Sports Bar, the San Carlos Events Center (seating for 6,000), a convenience store, a coffee shop, an RV park, and the Apache Gold Resort Hotel with 146 rooms. http://www.apache-gold-casino.com/casino/

Santa Ana Pueblo: $25,000

The Santa Ana Pueblo (The Tamayame people) operate the Hyatt Regency Tamaya Resort and Spa that boasts a conference center, the Twin Warriors Golf Course, and the Corn Maiden fine dining restaurant. The Santa Ana Pueblo also runs the Santa Ana Star Casino that aside from a large amount of gaming boasts the Stage Las Vegas style nightclub, and Lounge 54. The casino also has four different restaurants and Starlight bowling alley. http://www.tamaya.hyatt.com/en/hotel/our-hotel.html and http://www.santaanastar.com/attractions/starlight-bowling-center As was noted in table C1 above, the Santa Ana had a Net Win of more than $75 million in 2014.

Southern Ute Indian Tribe: $66,000

"Southern Ute Indian Tribe business activity generates millions of dollars each year for La Plata and Archuleta Counties. The Tribe is aggressively creating and operating new businesses both on and off Reservation in the areas of oil and gas production, natural gas gathering, real estate development, housing construction, and gaming. The Tribe is currently the largest employer in La Plata County and supports many area non-profit organizations." https://www.southernute-nsn.gov/business/

The Southern Ute Indian Tribe also operates the Sky Ute Casino. The Sky Ute Casino has a luxury hotel with 140 rooms, a day spa, fitness center, and four restaurants. The resort also has a bowling center (Rolling Thunder Lanes), a pool, and a mini golf course and playground. http://www.skyutecasino.com/resort-amenities/

Tonto Apache Tribe: $21,000

"ABOUT TONTO APACHE TRIBAL ENTERPRISES

On September 3, 1993, the Mazatzal Casino opened for business. This temporary facility was a small modular building with 90 slot machines and small snack bar. On April 2, 1995, the 35,000 square foot casino consisted of 300+ slot machines, a blackjack/poker room, a 200-seat bingo hall, restaurant, sports lounge, snack bar, gift shop and arcade.

In August 2007, we opened the NEW Mazatzal Hotel & Casino! The existing Casino was converted into an event, convention, and meeting center that will accommodate 500 for meetings and approximately 800 for theater style events.

The Mazatzal Hotel & Casino is one of the largest employers in Payson, Arizona, employing over 300. The Hotel & Casino are open 24/7.

The Tonto Apache Tribal Market, Smoke Shop, and Gas Station are located just south of the Mazatzal Hotel & Casino on Highway 87. It's much more than a convenience store, selling groceries, beer, tax-free cigarettes, Mobil gasoline, and much more."

http://www.mazatzal-casino.com/index.php/visit/Tonto-Apache-Tribal-Enterprises

Ute Indian Tribe: $33,000

The Utes have a tribal membership of 2,970 and over half of its membership lives on the Reservation. They operate their own tribal government and oversee approximately 1.3 million acres of trust land. The Utes also operate several businesses including a super market, gas stations, bowling alley, Tribal Feedlot, Uinta River Technologies, Ute Tribal Enterprises LLC and Water Systems. Cattle raising and mining of oil and natural gas is big business on the reservation. Water Systems manager provides water and sewer needs for several communities. http://utetribe.com/

Bottled Water: Ute Whiterocks Water Bottling

“The state-of-the-art water bottling equipment is capable of producing 24,000 bottles of water a day, said Raymond Murray, operations officer for the tribe's business enterprises. Within two to four years, the tribe envisions its water bottling plant operating three daily shifts with 36 employees and pulling in an estimated $2 million to $4 million annually. "Bottled water will be here forever," Murray said” http://www.deseretnews.com/article/863608/Ute-Tribe-turning-water-into-jobs.html?pg=all

Ute Mountain Tribe: $28,000

The Ute Mountain Tribe operates the Ute Mountain Casino, Hotel, and Resort. The complex boasts Colorado’s first tribal gaming facility. The complex has a hotel (90 rooms), Kuchu’s Restaurant, the Ute Mountain Convention and Meeting Space (for up to 800 people), and an RV park. http://www.utemountaincasino.com/sights.php

White Mountain Apache Tribe: $339,000

The White Mountain Apache Tribe owns a large ski area (Sunrise Peak http://www.sunriseskipark.com/), a large casino (Hon-Dah Resort/Casino http://hon-dah.com/), a timber company/mill (Fatco Fort Apache Timber Company http://www.wmat.nsn.us/fatco.html), and a game and fish office with campgrounds, fishing, hunting, rafting, etc… (http://www.wmatoutdoors.org/).

Wind River Reservation: $28,000

“Wind River Hotel and Casino is Wyoming's largest casino providing visitors with the Ultimate Gaming Experience. We are the only vacation destination in the state where you can stay, play and win! Featuring over 800 slot machines, table games, three restaurants, an espresso bar and two gift shops , the Wind River Casino provides visitors with hours of endless fun. The 90 room Wind River Hotel is within driving distance of all the great Wyoming hotspots such as Yellowstone National Park, The Grand Tetons and Jackson Hole Ski Resort.” http://www.windriverhotelcasino.com/

Yavapai Apache Nation: $96,000

The Yavapai Apache run the Cliff Castle Casino. The complex boasts an 80 room hotel, a conference facility, 8 dining/bar establishments, the Dragonfly nightclub and Stargazer Pavilion (open air theater), a bowling alley/arcade, a gift shop, and an events center for large meetings and events. (http://www.cliffcastlecasinohotel.com/).

Yavapai Prescott Indian Tribe: $44,000

The Yavapai Prescott Indian Tribe operates Bucky’s Casino. Bucky’s Casino adjoins to the Prescott Resort. The resort has 160 guest rooms, Icha Maajoh fine dining, the Urban Grind and Gallery coffee shop, The Salon and Spa at the Prescott Resort, a workout facility, a gift shop, and indoor pools/Jacuzzi. http://www.prescottresort.com/index

Appendix D: Calculating the potential effect of ending GCD derived power subsidies on customer rates

The energy produced at GCD is currently marketed by Western as part of the Colorado River Storage Project (CRSP). The CRSP allocates electricity to 139 contractors including 54 Native American tribes and pueblos, 9 Federal military installations, 2 State Universities, 1 DOE office, 66 utilities, and 7 utility cooperatives which have a total of 111 member utilities. The electricity generated in the CRSP is divided between the 139 contractors through an allocated Contract Rate of Delivery (CROD)[72] which is the total amount of electricity (in kW) that Western is obliged to provide at a pre-determined rate. If the CRSP does not generate enough power to supply the CROD for all 139 contractors, Western purchases power from the wholesale market to make up for this discrepancy. If, on the other hand, CSRP produces power than the CROD for all 139 contractors, the excess power is offered to the contractors based on each contractor's percentage of the total CROD[73].

Each contractor's (n) percentage of the total CROD is calculated by:

$$Percentage_n = \frac{CROD_n}{\sum_{All\ Contractors} CROD}.$$

The rate charged to CSRP contractors is reevaluated on 5 year intervals and it includes changing amounts and rates of power bought on the wholesale market. Thus, if the CSRP produced zero percent of the total CSRP marketed power, the rate of the power sold to the contractors would equal the wholesale market rate plus the cost of transmission, service, and maintenance. In other words, the rate offered by Western would trend toward the average market rate of power in the region, which was 2.64 times the rate offered by Western over the period analyzed in this study.

Herein we make a distinction between two types of contractors: utilities and non-utilities. The utilities market power to residential, commercial, or industrial end users; these utilities use the power purchased from CRSP to provide lower rates to their customers across all sectors. The non-utilities do not market the electricity to other entities;[74] the power purchased from CRSP is utilized directly by these non-utilities. The utilities comprise a total of 90.37% of the total winter CROD allocations and 88.06% of the summer CROD allocations from the CRSP. Thus the non-utilities purchase a relatively small part of the CROD allocations.

[72] There is a separate CROD for summer and winter for each of the contractors.

[73] Power is only offered to the contractors if the excess amount power generated is large enough to make this option fiscally solvent. In other words, if it costs more to redistribute the power than the contractors would save by using this power, the excess power is sold on the market.

[74] They do not file EIA-861 forms which include average rates and total sales for each sector.

Calculations for utilities

Our process of estimating the potential effect of reduced power generation at GCD on end user electric rates across all sectors is:

1. Calculate the amount of GCD power allocated (*PAGCD*) to each utility (*n*)

$$PAGCD_n = Percentage_n * GCD_{AveragePowerProduction}$$

2. Calculate the percentage of total power sales for each utility (TS_n) that is sourced from CRSP (*PSCRSP*)

$$PSCRSP_n = \frac{CRSP_{TotalAllocation(n)}}{TS_n}$$

3. Calculate the composite market rate (*CMR*) of electricity NOT provided by GCD, with the total power sales of the contractor and the rates (*R*) of the contractor (*n*) and of CRSP

$$CMR_n = \frac{(TS_n * R_n) - (PAGCD_n * R_{CRSP})}{TS_n - PAGCD_n}$$

4. Calculate the estimated rate change (*RC*) due to Western adjusting rates to account for having to source more power from the wholesale market, this equation includes the total revenue for the utility (TR_n). The subscripts *TA, CO,* and *EO* are total allocation, capacity only, and electric only (part of the Western rate), respectively. The capacity portion of the composite rate is $0.01743 per kWh and the calculated electric rate with the GCD electricity supplanted with wholesale priced market electricity is $0.0277 per kWh.

$$RC_n = \frac{CMR_n * \left(TS_n - CRSP_{TA(n)}\right) + (R_{CO} + R_{EO}) * \left(CRSP_{TA(n)}\right) - TR_n}{TS_n}$$

5. Calculate the total increase in electricity cost (*CI*) across all sectors that will likely be borne by all customers.

$$CI_n = RC_n * PAGCD_n$$

6. Calculate the average cost to each customer (*CPC*) by dividing the total increase in electricity by the number of customers (*NC*).

$$CPC_n = \frac{CI_n}{NC_n}$$

This gives us the cost increase per end user customer assuming all customers use the same amount of power.

We further divide the impact into residential, commercial, and industrial sectors by using a similar system of calculations. However, rates paid to utilities are not consistent across the sectors therefore the calculations incorporate more assumptions. First, we assume that the rate savings from the reduced rates of power that is received from the CRSP is divided equally across the three sectors. Thus, our process of estimating the potential effect of reduced power generation at CRSP on end user electric rates for each sector is:

1. Calculate the composite market rate (*CMR*) of electricity NOT provided by CRSP for each sector (s)

$$CMR_{s,n} = \frac{TR_{s,n} - \left(R_{CRSP} * PSCRSP_n * TS_{s,n}\right)}{TS_{s,n} - \left(PSCRSP_n * TS_{s,n}\right)}$$

2. Calculate the difference in the average annual utility rate for each sector (*s*) and the composite market rate

$$RC_{s,n} = \frac{CMR_{s,n} * \left(TS_{s,n} - \left(TS_{s,n} * PSCRSP_n\right)\right) + TS_{s,n} * PSCRSP_n * (R_{CO} + R_{EO}) - TR_{s,n}}{TS_{s,n}}$$

3. Calculate the total increase in electricity cost for each sector.

$$CI_{s,n} = RC_{s,n} * TS_{s,n} * PSCRSP_n$$

4. Calculate the average cost to each customer by dividing the total increase in electricity by the number of customers.

$$CPC_{s,n} = \frac{CI_{s,n}}{NC_{s,n}}$$

Calculations for non-utilities

To determine the potential price increase for non-utilities we assume that the non-utility gets 100% of their electricity directly from the CRSP[75] and that the price of the increase is shouldered solely by the contractor. The electricity provided to these non-utilities is marketed by Western directly to these contractors as commercial sector entities.[76]

With these assumptions, we calculate the potential price increase in power by:

1. Calculating the amount of GCD power allocated to each non-utility

$$PAGCD_n = Percentage_n * GCD_{AveragePowerProduction}$$

[75] This should be the only portion of their electric rate to increase even if they purchase part of their power from other sources.
[76] Western files an EIA-861 each year for this electrical distribution; all of the electricity marketed directly to non-utility entities is sold as commercial power.

2. We assume that the rate difference for non-utilities is 2.64 times the electricity portion of the rate. This value is $0.03168 per kWh which is just below the average historical on-peak price that Western paid for electricity during Water Years 2009-2014.

3. Calculate the total increase in annual price by multiplying this potential rate increase by $PAGCD_n$.

$$CI_n = PAGCD_n * (R_{CO} + (2.64 * R_{EO}))$$

Notation used in Appendix D	
SUBSCRIPTS	
n	Subscript to differentiate contractors
s	Subscript to differentiate sectors (residential, commercial, and industrial)
TA	Total allocation: winter allocation + summer allocation (kWh)
CO	Capacity portion of the CRSP rate ($)
EO	Electricity portion of the CRSP rate ($)
VARIABLES	
CROD	Contract rate of delivery (kWh)
PAGCD	Amount of power allocated from GCD (kWh)
PSCRSP	Percent of total CRSP power allocation
TS	Total power sales (kWh)
CMR	Composite market rate ($/kWh)
R	Rate charged by contractor ($/kWh)
RC	Estimated rate charged by contractor with GCD subsidized power removed ($/kWh)
TR	Total revenue ($) for contractor from EIA form 861 in 2012 (or 2009 if no data for 2012)
CI	Total increase in electricity cost borne by all customers ($)
CPC	Average cost to each customer ($)
NC	Number of customers

Appendix E: Simple Calculation of Potential Increase of Electrical Production of Hoover Dam

In this section we detail the simplistic calculations that we used to estimate the potential increase of electric generation of Hoover Dam under the assumption that all of the water in Lake Powell is transferred to Lake Mead. Clearly, this calculation is very rudimentary and there are many factors that we ignore here. This calculation is only an *estimate* and should be treated as such. We do not believe that this estimate should be used for any purpose other than getting a rough idea of the possible energy gain associated with an increase in head at Lake Mead.

The reported current estimated volume of Lake Powell (2015 average) is ~11,907,776 acre feet of water.[77] The all-time maximum volume of Lake Powell was 25,757,086 acre feet. The dead pool volume of Lake Powell is ~1,895,000 acre feet. So, if we assume that Lake Powell is reduced to dead pool storage levels, the volume of water available to transfer to Lake Mead is ~10,012,776 acre feet.

The 2015 average volume of Lake Mead storage was ~10,251,505 acre feet so the adjusted volume of Lake Mead would be 20,264,281 acre feet if we assume a perfect direct transfer of water from Lake Powell to Lake Mead. This corresponds to an elevation of ~1165 ft.[78] for Lake Mead. The average 2015 elevation of Lake Mead is ~1083 ft.[79] so the increase to Lake Mead is ~ 82 ft. or ~25 m.

Calculating the increase in electric output: [80]

The potential energy associated with water depth is given by:

$E = m*g*h$

where m is the mass of water, g is the acceleration due to gravity on Earth (9.8 m/s^2), and h is the height of the water column above the generator gates (head).

The power (P) that can be produced with a certain water height is given by:

$P = \eta*\rho*F*g*h$

where η is an energy transfer factor between the water and the generator turbine, ρ is the density of the water (1000 kg/m^3), and F is the flow rate of the water. The total flow rate of the water is related to the velocity (*v*) of the water and the area (*A*) over which the water is flowing:

$F=A*v$

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77 http://lakepowell.water-data.com/

78 From tables provided in the Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lakes Powell and Mead, FEIS, November 2007, Appendix A at: http://www.usbr.gov/lc/region/programs/strategies/FEIS/AppA.pdf

79 ibid

80 All equations are from http://physics.ucsd.edu/do-the-math/2011/12/how-much-dam-energy-can-we-get/

In the absence of turbines the velocity of the water leaving the penstocks is:

$v=(2*g*h)^{1/2}$

Now, maximum flow for power generation is 32,000[81] cfs (906 m^3/s) and full pool for Lake Mead is 1,229 ft.[82] which results in a maximum head of 590 ft. (179.8 m).[83] So, the area of the gates that lead to the generators is approximately:

$A= 906 / (2 * 9.8 * 179.8)^{1/2} = 15.26\ m^2$

and the flow rate at that level is ~59.4 m/s.

The current nameplate capacity of the Hoover Dam is 2.074 GW[84] meaning that the efficiency of transfer of kinetic energy to electric energy is:

$\eta = (1000\ kg/m^3 * 906\ m^3/s * 9.8\ m/s^2 * 179.8\ m) / 2.074 \times 10^9\ W = 0.77$

The current head at Lake Mead is ~446 ft. (135.9 m) thus, after the increase of 25 m head from the addition of water from Lake Powell, the maximum flow velocity is ~55.6 m/s. The velocity of the water after kinetic energy is transferred to the turbines (v') is given by:

$v'=v*(1-\eta)^{1/2}$

Thus, the flow rate is ~26.7 m/s, and the total flow is:

$26.7\ m/s * 15.26\ m^2 = \sim 407\ m^3/s$

Thus, the approximate POTENTIAL power increase associated with the calculated increase in head at Lake Mead if all of the water from Lake Powell were transferred to Lake Mead is:

$P=0.77 * 1000\ kg/m^3 * 407\ m^3/s * 9.8\ m/s^2 * 25\ m = \sim 76\ MW$[85]

To determine the annual increase in electricity output we multiply this power by the average number of hours in a year (8766). This gives us an estimate of ~673.1 GWh of increased electric production from Hoover Dam.

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[81] http://www.usbr.gov/lc/region/pao/brochures/faq.html#anngen
[82] ibid
[83] ibid
[84] ibid
[85] The difference in the estimate given here and the result of the equation given is due to rounding errors. The value given is a reasonable approximation of the full calculations.

Addendum to: The Impact of the Loss of Electric Generation at Glen Canyon Dam, Phase II: Financial Impacts on Existing Electric Consumers

A Report Prepared for the

Glen Canyon Institute

By

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May 9, 2016

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I. Glen Canyon Dam power generation as a function of pool elevation

The electrical power generation for any given day at the Glen Canyon Dam is dependent on many factors. These include the capacity of each generator in the dam, the potential energy held in the water (pool elevation of Lake Powell), regulations on maximum flow rates through the dam, regulations that limit the ramping rates of the flow through the dam, and electric demand in the region. Because there are many factors that influence the amount of electricity produced by the GCD on any given day, there is a potential for variation in the amount of electricity produced at the GCD for any given pool elevation. Here we analyze the historical relationship between Lake Powell pool elevation and electrical generation at the GCD on a daily time scale between 26 December, 1963 and 13 February, 2016.[1] We use this data to construct a chart that relates electrical generation to pool elevation at GCD.

The historical data provided online by the Bureau of Reclamation (BoR) does not include information about electrical generation, however, release rates related to electrical generation are provided. To determine the relationship between generation release rates and electricity generation, we used a linear regression of daily average power generation from 2004 to 2014[2] and the corresponding power release data to define the relationship between Power Releases and power generated for GCD (Figure 1).

Figure 1.

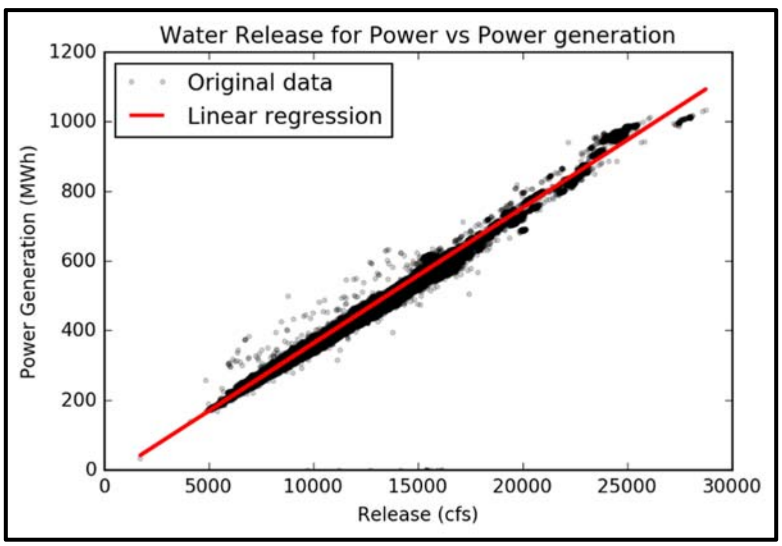
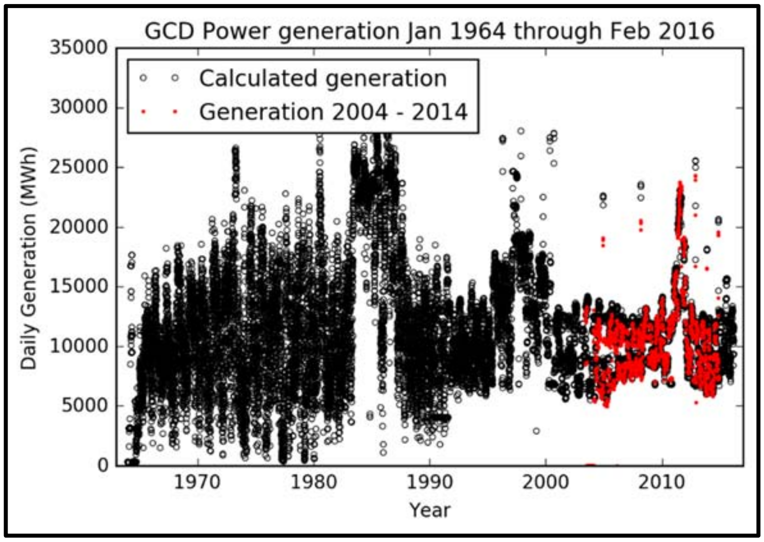


Figure 1 shows daily average release rates at Glen Canyon Dam and the power generated during that day for 2004-2014. A linear regression of the data is shown in red, the regression fits the data with an r-squared value of 0.994. We use the linear equation to construct generation values for release rates for the entire data series available from the BoR website.

We used this linear regression to calculate the electrical generation for the entire 1964 to 2016 daily power release data set. The results of the calculation and the comparison to generation between 2004 and 2014 data are shown in Figure 2.

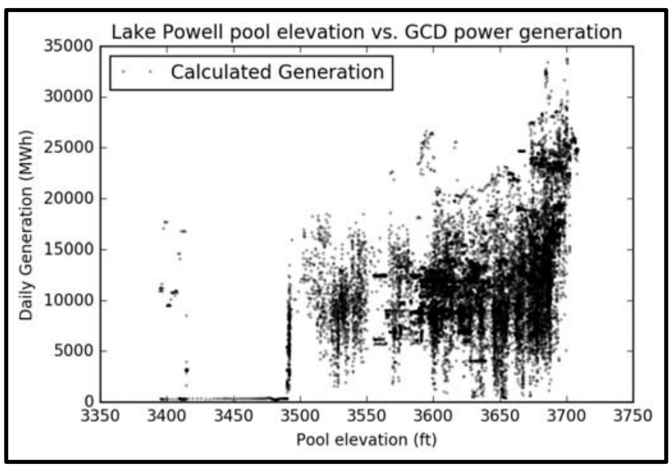
[1] Downloaded from http://www.usbr.gov/rsvrWater/faces/rvrOSMP.xhtml on 14 February, 2016
[2] Downloaded from http://www.usbr.gov/uc/crsp/GetDataSet?l=GLEN+CANYON+DAM+POWER+PLANT&c=2305&strSDate=1-JAN-2003&strEDate=25-NOV-2014 on 26 November, 2014 – This link has since been removed.

Figure 2.



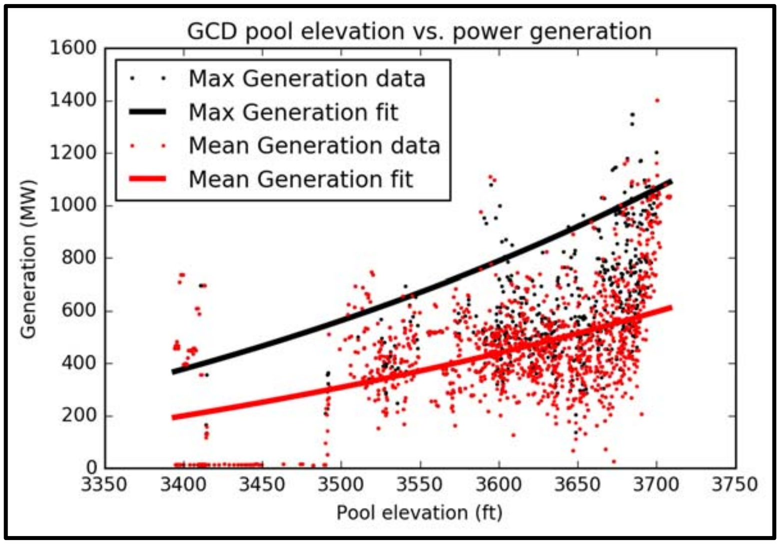
We then examined the calculated power generation with respect to each recorded pool elevation for the ~41 years of recorded data (Figure 3).

Figure 3.



Recall that the pool elevation is only one of the factors that influences the electrical generation at GCD. This is illustrated in the range of daily generation values associated with each pool elevation, especially between ~3500 ft. and ~3700 ft. elevation. To account for this variation we calculated the average (mean) and maximum generation for each recorded pool elevation and included both of these values in our generation vs. pool elevation chart. Further, we calculated the average and maximum generation per day over 2 year intervals and used this data to calculate a least squares regression of the form $Generation = \alpha^{PoolElevation} + \beta$ where α and β are coefficients. Because the historical data includes elevation measurements made during the time when Lake Powell was being filled and very little power was generated, we restrict our regression to pool elevations between 3500 and 3700 ft., the result of this analysis are shown in Figure 4.

Figure 4.



It is readily apparent from Figure 4 that the regression does not fully explain the data. The reason for this is that the pool elevation at Lake Powell determines the potential power generation at the GCD, not the actual power generation. Figure 1 shows that the actual power generation is determined primarily by the water release rate at each pool elevation. Throughout the history of the Glen Canyon Dam, the water release rate has been determined by the regulations, electrical demand, and for many years, the value of the electricity generated.[3] The spread in the average and maximum generation for all given elevations, then, is due to the fact that at any elevation, many different power generating scenarios are available for the dam. Thus the regression of the average generation data is indicative of the most likely generation rate for each pool elevation; the regression of the maximum generation is indicative of the most likely maximum generation for each pool elevation.[4] In other words, for each pool elevation, the regression of the average data is the best guess of what the Glen Canyon Dam will produce per hour assuming the dam operators act in a manner that is consistent with historical precedence. Likewise, the regression of the maximum data is the best guess for the maximum power that the Glen Canyon Dam will produce assuming the dam operators act in a historically consistent manner.

We have included a table in Appendix A which has the mean generation, maximum generation, and variance in the calculated generation at Glen Canyon Dam for every pool elevation measured between 1964 and 2016 at Lake Powell. We also include the values of the regression fit to the mean and maximum generation at each elevation in the table.

[3] For many years, the electrical generation at the dam was determined by the highest profit that the dam could make, daily and annually. Generating flow was increased during peak hours of electrical use and during the summer since the electricity is worth more at those times. When electrical loads were low, as they usually are in the spring and fall, generating flow was reduced to hold back water for use during higher load periods.

[4] This is a statistical 'best guess' for generation at each elevation assuming that dam operators make decisions that are consistent with historic operational decisions. This is not a reliable indicator of future dam operations.

II. Estimate of increased generation at Hoover Dam under the Fill Mead First proposal

Under the Fill Mead First (FMF) proposal, water from Lake Powell would be transferred to Lake Mead, increasing the total volume of Lake Mead, and thus the pool elevation would also increase. This increase in pool elevation increases the potential energy of the water which, in turn, increases the potential power generated at Hoover Dam. In the second phase of our analysis of the potential economic impacts of the loss of electrical generation at the Glen Canyon Dam, we estimated the potential increase in power generation at the Hoover Dam assuming an instantaneous transfer of water from Lake Powell to Lake Mead. Here we take our estimate a step further by accounting for more realistic transfer rates of water from Lake Powell to Lake Mead for three FMF prescribed pool elevations for Lake Powell; (1) the minimum power pool elevation, (2) the dead pool elevation, and (3) the natural river elevation (completely drained reservoir). Within this analysis we construct a water balance model for the two reservoirs based on historical inflow and release data, estimates of monthly evaporative loss, and reasonable flow rates through the Grand Canyon.[5] We use this highly simplified model to estimate the potential increase in pool elevation at Lake Mead over time.

The most basic formulation of the water balance model constructed for this analysis is a direct calculation of the change in water volume at Lake Mead. So, for Lake Mead, the change in volume is equal to the volume of water which flows into Lake Mead minus the volume of water which leaves Lake Mead. The volume of water which leaves Lake Mead is equal to the water released through the Hoover Dam plus the volume of water which evaporates plus the volume of water diverted from Lake Mead. Because we are interested in determining the potential change in water volume at Lake Mead we will assume that both the volume of water diverted from the reservoir, as well as the precipitation[6] are both invariant over the period of our analysis. Thus the water balance equation for Lake Mead becomes:

$$Volume\ Change_{Mead} = Inflow_{Mead} - Outflow_{Mead} - Evaporation_{Mead}$$

Similarly, the water balance for Lake Powell is:

$$Volume\ Change_{Powell} = Inflow_{Powell} - Outflow_{Powell} - Evaporation_{Powell}$$

In our model we assume that the inflow to Lake Mead is equal to the volume of water released from Lake Powell.[7] Thus, until Lake Powell reaches the FMF elevation for each scenario,[8] the total volume change at Lake Mead is:

$$Volume\ Change_{Mead} = Outflow_{Powell} - Outflow_{Mead} - Evaporation_{Mead}$$

After Lake Powell reaches the prescribed FMF elevation,[9] the volume change at Lake Mead is:

$$Volume\ Change_{Mead} = Inflow_{Powell} - Outflow_{Mead} - Evaporation_{Mead}$$

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[5] Regulations limit the absolute flow rates as well as the ramping rates through the Grand Canyon. We assume that flow rates would vary seasonally.

[6] We assume precipitation is invariant since the area of the collection basin does not change as the surface area of the reservoirs change. In other words, we do not distinguish between precipitation falling directly on the water surface and precipitation falling on the high water level banks of the reservoirs and running into the reservoirs.

[7] This implicitly assumes that the evaporation and loss of water flowing through the Grand Canyon is negligible in our calculations.

[8] Prior to achieving the prescribed FMF elevation, outflow from Lake Powell must be greater than the inflow for the pool elevation to decrease.

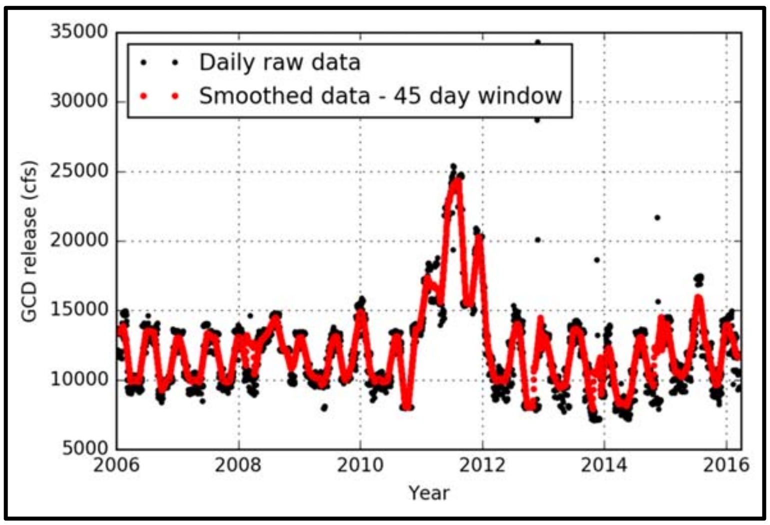
[9] After achieving the prescribed FMF elevation, the water balance at Lake Powell should be a net of zero, so all inflow to the (remnant) Lake Powell is immediately released to flow to Lake Mead.

1. Inflow to Lake Mead

For each FMF proposal, the volume of water released from Lake Powell changes over time. During the time that it takes for Lake Powell to drain, the release rates are constrained by regulations of flow rates through the Grand Canyon, after Lake Powell reaches the prescribed pool elevation, release rates follow natural variations in the flow of the Colorado River.

Water release rates for the Glen Canyon dam are currently set to range from 6,500 cfs to 25,000 cfs.[10] Historical releases rates from Lake Powell show that in high water years (such as WY2011) the release rate from Glen Canyon Dam varies between ~15,000 cfs and 25,000 cfs whereas in years that are more representative of the past decade, the release rate varies between ~7,000 cfs and ~15,000 cfs (Figure 5).

Figure 5.



In our analysis we assume that the release rate from Glen Canyon Dam varies between 8,000 cfs and 22,000 cfs in a sinusoidal manner with lower flow rates in the winter and higher flow rates in the summer; the peak flow is at the 183rd day of the year (DOY). [11]

2. Outflow from Lake Mead

Outflow through the Hoover Dam is not readily available on the BoR website, therefore we use historical data from the USGS stream gauge[12] just below the Hoover Dam as a proxy for the daily release rate from Lake Mead. The historical data from this stream gauge show that the release form Hoover Dam does not significantly vary from year to year (Figure 6). This is true even in high water years where the Glen Canyon Dam increases outflow. Over the last decade, the daily release rate from Hoover Dam fluctuates between ~5,000 cfs and ~23,000 cfs. To approximate potential future release from Hoover Dam we use ten years of daily historical stream gauge data from 1/1/2005 – 12/31/2014 as a proxy for future release rates.

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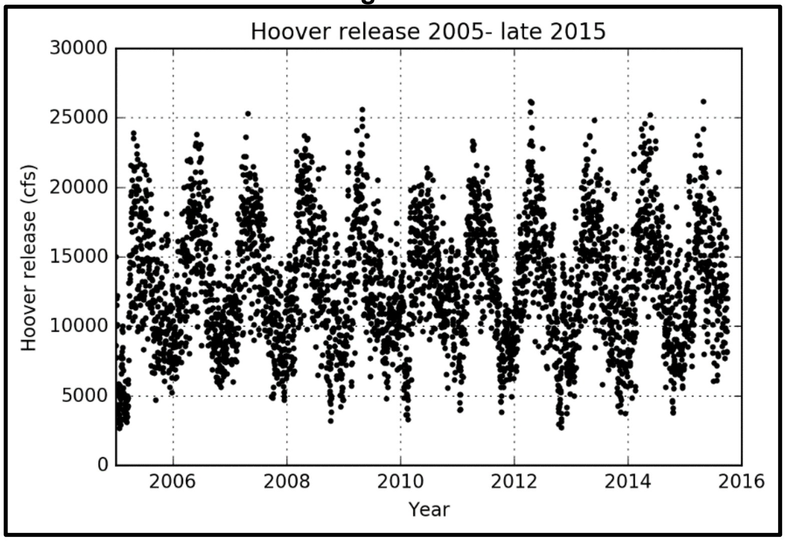
[10] From CRSS Model Documentation for the RiverWare™ modeling system; Appendix A describing the reservoir operating rules for Lake Powell and Lake Mead
[11] This is July 2nd most years and July 1st on leap years
[12] USGS stream gauge #09421500

Figure 6.



3. Evaporation from Lake Mead

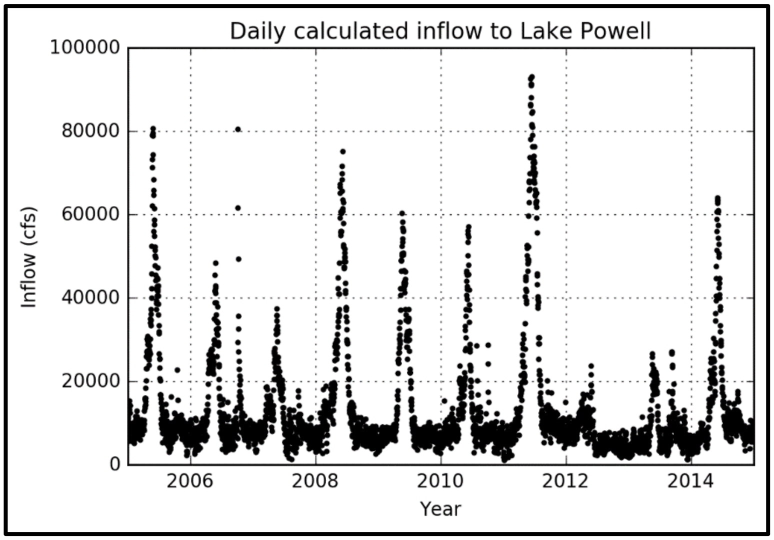
To calculate the daily evaporation at Lake Mead, we use the monthly BoR evaporation coefficients[13] multiplied by the surface area of the lake. The surface area of Lake Mead is estimated on a daily time scale by determining the change in reservoir volume[14] and determining the surface area associated with the new volume from the BoR volume vs surface area table.[15] Because the monthly evaporation coefficients account for a month of evaporation, daily evaporation volumes are given by the monthly coefficient divided by the number of days in the month.

4. Estimating inflow to Lake Powell

For Lake Powell, the BoR provides daily historical data for calculated and unregulated inflow to the reservoir.[16] Similar to outflow from Lake Mead, we use this historical daily data from 1/1/2005 to 12/31/2014 as a proxy for future inflow to Lake Powell. We use historical data to realistically model recent natural variation in precipitation. This time period includes both high input (2011) and low input (2013) years (Figure 7). This proxy is appropriate since forecasting future weather is extremely unreliable.

[13] CRSS Model Documentation for the RiverWare™ modeling system; Appendix A describing the reservoir operating rules for Lake Powell and Lake Mead – Table A-20
[14] Daily volume = previous day volume + inflow - outflow
[15] From CRSS Model Documentation for the RiverWare™ modeling system; Appendix A describing the reservoir operating rules for Lake Powell and Lake Mead – Attachment B
[16] http://www.usbr.gov/rsvrWater/faces/rvrOSMP.xhtml

Figure 7.



5. Evaporation for Lake Powell

Similar to Lake Mead, we use the BoR monthly evaporation coefficients and surface area of the reservoir to calculate the daily evaporation volume from Lake Powell. However, since we are modeling the draining of Lake Powell, we cannot use the BoR volume vs. surface area table for pool elevations below 3370 feet above sea level, thus we fit a function to the elevation vs. surface area relationship for Lake Powell and extrapolate surface areas below 3370 ft. from this function.[17]

6. Running the model

Using the input data described above, we calculate the change in volume, pool elevation, and surface area of both Lake Mead and Lake Powell on a daily time step. For each FMF scenario we calculate a ‘no change’ water balance[18] as well as the prescribed FMF scenario. We calculate the total potential increased power generation at Hoover Dam from the difference in head at the Hoover Dam between the ‘no change’ and FMF scenarios. As we describe in Appendix E of our previous document, the difference in head allows for increased energy production.

For each model scenario, we sum the daily potential electricity generation from the beginning of the increased release rate from Glen Canyon Dam until the prescribed pool elevation for Lake Powell is reached. The potential annual benefit of increased power generation is taken as total generation in MWh divided by the number of years it takes to reach the prescribed elevation for the FMF scenario.

7. Model Results

a. Power Pool Scenario

The FMF power pool scenario assumes that the final pool elevation of Lake Powell is at the minimum elevation for which power can be produced at Glen Canyon Dam. This elevation is 3490 feet above sea level. In this scenario, the final elevation of Lake Powell is reached ~4.9 years after increased release rates are initiated at Glen Canyon Dam.[19] Under this scenario, the average increase over the

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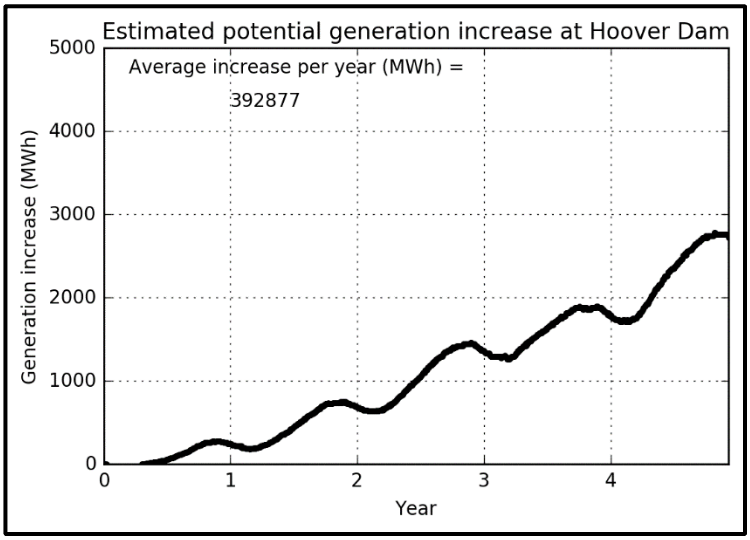
[17] We fit the surface area vs. elevation data with a logarithmic function (R squared value of 0.9952). The accuracy of this function to elevations below 3370 ft. is unknown. For a proper analysis of the relationship between surface area and elevation below 3370 ft., a bed map for the lake would need to be constructed which is beyond the scope of this analysis.

[18] This assumes that the historical release from the Glen Canyon Dam between 1/1/2005 and 12/31/2014 is a proxy for future releases for a non-FMF scenario.

[19] Higher electricity generation at Glen Canyon Dam could be achieved during the period of higher release rate modeled in this analysis. This higher electricity generation would be possible until the Lake Powell pool elevation dropped below the power pool level. The estimates of increased generation potential at Hoover Dam do not include this potential source of increased electrical generation.

4.9 years is 392,877 MWh per year, or roughly 9% of the current electricity production at GCD (Figure 8).

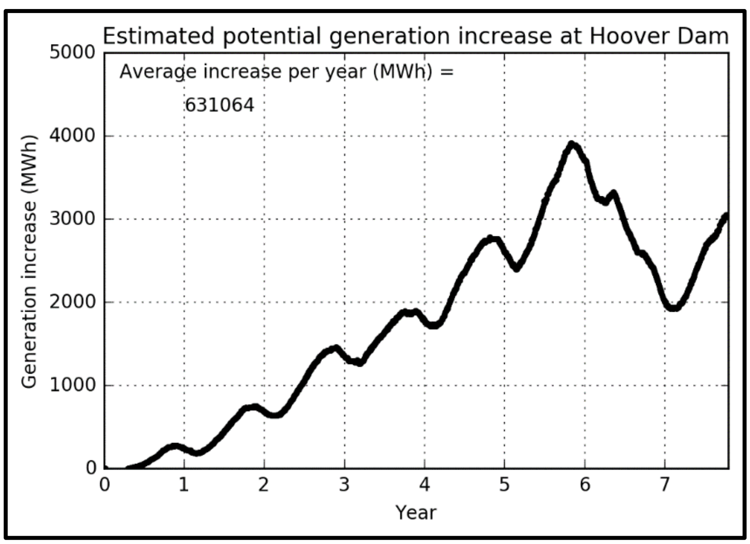
Figure 8.



b. Dead pool scenario

Under the dead pool FMF scenario, the final pool elevation is level with the lowest current water outlet in the Glen Canyon Dam. The dead pool elevation for Lake Powell is 3374 feet above sea level. In the dead pool FMF scenario the final pool elevation is achieved in ~7.8 years with an average potential electrical generation of 631,064 MWh per year, or roughly 15% of the current electric production at GCD (Figure 9).

Figure 9.[20]

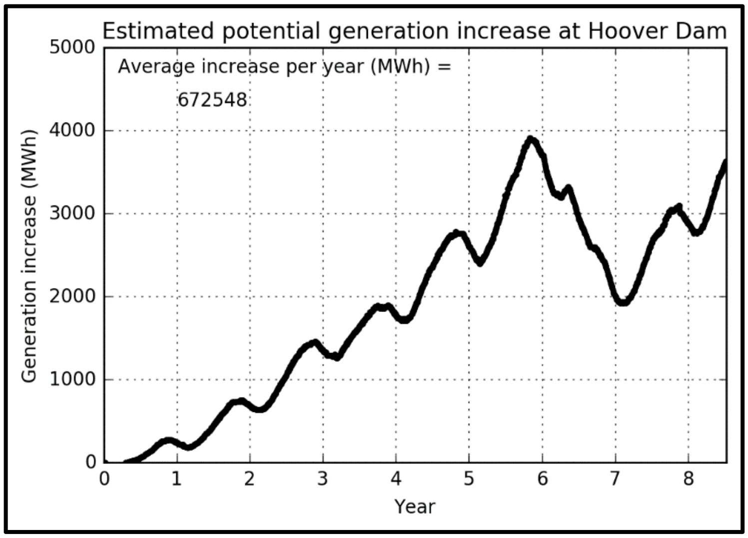


[20] Recall that the estimated potential generation increase is the difference between a 'no-change' (non-FMF) scenario and the FMF scenario. All inflow data for Lake Powell and outflow data for Lake Mead are based on historical data from 1/1/2005 to 12/31/2014. The drop in the potential generation increase at Hoover Dam from year 6 to year 7 in the figure is due to high inflow in the historical data in 2011 (six years after 2005), and the subsequent increase in generation potential under the 'no-change' scenario.

c. Natural River Level

Under the natural river level FMF scenario,[21] we assume that all remnants of the unnatural reservoir are removed and the Colorado river flows freely. For this scenario, we assume that the water level reaches the base of the GCD at 3005 feet above sea level. The results of this model scenario show that the natural river level would be reached in ~8.5 years and the average potential increase in generation at Hoover dam would be ~672,548 MWh per year over the 8.5 years, or roughly 16% of the current power production at GCD (Figure 10).

Figure 10.



III. Estimated costs associated with continued operation of the Glen Canyon Dam

1. Dam operation

The expenses for operations and maintenance for the Glen Canyon Dam are shared between Western and the Bureau of Reclamation. Western's WAPA-169 Public Information Forum Binder[22] shows the relevant, projected operations and maintenance expenses for GCD from 2014-2025 are an average cost of $46,578,983 annually. Dam operations account for $22,585,265 of this total annually.

Cost: $22,585,265 annually.

2. Compliance with US FWS and ESA

Fish and Wildlife Management and Development - Glen Canyon Unit - Continues implementation of Biological Opinion requirements to ensure compliance with the Endangered Species Act. Decrease is due to completion of the Long-Term Experimental and Management Plan Environmental Impact Statement in 2015.

Cost: $1,900,000 annually.

3. Glen Canyon Dam Adaptive Management Program

The Glen Canyon Dam Adaptive Management Program released a triennial budget and work plan in August 2014. Within this document the Bureau of Reclamation and USGS put forth their projected budget for 2015 –

[21] For this scenario, we assume that the water would be drained via means that do not involve the current penstocks used for power generation.

[22] WAPA-169 Public Information Forum Binder; Link accessed on 3-23-16 at: https://www.wapa.gov/regions/CRSP/rates/Pages/rate-order-169.aspx

2017 in Appendix 2-B 2-C and 2-D.[23] The total budget for 2015 is $9,627,600, for 2016 the budget is $10,905,100, and the budget for 2017 is $10,884,400. Thus the average budget for the three years is $10,472,367. This is a reasonable estimate of the annual cost of the GCD Adaptive Management Program since we are estimating the average cost per year associated with the continued operation of the Glen Canyon Dam.

Cost: $10,472,367 annually.

4. Foregone Hoover Dam hydropower

This cost is an estimate of the potential revenue lost due to the low water levels at Lake Mead. The potential for producing power at the Hoover dam increases with higher reservoir levels. Increased reservoir levels, however, do not predicate higher electrical production. The actual production of power at Hoover Dam is dependent on regulatory constraints and demand. Thus the estimate of the cost associated with potential revenue lost due to low water levels at Lake Mead presented here is based on the potential increase in power production that would result in a higher pool elevation at Lake Mead.

Recall that under the 3 FMF scenarios the potential generation increase at Hoover Dam ranges from ~390,000 MWh to ~673,000 MWh (Section II.7, this document). The Arizona Power Authority markets the power from Hoover Dam on a contractual basis wherein the contractors agree to purchase the power at a rate which is determined annually. For the operating year of 2016 rates are $3.21 / kW-mo for capacity and $18.68 /MWh for energy.[24] Without knowledge of the future potential rate structure, we assume that these rates are constant over the term of the increased power generation at Hoover. This results in ~$7,285,200 to $12,571,640 in increased energy sales.[25] However we will use the dead pool storage FMF for this analysis which results in a potential of $11,787,080 in increased energy sales. Please note that these are potential energy generation values. If higher energy production from the Hoover Dam is realized, the release rate (outflow) from the Hoover Dam must increase.[26] This will reduce the pool elevation at Lake Mead, thus reducing the potential energy generation at Hoover Dam. Ultimately, dam operators determine the actual energy generation at Hoover Dam based on regulations, electrical demand, and the instantaneous price of electricity.

Potential earnings loss: $11,787,080.

5. Water lost to Lake Powell seepage

a. Determining the volume of water recovered from the banks of Lake Powell

Lake Powell is a reservoir that sits atop various sandstone formations. Each of these formations has a different hydrologic conductivity[27] associated with them. The most highly conductive formation under Lake Powell is the Navajo Sandstone formation. In 2013 hydrologist Dr. Tom Myers wrote an article for 'Hidden Passage – the journal of glen canyon institute'. In this article, he states that "*The combination of reduced seepage into the banks and water recovered from the banks supports the conclusion that Fill Mead First can save or recover up to 300,000 af/y in seepage*."

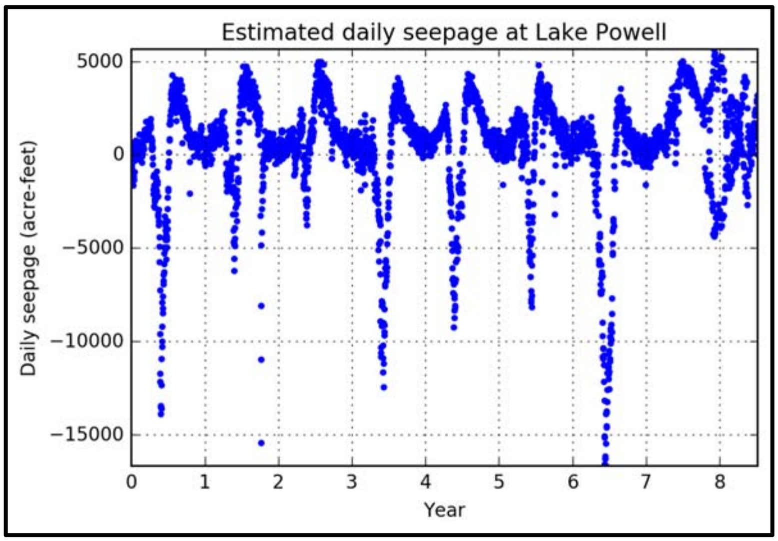
In a different 2013 estimate of bank storage based on historical reservoir water balance Dr. Myers indicates that "*Lake Powell has lost or stored more than 14.8 Gm^3 [~11.2 million acre-feet] of water in its banks since the bypass tubes were closed in 1963*."[28] The full range of the storage estimates for the Navajo Sandstone is ~8.3 million acre-feet to ~16.9 million acre-feet. Dr. Myers further states that

[23] Bureau of Reclamation. 2014. Glen Canyon Dam Adaptive Management Program Triennial Budget and Work Plan—Fiscal Years 2015-2017. U.S. Department of the Interior and U.S. Geological Survey. Appendix 2-C. Fiscal Year 2016 Budget. p. 510. http://www.usbr.gov/uc/rm/amp/twg/mtgs/14jun24/TWP_rev_14aug01.pdf
[24] http://www.powerauthority.org/wp-content/uploads/2016/01/Rate-Letter.pdf
[25] The variation represents the difference in the potential power increase between the three FMF scenarios.
[26] This is apparent in the extremely high correlation between release rates and power generation shown in Figure 1 of this document.
[27] Hydrologic conductivity is the measure of the volume of water that can be conducted through an area over a given amount of time under a given pressure.
[28] Myers, T. (2013). Loss Rates from Lake Powell and Their Impact on Management of the Colorado River. JAWRA Journal of the American Water Resources Association, 49(5), 1213-1224.

the median bank storage is 12% of the monthly change in reservoir storage since 1983[29] and that "*Bank storage returns to the reservoir slowly as the reservoir volume decreases — much slower than the water flowed to the banks while it was filling — because the reservoir levels generally decrease more slowly than they increase*."

Using Dr. Myers' assessment of the return rate for bank storage of 12% of the monthly change in storage we use our water balance model described in section II of this document to estimate the return rate of bank storage under the FMF scenarios.[30] We further assume that the benefits of water seeping from the Navajo Sandstone back into Lake Powell expire when the prescribed FMF elevation has been reached. Figure 11 (below) shows the daily calculated seepage for Lake Powell under the natural river level FMF scenario; negative values are loss to the bank and positive values are seepage from the bank.

Figure 11.



The result of this modeling of seepage indicates that the total water recovered from the bank storage is ~180,000 acre-feet per year over the 8.5 years that it takes to achieve a natural river level at the Glen Canyon Dam. This means that if the FMF river elevation scenario were implemented immediately, ~120,000 acre-feet of water from the previous year would remain unrecoverable. Under Dr. Myers' estimate of 300,000 af/y seepage rate, each year that the GCD is operated, all 300,000 acre-feet per year of water is not recoverable through bank seepage return.

Although there is some seepage at Lake Mead, the geologic formations that form the basin within which Lake Mead resides are a complex mixture of volcanic, granitic, and metamorphic strata.[31] These formations have very low hydraulic conductivities and thus, limit the seepage from Lake Mead, both in terms of seepage rate and total volume of water. This is in stark contrast to the geology around Lake Powell, specifically the Navajo sandstone formation which dips away from the reservoir

[29] Myers, T. (2013). Loss Rates from Lake Powell and Their Impact on Management of the Colorado River. JAWRA Journal of the American Water Resources Association, 49(5), 1213-1224.

[30] Dr. Myers' assessment of the relationship between the volume of water seeping into the banks of Lake Mead was not conducted on a draining reservoir wherein the area of the banks is getting smaller. Thus, the 12% of the monthly change in water storage used in this modeling may overestimate the actual gain from seepage, however, this would also overestimate the seepage loss to the bank during the potential draining. With a lack of other creditable estimates of seepage return rates, we assume that the net balance over the time period of this study is a reasonable estimate for all reservoir levels.

[31] http://pubs.usgs.gov/of/2007/1010/of2007-1010_plate1_map.pdf

and holds an estimated 9-14 million acre-feet of water.[32] Indeed, Dr. Myers states in his article for 'Hidden Passage' *"From 1934 through 1990, Lake Mead lost an average of about 0.14 maf/y to bank seepage, but since 1990 it has neither lost nor gained much water to bank storage."* This indicates that sediment that lines the banks of Lake Mead are saturated.

b. Determining the value of the water

The valuation of water is complex; the rate charged by water companies incorporates both fixed costs of obtaining water rights and building the proper infrastructure to move the water as well as variable costs of maintaining the infrastructure and moving the water from one place to another.[33] These operations and maintenance costs are incorporated into the base rate which is paid by all consumers, a volumetric rate is also charged to consumers which incentivizes water conservation. In addition to incentivizing water conservation, the volumetric rate also pays for the excess energy required to move excess amounts of water. What we find then, is that the water, as a commodity alone, does not have a value associated with it. Instead we find that only the right to use water and the distribution of water has a computable value. We assert that this value is equal to the cost associated with the water rights amortized over the length of time that the water right is held.

Recently Buck et al. (2014)[34] conducted a multi-regression study of the value of water within the San Joaquin Valley, California. This study determined the value of water rights in the valley by incorporating many types of data that are related to the resale price of farmland including sale price, water deliveries in acre-feet, land acreage, depth of groundwater, historical temperature, historical precipitation, soil quality, population density, and land classification codes. By analyzing all of the data simultaneously, Buck et al. isolated the value of the water deliveries per acre foot from the total sale price of the land, thus determining the value associated with the water rights. Their analysis of the value of water rights associated with the sale of land parcels resulted in a mean value of $3,723/acre-foot of surface water with the 95% confidence interval spanning $1,146-$6,300/acre-foot.[35] Although the San Joaquin Valley is not directly served by diversions from Lake Mead, since the vast majority of the water diverted from Lake Mead is used for irrigation, we use this value of water as a close proxy for the value of water diverted from Lake Mead. Water rights do not currently expire, meaning the cost of the water right is a sunk cost which needs to be amortized over the time that the water right is held. Thus, the value of the water which could seep out of the sandstone is dependent on the average time that water rights are held.

In California, the average length of time that current water rights holders have held their claim (either licensed, active, or permitted) is 50 years.[36] So, an investment in water rights can be thought of as a long term investment which will be amortized over a 50-year period, on average. When calculating the future value of this initial investment we need to consider the value of 2015$ over the average term of the water right ownership. Because we are estimating the future value of the water in present day values we discount[37] the value of the water. Amortizing the value of the water over the average term of water right ownership, then, is similar to estimating a mortgage payment where the discount

[32] Myers, T. (2013). Loss Rates from Lake Powell and Their Impact on Management of the Colorado River. JAWRA Journal of the American Water Resources Association, 49(5), 1213-1224.
[33] The price of moving water from one point to another is highly dependent on the cost of the energy required to move the water.
[34] From: Buck, S., Auffhammer, M., & Sunding, D. (2014). Land markets and the value of water: Hedonic analysis using repeat sales of farmland. American Journal of Agricultural Economics, aau013.
[35] All values reported in Buck et al. (2014) are in 2012$.
[36] Analysis of licensed, active, and permitted water rights in California. Data downloaded from: https://ciwqs.waterboards.ca.gov/ciwqs/ewrims/EWServlet?Redirect_Page=EWWaterRightPublicSearch.jsp&Purpose=getEWAppSearchPage
[37] "Discounting represents the time value of money. Benefits and costs are worth more if they are experienced sooner." From the Office of Management and Budget circular A-94, revised 10/29/1992 https://www.whitehouse.gov/omb/circulars_a094#8

rate is analogous to an interest rate applied to the value of the water.[38] The Office of Management and Budget (OMB) recommends that a 3.4% discount rate be applied to a 30-year investment for the year 2015.[39] We use this discount rate to determine the annual value of the water. However, since the future value of money is uncertain we include four separate discount rates that span the range of discount rates recommended by the OMB over the past decade in the valuation of the potential water savings (Table 1).

Table 1.

Discount rate	Average discounted price over 50 years	Value of recovered water lost to seepage	Value of unrecoverable water lost to seepage
3%	$144.70	$26,045,322	$17,364,000
3.4%	$155.87	$28,057,286	$18,704,400
5.5%	$219.89	$39,579,440	$26,386,800

Our estimate of the annual value of the water that may be recovered from the banks of Lake Powell under the natural river elevation FMF is $26 million to $39.6 million per year over the 8.5 years that it takes to achieve a natural river level at Glen Canyon Dam.

Potentially recoverable earnings loss:	$28,057,286.
Unrecoverable potential earnings loss:	$18,704,400.
Total potential earnings loss:	$46,761,686

IV. Total Estimated Annual Cost Savings Associated with Continued Operation of the Glen Canyon Dam

There are two types of cost savings associated with the FMF scenarios: current costs associated with running the Glen Canyon Dam; and loss of potential earnings. Costs associated with running the Glen Canyon Dam accrue annually for every year that the dam generates power. We summarize these costs below.

Cost Category	**Cost/year**
Dam operation	$22,585,265
Compliance with USFWS and ESA	$1,900,000
GC Dam Adaptive Management Program	$10,472,367
TOTAL ANNUAL COST	**$34,957,632**

[38] Instead of paying interest, the value of money decreases annually in proportion to the potential investment earnings of the money. This means that the sum of the average payment over the life of the water right must be higher than present value of the water right to account for the decreased value of money.
[39] This is the longest-term discount rate provided by the OMB. OMB Table of Past Years Discount Rates from Appendix C of OMB Circular No. A-94, https://www.whitehouse.gov/sites/default/files/omb/assets/a94/dischist-2016.pdf

Costs associated with potential earnings loss are based on the potential value of resources related to increased water levels in Lake Mead. It is unclear to us how increased water levels at Lake Mead might be allocated. However, it is clear that increasing power production to a generation rate wherein release rates through Hoover Dam are greater than inflow will result in a reduction in pool elevation. Similarly, increased consumption of water from Lake Mead could outstrip the increased volume from seepage. The potential earnings under the FMF scenarios are summarized below. These earnings do not accrue in the same manner as the costs associated with running the Glen Canyon Dam. The earnings that would be actualized are dependent on the operations of the Hoover Dam and Lake Mead.

Potential Earnings Loss Category	**Loss**
Foregone Hoover Dam hydropower	$11,787,080 [$6,911,600 to $11,805,760]
Recoverable Water lost to Lake Powell seepage	$28,057,286 [$26,045,322 to $39,579,440]
Unrecoverable water lost to Lake Powell Seepage	$18,704,400 [$17,364,000 to $26,386,800]
TOTAL ANNUAL LOSS	***$58,548,766***

TOTAL SINGLE-YEAR SAVINGS[40] UNDER DEAD POOL FMF SCENARIO $93,506,398

40 Annual cost plus potential earnings.

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Appendix A.

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3394.5	456.4	456.4	193.5	368.1	0.0
3394.6	456.4	456.4	193.6	368.3	0.0
3394.8	468.1	468.1	193.8	368.6	0.0
3395	13.2	13.2	194.0	369.0	0.0
3395.1	468.1	468.1	194.1	369.1	0.0
3395.4	468.1	468.1	194.4	369.6	0.0
3395.5	12.4	12.4	194.5	369.8	0.0
3395.6	468.1	468.1	194.6	369.9	0.0
3395.8	483.7	483.7	194.8	370.3	0.0
3395.9	12.4	12.4	194.9	370.4	0.0
3396.1	456.4	456.4	195.1	370.8	0.0
3396.4	12.4	12.4	195.4	371.3	0.0
3396.5	456.4	456.4	195.5	371.4	0.0
3396.7	468.1	468.1	195.6	371.8	0.0
3397	12.4	12.4	195.9	372.3	0.0
3397.4	709.4	709.4	196.3	372.9	0.0
3397.5	12.4	12.4	196.4	373.1	0.0
3398.2	736.6	736.6	197.1	374.3	0.0
3398.5	12.4	12.4	197.4	374.8	0.0
3399	736.6	736.6	197.9	375.6	0.0
3399.8	736.6	736.6	198.7	376.9	0.0
3399.9	12.4	12.4	198.8	377.1	0.0
3400.2	394.9	394.9	199.1	377.6	0.0
3400.3	394.9	394.9	199.2	377.8	0.0
3400.5	396.5	396.5	199.4	378.1	0.0
3400.8	396.5	396.5	199.7	378.6	0.0
3401	396.5	396.5	199.9	379.0	0.0
3401.2	396.5	396.5	200.1	379.3	0.0
3401.4	396.5	396.5	200.3	379.6	0.0
3401.7	204.5	396.5	200.6	380.1	384.1
3402	396.5	396.5	200.9	380.6	0.0
3402.3	394.9	394.9	201.2	381.1	0.0
3402.7	421.4	421.4	201.6	381.8	0.0
3403.2	449.4	449.4	202.1	382.6	0.0
3403.8	449.4	449.4	202.7	383.7	0.0
3404	12.4	12.4	202.9	384.0	0.0
3404.2	449.4	449.4	203.1	384.3	0.0
3404.6	448.6	448.6	203.5	385.0	0.0
3405	448.6	448.6	203.9	385.7	0.0
3405.3	448.6	448.6	204.2	386.2	0.0
3406	437.0	437.0	204.9	387.4	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3406.1	456.4	456.4	205.0	387.5	0.0
3406.4	456.4	456.4	205.3	388.1	0.0
3406.7	12.8	12.8	205.6	388.6	0.0
3406.8	456.4	456.4	205.7	388.7	0.0
3407	452.5	456.4	205.9	389.1	7.8
3407.7	448.6	448.6	206.6	390.3	0.0
3408.4	610.1	610.1	207.3	391.4	0.0
3409	14.0	14.0	207.9	392.5	0.0
3409.1	610.1	610.1	208.0	392.6	0.0
3409.2	14.0	14.0	208.1	392.8	0.0
3409.4	14.0	14.0	208.3	393.2	0.0
3409.6	13.4	14.0	208.5	393.5	1.2
3409.8	14.0	14.0	208.7	393.8	0.0
3409.9	588.7	588.7	208.8	394.0	0.0
3410	14.0	14.0	208.9	394.2	0.0
3410.2	14.0	14.0	209.1	394.5	0.0
3410.4	12.4	12.4	209.3	394.9	0.0
3410.6	12.4	12.4	209.5	395.2	0.0
3410.8	355.1	697.7	209.7	395.5	685.3
3411	12.4	12.4	209.9	395.9	0.0
3411.2	12.4	12.4	210.1	396.2	0.0
3411.3	12.4	12.4	210.2	396.4	0.0
3411.5	12.4	12.4	210.4	396.7	0.0
3411.7	12.4	12.4	210.6	397.1	0.0
3411.8	355.1	697.7	210.7	397.3	685.3
3411.9	12.4	12.4	210.8	397.4	0.0
3412	12.4	12.4	210.9	397.6	0.0
3412.1	12.4	12.4	211.0	397.8	0.0
3412.2	12.4	12.4	211.1	397.9	0.0
3412.3	12.4	12.4	211.2	398.1	0.0
3412.4	12.4	12.4	211.3	398.3	0.0
3412.5	12.4	12.4	211.4	398.5	0.0
3412.7	12.4	12.4	211.6	398.8	0.0
3412.8	697.7	697.7	211.7	399.0	0.0
3412.9	12.8	12.8	211.8	399.1	0.0
3413	13.2	13.2	211.9	399.3	0.0
3413.1	12.8	12.8	212.0	399.5	0.0
3413.3	12.8	12.8	212.2	399.8	0.0
3413.5	12.8	12.8	212.4	400.2	0.0
3413.6	697.7	697.7	212.5	400.3	0.0
3413.7	12.8	12.8	212.6	400.5	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3414	12.8	12.8	213.0	401.0	0.0
3414.2	12.8	12.8	213.2	401.4	0.0
3414.4	116.3	131.9	213.4	401.7	119.1
3414.5	128.8	165.2	213.5	401.9	96.4
3414.6	157.0	355.2	213.6	402.1	234.6
3414.7	129.9	129.9	213.7	402.2	0.0
3414.8	132.0	133.8	213.8	402.4	3.1
3414.9	131.0	131.9	213.9	402.6	1.2
3416.2	13.2	13.2	215.2	404.8	0.0
3419.4	13.6	13.6	218.5	410.4	0.0
3422.6	14.0	14.0	221.8	416.0	0.0
3425.8	14.4	14.4	225.1	421.6	0.0
3429	12.8	12.8	228.4	427.2	0.0
3432	12.8	12.8	231.6	432.6	0.0
3434.7	13.2	13.2	234.4	437.4	0.0
3436.8	13.2	13.2	236.6	441.2	0.0
3438.7	13.6	13.6	238.6	444.6	0.0
3440.3	13.6	13.6	240.3	447.5	0.0
3441.8	14.0	14.0	241.9	450.2	0.0
3443.1	14.0	14.0	243.3	452.6	0.0
3444.3	14.0	14.0	244.6	454.8	0.0
3445.5	14.4	14.4	245.9	456.9	0.0
3446.7	14.8	14.8	247.2	459.1	0.0
3448	14.0	14.0	248.6	461.5	0.0
3449.5	12.8	12.8	250.2	464.3	0.0
3463.3	14.4	14.4	265.4	490.1	0.0
3474.2	15.1	15.1	277.7	511.0	0.0
3475.5	16.3	16.3	279.1	513.5	0.0
3482.1	10.1	10.1	286.7	526.5	0.0
3482.3	10.1	10.1	286.9	526.9	0.0
3489.1	13.6	13.6	294.8	540.3	0.0
3489.8	13.6	13.6	295.6	541.7	0.0
3490.2	94.9	208.5	296.1	542.5	149.4
3490.3	226.1	226.1	296.2	542.7	0.0
3491	202.7	202.7	297.0	544.1	0.0
3491.1	295.5	356.0	297.2	544.3	104.7
3491.3	142.0	228.0	297.4	544.7	172.0
3491.4	51.1	51.1	297.5	544.9	0.0
3491.5	261.9	292.6	297.6	545.1	61.5
3491.6	245.3	363.8	297.7	545.3	234.6
3491.7	242.0	361.9	297.9	545.5	239.7

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3491.8	298.4	298.4	298.0	545.7	0.0
3491.9	266.5	323.3	298.1	545.9	113.6
3492	512.1	512.1	298.2	546.1	0.0
3492.1	268.1	268.1	298.3	546.3	0.0
3492.5	308.6	308.6	298.8	547.1	0.0
3498.9	453.5	453.5	306.4	560.1	0.0
3502.5	491.2	491.2	310.7	567.4	0.0
3504.3	587.1	587.1	312.8	571.1	0.0
3504.7	623.6	623.6	313.3	572.0	0.0
3505.2	496.9	496.9	313.9	573.0	0.0
3505.8	392.5	392.5	314.6	574.2	0.0
3505.9	358.5	358.5	314.7	574.4	0.0
3506.2	502.5	502.5	315.1	575.1	0.0
3508	349.1	349.1	317.3	578.8	0.0
3508.6	614.4	614.4	318.0	580.0	0.0
3508.8	694.0	694.0	318.2	580.4	0.0
3509.1	444.3	444.3	318.6	581.1	0.0
3510.6	489.6	489.6	320.4	584.2	0.0
3510.7	441.8	499.8	320.6	584.4	115.9
3512.5	318.8	318.8	322.7	588.2	0.0
3512.8	327.3	327.3	323.1	588.8	0.0
3513.3	608.8	608.8	323.7	589.8	0.0
3513.5	689.5	689.5	324.0	590.2	0.0
3513.8	342.9	342.9	324.3	590.9	0.0
3514.4	521.3	521.3	325.1	592.1	0.0
3514.5	456.9	456.9	325.2	592.3	0.0
3514.6	459.5	459.5	325.3	592.6	0.0
3515	347.7	347.7	325.8	593.4	0.0
3515.2	533.7	533.7	326.0	593.8	0.0
3515.5	307.9	307.9	326.4	594.4	0.0
3515.9	664.5	664.5	326.9	595.3	0.0
3516.2	315.6	315.6	327.3	595.9	0.0
3516.4	392.3	392.3	327.5	596.3	0.0
3516.5	531.0	531.0	327.6	596.6	0.0
3516.9	649.9	649.9	328.1	597.4	0.0
3517.1	664.3	664.3	328.4	597.8	0.0
3517.5	266.7	341.4	328.9	598.7	149.4
3518.2	634.7	634.7	329.7	600.1	0.0
3518.4	364.2	364.2	330.0	600.6	0.0
3519.1	372.4	372.4	330.8	602.0	0.0
3519.3	325.0	325.0	331.1	602.5	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3519.4	745.0	745.0	331.2	602.7	0.0
3519.7	348.4	348.4	331.6	603.3	0.0
3520.1	734.9	734.9	332.1	604.2	0.0
3520.9	472.5	472.5	333.1	605.9	0.0
3521.2	258.7	258.7	333.4	606.5	0.0
3521.7	421.6	421.6	334.1	607.6	0.0
3522.9	332.3	332.3	335.5	610.1	0.0
3523	366.7	366.7	335.7	610.3	0.0
3523.2	377.9	377.9	335.9	610.8	0.0
3523.3	552.5	552.5	336.0	611.0	0.0
3523.4	151.6	151.6	336.2	611.2	0.0
3523.5	263.7	263.7	336.3	611.4	0.0
3523.6	296.0	296.0	336.4	611.6	0.0
3523.7	280.5	280.5	336.5	611.8	0.0
3523.8	443.2	443.2	336.7	612.1	0.0
3523.9	483.7	483.7	336.8	612.3	0.0
3524	444.0	444.0	336.9	612.5	0.0
3524.2	424.7	424.7	337.2	612.9	0.0
3524.4	417.5	417.5	337.4	613.3	0.0
3524.6	354.9	354.9	337.7	613.8	0.0
3525	455.4	455.4	338.2	614.6	0.0
3525.2	482.9	567.8	338.4	615.0	169.9
3525.6	428.8	496.0	338.9	615.9	134.3
3525.7	349.9	349.9	339.0	616.1	0.0
3525.9	470.1	470.1	339.3	616.6	0.0
3526.4	371.5	390.1	339.9	617.6	37.3
3526.5	217.7	217.7	340.0	617.8	0.0
3526.8	300.5	300.5	340.4	618.5	0.0
3526.9	379.7	379.7	340.5	618.7	0.0
3527.1	407.9	407.9	340.8	619.1	0.0
3527.3	304.7	403.4	341.0	619.6	197.4
3527.6	426.3	480.7	341.4	620.2	108.7
3528.1	209.1	209.1	342.0	621.3	0.0
3528.2	200.6	288.2	342.2	621.5	175.2
3528.3	228.0	282.9	342.3	621.7	172.9
3528.4	329.8	386.4	342.4	621.9	158.0
3528.5	271.9	397.6	342.5	622.1	258.0
3528.6	211.3	211.3	342.7	622.4	0.0
3529.2	426.9	426.9	343.4	623.7	0.0
3529.3	260.4	260.4	343.5	623.9	0.0
3529.5	343.2	417.5	343.8	624.3	122.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3529.7	420.2	420.2	344.0	624.7	0.0
3530.3	408.6	408.6	344.8	626.0	0.0
3530.6	405.8	424.1	345.2	626.7	36.6
3530.7	537.4	537.4	345.3	626.9	0.0
3530.8	500.4	536.2	345.4	627.1	71.6
3531.3	490.8	627.0	346.1	628.2	270.5
3531.4	382.5	427.9	346.2	628.4	90.8
3531.5	439.2	443.0	346.3	628.6	7.6
3531.8	360.2	360.2	346.7	629.3	0.0
3532.3	356.0	387.2	347.3	630.4	62.2
3532.4	364.1	364.1	347.5	630.6	0.0
3532.6	310.2	351.4	347.7	631.0	82.4
3532.7	316.3	361.9	347.8	631.3	111.5
3532.8	308.4	308.4	348.0	631.5	0.0
3533	339.8	339.8	348.2	631.9	0.0
3533.4	414.9	414.9	348.7	632.8	0.0
3533.8	427.2	468.1	349.2	633.7	81.7
3533.9	367.5	418.2	349.4	633.9	154.4
3534	403.2	403.2	349.5	634.1	0.0
3534.2	498.5	498.5	349.7	634.5	0.0
3534.3	308.0	375.3	349.9	634.7	112.1
3534.9	459.8	459.8	350.6	636.1	0.0
3535.4	214.9	246.6	351.3	637.1	63.5
3536	321.1	383.1	352.0	638.5	124.2
3536.5	473.2	473.2	352.7	639.6	0.0
3537.1	368.2	368.2	353.4	640.9	0.0
3537.8	401.4	401.4	354.3	642.4	0.0
3538.2	415.8	415.8	354.8	643.3	0.0
3538.9	656.2	656.2	355.7	644.8	0.0
3539	563.7	563.7	355.9	645.1	0.0
3539.3	465.2	561.7	356.2	645.7	193.1
3539.6	224.8	224.8	356.6	646.4	0.0
3539.7	350.7	350.7	356.8	646.6	0.0
3539.8	166.6	166.6	356.9	646.8	0.0
3540	408.6	408.6	357.1	647.3	0.0
3540.3	522.0	533.3	357.5	647.9	22.7
3540.4	515.3	515.3	357.6	648.1	0.0
3540.5	254.3	254.3	357.8	648.4	0.0
3540.7	268.5	268.5	358.0	648.8	0.0
3540.9	531.9	694.0	358.3	649.2	324.2
3541	329.1	369.1	358.4	649.5	80.2

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3541.7	408.2	408.2	359.3	651.0	0.0
3542.1	494.4	494.4	359.8	651.9	0.0
3542.4	474.5	474.5	360.2	652.6	0.0
3542.7	466.9	466.9	360.6	653.2	0.0
3543.3	389.8	389.8	361.4	654.6	0.0
3543.5	615.5	620.7	361.6	655.0	10.3
3543.7	455.9	560.4	361.9	655.5	209.0
3543.8	527.6	527.6	362.0	655.7	0.0
3544.3	545.5	545.5	362.7	656.8	0.0
3544.8	338.2	338.2	363.3	657.9	0.0
3545	657.3	657.3	363.6	658.4	0.0
3545.2	395.0	395.0	363.8	658.8	0.0
3545.4	366.1	578.1	364.1	659.2	349.7
3545.6	487.6	487.6	364.4	659.7	0.0
3545.7	351.5	351.5	364.5	659.9	0.0
3546	504.2	504.2	364.9	660.6	0.0
3546.1	499.8	499.8	365.0	660.8	0.0
3546.3	593.0	593.0	365.3	661.3	0.0
3546.4	478.8	478.8	365.4	661.5	0.0
3546.9	362.8	362.8	366.0	662.6	0.0
3547	401.6	401.6	366.2	662.8	0.0
3547.4	511.3	653.2	366.7	663.7	284.0
3547.9	373.9	491.4	367.3	664.8	235.0
3548.3	377.7	457.8	367.9	665.7	160.2
3548.6	426.8	543.9	368.3	666.4	324.6
3549.1	424.0	424.0	368.9	667.5	0.0
3549.7	593.0	593.0	369.7	668.9	0.0
3555.1	518.1	518.1	376.8	681.1	0.0
3555.3	519.5	519.5	377.0	681.6	0.0
3555.9	507.9	507.9	377.8	682.9	0.0
3556	518.0	518.0	378.0	683.2	0.0
3556.3	520.2	520.2	378.4	683.8	0.0
3556.4	520.3	520.3	378.5	684.1	0.0
3556.8	519.7	519.7	379.0	685.0	0.0
3557.1	255.8	255.8	379.4	685.7	0.0
3558.3	516.5	516.5	381.0	688.4	0.0
3558.6	518.4	518.4	381.4	689.1	0.0
3559.1	623.7	623.7	382.1	690.2	0.0
3559.4	518.1	518.1	382.5	690.9	0.0
3559.7	517.2	517.2	382.9	691.6	0.0
3559.8	255.6	255.6	383.0	691.9	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3560	518.9	518.9	383.3	692.3	0.0
3560.2	615.6	615.6	383.5	692.8	0.0
3560.4	239.4	239.4	383.8	693.2	0.0
3561.3	237.7	237.7	385.0	695.3	0.0
3562.4	520.7	520.7	386.5	697.8	0.0
3562.5	524.2	524.2	386.6	698.1	0.0
3563.7	520.3	520.9	388.2	700.8	1.4
3563.8	518.8	518.8	388.3	701.1	0.0
3564	521.9	521.9	388.6	701.5	0.0
3564.4	377.3	377.3	389.2	702.5	0.0
3564.7	362.4	362.4	389.6	703.2	0.0
3565.4	358.2	358.2	390.5	704.8	0.0
3566	358.4	358.4	391.3	706.2	0.0
3566.5	358.5	358.5	392.0	707.3	0.0
3566.7	377.6	377.6	392.2	707.8	0.0
3567	533.0	533.0	392.6	708.5	0.0
3567.1	361.0	361.0	392.8	708.7	0.0
3567.3	288.3	288.3	393.1	709.2	0.0
3567.4	287.4	287.4	393.2	709.4	0.0
3569.2	322.7	322.7	395.6	713.6	0.0
3569.3	324.5	324.5	395.8	713.9	0.0
3569.4	283.0	283.0	395.9	714.1	0.0
3569.6	407.4	407.4	396.2	714.6	0.0
3570	229.0	229.0	396.7	715.5	0.0
3570.3	375.9	375.9	397.1	716.2	0.0
3570.4	237.1	237.1	397.2	716.5	0.0
3570.5	269.1	269.1	397.4	716.7	0.0
3570.7	216.2	292.9	397.7	717.2	153.3
3570.8	296.9	296.9	397.8	717.4	0.0
3570.9	324.7	376.9	397.9	717.6	104.4
3571	295.6	295.6	398.1	717.9	0.0
3571.1	289.2	289.2	398.2	718.1	0.0
3571.2	652.6	652.6	398.3	718.3	0.0
3571.7	600.9	600.9	399.0	719.5	0.0
3572.1	516.4	516.4	399.6	720.4	0.0
3572.2	563.4	563.4	399.7	720.7	0.0
3572.3	163.4	163.4	399.8	720.9	0.0
3572.4	371.3	371.3	400.0	721.2	0.0
3572.5	684.3	684.3	400.1	721.4	0.0
3572.6	504.4	515.9	400.2	721.6	22.9
3573.7	626.4	626.4	401.7	724.2	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3573.8	468.7	554.3	401.9	724.5	173.4
3574.1	558.1	558.1	402.3	725.2	0.0
3574.4	352.9	352.9	402.7	725.9	0.0
3574.5	427.7	591.4	402.8	726.1	327.3
3574.6	505.0	505.0	403.0	726.3	0.0
3574.7	494.9	494.9	403.1	726.6	0.0
3574.8	351.1	351.1	403.2	726.8	0.0
3574.9	401.1	513.0	403.4	727.1	223.7
3575	452.3	452.3	403.5	727.3	0.0
3575.1	432.0	562.9	403.7	727.5	261.7
3575.2	296.7	296.7	403.8	727.8	0.0
3575.3	305.3	305.3	403.9	728.0	0.0
3575.4	290.5	290.5	404.1	728.2	0.0
3575.9	486.6	486.6	404.7	729.4	0.0
3576.2	610.3	610.3	405.2	730.1	0.0
3576.9	575.4	575.4	406.1	731.8	0.0
3577.6	596.0	596.0	407.1	733.5	0.0
3578.6	560.8	579.9	408.5	735.8	33.5
3578.8	304.3	304.3	408.7	736.3	0.0
3579.1	556.2	556.2	409.1	737.0	0.0
3579.6	605.6	605.6	409.8	738.2	0.0
3579.7	535.7	535.7	410.0	738.5	0.0
3580.3	660.3	660.3	410.8	739.9	0.0
3580.6	656.1	656.1	411.2	740.6	0.0
3580.7	596.7	643.8	411.4	740.9	94.3
3580.9	493.7	624.1	411.6	741.3	341.9
3581.1	377.9	377.9	411.9	741.8	0.0
3581.4	491.4	491.4	412.3	742.5	0.0
3581.8	575.1	575.1	412.9	743.5	0.0
3582.4	278.4	278.4	413.7	744.9	0.0
3582.5	275.5	275.5	413.9	745.2	0.0
3583	315.6	418.8	414.5	746.4	182.2
3583.2	397.5	414.3	414.8	746.9	47.0
3583.6	401.9	517.5	415.4	747.8	231.2
3583.9	279.8	279.8	415.8	748.5	0.0
3584.5	541.6	541.6	416.6	750.0	0.0
3585.1	369.6	369.6	417.5	751.4	0.0
3585.3	372.4	372.4	417.7	751.9	0.0
3585.4	507.9	507.9	417.9	752.2	0.0
3585.5	474.3	580.1	418.0	752.4	211.7
3585.9	365.3	365.3	418.6	753.4	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3586.4	459.0	459.0	419.3	754.6	0.0
3586.9	521.6	521.6	420.0	755.8	0.0
3587.1	457.9	457.9	420.3	756.3	0.0
3587.2	519.9	519.9	420.4	756.5	0.0
3587.3	461.6	461.6	420.5	756.8	0.0
3587.5	365.9	365.9	420.8	757.2	0.0
3587.6	491.7	491.7	421.0	757.5	0.0
3587.9	254.6	254.6	421.4	758.2	0.0
3588.4	975.9	975.9	422.1	759.4	0.0
3588.5	756.3	756.3	422.2	759.7	0.0
3588.6	335.4	335.4	422.4	759.9	0.0
3588.7	347.6	372.9	422.5	760.2	45.8
3589.1	334.0	334.0	423.1	761.1	0.0
3589.5	376.7	378.6	423.6	762.1	3.7
3589.6	381.7	520.9	423.8	762.4	217.4
3589.7	513.0	528.3	423.9	762.6	30.4
3590	474.4	520.7	424.3	763.3	92.8
3590.6	532.9	953.0	425.2	764.8	579.9
3590.7	480.8	480.8	425.3	765.0	0.0
3590.8	352.2	471.0	425.5	765.3	220.2
3591	278.4	278.4	425.7	765.8	0.0
3591.1	341.5	399.7	425.9	766.0	116.4
3591.2	387.0	488.5	426.0	766.3	171.8
3591.3	451.1	473.3	426.2	766.5	44.3
3591.4	445.1	492.0	426.3	766.7	93.8
3591.5	553.4	553.4	426.4	767.0	0.0
3591.7	396.1	396.1	426.7	767.5	0.0
3591.8	488.9	497.7	426.9	767.7	17.6
3591.9	526.0	930.6	427.0	768.0	557.4
3592.4	398.9	398.9	427.7	769.2	0.0
3592.9	435.1	435.1	428.4	770.4	0.0
3593.4	215.9	215.9	429.1	771.6	0.0
3593.5	401.8	401.8	429.3	771.9	0.0
3593.8	473.4	473.4	429.7	772.6	0.0
3594	530.8	530.8	430.0	773.1	0.0
3594.2	602.2	602.2	430.3	773.6	0.0
3594.5	1109.1	1109.1	430.7	774.4	0.0
3594.6	443.5	443.5	430.8	774.6	0.0
3594.9	776.2	1079.5	431.3	775.3	606.7
3595	472.3	472.3	431.4	775.6	0.0
3595.1	539.2	539.2	431.5	775.8	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3595.2	469.3	469.3	431.7	776.1	0.0
3595.3	504.8	507.4	431.8	776.3	5.3
3595.4	481.6	536.7	432.0	776.6	110.2
3595.5	425.8	425.8	432.1	776.8	0.0
3595.6	466.7	515.4	432.2	777.1	97.4
3595.7	501.7	501.7	432.4	777.3	0.0
3595.9	474.4	474.4	432.7	777.8	0.0
3596	447.4	447.4	432.8	778.0	0.0
3596.1	344.3	344.3	433.0	778.3	0.0
3596.2	394.9	394.9	433.1	778.5	0.0
3596.3	358.6	358.6	433.2	778.8	0.0
3596.5	515.4	515.4	433.5	779.3	0.0
3596.8	497.2	497.2	434.0	780.0	0.0
3596.9	472.9	472.9	434.1	780.3	0.0
3597.1	421.7	502.0	434.4	780.8	160.5
3597.2	1096.2	1096.2	434.5	781.0	0.0
3597.4	431.7	431.7	434.8	781.5	0.0
3597.5	364.8	364.8	435.0	781.8	0.0
3597.6	433.4	488.0	435.1	782.0	138.3
3597.8	352.6	368.9	435.4	782.5	32.6
3597.9	736.2	952.2	435.5	782.7	431.9
3598	449.2	497.2	435.7	783.0	96.0
3598.2	498.1	498.1	436.0	783.5	0.0
3598.3	514.9	514.9	436.1	783.7	0.0
3598.4	507.2	507.2	436.2	784.0	0.0
3598.5	532.8	587.2	436.4	784.2	108.8
3598.6	463.8	562.0	436.5	784.5	194.6
3598.7	409.6	409.6	436.7	784.7	0.0
3598.8	300.8	321.2	436.8	785.0	40.8
3598.9	421.9	615.3	437.0	785.2	309.2
3599	385.9	385.9	437.1	785.5	0.0
3599.1	463.8	545.0	437.2	785.7	162.4
3599.2	331.3	380.0	437.4	786.0	126.0
3599.3	513.7	534.5	437.5	786.2	41.6
3599.5	504.1	541.3	437.8	786.7	90.1
3599.6	465.3	465.3	438.0	787.0	0.0
3599.8	438.3	472.8	438.2	787.5	102.9
3599.9	368.6	368.6	438.4	787.7	0.0
3600	431.7	493.2	438.5	788.0	112.7
3600.1	506.2	533.5	438.7	788.2	55.5
3600.2	367.1	367.1	438.8	788.5	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3600.3	519.3	721.1	439.0	788.7	363.8
3600.4	598.0	999.7	439.1	789.0	742.4
3600.5	473.0	504.8	439.2	789.2	63.5
3600.6	483.4	506.0	439.4	789.5	45.2
3600.7	259.9	350.9	439.5	789.7	220.8
3600.8	467.0	593.1	439.7	789.9	242.7
3600.9	432.2	613.3	439.8	790.2	256.6
3601	200.8	200.8	440.0	790.4	0.0
3601.1	346.4	416.4	440.1	790.7	127.3
3601.2	529.6	529.6	440.3	790.9	0.0
3601.3	353.0	417.3	440.4	791.2	128.6
3601.4	283.1	283.1	440.5	791.4	0.0
3601.5	359.3	359.3	440.7	791.7	0.0
3601.6	468.7	556.8	440.8	791.9	176.2
3601.7	627.3	862.2	441.0	792.2	469.8
3601.8	392.8	694.6	441.1	792.4	536.1
3601.9	378.9	455.8	441.3	792.7	168.3
3602	291.1	295.7	441.4	792.9	10.7
3602.1	321.3	377.1	441.5	793.2	86.6
3602.2	298.4	304.0	441.7	793.4	11.1
3602.3	371.9	450.5	441.8	793.7	157.2
3602.4	292.9	334.1	442.0	793.9	77.0
3602.5	344.8	361.2	442.1	794.2	32.8
3602.6	313.1	321.5	442.3	794.4	16.9
3602.7	370.7	442.8	442.4	794.7	143.3
3602.9	521.1	674.3	442.7	795.2	306.4
3603.1	343.7	343.7	443.0	795.7	0.0
3603.3	341.5	341.5	443.3	796.2	0.0
3603.4	401.0	509.9	443.4	796.4	217.8
3603.6	616.9	616.9	443.7	796.9	0.0
3603.7	488.7	805.4	443.9	797.2	531.0
3603.9	291.3	291.3	444.1	797.7	0.0
3604	475.5	540.3	444.3	797.9	129.6
3604.2	444.2	444.2	444.6	798.4	0.0
3604.3	373.5	498.5	444.7	798.7	250.0
3604.4	397.6	500.0	444.9	798.9	204.9
3604.5	476.9	500.4	445.0	799.2	47.2
3604.6	528.2	870.9	445.2	799.5	624.0
3604.7	584.1	584.1	445.3	799.7	0.0
3604.9	491.5	518.7	445.6	800.2	54.5
3605	543.1	543.1	445.7	800.5	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3605.1	498.7	611.1	445.9	800.7	221.9
3605.2	335.2	394.0	446.0	801.0	117.5
3605.3	268.9	268.9	446.2	801.2	0.0
3605.4	544.2	727.6	446.3	801.5	366.8
3605.5	360.3	360.3	446.5	801.7	0.0
3605.6	509.7	586.6	446.6	802.0	153.8
3605.7	363.8	379.1	446.7	802.2	30.5
3605.8	439.0	542.8	446.9	802.5	207.5
3605.9	584.9	783.3	447.0	802.7	396.9
3606	498.7	503.5	447.2	803.0	9.6
3606.1	368.0	371.0	447.3	803.2	6.5
3606.2	426.5	478.4	447.5	803.5	103.8
3606.3	396.3	432.3	447.6	803.7	72.0
3606.4	466.5	466.5	447.8	804.0	0.0
3606.5	641.2	716.8	447.9	804.2	222.4
3606.6	541.2	541.2	448.0	804.5	0.0
3607	419.8	497.9	448.6	805.5	156.2
3607.1	366.6	431.8	448.8	805.7	145.5
3607.3	453.2	453.2	449.1	806.2	0.0
3607.4	391.3	404.3	449.2	806.5	31.9
3607.5	467.5	581.7	449.4	806.8	228.5
3607.6	531.2	714.0	449.5	807.0	350.2
3607.8	704.5	704.5	449.8	807.5	0.0
3607.9	632.1	731.7	449.9	807.8	199.3
3608.1	699.2	848.4	450.2	808.3	298.5
3608.2	574.4	574.4	450.4	808.5	0.0
3608.5	391.7	391.7	450.8	809.3	0.0
3608.6	372.5	372.5	451.0	809.5	0.0
3608.8	515.8	598.3	451.2	810.0	125.5
3608.9	516.3	560.2	451.4	810.3	87.9
3609	499.8	499.8	451.5	810.5	0.0
3609.3	125.2	125.2	452.0	811.3	0.0
3609.5	637.5	637.5	452.3	811.8	0.0
3609.6	274.2	274.2	452.4	812.1	0.0
3609.7	496.7	673.9	452.6	812.3	410.6
3609.8	522.6	522.6	452.7	812.6	0.0
3609.9	453.5	453.5	452.8	812.8	0.0
3610	409.3	516.3	453.0	813.1	180.1
3610.2	534.3	639.3	453.3	813.6	210.0
3610.3	471.1	471.1	453.4	813.8	0.0
3610.4	497.4	497.4	453.6	814.1	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3610.6	466.5	474.8	453.9	814.6	16.7
3610.7	492.3	543.8	454.0	814.9	103.0
3610.8	496.0	521.0	454.2	815.1	50.0
3610.9	687.9	687.9	454.3	815.4	0.0
3611	452.6	452.6	454.5	815.6	0.0
3611.1	250.6	250.6	454.6	815.9	0.0
3611.4	415.1	453.2	455.0	816.6	76.2
3611.5	508.3	691.1	455.2	816.9	319.0
3611.6	445.5	518.1	455.3	817.1	145.2
3611.7	744.0	744.0	455.5	817.4	0.0
3611.8	362.4	362.4	455.6	817.7	0.0
3612	632.0	632.0	455.9	818.2	0.0
3612.1	521.2	688.3	456.1	818.4	334.4
3612.4	252.4	252.4	456.5	819.2	0.0
3612.5	463.2	496.4	456.7	819.4	66.4
3612.6	396.7	415.0	456.8	819.7	36.6
3612.7	445.5	445.5	456.9	819.9	0.0
3612.8	344.5	344.5	457.1	820.2	0.0
3612.9	474.3	474.3	457.2	820.5	0.0
3613	415.3	415.3	457.4	820.7	0.0
3613.1	477.2	587.4	457.5	821.0	211.8
3613.2	460.6	587.2	457.7	821.2	185.2
3613.4	474.0	542.2	458.0	821.7	136.4
3613.5	543.3	580.7	458.1	822.0	74.7
3613.6	554.4	586.4	458.3	822.2	63.9
3613.7	425.9	458.8	458.4	822.5	65.7
3613.8	477.7	583.6	458.6	822.8	214.3
3614	614.9	650.4	458.9	823.3	71.1
3614.1	380.9	380.9	459.0	823.5	0.0
3614.2	530.2	630.9	459.1	823.8	201.3
3614.3	581.7	649.9	459.3	824.0	136.4
3614.5	490.5	525.8	459.6	824.5	70.6
3614.7	509.3	522.4	459.9	825.1	26.2
3614.8	590.1	590.1	460.0	825.3	0.0
3615	477.8	477.8	460.3	825.8	0.0
3615.1	436.2	582.1	460.5	826.1	291.8
3615.3	355.4	355.4	460.8	826.6	0.0
3615.6	567.6	650.3	461.2	827.4	165.4
3615.7	428.6	428.6	461.4	827.6	0.0
3615.8	372.6	372.6	461.5	827.9	0.0
3615.9	467.7	467.7	461.7	828.1	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3616	587.8	587.8	461.8	828.4	0.0
3616.2	511.5	566.8	462.1	828.9	95.5
3616.4	370.1	370.1	462.4	829.4	0.0
3616.6	532.4	554.0	462.7	829.9	43.1
3616.8	483.3	494.9	463.0	830.4	23.2
3617	684.4	684.4	463.3	831.0	0.0
3617.3	639.1	639.1	463.7	831.7	0.0
3617.5	571.0	630.4	464.0	832.2	119.0
3617.6	727.9	727.9	464.2	832.5	0.0
3617.7	673.8	673.8	464.3	832.8	0.0
3617.9	563.9	563.9	464.6	833.3	0.0
3618.1	572.9	572.9	464.9	833.8	0.0
3618.3	683.0	683.0	465.2	834.3	0.0
3618.6	352.1	352.1	465.6	835.1	0.0
3618.7	281.5	281.5	465.8	835.3	0.0
3618.8	359.8	359.8	465.9	835.6	0.0
3619	474.2	474.2	466.2	836.1	0.0
3619.1	454.3	492.0	466.4	836.4	75.4
3619.2	384.1	425.2	466.5	836.6	76.0
3619.3	721.4	721.4	466.7	836.9	0.0
3619.4	369.7	450.9	466.8	837.1	158.0
3619.7	354.8	363.6	467.3	837.9	17.6
3619.9	374.0	491.6	467.6	838.4	201.1
3620	430.0	495.1	467.7	838.7	130.2
3620.1	361.8	433.8	467.9	839.0	146.4
3620.2	606.7	606.7	468.0	839.2	0.0
3620.5	371.5	375.8	468.5	840.0	8.6
3620.6	366.3	402.3	468.6	840.3	71.9
3620.7	393.1	393.1	468.8	840.5	0.0
3620.8	432.3	558.9	468.9	840.8	268.8
3621	611.2	611.2	469.2	841.3	0.0
3621.2	333.3	380.1	469.5	841.8	93.5
3621.3	504.2	715.3	469.7	842.1	415.4
3621.5	341.7	341.7	470.0	842.6	0.0
3621.6	397.8	437.0	470.1	842.8	78.4
3621.8	282.0	282.0	470.4	843.4	0.0
3621.9	352.1	352.1	470.6	843.6	0.0
3622	693.3	693.3	470.7	843.9	0.0
3622.1	371.8	371.8	470.9	844.1	0.0
3622.2	608.7	608.7	471.0	844.4	0.0
3622.3	526.1	664.3	471.2	844.7	291.5

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3622.4	286.8	286.8	471.3	844.9	0.0
3622.6	370.7	455.9	471.6	845.4	170.4
3622.7	451.8	531.5	471.8	845.7	159.5
3622.8	336.6	386.5	471.9	846.0	99.8
3623.4	398.7	506.3	472.8	847.5	215.3
3623.5	379.6	379.6	473.0	847.8	0.0
3623.6	472.0	479.3	473.1	848.0	14.7
3623.7	327.2	360.3	473.3	848.3	66.0
3623.8	388.4	388.4	473.4	848.6	0.0
3623.9	416.0	476.2	473.5	848.8	120.4
3624	460.8	460.8	473.7	849.1	0.0
3624.1	452.5	460.2	473.8	849.4	15.3
3624.2	345.5	451.3	474.0	849.6	159.9
3624.3	409.0	483.5	474.1	849.9	189.7
3624.4	514.0	584.9	474.3	850.1	141.9
3624.6	324.0	478.3	474.6	850.7	308.7
3624.8	477.7	519.3	474.9	851.2	83.4
3624.9	246.8	246.8	475.0	851.4	0.0
3625.1	435.1	507.9	475.3	852.0	145.6
3625.2	507.0	621.2	475.5	852.2	309.6
3625.3	440.7	450.2	475.6	852.5	19.0
3625.4	471.2	591.4	475.8	852.7	240.3
3625.5	385.6	388.2	475.9	853.0	5.3
3625.6	445.9	446.7	476.1	853.3	1.6
3625.7	363.9	432.1	476.3	853.5	136.4
3625.8	379.9	379.9	476.4	853.8	0.0
3626	736.9	736.9	476.7	854.3	0.0
3626.1	351.4	351.4	476.9	854.6	0.0
3626.4	447.9	503.6	477.3	855.4	111.3
3626.6	259.1	259.1	477.6	855.9	0.0
3626.7	352.4	449.6	477.8	856.2	194.4
3626.8	354.9	451.1	477.9	856.4	153.6
3626.9	425.6	693.6	478.1	856.7	396.5
3627	496.2	511.9	478.2	856.9	31.4
3627.1	459.3	459.3	478.4	857.2	0.0
3627.2	374.1	556.5	478.5	857.5	387.2
3627.3	429.7	569.0	478.7	857.7	263.8
3627.5	431.5	458.3	479.0	858.3	68.3
3627.6	459.4	820.9	479.1	858.5	689.8
3627.7	552.2	552.2	479.3	858.8	0.0
3627.8	580.4	580.4	479.4	859.0	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3627.9	322.7	486.5	479.6	859.3	342.1
3628	272.3	272.3	479.7	859.6	0.0
3628.2	416.9	451.7	480.0	860.1	69.7
3628.3	637.2	637.2	480.2	860.4	0.0
3628.8	405.9	445.7	480.9	861.7	79.5
3629	294.9	294.9	481.2	862.2	0.0
3629.2	458.2	513.9	481.5	862.7	91.3
3629.3	541.4	541.4	481.7	863.0	0.0
3629.4	442.0	573.5	481.8	863.3	262.9
3629.6	492.1	495.7	482.1	863.8	7.2
3629.7	453.7	453.7	482.3	864.0	0.0
3629.9	501.5	501.5	482.6	864.6	0.0
3630	657.8	657.8	482.7	864.8	0.0
3630.2	464.8	548.1	483.0	865.4	166.6
3630.4	823.1	823.1	483.3	865.9	0.0
3630.5	461.0	510.1	483.5	866.2	131.1
3630.6	206.4	379.5	483.6	866.4	346.2
3630.8	377.5	377.5	484.0	866.9	0.0
3630.9	272.6	272.6	484.1	867.2	0.0
3631	550.6	550.6	484.3	867.5	0.0
3631.1	282.7	422.5	484.4	867.7	254.4
3631.2	503.4	503.4	484.6	868.0	0.0
3631.3	533.4	564.1	484.7	868.3	61.5
3631.5	569.4	569.4	485.0	868.8	0.0
3631.6	386.1	471.2	485.2	869.1	170.2
3631.7	392.5	392.5	485.3	869.3	0.0
3631.9	443.5	443.5	485.6	869.9	0.0
3632	551.3	559.4	485.8	870.1	16.2
3632.1	546.9	546.9	485.9	870.4	0.0
3632.3	316.1	462.9	486.2	870.9	293.5
3632.4	526.4	552.5	486.4	871.2	55.5
3632.8	497.8	539.8	487.0	872.2	83.9
3633	539.3	539.3	487.3	872.8	0.0
3633.1	458.4	458.4	487.4	873.0	0.0
3633.2	601.1	601.1	487.6	873.3	0.0
3633.3	434.0	514.3	487.8	873.6	159.5
3633.4	480.8	545.1	487.9	873.8	166.7
3633.5	549.3	549.3	488.1	874.1	0.0
3633.6	438.3	438.3	488.2	874.4	0.0
3633.7	411.2	411.2	488.4	874.6	0.0
3633.8	288.5	289.3	488.5	874.9	1.6

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3633.9	392.8	424.0	488.7	875.2	47.2
3634.1	312.8	363.4	489.0	875.7	76.2
3634.2	475.8	475.8	489.1	876.0	0.0
3634.3	243.7	360.8	489.3	876.2	234.2
3634.4	477.6	590.6	489.4	876.5	225.9
3634.5	462.4	521.9	489.6	876.8	118.9
3634.6	372.5	372.5	489.7	877.0	0.0
3634.7	553.9	553.9	489.9	877.3	0.0
3634.8	382.6	523.2	490.0	877.6	281.3
3634.9	366.4	366.4	490.2	877.8	0.0
3635.1	255.3	427.4	490.5	878.4	258.2
3635.2	306.4	449.8	490.7	878.6	356.0
3635.3	459.1	553.1	490.8	878.9	187.9
3635.5	271.2	475.7	491.1	879.4	408.9
3635.6	366.6	388.4	491.3	879.7	39.9
3635.7	322.8	322.8	491.4	880.0	0.0
3635.8	379.4	428.5	491.6	880.2	82.7
3635.9	197.3	311.4	491.7	880.5	209.1
3636	416.5	558.3	491.9	880.8	200.5
3636.1	169.6	169.6	492.0	881.0	0.0
3636.2	238.9	337.5	492.2	881.3	197.1
3636.4	467.7	467.7	492.5	881.8	0.0
3636.5	279.3	492.6	492.6	882.1	426.6
3636.6	390.0	495.4	492.8	882.4	210.7
3636.7	527.8	645.6	493.0	882.6	235.7
3636.9	346.7	346.7	493.3	883.2	0.0
3637	608.1	714.8	493.4	883.4	213.4
3637.1	695.6	695.6	493.6	883.7	0.0
3637.3	227.6	286.4	493.9	884.2	117.5
3637.4	361.9	725.0	494.0	884.5	546.3
3637.5	400.5	473.6	494.2	884.8	146.2
3637.6	502.5	702.0	494.3	885.0	399.1
3637.7	425.3	620.0	494.5	885.3	389.4
3637.8	561.6	561.6	494.6	885.6	0.0
3637.9	489.2	542.6	494.8	885.9	106.8
3638	492.1	492.1	494.9	886.1	0.0
3638.2	433.0	490.0	495.3	886.7	114.1
3638.4	486.2	486.2	495.6	887.2	0.0
3638.5	418.9	493.2	495.7	887.5	148.6
3638.7	690.2	690.2	496.0	888.0	0.0
3638.8	354.1	489.3	496.2	888.3	319.8

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3638.9	542.5	542.5	496.3	888.5	0.0
3639.1	427.3	539.0	496.6	889.1	223.5
3639.3	541.3	541.3	496.9	889.6	0.0
3639.4	426.8	426.8	497.1	889.9	0.0
3639.8	356.4	356.4	497.7	891.0	0.0
3639.9	546.1	546.1	497.9	891.2	0.0
3640	335.9	442.6	498.0	891.5	213.5
3640.1	311.3	311.3	498.2	891.8	0.0
3640.3	765.0	765.0	498.5	892.3	0.0
3640.4	650.6	650.6	498.6	892.6	0.0
3640.5	560.3	560.3	498.8	892.8	0.0
3640.8	538.7	824.0	499.3	893.7	570.6
3640.9	507.4	507.4	499.4	893.9	0.0
3641.2	457.5	494.0	499.9	894.7	91.2
3641.4	628.9	763.8	500.2	895.3	269.8
3641.5	456.2	493.7	500.3	895.5	65.2
3642.1	548.3	610.9	501.3	897.2	125.2
3642.2	544.8	544.8	501.4	897.4	0.0
3642.3	490.9	495.0	501.6	897.7	9.1
3643	734.7	734.7	502.7	899.6	0.0
3643.1	431.6	431.6	502.8	899.9	0.0
3643.5	263.4	263.4	503.4	901.0	0.0
3643.7	764.8	764.8	503.8	901.5	0.0
3643.8	230.7	230.7	503.9	901.8	0.0
3644	541.7	919.7	504.2	902.3	656.6
3644.1	628.0	700.1	504.4	902.6	144.1
3644.2	233.4	233.4	504.5	902.9	0.0
3644.3	178.1	178.1	504.7	903.1	0.0
3644.4	458.8	458.8	504.8	903.4	0.0
3644.6	403.1	403.1	505.2	903.9	0.0
3644.7	376.5	376.5	505.3	904.2	0.0
3644.8	414.3	414.3	505.5	904.5	0.0
3644.9	291.7	382.9	505.6	904.8	182.4
3645.1	390.8	390.8	505.9	905.3	0.0
3645.2	331.5	331.5	506.1	905.6	0.0
3645.3	231.5	297.8	506.2	905.8	132.6
3645.4	423.7	423.7	506.4	906.1	0.0
3645.5	506.8	758.9	506.6	906.4	504.3
3645.8	493.1	803.8	507.0	907.2	591.2
3645.9	415.7	570.8	507.2	907.5	301.5
3646	368.9	521.4	507.3	907.7	339.8

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3646.1	313.2	317.4	507.5	908.0	8.4
3646.2	350.3	379.0	507.7	908.3	85.7
3646.3	423.0	661.6	507.8	908.6	379.3
3646.5	239.2	336.8	508.1	909.1	195.2
3646.8	313.6	377.9	508.6	909.9	128.6
3647	66.7	66.7	508.9	910.5	0.0
3647.1	891.5	891.5	509.1	910.7	0.0
3647.2	375.6	375.6	509.2	911.0	0.0
3647.4	264.4	264.4	509.5	911.6	0.0
3647.6	258.9	409.4	509.8	912.1	301.1
3647.7	542.0	814.2	510.0	912.4	544.4
3648.1	747.8	828.9	510.6	913.5	162.2
3648.2	713.4	713.4	510.8	913.8	0.0
3648.3	552.9	579.3	510.9	914.0	58.4
3648.5	265.6	416.5	511.2	914.6	326.1
3648.6	172.3	202.6	511.4	914.8	60.6
3648.7	379.5	725.0	511.6	915.1	602.0
3648.8	109.8	136.9	511.7	915.4	54.2
3649	430.2	458.7	512.0	915.9	57.0
3649.4	415.2	559.7	512.7	917.0	390.2
3649.5	341.6	357.0	512.8	917.3	30.7
3649.6	428.8	558.8	513.0	917.6	389.4
3649.7	365.5	504.1	513.1	917.9	283.5
3649.8	525.6	558.8	513.3	918.1	98.3
3650	463.6	463.6	513.6	918.7	0.0
3650.2	617.1	685.8	513.9	919.2	137.4
3650.3	633.1	926.7	514.1	919.5	513.1
3650.4	358.9	413.1	514.2	919.8	108.3
3650.5	408.8	413.5	514.4	920.1	9.5
3650.6	464.0	546.9	514.5	920.3	165.7
3650.7	479.3	656.8	514.7	920.6	299.7
3650.8	448.8	576.9	514.9	920.9	302.3
3650.9	428.4	628.1	515.0	921.2	329.9
3651.1	265.0	406.3	515.3	921.7	282.7
3651.2	150.1	150.1	515.5	922.0	0.0
3651.4	254.5	296.0	515.8	922.5	83.1
3651.5	355.3	490.1	516.0	922.8	280.9
3651.6	286.7	501.6	516.1	923.1	447.0
3651.7	416.4	460.5	516.3	923.4	88.4
3651.9	268.7	268.7	516.6	923.9	0.0
3652	489.0	575.3	516.8	924.2	172.7

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3652.1	253.4	457.6	516.9	924.5	408.5
3652.2	431.3	431.3	517.1	924.7	0.0
3652.3	680.5	683.6	517.2	925.0	6.2
3652.4	381.0	431.6	517.4	925.3	101.1
3652.5	511.4	511.4	517.5	925.6	0.0
3652.6	342.2	388.9	517.7	925.8	93.4
3652.9	288.4	330.6	518.2	926.7	110.5
3653	329.6	329.6	518.3	927.0	0.0
3653.1	473.5	473.5	518.5	927.2	0.0
3653.2	287.4	320.5	518.6	927.5	66.2
3653.3	276.7	296.4	518.8	927.8	39.3
3653.4	443.6	443.6	519.0	928.1	0.0
3653.5	431.4	568.9	519.1	928.3	275.1
3653.6	650.7	963.8	519.3	928.6	551.6
3653.7	328.4	400.5	519.4	928.9	165.2
3653.8	361.1	432.7	519.6	929.2	187.7
3653.9	321.8	581.0	519.8	929.4	451.9
3654.3	445.8	513.6	520.4	930.5	135.7
3654.4	197.1	197.1	520.5	930.8	0.0
3654.6	130.9	130.9	520.9	931.4	0.0
3654.7	477.4	572.7	521.0	931.7	190.6
3654.9	313.8	511.2	521.3	932.2	479.1
3655	374.2	386.9	521.5	932.5	26.1
3655.1	282.7	303.2	521.7	932.8	41.0
3655.2	658.3	658.3	521.8	933.0	0.0
3655.4	242.4	285.3	522.1	933.6	92.3
3655.5	362.8	409.3	522.3	933.9	93.1
3655.6	411.5	522.1	522.5	934.2	221.3
3655.8	386.0	386.0	522.8	934.7	0.0
3655.9	524.9	524.9	522.9	935.0	0.0
3656	485.5	485.5	523.1	935.3	0.0
3656.1	418.1	418.1	523.2	935.5	0.0
3656.4	222.2	222.2	523.7	936.4	0.0
3656.5	425.1	511.6	523.9	936.7	173.0
3656.7	496.6	647.9	524.2	937.2	236.8
3656.9	518.4	546.8	524.5	937.8	56.7
3657.1	453.7	453.7	524.8	938.3	0.0
3657.3	409.1	409.1	525.2	938.9	0.0
3657.5	489.4	489.4	525.5	939.4	0.0
3657.7	384.1	453.2	525.8	940.0	138.2
3657.8	374.2	374.2	526.0	940.3	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3657.9	426.2	426.2	526.1	940.6	0.0
3658.1	369.9	369.9	526.4	941.1	0.0
3658.2	487.2	487.2	526.6	941.4	0.0
3658.4	936.7	936.7	526.9	941.9	0.0
3658.5	501.6	539.9	527.1	942.2	76.7
3658.8	598.1	611.1	527.5	943.1	25.9
3658.9	547.8	547.8	527.7	943.3	0.0
3659.1	309.0	309.0	528.0	943.9	0.0
3659.2	510.6	510.6	528.2	944.2	0.0
3659.3	611.4	611.4	528.3	944.5	0.0
3659.4	465.5	506.8	528.5	944.7	82.7
3659.9	653.4	653.4	529.3	946.1	0.0
3660.1	915.5	915.5	529.6	946.7	0.0
3660.2	557.7	576.5	529.8	947.0	37.6
3660.3	912.5	912.5	529.9	947.3	0.0
3660.4	547.6	547.6	530.1	947.5	0.0
3660.6	587.1	620.6	530.4	948.1	66.9
3660.8	336.5	336.5	530.7	948.7	0.0
3660.9	697.7	913.6	530.9	948.9	431.9
3661.2	300.5	300.5	531.4	949.8	0.0
3661.3	366.7	366.7	531.6	950.1	0.0
3661.5	708.5	708.5	531.9	950.6	0.0
3661.6	743.2	743.2	532.0	950.9	0.0
3661.7	487.5	597.8	532.2	951.2	220.4
3661.8	387.0	637.4	532.4	951.5	388.4
3661.9	376.8	376.8	532.5	951.8	0.0
3662	379.6	379.6	532.7	952.0	0.0
3662.1	161.4	161.4	532.8	952.3	0.0
3662.3	349.3	483.8	533.2	952.9	208.1
3662.4	504.2	798.6	533.3	953.2	413.5
3662.5	473.6	521.4	533.5	953.4	133.9
3662.6	297.3	370.7	533.6	953.7	114.1
3662.7	317.4	317.4	533.8	954.0	0.0
3662.8	423.7	423.7	534.0	954.3	0.0
3662.9	415.0	451.2	534.1	954.6	81.6
3663	430.6	459.7	534.3	954.9	58.2
3663.1	669.6	908.4	534.4	955.1	477.7
3663.2	736.5	907.8	534.6	955.4	403.9
3663.4	553.8	903.8	534.9	956.0	544.0
3663.5	475.8	797.5	535.1	956.3	572.3
3663.6	256.8	256.8	535.3	956.5	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3663.8	401.8	401.8	535.6	957.1	0.0
3663.9	405.6	490.0	535.7	957.4	143.4
3664	520.4	746.7	535.9	957.7	609.6
3664.1	541.4	672.3	536.1	958.0	302.2
3664.2	363.8	363.8	536.2	958.2	0.0
3664.3	587.3	587.3	536.4	958.5	0.0
3664.5	433.4	433.4	536.7	959.1	0.0
3664.6	387.6	520.9	536.9	959.4	227.1
3664.7	480.4	524.9	537.0	959.7	127.6
3664.8	305.3	878.5	537.2	959.9	709.9
3664.9	582.7	582.7	537.3	960.2	0.0
3665	368.5	471.8	537.5	960.5	206.6
3665.1	656.8	1029.0	537.7	960.8	620.3
3665.2	250.0	344.5	537.8	961.1	189.2
3665.3	728.5	728.5	538.0	961.3	0.0
3665.4	276.1	276.1	538.2	961.6	0.0
3665.5	387.9	387.9	538.3	961.9	0.0
3665.6	478.8	768.6	538.5	962.2	505.8
3665.8	795.9	795.9	538.8	962.8	0.0
3666	1029.0	1029.0	539.1	963.3	0.0
3666.1	699.3	699.3	539.3	963.6	0.0
3666.2	611.3	788.1	539.5	963.9	353.5
3666.3	564.4	564.4	539.6	964.2	0.0
3666.4	486.4	718.2	539.8	964.5	513.1
3666.5	234.0	303.6	539.9	964.8	151.6
3666.6	546.7	609.1	540.1	965.0	124.8
3666.7	683.0	1028.2	540.3	965.3	576.8
3666.8	356.9	356.9	540.4	965.6	0.0
3666.9	540.4	755.4	540.6	965.9	430.1
3667	180.0	180.0	540.7	966.2	0.0
3667.1	679.1	792.9	540.9	966.5	227.8
3667.2	636.3	742.1	541.1	966.7	211.6
3667.3	454.6	604.8	541.2	967.0	300.3
3667.4	363.4	363.4	541.4	967.3	0.0
3667.5	656.8	787.7	541.6	967.6	203.0
3667.6	270.1	270.1	541.7	967.9	0.0
3667.7	360.5	528.4	541.9	968.2	408.6
3667.8	72.1	72.1	542.0	968.4	0.0
3668.1	517.1	517.1	542.5	969.3	0.0
3668.2	622.2	622.2	542.7	969.6	0.0
3668.3	363.4	557.2	542.9	969.9	387.7

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3668.4	315.3	315.3	543.0	970.2	0.0
3668.7	411.1	454.8	543.5	971.0	87.3
3668.9	592.6	752.5	543.8	971.6	427.6
3669	526.5	526.5	544.0	971.9	0.0
3669.3	227.6	227.6	544.5	972.7	0.0
3669.6	523.5	523.5	545.0	973.6	0.0
3669.7	318.4	412.2	545.1	973.9	187.6
3669.9	435.9	435.9	545.5	974.4	0.0
3670	550.5	718.8	545.6	974.7	336.6
3670.1	469.1	720.1	545.8	975.0	501.9
3670.3	351.2	351.2	546.1	975.6	0.0
3670.4	246.4	246.4	546.3	975.9	0.0
3670.5	204.1	204.1	546.4	976.1	0.0
3670.6	520.5	520.5	546.6	976.4	0.0
3670.7	448.7	448.7	546.8	976.7	0.0
3670.8	655.3	725.5	546.9	977.0	140.4
3671.1	579.9	699.2	547.4	977.9	179.4
3671.2	511.8	511.8	547.6	978.1	0.0
3671.4	273.5	273.5	547.9	978.7	0.0
3671.5	401.8	543.2	548.1	979.0	282.7
3671.6	418.4	453.5	548.2	979.3	70.1
3671.7	365.1	536.7	548.4	979.6	264.3
3671.8	232.3	232.3	548.6	979.9	0.0
3671.9	622.2	1134.8	548.7	980.2	824.0
3672	539.2	706.9	548.9	980.4	256.3
3672.1	677.4	767.6	549.1	980.7	180.4
3672.2	667.3	817.9	549.2	981.0	301.3
3672.3	488.4	593.9	549.4	981.3	211.0
3672.4	675.9	675.9	549.6	981.6	0.0
3672.5	499.1	758.0	549.7	981.9	669.9
3672.6	26.9	26.9	549.9	982.2	0.0
3672.7	562.2	670.6	550.0	982.5	306.3
3672.8	570.2	656.1	550.2	982.7	126.8
3672.9	379.7	485.9	550.4	983.0	279.6
3673	384.3	384.3	550.5	983.3	0.0
3673.1	910.6	991.9	550.7	983.6	229.0
3673.2	728.1	1142.0	550.9	983.9	674.4
3673.3	324.3	324.3	551.0	984.2	0.0
3673.5	793.6	979.2	551.4	984.8	371.2
3673.7	665.4	986.2	551.7	985.3	542.3
3673.8	647.0	755.6	551.8	985.6	217.3

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3673.9	637.2	637.2	552.0	985.9	0.0
3674	890.1	1146.5	552.2	986.2	692.3
3674.1	711.9	964.7	552.3	986.5	505.4
3674.3	570.8	889.3	552.7	987.1	611.5
3674.4	609.3	932.1	552.8	987.3	645.6
3674.5	395.5	612.4	553.0	987.6	523.1
3674.6	424.9	424.9	553.2	987.9	0.0
3674.7	302.4	416.4	553.3	988.2	196.6
3674.8	614.5	990.6	553.5	988.5	740.8
3674.9	659.0	777.3	553.7	988.8	321.9
3675	326.0	548.5	553.8	989.1	444.8
3675.1	760.5	855.1	554.0	989.4	189.2
3675.2	569.2	569.2	554.2	989.7	0.0
3675.3	440.7	440.7	554.3	989.9	0.0
3675.4	560.8	695.4	554.5	990.2	409.3
3675.5	701.3	999.8	554.6	990.5	464.1
3675.6	329.6	329.6	554.8	990.8	0.0
3675.7	457.9	777.5	555.0	991.1	563.2
3675.8	716.3	980.5	555.1	991.4	474.7
3676.1	571.3	639.9	555.6	992.3	137.2
3676.2	803.2	971.1	555.8	992.5	335.7
3676.3	650.7	979.5	556.0	992.8	560.2
3676.4	635.5	635.5	556.1	993.1	0.0
3676.5	517.9	669.9	556.3	993.4	303.9
3676.6	485.1	615.4	556.5	993.7	251.1
3676.8	333.7	376.0	556.8	994.3	84.6
3676.9	336.4	336.4	557.0	994.6	0.0
3677	506.9	674.4	557.1	994.9	311.5
3677.1	381.9	633.8	557.3	995.1	390.8
3677.2	416.0	444.0	557.5	995.4	84.0
3677.3	1002.2	1002.2	557.6	995.7	0.0
3677.4	448.6	739.4	557.8	996.0	456.4
3677.5	464.6	626.2	557.9	996.3	373.3
3677.6	494.8	998.6	558.1	996.6	784.0
3677.7	435.4	435.4	558.3	996.9	0.0
3677.8	322.5	490.1	558.4	997.2	358.5
3677.9	349.8	349.8	558.6	997.5	0.0
3678	463.5	976.3	558.8	997.8	809.9
3678.1	512.0	725.5	558.9	998.0	426.9
3678.2	273.1	373.5	559.1	998.3	161.1
3678.3	965.0	965.0	559.3	998.6	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3678.4	441.2	737.7	559.4	998.9	457.7
3678.5	495.1	598.3	559.6	999.2	175.3
3678.6	471.4	528.9	559.8	999.5	143.6
3678.7	371.3	540.9	559.9	999.8	254.8
3678.8	974.2	974.2	560.1	1000.1	0.0
3678.9	489.1	607.8	560.3	1000.4	237.6
3679	715.0	715.0	560.4	1000.7	0.0
3679.1	426.4	554.3	560.6	1001.0	248.5
3679.2	458.9	478.8	560.8	1001.2	39.8
3679.3	358.9	358.9	560.9	1001.5	0.0
3679.4	405.6	456.2	561.1	1001.8	101.3
3679.5	1159.2	1159.2	561.3	1002.1	0.0
3679.6	391.6	495.4	561.4	1002.4	172.7
3679.7	523.5	968.4	561.6	1002.7	747.5
3679.8	602.5	1050.2	561.8	1003.0	827.1
3679.9	695.3	963.8	561.9	1003.3	461.4
3680	759.1	934.1	562.1	1003.6	523.3
3680.1	473.8	473.8	562.3	1003.9	0.0
3680.2	423.8	529.0	562.4	1004.2	180.5
3680.3	285.8	285.8	562.6	1004.4	0.0
3680.4	498.0	625.6	562.8	1004.7	338.2
3680.5	988.9	988.9	562.9	1005.0	0.0
3680.6	555.8	824.7	563.1	1005.3	538.0
3680.7	420.0	497.2	563.3	1005.6	208.1
3680.8	621.5	850.4	563.4	1005.9	367.7
3680.9	574.1	642.6	563.6	1006.2	137.1
3681	539.9	921.8	563.8	1006.5	635.1
3681.2	602.0	868.4	564.1	1007.1	532.8
3681.3	698.2	745.4	564.3	1007.4	94.5
3681.4	529.8	529.8	564.4	1007.7	0.0
3681.5	947.7	1180.0	564.6	1008.0	897.9
3681.6	1172.3	1172.3	564.8	1008.2	0.0
3681.7	598.5	946.5	564.9	1008.5	537.9
3681.8	571.1	969.9	565.1	1008.8	683.2
3681.9	450.3	592.7	565.3	1009.1	305.3
3682	707.6	949.7	565.4	1009.4	484.1
3682.1	379.2	612.4	565.6	1009.7	412.6
3682.2	430.5	599.3	565.8	1010.0	310.8
3682.3	679.7	925.8	565.9	1010.3	472.5
3682.4	623.6	644.4	566.1	1010.6	41.7
3682.5	443.3	550.3	566.3	1010.9	262.9

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3682.6	420.2	524.0	566.4	1011.2	275.7
3682.7	619.1	671.1	566.6	1011.5	104.0
3682.8	339.5	339.5	566.8	1011.8	0.0
3682.9	645.9	645.9	566.9	1012.1	0.0
3683	614.5	656.8	567.1	1012.3	84.6
3683.2	337.3	441.6	567.4	1012.9	156.5
3683.3	534.7	779.7	567.6	1013.2	541.4
3683.4	536.4	790.8	567.8	1013.5	507.4
3683.5	515.0	733.5	567.9	1013.8	383.8
3683.6	746.2	766.1	568.1	1014.1	39.8
3683.7	561.0	760.4	568.3	1014.4	517.5
3683.8	1084.8	1084.8	568.4	1014.7	0.0
3683.9	867.1	1025.8	568.6	1015.0	317.5
3684	598.9	1073.5	568.8	1015.3	745.7
3684.1	267.1	267.1	568.9	1015.6	0.0
3684.2	991.6	991.6	569.1	1015.9	0.0
3684.3	429.3	446.5	569.3	1016.2	34.5
3684.4	1092.7	1092.7	569.4	1016.5	0.0
3684.5	946.9	1311.0	569.6	1016.7	778.2
3684.6	923.8	1346.0	569.8	1017.0	844.4
3684.7	611.7	1346.0	569.9	1017.3	1036.7
3684.8	415.2	504.7	570.1	1017.6	262.9
3684.9	466.2	620.1	570.3	1017.9	290.8
3685	416.3	542.0	570.4	1018.2	389.5
3685.1	680.9	742.4	570.6	1018.5	123.0
3685.2	565.1	968.4	570.8	1018.8	806.6
3685.3	483.3	675.0	570.9	1019.1	297.6
3685.4	550.6	550.6	571.1	1019.4	0.0
3685.5	772.0	937.9	571.3	1019.7	331.8
3685.6	556.9	678.3	571.4	1020.0	242.8
3685.7	397.2	397.2	571.6	1020.3	0.0
3685.8	525.3	744.4	571.8	1020.6	470.0
3685.9	636.1	767.1	571.9	1020.9	307.5
3686	398.5	592.0	572.1	1021.2	387.0
3686.1	618.3	618.3	572.3	1021.5	0.0
3686.3	365.7	499.4	572.6	1022.1	315.2
3686.4	540.5	676.1	572.8	1022.3	363.0
3686.5	577.9	746.1	573.0	1022.6	342.2
3686.6	514.6	807.8	573.1	1022.9	669.7
3686.7	544.2	834.7	573.3	1023.2	429.5
3686.8	449.9	526.7	573.5	1023.5	160.6

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3686.9	412.7	412.7	573.6	1023.8	0.0
3687	536.5	641.8	573.8	1024.1	210.6
3687.1	531.7	702.9	574.0	1024.4	384.5
3687.2	517.8	609.2	574.1	1024.7	178.5
3687.3	502.0	780.5	574.3	1025.0	407.5
3687.4	388.3	537.6	574.5	1025.3	330.8
3687.5	553.6	615.4	574.6	1025.6	123.6
3687.6	312.2	461.8	574.8	1025.9	267.5
3687.7	692.8	917.5	575.0	1026.2	451.2
3687.8	409.1	621.7	575.1	1026.5	425.2
3688	1082.3	1082.3	575.5	1027.1	0.0
3688.1	570.0	700.5	575.7	1027.4	386.4
3688.2	591.3	712.4	575.8	1027.7	242.2
3688.5	517.7	517.7	576.3	1028.6	0.0
3688.6	858.8	858.8	576.5	1028.9	0.0
3688.7	536.5	793.9	576.7	1029.2	514.8
3688.9	449.5	664.7	577.0	1029.7	430.3
3689	887.5	887.5	577.2	1030.0	0.0
3689.1	734.0	734.0	577.3	1030.3	0.0
3689.2	719.5	934.5	577.5	1030.6	287.5
3689.3	517.0	559.1	577.7	1030.9	84.2
3689.4	850.6	1170.0	577.8	1031.2	638.8
3689.5	722.3	749.7	578.0	1031.5	54.8
3689.6	564.0	682.3	578.2	1031.8	339.9
3689.7	603.8	676.6	578.4	1032.1	188.0
3689.8	685.3	685.3	578.5	1032.4	0.0
3689.9	911.9	1172.0	578.7	1032.7	432.5
3690.1	632.9	785.4	579.0	1033.3	305.2
3690.2	726.2	964.6	579.2	1033.6	402.1
3690.3	207.7	207.7	579.4	1033.9	0.0
3690.4	661.5	661.5	579.5	1034.2	0.0
3690.5	689.3	689.3	579.7	1034.5	0.0
3690.6	814.6	929.7	579.9	1034.8	230.2
3690.7	801.4	801.4	580.0	1035.1	0.0
3690.8	1012.3	1012.3	580.2	1035.4	0.0
3690.9	656.6	656.6	580.4	1035.7	0.0
3691	722.0	722.0	580.6	1036.0	0.0
3691.1	491.8	640.0	580.7	1036.3	296.5
3691.2	809.8	809.8	580.9	1036.6	0.0
3691.3	809.5	980.9	581.1	1036.9	322.3
3691.4	696.6	696.6	581.2	1037.2	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3691.6	906.1	906.1	581.6	1037.8	0.0
3691.7	616.6	659.4	581.7	1038.1	85.6
3691.8	633.5	804.7	581.9	1038.4	267.5
3692.1	683.8	683.8	582.4	1039.3	0.0
3692.2	726.9	1097.9	582.6	1039.6	680.9
3692.5	691.6	691.6	583.1	1040.5	0.0
3692.6	1086.5	1086.5	583.3	1040.8	0.0
3692.7	746.6	798.5	583.4	1041.1	103.7
3692.8	491.4	491.4	583.6	1041.4	0.0
3692.9	656.8	805.8	583.8	1041.7	443.1
3693	730.4	730.4	584.0	1042.0	0.0
3693.1	669.1	791.0	584.1	1042.3	253.4
3693.2	733.9	979.7	584.3	1042.6	366.3
3693.4	525.7	785.1	584.6	1043.2	518.8
3693.5	948.5	1071.5	584.8	1043.5	269.6
3693.6	732.1	742.1	585.0	1043.8	20.0
3693.7	815.7	908.1	585.1	1044.1	184.7
3693.8	851.5	977.2	585.3	1044.4	251.6
3693.9	866.3	1030.8	585.5	1044.6	375.9
3694	803.8	803.8	585.7	1044.9	0.0
3694.1	957.0	957.0	585.8	1045.2	0.0
3694.2	974.8	974.8	586.0	1045.5	0.0
3694.4	1020.5	1020.5	586.3	1046.1	0.0
3694.5	652.5	688.1	586.5	1046.4	86.5
3694.6	868.8	964.9	586.7	1046.7	192.2
3694.8	1096.9	1096.9	587.0	1047.3	0.0
3695	933.0	1073.9	587.4	1047.9	281.8
3695.1	728.3	728.3	587.5	1048.2	0.0
3695.4	967.9	967.9	588.0	1049.2	0.0
3695.5	788.5	788.5	588.2	1049.5	0.0
3695.7	778.0	778.0	588.6	1050.1	0.0
3695.8	925.0	1002.0	588.7	1050.4	202.9
3696	1023.0	1023.0	589.1	1051.0	0.0
3696.2	652.7	652.7	589.4	1051.6	0.0
3696.3	1033.7	1033.7	589.6	1051.9	0.0
3696.4	933.9	942.6	589.8	1052.2	17.4
3696.5	759.9	782.7	589.9	1052.5	45.7
3696.6	695.8	695.8	590.1	1052.8	0.0
3696.8	894.4	988.4	590.4	1053.4	188.0
3697	919.0	1034.9	590.8	1054.0	231.8
3697.3	740.9	740.9	591.3	1054.9	0.0

Pool Elevation (ft)	Average electrical generation per day (MWh)	Maximum electrical generation per day (MWh)	Regression fit to 1 year average daily generation (MWh)	Regression fit to 1 year maximum daily generation (MWh)	Variance in historical generation per elevation (MWh)
3697.5	877.1	894.4	591.6	1055.5	34.6
3697.8	815.8	964.2	592.2	1056.4	435.1
3697.9	1070.6	1070.6	592.3	1056.7	0.0
3698	1031.3	1031.3	592.5	1057.0	0.0
3698.1	676.7	676.7	592.7	1057.3	0.0
3698.2	938.3	1008.1	592.8	1057.6	139.5
3698.3	1040.2	1040.2	593.0	1057.9	0.0
3698.6	820.7	820.7	593.5	1058.8	0.0
3699.1	734.0	734.0	594.4	1060.3	0.0
3699.2	795.0	968.1	594.6	1060.6	346.2
3699.4	735.3	1036.9	594.9	1061.2	603.2
3699.6	935.7	935.7	595.3	1061.8	0.0
3700	955.1	1038.6	595.9	1063.0	141.1
3700.1	1162.6	1202.8	596.1	1063.3	80.4
3700.2	992.9	1057.1	596.3	1063.6	128.5
3700.3	1115.5	1115.5	596.5	1063.9	0.0
3700.4	1026.5	1026.5	596.6	1064.2	0.0
3700.5	1400.8	1400.8	596.8	1064.6	0.0
3700.7	932.3	932.3	597.2	1065.2	0.0
3700.8	999.7	999.7	597.3	1065.5	0.0
3701.1	1051.0	1051.0	597.8	1066.4	0.0
3701.2	856.1	856.1	598.0	1066.7	0.0
3701.5	1043.2	1043.2	598.5	1067.6	0.0
3702.1	936.5	936.5	599.6	1069.4	0.0
3702.2	841.3	841.3	599.7	1069.7	0.0
3702.4	1007.4	1007.4	600.1	1070.3	0.0
3705.6	1078.2	1078.2	605.6	1080.1	0.0
3706.9	1031.2	1031.2	607.9	1084.1	0.0
3707.1	1034.3	1034.3	608.3	1084.7	0.0
3707.5	1033.5	1033.5	609.0	1085.9	0.0
3707.9	1028.5	1028.5	609.7	1087.2	0.0
3708.1	1034.3	1034.3	610.0	1087.8	0.0
3708.3	1035.8	1035.8	610.4	1088.4	0.0