RECLAMATION

Managing Water in the West

Hydropower Benefits Technical Report

For the Secretarial Determination on Whether to Remove Four Dams on the Klamath River in California and Oregon

U.S. Department of the Interior
Bureau of Reclamation
Technical Service Center
Denver, Colorado

August 2011

Mission Statements

The U.S. Department of the Interior protects America's natural resources and heritage, honors our cultures and tribal communities, and supplies the energy to power our future.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Cover photo – Copco No. 2 Dam and Reservoir (U.S. Fish and Wildlife Service, 2009).

Hydropower Benefits Technical Report

For the Secretarial Determination on Whether to Remove Four Dams on the Klamath River in California and Oregon

U.S. Department of the Interior
Bureau of Reclamation
Technical Service Center
Denver, Colorado

August 2011

Acronyms and Abbreviations

AC	alternating current
AIP	Agreement in Principle
cfs	cubic feet per second
COB	California Oregon Border
CO_2	carbon dioxide
CY	calendar year
FERC	Federal Energy Regulatory Commission
Hg	mercury
Hz	Hertz
KBRA	Klamath Basin Restoration Agreement
KDRM	Klamath Dam Removal Model
KHSA	Klamath Hydroelectric Settlement Agreement
kWh	kilowatt-hours
MW	megawatts
MWh	megawatt-hours
NO_x	nitrogen oxides
NWPCC	Northwest Power and Conservation Council
OM&R	operation, maintenance and replacement
RPS	renewable portfolio standards
SO_2	sulfur dioxide
WY	water years

Contents

Tables

Figures

Appendices

EXECUTIVE SUMMARY

The removal of four hydropower plants on the Klamath River (J.C. Boyle, Copco 1, Copco 2, and Iron Gate) is being considered as one component of a larger plan to restore aquatic habitat in the Klamath River Basin. In aggregate, these four plants have an installed generation capacity of approximately 163 megawatts (MW).

By design, this analysis is limited to the hydropower economic benefits provided by the four Klamath River hydropower plants and provides an assessment of how these benefits are expected to change with dam removal. The costs of operating these four hydropower plants, maintaining them and replacing their capital equipment, are treated in a separate document.

The economic analysis described here conforms to the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resource Council, 1983). The base year for this analysis is 2012, and the period of analysis is January 1, 2012, through December 31, 2061, a 50-year period.

Underlying this analysis are 49 modeled future hydrologic sequences or traces, each of which is 50 years in length. These modeled sequences are employed for both the No Action Alternative and the Full Facilities Dam Removal Alternative in order to capture the effects of hydrologic variability. The No Action hydrology characterizes the management of the Klamath River Basin under the National Marine Fisheries Service (2010) and U.S. Fish and Wildlife Service (2008) Biological Opinions. The hydrology for the Full Facilities Dam Removal Alternative reflects the expected operation of the Klamath River Basin under the Klamath Basin Restoration Agreement (Klamath Settlement Parties 2010).

The Klamath Dam Removal Model (KDRM), a RiverWare based model of the four Klamath River hydropower plants, was used to simulate daily plant operations, which were then aggregated to a monthly time-step for this analysis. Monthly onpeak and offpeak generation at these plants was evaluated using monthly forecast prices for the California Oregon Border (COB) electrical interchange, developed by the Northwest Power and Conservation Council.

For the No Action Alternative, the four Klamath River hydropower plants generate an average of 895,847 megawatt-hours (MWh) of electricity annually. Dependable capacity, a measure of the current maximum generation capability available on a reliable basis, is estimated to be 55.9 MW in summer and 66.6 MW in winter, using the 90 percent exceedence method. The output from these four plants is estimated to have a mean present economic value of $1,609,310,821 (2012$) over the 50-year analysis period.

Under the Full Facilities Dam Removal Alternative, the four Klamath River hydropower plants are expected to operate normally during the period 2012 through 2019 (8 years). Dam removal is assumed to occur instantaneously at one minute past midnight on January 1, 2020 and the production of electrical energy and capacity at the four hydropower plants is expected to be zero from January 1, 2020, through the end of 2061 (42 years). For the Full Facilities Dam Removal Alternative, the estimated mean present value of hydropower economic benefits is approximately $289,228,758 (2012$), over the 50-year analysis period. Relative to the No Action Alternative, this represents a mean reduction in economic benefits of $1,320,087,063 (2012$), a loss of approximately 82 percent.

Under the Partial Facilities Dam Removal Alternative, the four Klamath River hydropower plants are also expected to operate normally from 2012 through 2019 (8 years), with dam decommissioning also assumed to occur on January 1, 2020. The impacts on dependable capacity, energy and economic benefits are expected to be identical to the Full Facilities Dam Removal Alternative.

ELECTRICITY TERMS AND UNITS OF MEASURE

When working with electricity, the terms watts, kilowatts, and megawatts are commonly encountered. The fundamental unit of electric power measurement is the watt. One watt of electric power flowing continuously for one hour is known as a watt-hour. Residential electricity is typically measured in thousands of watt-hours or kilowatt-hours (kWh). At the bulk generation and transmission level, electricity is generally measured in thousands of kilowatt-hours or megawatt-hours. Equivalently, 1 megawatt-hour is also equal to 1 million watt-hours. Table 1 summarizes these units of measure and their abbreviations.

Table 1.—Electricity units of measure

Term	Definition	Abbreviation
Watt	Fundamental unit of measure	W
Kilowatt	1,000 watts	kW
Kilowatt-hour	1,000 watt-hours	kWh
Megawatt	1,000,000 watts	MW
Megawatt-hour	1,000,000 watt-hours	MWh

ELECTRICITY BACKGROUND

Electricity cannot be efficiently stored on a large scale using currently available technology. It must be produced as needed. Consequently, when a change in demand occurs—such as when an irrigation pump or central air conditioner is turned on—somewhere in the interconnected power system, the production of electricity must be increased to satisfy this demand.

The electricity supplied for commercial, industrial, and residential use in the United States is of a type known as alternating current (AC). In the United States, Canada and much of Mexico, AC electricity is supplied at 60 Hertz (Hz) or cycles per second. Residential users commonly receive single-phase AC electricity at 240/120 volts.

In the language of the utility industry, the demand for electricity is known as "load." Load varies on a second-by-second basis and has characteristic daily, weekly, and seasonal patterns. As with other commodities, electric energy is most valuable when it is most in demand—during the day when people are awake and when industry and businesses are operating. This period, when the demand is highest, is called the "onpeak period." In the West, the "onpeak" period is typically defined as the hours from 0700 to 2300 hours, Monday through Saturday. All other hours are considered to be "offpeak."

Figure 1 illustrates the characteristic hourly pattern of load for typical weekdays in the summer and the winter (Harpman, 2006). The vertical (purple) lines in the figure demarcate the onpeak period of the day (0700 to 2300 hours). In the summer, the hourly pattern of load is significantly influenced by air conditioning needs. In the very early morning (0100 hours), the temperature is relatively low, many people are sleeping and there is little business or industrial activity. Around 0500 hours, load begins to rise as residents begin their daily activities, the temperature starts to increase, and commercial and industrial entities commence operations. As the temperature rises, the use of electricity by air conditioning units increases. By late afternoon (1700 hours), temperatures have increased markedly, personal, business and commercial activities are at their height, and electricity use reaches its maximum. In the evening, people return home, businesses and industries close for the day and the temperatures begin to fall. By around 2000 hours, falling temperatures and reduced human activities result in a drastic decline in the demand for electricity.

In the winter, the hourly pattern of load is shaped by heating requirements. In the very early morning (0100 hours), many people are sleeping and there is little business or industrial activity. Around 0500 hours, load begins to rise as residents begin their daily activities by turning up the heat, making coffee and cooking breakfast. Load rises to an initial peak during this time. When they leave for work, they turn down or turn off the heat in their residences. Temperatures rise to their maximums during the middle of the day, decreasing the use of electricity for

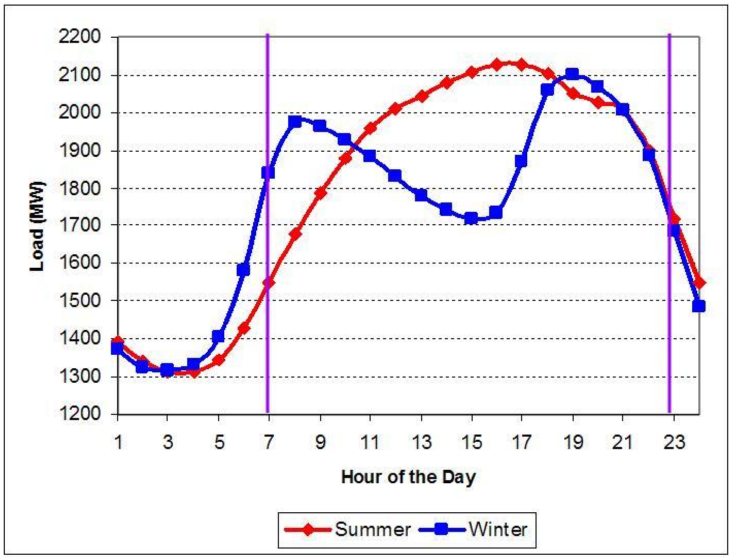

Figure 1.—Typical summer and winter weekday load.

heating purposes. Load declines from the initial peak. In the late afternoon and early evening, the temperatures begin to fall, people return home from work, turn up the heat and start cooking dinner. Their aggregate activities cause the load to rise again resulting in a second peak, which is characteristic of the winter season. By around 2000 hours, people begin to reduce their activities and turn down the heat in their homes. As a result, there is again a marked decline in load.

The pattern of human activities during the week results in a characteristic load pattern at that time-scale. Hourly load during a typical summer week is illustrated in figure 2. As shown in this figure, peak use and the pattern of use are very similar Monday through Friday. The load on a Saturday is often, but not always, less than the load on a typical weekday. As illustrated in figure 2, there is typically less human activity on Sunday than there is during the other days of the week. As a result, Sunday peak load is lower and all Sunday hours are typically considered to be "offpeak." Additional weekly load patterns for typical weeks during the fall, winter and spring seasons can be found in Harpman (2006, Appendix 3).

There is also a characteristic pattern of load across the seasons of the year (Harpman, 2006). The seasonal load pattern for the WECC region of the United States is illustrated in figure 3. As shown, the maximum load typically occurs in the summer months due to air conditioning requirements. Load is also high in the winter months in response to heating needs. Load in the spring and fall is typically less than in the winter and summer. Collectively, the spring and fall months are sometimes referred to as "shoulder months" and the winter and summer months as the "peak months."

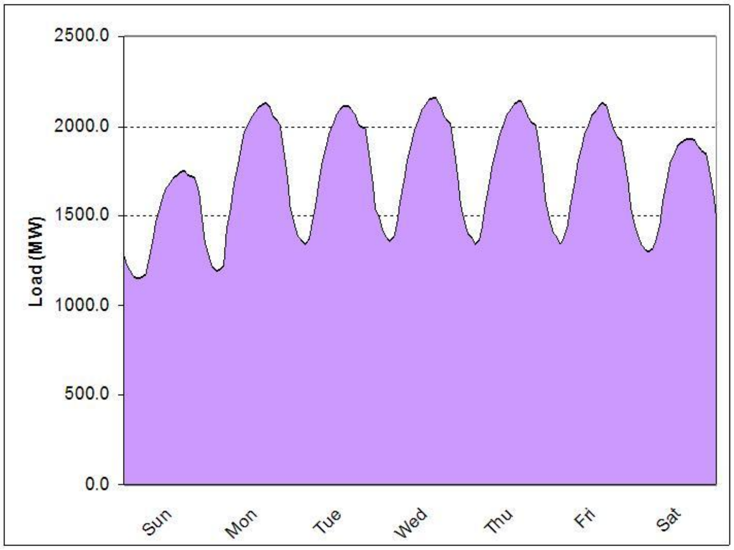

Figure 2.—Typical load pattern in summer.

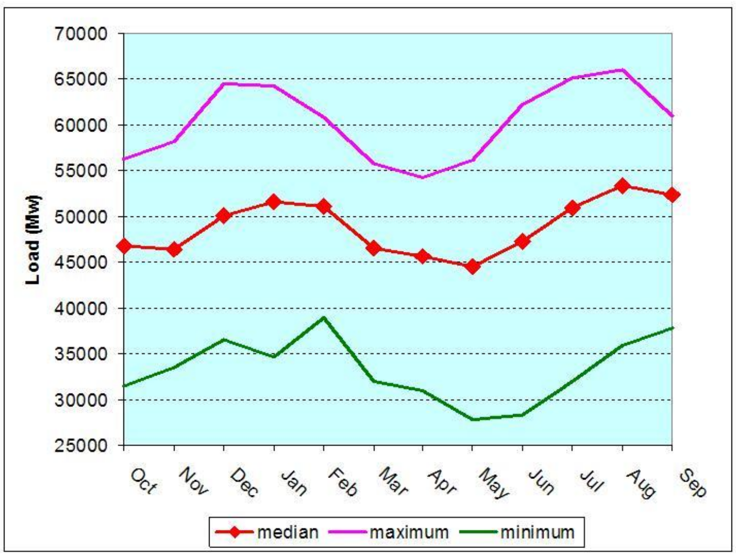

Figure 3.—Typical seasonal load pattern.

The term "energy" is used to describe generation over a period of time. Energy is typically measured in MWh. Another commonly used term is "capacity." The maximum amount of electricity which can be produced by a powerplant or transmitted by power lines is called capacity. Capacity is typically measured in MW. The capacity of most powerplants is determined by their design, size, location, and the ambient temperature. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, environmental and other constraints, and the amount of water available for release and the design of the facility. Because the capacity at hydropower plants is highly variable, the amount of dependable or marketable capacity is of particular significance. Dependable capacity is the maximum amount of generation which is reliably available.

THE KLAMATH RIVER WATERSHED

The Klamath River watershed encompasses parts of south-central Oregon and northwest California (figure 4). As shown in this figure, which is reproduced from Powers et al (2005), the Klamath River begins about a mile below Upper Klamath Lake near Klamath Falls, Oregon and flows nearly 260 miles to the Pacific Ocean just south of Klamath, California (Federal Energy Regulatory Commission, [FERC] 2007). An Upper and Lower Basin comprises the watershed. The Upper Klamath Basin covers 4,630 square miles and includes Reclamation's Klamath Project (Powers, et al., 2005). The Klamath Project is one of the oldest projects in the basin, having been authorized in 1905 and mostly completed in 1907. The J.C. Boyle Dam is in the Upper Klamath Basin in southern Oregon.

The Wood, Williamson, and Sprague Rivers are the main tributaries feeding into Upper Klamath Lake. Upper Klamath Lake, Clear Lake, and Gerber Reservoir are the principal sources of irrigation water for the approximately 235,000 acres of irrigated agricultural lands in the basin – see figure 4 (Powers, et al., 2005). The Upper Basin has 38.3 percent of the total land area of the basin but receives on average only 12 percent of the annual water runoff (Powers, et al., 2005). Besides being an area with limited water resources, the system has limited ability to store water.

Clear Lake, Gerber Reservoir, Lower Klamath Lake, Tule Lake, and the rest of the Lost River drainage within the Klamath watershed make up a closed water system in that it has no natural connection to the Klamath River. As part of Reclamation's Klamath Project there is the Lost River Diversion Channel that allows excess drainage water or additional irrigation water to be exchanged between Klamath Project agricultural lands (the Lost River drainage) and the Klamath River. The Lost River Drainage is not a dependable source of extra water for power production.

The Upper Klamath Lake while having a large surface area is relatively shallow so it has little carry over capacity from year to year. Various studies have been conducted over the years by Reclamation in an attempt to find a way to increase the water supply for irrigation in the Upper Basin but geography, geology,

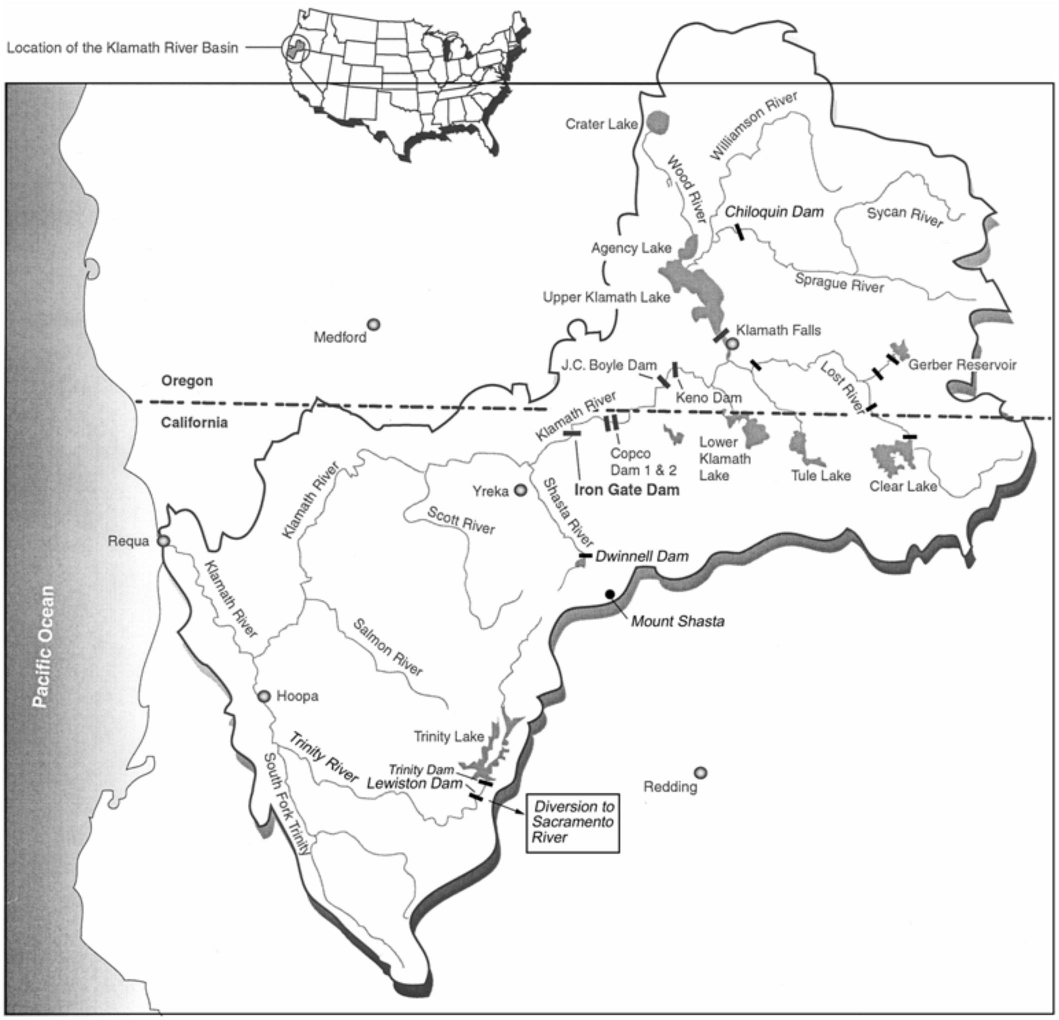

Figure 4.—The Klamath River watershed.

economics, water rights, and other factors have combined to prevent such efforts.[1] In a dry environment with limited storage capability there is increasing demand from compeating uses such as irrigated agriculture, fish and wildlife, Municipal and Industial, recreation, hydropower, tribal trust, etc. These various uses, some of which are comsumptive, some of which are not, all affect the quantity and quality of water in the Klamath River.

The demarcation of the two basins is at the Iron Gate Dam. The Lower Basin is the area below and west of the Iron Gate Dam and it covers about 7,470 square miles or 61.7 percent of the land area of the total Klamath Basin (Powers, et al., 2005). This portion recieves 88 percent of the basin's water runoff. Here the

[1] For examples see *Raising Upper Klamath Lake Appraisal Study*, November 2000, Department of the Interior, Bureau of Reclamation and *Increasing the Storage Capacity of Gerber Reservoir Klamath Project, Oregon Concluding Report,* U.S. Department of the Interior, Bureau of Reclamation, February 2005.

Klamath River is fed by the Shasta , Scott, Salmon, and Trinity Rivers. Copco Dams No. 1 and No. 2 and Iron Gate Dam are located in Northern California (figure 4). From the Iron Gate Dam the Klamath River flows unimpeaded to the Pacific Ocean.

PACIFICORP'S GENERATION RESOURCES

Headquartered in Portland, Oregon, PacifiCorp sells electricity from 78 generating plants to approximately 1,719,000 customers in six states – California, Idaho, Oregon, Utah, Washington, and Wyoming (PacifiCorp, 2010 a). The total annual forecasted load for 2010 is 59,403,758 MW and by 2019 the load is expected to grow by an average of 2.3 percent (for the period 2010 to 2019) to 72,870,856 MW (PacifiCorp, 2010 a). The peak load expected the summer of 2010 is 9,883 MW and the expected annual growth rate of 2.3 percent pushes the 2019 peak load to 12,112 MW (PacifiCorp, 2010 a).

To provide for this growth PacifiCorp owns 10,230 MW of installed capacity[2] (table 2) and purchases power from other sources and uses demand side management to reduce/switch usage to offpeak times (PacifiCorp, 2009).[3] PacifiCorp has also brought some new wind-power generation on-line (127.5 MW of capacity in 2009) to add to its generation resources.

Table 2.—PacifiCorp's generation resources

Fuel type	Capacity at time of system peak (MW)	Percent
Coal	6,128	46.6
Gas	2,405	18.3
Hydroelectric	1,450	11.0
Renewables	247	1.9
Other[1]	2,914	22.2
Total	13,145	100.0

Source: PacifiCorp, 2009.
[1] Purchased power and other non-generated sources.

[2] The maximum rated output of a generator or other electric power production equipment under specified operating conditions. Installed capacity, also known as nameplate capacity, is typically reported on a nameplate physically attached to the generator.

[3] As of June 8, 2010 PacifiCorp's generation resources were composed of 11 coal fueled, 47 hydroelectric, 6 natural gas, 12 wind, 2 geothermal and other facilities (PacifiCorp, 2010 b).

KLAMATH HYDROELECTRIC PROJECT

There are seven hydropower plants in the Klamath Hydroelectric Project (FERC Project No. 2082-027) with a total installed capacity of approximately 169 MW[4]. The four Klamath River plants, which are the subject of this analysis, account for about 163 MW. Table 3 illustrates the installed capacity for these four plants.

Table 3.—Capacity of the four Klamath hydropower plants

Powerplant	Installed capacity (MW)
J.C. Boyle	97.98
Copco No. 1	20.00
Copco No. 2	27.00
Iron Gate	18.00
Total	162.98

Source: FERC (2007).

The four Klamath River plants make up approximately 2 percent of PacifiCorp's total generation resource and approximately 11% of PacifiCorp's hydropower resource, measured on an installed capacity basis.

J.C. Boyle Dam

The J.C. Boyle portion of the Klamath Hydroelectric Project consists of a dam (at river mile 224.7), reservoir, water conveyance system, and powerplant all of which are located between river mile 228.3 and 220.4 (U.S. Fish and Wildlife Service, 2009 and FERC, 2007). The dam is a combination 68-foot high earth-fill embankment that is 413.5 feet long and a concrete portion that is 279 feet long (FERC, 2007). The concrete part is composed of a spillway section, an intake section, and a gravity section that is 23 feet high and 115 feet long.[5] The reach from Keno Dam is 4.7 miles long and flows into J.C. Boyle Reservoir (also known as Topsy Reservoir), which is long and narrow and covers about 420 surface acres (FERC 2007, U.S. Fish and Wildlife Service 2009). Total

[4] The East Side Powerhouse has an installed capacity of 3.2 MW and the West Side Powerhouse has an installed capacity of 0.6 MW. While not a part of this study, both of these units are scheduled to be decommissioned by PacifiCorp. The Fall Creek Powerhouse has an installed capacity of 2.2 MW. The Fall Creek generation facility will remain in operation regardless of the future of the other power facilities.

[5] A gravity dam is a dam that is constructed of concrete and/or masonry which relies on its weight and internal strength for stability.

storage capacity is 3,495-acre feet of which 1,724 acre-feet is active capacity (FERC, 2007). The normal operating range is between the maximum and minimum elevations of 3,793.5 and 3,788 feet (FERC, 2007). Normal pool is at elevation 3,793.5 feet which is approximately one-half foot below the top of the three 12-foot high by 36-foot-wide radial spillway control gates (FERC, 2007). For fish passage upstream there is a pool and weir fish-way approximately 569 feet long. To prevent entrapment, a 24-inch fish screen bypass pipe provides 20 cubic feet per second (cfs) of flow below the dam. The fish passage and screens do not meet current National Marine Fisheries Service fish passage criteria (U.S. Fish and Wildlife Service, 2009).

There is a 40-foot-high reinforced concrete intake tower to begin the conveyance of water to the powerplant, which is more than 2.5 miles (4.3 river miles) farther downstream. A combination of steel pipeline and concrete canal carry water to a forebay. From here, a 15.5 feet high and 1,660 long tunnel takes the water to two 10.5 feet diameter penstocks that each feed a vertical-Francis turbine. The powerhouse is a conventional outdoor-type reinforced concrete structure housing the two turbines and two generators. Each turbine has a discharge of 1,425 cfs. This flow goes into the 17.3 mile-long J.C. Boyle peaking reach of the Klamath River before entering the Copco Reservoir. The Unit 1 generator has a capacity of 50.35 MW and the Unit 2 generator has a capacity of 48.45 MW (FERC, 2007). Power from the J.C. Boyle Powerhouse is transmitted about a quarter of a mile to the J.C. Boyle substation.

Copco No. 1 Dam

Copco No. 1 Dam is found at river mile 198.6. It is a concrete gravity arch dam that is 126 feet high with a crest length of 410 feet (FERC, 2007).[6] The spillway crest is at elevation 2,593.5 feet and is divided into 13 bays controlled by 14-foot by 14-foot Taintor gates[7] with the normal operating elevation being 2,606.0 feet (FERC, 2007). The maximum and minimum normal operating water levels are between 2,607.5 and 2,601.0 feet. At elevation 2,607.5 feet Copco Reservoir[8] contains about 33,724 acre-feet of total storage capacity (6,235 acre-feet of active capacity) and covers a surface area of approximately 1,000 acres (FERC, 2007).

[6] A concrete gravity arch dam is a concrete or masonry dam that is curved upstream in plan so as to transmit the major part of the water load to the abutments and to keep the dam in compression in combination with an arch dam which is only slightly thinner than a gravity dam.

[7] A Taintor gate is a type of radial gate which is a pivoted crest gate, the face of which is usually a circular arc, with the center of curvature at the pivot about which the gate swings (Reclamation, 2009 a). It is a gate with a curved upstream plate and radial arms hinged to piers or other supporting structure (Reclamation, 2009 a).

[8] Copco No. 1 Reservoir is also known as Copco Reservoir. Copco No. 2 Reservoir is referred to by its full name to distinguish it from Copco Reservoir.

Two intake structures feed the Copco No. 1 powerhouse at the base of the dam. The left intake funnels water to two, 10-foot diameter (reducing to eight-foot-diameter) steel penstocks to drive Unit No. 1. The right intake takes water to one 14-foot diameter (reducing to two eight-foot diameter) penstocks that drive Unit No. 2. Both turbines are double-runner, horizontal-Francis units, with a discharge rate of 1,180 cfs each. The two generators have a capacity of 10 MW each (FERC, 2007).

Copco No. 2 Dam

Copco Dam No. 2 is located on the river at mile number 198.3. Copco No. 2 is a concrete gravity dam 33 feet high with a crest length of 335 feet (FERC 2007). The dam also has a 132-foot-long earthen embankment. The reservoir is only 0.25 mile long and stores 73 acre-feet. The reservoir is held at the normal elevation of 2,483 feet with little active storage and as a result Copco No. 2 generation follows Copco No. 1 generation (FERC 2007). There is a 1.5 mile bypassed reach of the Klamath River that receives 5 to 10 cfs of instream flow via a corrugated metal flume. The concrete dam has a 145-foot long spillway section with five controling gates.

The powerhouse, served by a combination of about a mile of concrete-lined tunnels and wood-stave pipeline and two penstocks, is a reinforced concrete building containing two vertical-Francis turbines. Each turbine has a discharge of 1,338 cfs each. Each generator has a capacity of 13.5 MW (FERC, 2007).

Iron Gate Dam

Iron Gate Dam and Reservoir are located between river miles 196.9 and 190.1 about 20 miles northeast of Yreka, California (FERC, 2007). The dam is a zoned earthfill embankment.[9] The steel extension wall on the crest makes the elevation 2,348.0 feet. The height of the dam is 194 feet and it is 740 feet long (FERC, 2007). The spillway is a non-gated chute 727 feet excavated in rock at the right dam abutment. The diversion tunnel developed during the construction of Iron Gate dam is still used for emergency high flow events. There is a fish hatchery associated with this dam and it has high (elevation 2,310 feet) and low (elevation 2,250 feet) intakes for fish facility water.

Iron Gate Reservoir contains approximately 50,941-acre feet of storage capacity at elevation 2,328 feet with about 3,790 acre-feet of that being active storage

[9] An embankment dam composed of zones of selected materials where the permeability of the material increases to the upstream or downstream face from the relatively impermeable core material.

capacity (FERC, 2007). The surface area covers 944 acres. The normal maximum and minimum operating levels are elevations 2,328.0 feet, the invert of the unregulated spillway, and 2,324.0 feet.

The powerhouse, located at the base of the dam, houses one vertical Francis turbine that has a discharge capacity of 1,735 cfs. The generator has a capacity of 18 MW (FERC, 2007). There is a synchronized bypass valve located immediately upstream of the turbine to maintain stream flows in case of a turbine shutdown.

As part of fishery mitigation measures, the Iron Gate Fish Hatchery is located downstream from the dam. The hatchery is adjacent to Bogus Creek. Water diverted from the reservoir (up to 50 cfs) supplies a fish ladder, fish trapping facilities, 32 raceways, and fish rearing facilities. The California Department of Fish and Game manages the facility and PacifiCorp provides up to 80 percent of the annual operation and maintenance funding.

RECENT PROJECT HISTORY

Water in the Klamath Basin has been a source of ongoing conflict for many years. Tribes, anglers, farmers, conservationists, state and federal agencies and individual members of the public all have an interest, need, or claim on the Basin's limited water supply and other associated resources (e.g., fish). The conflict became highly visible when in 2001(a low water year) Reclamation, in order to protect endangered fish populations, reduced water deliveries significantly to most irrigation contractors in Reclamation's Klamath Project. The affected farmers and other businesses within the local community suffered economic damage in the tens of millions of dollars range. A later study by the National Research Council showed that reducing water delivery to keep more water in Upper Klamath Lake and increase flows in the Klamath River action was of questionable benefit to the threatened or endangered fish populations (Powers, et al., 2005).

Then in 2002, there was a major die-off of adult salmon returning to the Klamath River (U.S. Department of the Interior, et al., undated). It was later determined that two common pathogens that are lethal to fish under stress killed about 30,000 salmon, mostly Chinook (The National Academies, 2007). This event brought additional attention to the Klamath Basin and the conflicts over competing uses of the basin's limited water supply.

In February 2004, PacifiCorp, the owner of the Klamath Hydroelectric Project, was in the process of developing an application to the Federal Energy Regulatory commission to have this project relicensed. In this application the J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate Dams were proposed for reoperation.

The small hydropower plants known as the East Side and West Side Developments were planned to be decommissioned and Keno Dam was to be removed from the project.

In 2006, the commercial salmon-fishing season was closed along 700 miles of the West coast to protect the weak Klamath River stocks (U.S. Department of the Interior, et al., undated).

On September 25, 2006, the Draft Environmental Impact Statement for Relicensing of the Klamath Hydroelectric Project No. 2082-027 was issued. The existing project consisted of eight developments, seven of which were on the Klamath River. The draft included several alternatives. A central theme was that PacifiCorp proposed to decommission the East Side and West Side powerplant developments and to remove the Keno Dam from the project, which does not have any hydroelectric generating facilities. Then the J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate Dams on the Klamath River would be kept, as would the Fall Creek development. One prominent alternative would include 31 environmental improvements in addition to those proposed by PacifiCorp.

A study completed in April 2007, determined that decommissioning the Klamath Hydroelectric Project rather than relicensing, increases the economic benefits to PacifiCorp's rate payers in the range of $32 million to $286 million and for the midline case it would be $114 million less costly to decommission rather than to relicense and add environmental improvements (M. Cubed, 2007).

On November 16, 2007, the Final Environmental Impact Statement for Relicensing of the Klamath Hydroelectric Project No. 2082-027 was issued. The preferred alternative included relicensing the four major powerplants on the Klamath River, J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate Dams and keeping the Fall Creek development on a Klamath River tributary; decommissioning the East Side and West Side developments and removing the Keno Dam from the project; incorporating most of PacifiCorp's proposed environmental measures; and implementing more than two dozen other environmental measures and programs.

After negotiations relicensing was sidelined and the following year on November 13, 2008 Oregon, California, the Department of the Interior, and PacifiCorp signed an Agreement in Principle (AIP) that provided a framework for the transfer of Pacificorp's four major dams to a designated dam removal entity (Govenor of California, 2008). This historic AIP has the potential to help resolve many Klamath River resource issues and lead to the removal of the four major dams on the river belonging to PacifiCorp.

The Klamath Basin Restoration Agreement (KBRA) for the Sustainability of Public and Trust Resources and Affected Communities was signed on

February 18, 2010 and began to go into effect (Klamath Settlement Parties 2010). This agreement is important because it is the vehicle expected to help resolve long-standing conflicts over many basin resources.

> “The Agreement is intended to result in effective and durable solutions which: (i) restore and sustain natural production and provide for Full Participation in Harvest Opportunities of fish Species throughout the Klamath Basin; (ii) establish reliable water and power supplies which sustain agricultural uses and communities and National Wildlife Refuges; (iii) contribute to the public welfare and the sustainability of all Klamath Basin communities through these and other measures provided herein to resolve the disputes described in section 1.2” (Klamath Settlement Parties, 2010).

In conjunction with the KBRA, the Klamath Hydroelectric Settlement Agreement (KHSA) was also signed on February 18, 2010 (U.S. Department of the Interior, et al., 2010). The KHSA refers to the Agreement in Principle executed on November 13, 2008 by the States of Oregon, California, the Department of the Interior, and PacifiCorp which set forth a framework for the potential removal of J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate Dams and appurtenant works currently licensed to PaciFiCorp (U.S. Department of the Interior, et al., 2010).

These two agreements pave the way for the removal of the four major dams downstream from Reclamation’s Klamath Project beginning in 2020. If this action occurs, it would be the largest dam removal project in the nation’s history.

HYDROPOWER FUNDAMENTALS

In 2009, approximately 6.8 percent (%) of the electricity generated in the United States was produced by hydroelectric powerplants (EIA, 2010, p. 2). In the West, hydropower plants contribute a much larger share of the total electricity supplied—around 25%. These plants are an invaluable component of the Nation's interconnected electric power system which also consists of fossil fuel, nuclear, solar, wind, and other generation resources. In comparison to other types of generation resources, hydropower plants have exceptionally low costs of operation, are highly reliable, and produce electricity without burning fossil fuels and producing air pollution. In addition, they provide voltage control, system regulation and other ancillary services which help to ensure the reliability and electrical integrity of the system.

Ignoring pumped storage facilities, there are two principle types of hydropower plants. These are run-of-river plants and peaking plants. Run-of-river plants typically have little water storage capability. Consequently, generation at run-of-river plants is proportional to water inflow and there is little variation in electrical output during the day. Peaking hydropower plants, such as the one at Glen Canyon, often have significant water storage capability and are designed to rapidly change output levels in order to satisfy changes in the demand for electricity. Peaking hydropower plants are particularly valuable because they can be used to generate power during onpeak periods avoiding the cost of operating more expensive thermal plants such as gas turbine units.

The amount and timing of inflows can have a substantial effect on the operation of a hydropower facility. Reservoirs are filled by waters which flow into them. In aggregate, these are referred to as "inflows." Inflows are often, but not always, derived from water flowing down streams and rivers which empty into the reservoir. To the extent that inflows arise from natural or uncontrolled watersheds, their magnitude and timing is uncertain.

The total release from a hydropower reservoir is made up of two components; releases from the turbines (turbine release) and bypasses, also known as spills. Turbine releases rotate the blades of the turbines, turn the generators and produce electricity. Spills are made from outlet works such as spillways, overflow valves, jet-tubes, etc. These releases bypass the turbines and *do not* produce any electricity. From the hydropower production standpoint, spills are considered undesirable and wasteful since they represent water that passes through the dam without producing hydropower.

Operation of a reservoir and hydropower plant is a complex endeavor. A given storage reservoir has a finite maximum storage volume which must be considered in the decision process. Although there are exceptions of course, typically, storage reservoirs are relatively small in proportion to the annual water yield from the watershed where they are located. In many circumstances, there is little or no year-to-year carryover storage. The volume of water stored in the reservoir at any given point in time can be measured and is known to the operator. The amount and timing of future inflow and the nature of future conditions in the electric power markets are uncertain.

The amount of "active" storage at a particular reservoir depends on the topography of the site and the design of the plant. Generally, active storage is defined as the volume of water which can be retained in the reservoir and then released through the generators and/or outlet structures *under normal circumstances*. Typically, the lower elevation limit of the active storage pool is dependent on the elevation of the penstocks plus the minimum required level of penstock submergence. Some level of minimum penstock submergence is necessary to avoid entrainment of air in the turbines and consequent equipment damage. The upper limit of the active storage pool is often the level of the dam crest minus some amount of freeboard space. "Inactive" storage is that part of the reservoir pool which is not released from the reservoir *under normal circumstances.* Depending on the particulars of the facility and the site, inactive storage can be a substantial portion of total storage.

At a hydropower plant, electricity is produced by the force of falling water which falls through the penstocks into the turbines. The force of the water against the blades of the turbine rotates a large shaft. This shaft turns the rotor within the generator and produces electricity.

The amount of electricity produced depends on the amount of water released and the vertical distance the water falls. This vertical distance is called “head.” The head at any point in time is measured by the difference between the water surface elevation of the reservoir and the elevation of the tailwater below the dam. For any given instant in time, the elevation of the reservoir is fixed and known. The elevation of the tailwater increases as the total amount of water released is increased. As further described in Appendix 2, for any given level of release, higher reservoir elevations produce greater amounts of electrical generation. For any given level of release, lower reservoir elevations result in lower levels of head and lower generation levels.

Due to engineering constraints inherent in the design of the turbines, generators and other equipment, the maximum power generation capability or capacity is limited. As releases increase, the amount of electricity generated increases. When the maximum generation capability is reached, further releases cause an increase in the tailwater elevation without any addition to generation.

To the extent possible, the operation of hydropower plants reflects current and expected electricity market conditions. During high demand periods (such as July and August, prices are generally higher and it is advantageous to release more water and generate more hydropower. During periods of reduced electricity demand (for example during shoulder months, like March and April), the value of electricity is relatively lower and it is less desirable to use limited water resources for the production of hydropower. Insofar as the pattern of inflows and the storage capability of the reservoir allows, and it is consistent with other reservoir purposes, the pattern of releases (and generation) at a hydropower plant tends to follow anticipated conditions in the electricity market.

Economic Value of Hydropower

The economic benefit of operating an existing hydropower plant is measured by the avoided cost of doing so. The market price of electricity is a commonly employed proxy for avoided cost.

Avoided cost is the difference between the total power system cost of satisfying the demand for electricity “with” and “without” operating the hydropower plant. Conceptually, avoided cost is the savings realized by supplying electricity from a low-cost hydropower source rather than a higher-cost thermal source. These savings arise, in part, because the cost of operating a hydropower plant is typically rather low in comparison to thermal units.

The market price of electricity reflects the cost of operating the marginal, or price setting generation unit. At a given level of electricity demand, generation of an additional megawatt of hydropower would avoid the costs associated with generating a megawatt of electricity using the marginal generation unit. The economic benefit, or value of the costs avoided-- is the market price of that megawatt of electricity.

The economic value of operating an existing hydropower plant varies considerably with time of day. The variable cost of meeting demand varies on a second by second basis depending on the load, the mix of plants being operated to meet load, and their output levels. During offpeak periods, demand is typically satisfied with lower-cost coal, run-of-river hydropower, and nuclear units. During onpeak periods, the additional load is met with more expensive sources such as natural gas combustion turbine units. Consequently, the economic value of hydropower is greatest during hours when the demand for electricity, and the variable cost of meeting demand, is the highest.

ANALYSIS SCOPE

The analysis described here is limited to an assessment of the (gross) economic benefits of hydropower production and how those benefits might change with dam removal. The costs associated with operation, maintenance and equipment replacements (OM&R costs) at the four Klamath River hydropower plants are not considered in this document. There are a variety of fixed and variable costs associated with operating and maintaining these plants and replacing equipment as it reaches the end of its useful life. These costs are a necessary component of a systematic benefit-cost analysis and are described in Auslam, et al. (2011).

PERIOD OF ANALYSIS

This hydropower economic impact assessment spans the period from 1 January 2012 to 31 December 2061, a period of 50 calendar years. The period of analysis used in the hydropower analysis differs slightly from the period employed in the hydrologic modeling effort. The hydrology analysis is based on water years (WY) and the hydropower economic analysis, on the subset of calendar year (CY) data in that range. A water year runs from 1 October to September 30. A calendar year, of course, goes from 1 January to December 31. Figure 5 visually compares a water year and a calendar year.

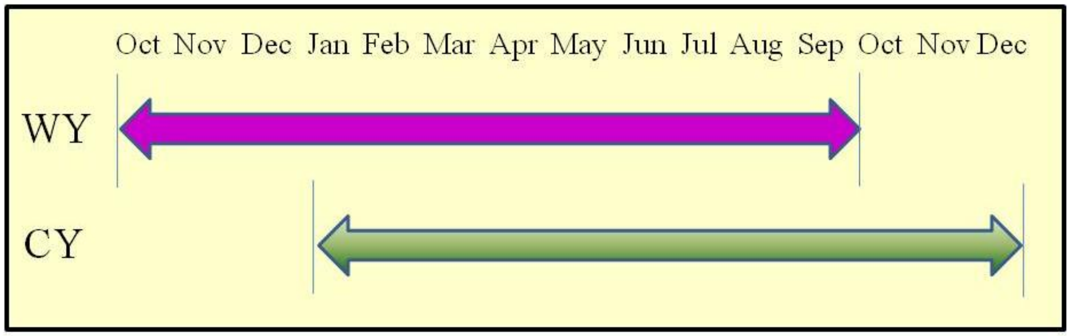

Figure 5.—Water year and calendar year compared.

In contrast to hydrologic information, economic phenomena are commonly measured over the calendar year. For example, production, product prices, price inflators and deflators are typically reported annually, on a calendar year basis. In addition, compounding and discounting calculations for long-term planning exercises are commonly carried out on an annual (CY) time-step.

The hydrologic modeling carried out for this assessment spans the period 1 October 2011 to 30 September 2062, a period of 51 water years. In order to accommodate the available economic data, and to conform to typical economic conventions, the hydropower impact analysis is based on calendar years and spans the entire range of available calendar year data (50 years).

ANTICIPATED EFFECTS OF DAM REMOVAL

For purposes of this analysis, the Full Facilities Dam Removal Alternative assumes the four Klamath River Dams are operated from January 1, 2012, through midnight on December 31, 2019. All four dams are then assumed to be removed simultaneously and instantaneously at 1 minute past midnight on January 1, 2020 (the first day of calendar year 2020). As described in this analysis, the 2020 removal of the four dams will eliminate all hydroelectricity generation at these facilities.

IMPACT INDICATORS

In this analysis, three indicators are employed to capture the effects of the alternatives on hydropower generation at the four Klamath River dams. These are (1) the amount of electrical energy generated (generation), (2) the dependable generation capacity (capacity) and, (3) the economic value of the hydropower produced (economic value).

Generation

The annual quantity of electrical energy produced by the four Klamath River hydropower plants, measured in MWh, is estimated for both the no action and action alternatives.

Capacity

The maximum amount of electricity in MW, which can be produced by the four Klamath River hydropower plants, is estimated for both the no action and the action alternatives. Dependable or marketable capacity is the amount of capacity which is reliably available. The dependable capacity is determined using a probabilistic method described subsequently.

Economic Value

The economic value of the electricity produced at the four Klamath River dams is the monetary value of that electricity from the national economic viewpoint. The economic value is measured in 2012 present value terms.

CONCEPTUAL APPROACH

Figure 6 illustrates the conceptual approach used in this hydropower analysis. For each alternative, the onpeak generation and the offpeak generation at the four Klamath River hydropower plants were estimated using the KDRM hydrology model. KDRM is a RiverWare (Zagona, et al., 2001) based hydrology operations model of the Klamath River Basin. These data are estimated on a daily basis for each modeled hydrologic sequence, for the period of analysis, as described in King and Parker (2011). The resultant daily onpeak and offpeak generation data were aggregated to a monthly time-step for the hydropower economic and capacity analysis.

Two hydropower utility programs were employed for this analysis. These are the Klamath Generation (KLAMGEN) program and the Klamath Capacity (KLAMCAP) program. The former program aggregates and reports generation and computes the economic value of hydropower. The latter program calculates selected measures of dependable capacity.

Using observations of monthly onpeak and offpeak generation estimated by the KDRM hydrology operations model, summary measures of total annual generation are computed and reported by the KLAMGEN hydropower utility

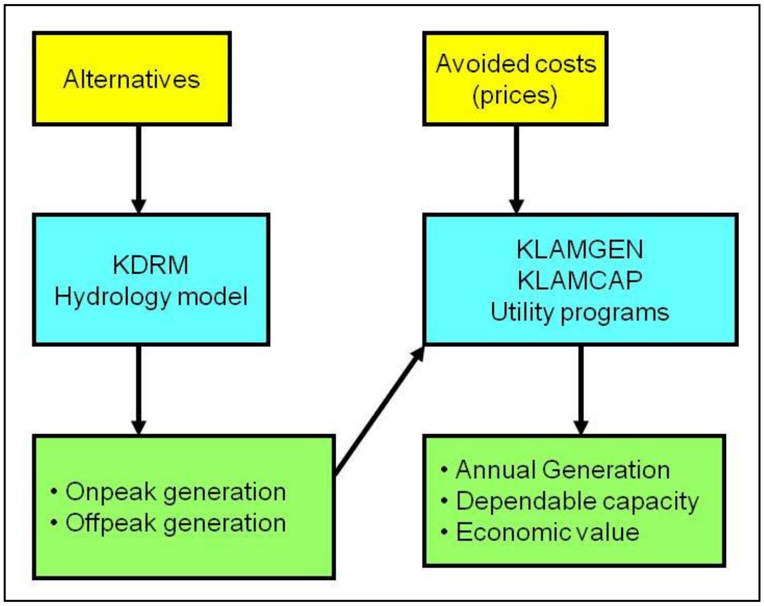

Figure 6.—Conceptual approach.

program for each alternative. The present economic value for each hydrologic sequence or trace is calculated by the KLAMGEN hydropower utility program using the monthly generation data, the forecast monthly price of electricity, and the discount and escalation rates identified for this analysis. This process yields a distribution of estimated present economic value for each alternative. Summary measures of present economic value are then reported by this utility program for each alternative.

For each alternative, the summer and winter dependable capacity are calculated from the monthly onpeak generation and summary results are reported by the KLAMCAP utility program.

MODELING THE HYDROPOWER PLANTS

The operation of the four Klamath River hydropower plants was characterized using the KDRM model as described more fully by King and Parker (2011). Table 4 summarizes some of the salient features of this modeling effort.

The storage reservoirs at the four Klamath River hydropower plants are relatively small. Active storage is a measure of the storage volume used for normal (non-emergency) operations. In aggregate, the active storage volume at all four plants is approximately 18,756 af. Because of their limited storage volume, power operations at these facilities are constrained by available inflow, particularly

Table 4.—Characterization of plants in KDRM model

Plant	2012 installed capacity (MW)	Active storage volume (af)[10]	Operation mode
J.C. Boyle	97.98	1,995	Peaking
Copco 1	20.00	12,971	Run-of-river
Copco 2	27.00	None	Run-of-river
Iron Gate	18.00	3,790	Run-of-river

during the winter months. The Copco 2 unit is the extreme case. It has no active storage and relies entirely on releases made from the upstream Copco 1 plant to drive its operations.

The four Klamath River hydropower plants and their operations are characterized within the KDRM, forming the basis for the hydropower economic analysis. J.C. Boyle is modeled as a peaking plant, while the other plants are modeled as run-of-river plants. In this RiverWare based model, the relationship between the amount of water released through the turbines, head and the generation of electricity is derived from the curves shown in Pacificorp (2004a).

The operation of the J.C. Boyle and Copco 2 plants are simulated as inline powerplants in the KDRM RiverWare model. The Copco 1 and Iron Gate plants are simulated in KDRM using RiverWare level power reservoir objects. The daily generation at all four plants is classified into onpeak generation and offpeak generation. The onpeak period is defined as 7 am through 11 pm Monday through Saturday and all other hours are considered offpeak. For the J.C. Boyle plant, a rule is used to reallocate as much generation as possible to the onpeak period, while respecting the physical and engineering characteristics of the plant.

Under the No Action Alternative, the four Klamath River dams will remain in operation over the 2012 to 2061 analysis period. Some of the existing capital equipment at these plants will reach the end of its engineering life during this 50-year period. Replacement and refurbishment of aged equipment will be required to maintain continuing operations at these plants. Manufacturing capabilities, technology and computerized controls systems have improved markedly since these four powerplants were initially constructed and the required equipment replacements will increase the efficiency and the amount of generation capacity at these plants.

[10] Active storage volumes used in KDRM were derived from historical data and may differ somewhat from the values reported in other sources.

In a separate document, Auslam et al (2011) estimate the nature and timing of required capital replacements, expected improvements in powerplant efficiency and capacity, and the operation, maintenance and replacement (OM&R) costs for the four Klamath hydropower plants. Auslam et al (2011) assert there will be no replacement costs incurred under the Full Facilities Dam Removal Alternative. In contrast, an extensive program of replacements will be required under the No Action Alternative to keep these facilities operational, safe and acceptably reliable. Figure 7 summarizes the change in the installed generation capacity estimated by Auslam, et al (2011) for the No Action Alternative. As shown in this figure, installed generation capacity is forecast to increase from 162.99 MW in 2012 to 199.10 MW in 2061, or approximately 22%. The results of the Auslam, et al. (2011) study are shown on a year-by-year basis in Appendix 7.

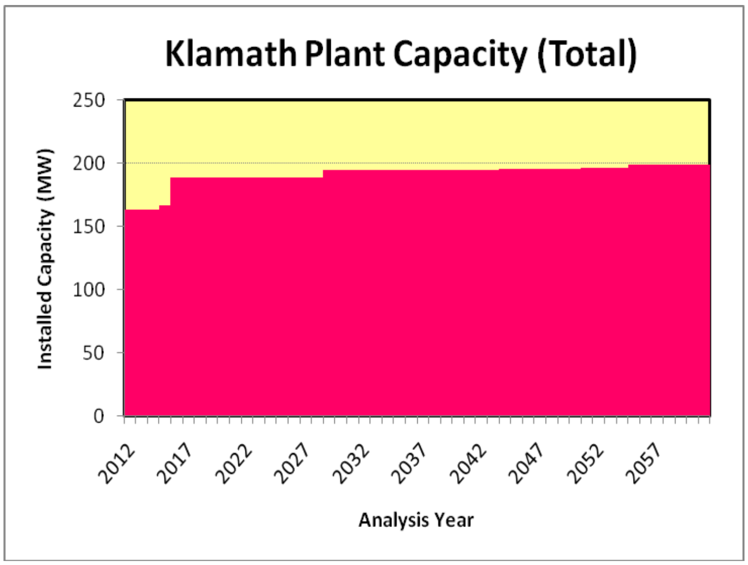

Figure 7.—No Action installed capacity over the analysis period.

The expected increases in installed generation capacity under the No Action Alternative are relevant to this analysis of hydropower benefits. These increases affect the output capability of the hydropower plants and hence the economic benefits they produce.

The KDRM model described in King and Parker (2011) utilizes static relationships to represent release, efficiency, head and generation capacity. Consequently, the KDRM model cannot directly characterize the temporally specific increases in installed capacity forecast to occur under the No Action Alternative (King 2011, personal communication).

For purposes of this analysis, the changes in the installed capacity for the No Action Alternative were characterized by post-processing output from KDRM.

Specifically, the no action generation estimated using the KDRM was scaled proportionately at the times consistent with the findings of Auslam et al (2011). The post-processed generation data for the No Action Alternative were then employed in all subsequent analyses of generation and economic benefits.

The equipment replacements required under the No Action Alternative will necessitate substantial capital expenditures. The associated capital costs and the ongoing operation and maintenance costs are reflected in the larger cost benefit analysis and are not described further in this document.

Known Analysis Limitations

The approach used in this analysis is relatively simple and readily applied but has some limitations. In particular, the model described here employs a monthly time step. As a result, intra-month phenomena, such as shifts in the timing of generation during the month, cannot be characterized. In contrast, alternative modeling frameworks (e.g., Harpman 1999; Edwards, Flaim and Howitt, 1999) are designed to characterize hourly generation effects-- although their implementation is both more complex and resource intensive. Models utilizing an hourly time-step are clearly indicated for analyses of hourly effects, such as changes in ramp rates. The Klamath analysis is a long-run planning study which focuses on a more fundamental question; continued powerplant operations versus decommissioning. Use of an hourly time-step model is unwarranted and unnecessary for this purpose. If an hourly time-step model were employed, the implications for dependable capacity, generation and economic value are unknown, but suspected to be negligible.

Forced and planned outages are not considered in this analysis. Powerplants are large, complex mechanical devices. They require routine or scheduled maintenance on a periodic basis. They are also subject to unscheduled outages, termed “forced outages.” As a consequence, powerplants do not operate 100 % of the time. The effects of such outages on generation, economic value and capacity are not considered in this document. Explicit consideration of these forced and planned outages would be expected to reduce the estimated dependable capacity, generation and economic benefits reported here.

The timing and extent of the outages associated with the replacement of capital equipment described in Auslam, et al (2011) are currently unknown. Some of these outages may well be extensive. For example, replacement of the wicket gates, guide tubes, turbine shafts and draft tubes at J.C. Boyle in 2019 could idle the plant for six months, or more. Replacements of turbines and generators typically occur only every 25-50 years and are carefully scheduled to minimize the loss of generation and revenue. Consideration of the outages associated with capital replacements would reduce the dependable capacity, generation and estimated economic benefits reported here.

This analysis makes no attempt to quantify or value the ancillary services produced by the four Klamath River hydropower plants, if any. In addition to producing capacity and energy, some hydropower plants produce ancillary services which are essential to the operation of the interconnected electricity system. Ancillary services include spinning and non-spinning reserves, regulation up and down, voltage and frequency control, black start and other services essential to the reliable functioning of the electric power system (see FERC 1995 and Hirst and Kirby (1996) for a more exhaustive treatment). Explicit consideration of ancillary services is outside the scope of this analysis. If these plants produce any ancillary services, their consideration could be expected to increase the estimated economic benefits reported here.

The approach used in this hydropower economic analysis does not consider the possible effect of changing hydropower operations on powerplant emissions. Approximately 61% of the 2008 summer generation capacity in the West was composed of fossil fuel fired power plants including coal, oil and natural gas fired plants[11.] Combustion of fossil fuels produces undesirable emissions of gasses and other materials into the atmosphere. These include waste gases such as carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), heavy metals such as mercury (Hg) as well as various particulates (See Harpman, 2006, page 93 for representative emission rates). In aggregate, generation of electricity by hydropower plants reduces the amount of electricity fossil fuel plants are required to provide and reduces emissions. The hydropower analysis described in this document does not consider the effect, if any, of changing hydropower production levels on system-wide powerplant emissions, or regional air quality.

DATA AND SOURCES

Electricity Price Data

For purposes of this analysis, the economic value of the hydroelectric energy generated for each of the alternatives is evaluated using a set of forecast monthly onpeak and offpeak electricity prices, which are reported in 2006 constant dollars. Removal of the four Klamath River hydropower plants is assumed to have no effect on these forecast prices. These forecast prices were generated by the Northwest Power and Conservation Council (NWPCC) as part of the Sixth Northwest Conservation and Electric Power Plan (NWPCC 2010 and NWPCC 2010, Appendix D). Specifically, this analysis utilizes the monthly Base Forecast prices for the COB electric power interchange.

The Sixth Northwest Conservation and Electric Power Plan is a transparent process with significant stakeholder and public involvement as well as expert

[11] Calculated for 2008 using data furnished by the Western Electricity Coordinating Council (WECC).

review. The underlying assumptions and approach are richly documented and the approach is informed, methodical and systematic. The AURORA^{XMP} model (Electric Power Information Solutions, Inc., 2010) was used by NWPCC staff to simulate the behavior of the interconnected electric power system on an hourly basis over the period of analysis. Mean monthly onpeak and mean monthly offpeak prices were calculated from these hourly data and used in this analysis.

The base price forecast spans the period from 2008 to 2030. Over the entire forecast period, there is a 3.4 percent real rate of annual increase. During the last 5 years of the forecast (2026 to 2030) there is an approximate 1.0 percent real rate of annual increase. To accommodate the 50 year period (2012 to 2061) of this analysis, the forecast price data were extended by an additional 31 years. Prices during the 31 year extension period are identical to the forecast prices in CY 2030, with a 1-percent real rate of annual growth, a rate which is consistent with the last 5 years of the forecast. A plot of the COB monthly base electricity price forecast with the extension period is shown in figure 8.

As shown in figure 8, the forecast prices trend upward over the analysis period. The real price increase during the 2012 – 2030 period results from several factors which are more fully described in NWPCC (2010 Appendix D). The economic downturn which began in 2007 caused a decline in natural gas prices as well as a decline in the demand for electricity. As a result, electricity prices at the beginning of the forecast period were relatively low. NWPCC staff forecast a slow economic recovery with an associated increase in natural gas prices over the early years of the analysis period. Additional upward real price pressures stem from costs associated with meeting utility renewable portfolio standards (RPS) and the assumed costs of acquiring carbon dioxide emission allowances.

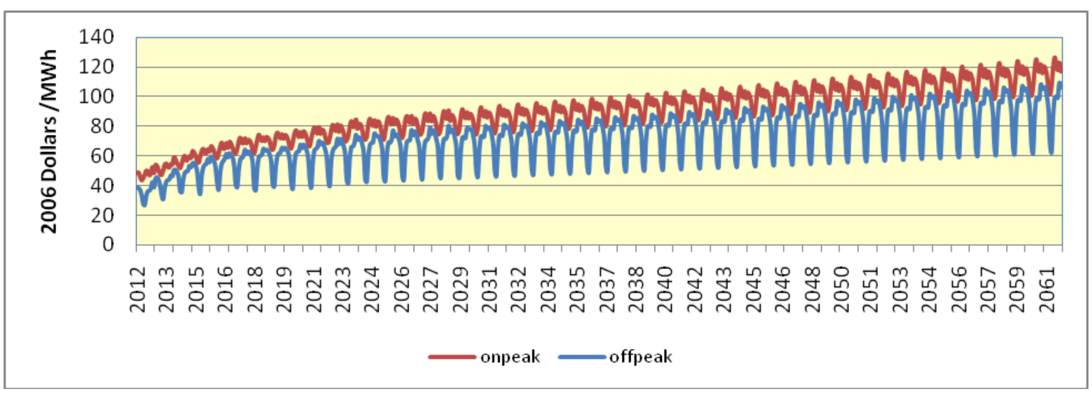

Figure 8.—COB forecast prices with extension period.

Due to the construction of new renewable generation resources, primarily wind resources, the forecast prices produced for the Sixth Northwest Conservation and Electric Power Plan may not represent avoided costs (NWPPC, 2010 Appendix D, page D-22). Surplus generating capability early in the forecast period is exacerbated by the construction of new renewable generation resources. The development of these renewable sources is spurred in large part by new state RPS, as well as local, state and federal subsidy programs (see North Carolina State University [2011] for an overview of state RPS requirements). As a result, the forecast prices are shaped, to an unknown extent, by the construction (and operation) of renewable generation resources, which are not least cost capital additions.

Interventions in the electricity markets, such as RPS requirements, certainly result in market price distortions. To provide some context, it is useful to recall that direct and indirect interventions in the U.S. electricity market are pervasive. The ongoing subsidies paid to the coal, gas and oil industries (EIA, 2000) are but one high-profile example of indirect market interventions. There is also a long history of Federal involvement in the provision, operation and regulation of the electric power system. The Federal Government facilitated the provision of electricity to large areas of the rural United States, regulates interstate electricity markets and continues to own most of the Nation’s large-scale hydroelectric resources (EIA, 1996).

The forecasts of electricity prices developed for the Sixth Northwest Conservation and Electric Power Plan represent the forecast marginal value of changes in generation. These price forecasts explicitly reflect the past history of market interventions as well as expected future institutional frameworks, including state RPS requirements. These factors shape future electricity markets and future electricity prices. The NWPPC base price forecasts characterize the expected future monetary value of increments or decrements in generation, and are well-suited for use in this analysis.

Hydrology Data

The hydropower analysis described here is critically dependent on the input data, and the KDRM, the RiverWare operations model of the Klamath River Basin. The assumptions made, the input data employed and the modeling approach are systematically described in King and Parker (2011). Interested readers are referred to that source for complete details.

By their nature, future hydrologic conditions are variable and uncertain. The historical hydrologic record represents only one possible outcome from the distribution of possible future hydrologic realizations. The term “trace” is used to describe an artificially constructed sequence of future hydrologic data. Typically, multiple traces are constructed to more fully explore the potential effects of different sequences of these data. These traces can then be used to drive operational models, allowing a much richer range of future operational results to be explored.

The KDRM simulates operations at the four Klamath River hydropower plants and produces the onpeak and offpeak generation data which form the basis for the hydropower economic analysis. A large number of different hydrologic analyses were undertaken for the Klamath Dam Removal Analysis. These hydrologic analyses were undertaken to support various purposes and resource requirements.

The hydropower economic analysis reported in this document utilizes 49 traces of future hydrologic data, each of which is 50 calendar years in length. These traces were constructed using the indexed sequential method, which synthetically generates a series of future inflow sequences directly from the historical record (Ouarda, Labadie and Fontane, 1997a, 1997b). Historical inflow data spanning the period from 1961 to 2009 were employed. Each one of the 49 traces uses a historic year as a starting year for the sequence.

For the 50-year period of analysis there are 49 different hydrologic traces, yielding 12*50*49 (29,400) observations of estimated monthly onpeak generation and offpeak generation for each alternative. Generation at the four Klamath River hydropower plants is directly related to the magnitude and sequence of inflows, which are variable and uncertain. Use of this approach is somewhat data intensive but allows the potential effects of hydrologic variability and uncertainty to be more fully characterized in the hydropower analysis.

METHODOLOGY

Generation

For each alternative, the KDRM was employed to estimate daily onpeak and offpeak electrical generation at the four Klamath River hydropower plants for each day and trace (King and Parker, 2011). The no action onpeak and offpeak generation were post-processed to reflect the changes in installed capacity forecast by Auslam et al (2011). The total daily generation (sum of onpeak and offpeak) data were then aggregated up to the annual time-step to facilitate reporting and allow comparisons with previous studies. This process yields 50 years times 49 traces, or 2450 observations of annual generation, for each alternative. The mean, maximum, 90 percent exceedence and 10 percent exceedence values of these 2450 observations of annual generation were calculated and are reported in the narrative and tables which follow. A 90 percent exceedence value is the value which is equaled or exceeded by 90 percent of the calculated values of a particular measure. Likewise the 10 percent exceedence value is a value which is equaled or exceeded by 10 percent of the calculated values of a particular measure.

Capacity

Capacity is the maximum generation capability of a powerplant. The capacity of most thermal powerplants is determined by their design, condition, location and the ambient temperature. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, environmental and other constraints, the water available for release and the design of the facility.

Because the capacity at hydropower plants is highly variable, dependable or marketable capacity is the most meaningful metric of hydroelectric generation capability. This measure is commonly used for planning purposes, as a basis for making power marketing decisions and for making comparisons with thermal power plants. By definition, dependable capacity is a statistically based metric calculated using a variety of techniques depending on the target time-frame, the ultimate end-use and the risk tolerance of the hydropower plant owner (Ouarda, Labadie and Fontane, 1997a, 1997b).

For each alternative, the KDRM was employed to estimate onpeak and offpeak electrical generation at the four Klamath River hydropower plants for each day and trace (King and Parker, 2011). These daily outputs were then aggregated to a monthly time-step for the capacity analysis. The estimated average monthly onpeak generation data are employed in this analysis to approximate the maximum generation capability of the four Klamath River hydropower plants.

All dependable capacity calculations are based on 2012 (existing) installed capacities at the 4 Klamath River hydropower plants (approximately 163 MW). Under the Full Facilities Dam Removal Alternative, no equipment replacements and no increases in generation capabilities are envisioned (Auslam, et al., 2011). Estimates of 2012 dependable capacity provide the most appropriate measure of the capacity which would be lost, should these facilities be decommissioned.

As described further in Appendix 2, dependable capacity is calculated here using a nonparametric (distribution-free) exceedence approach. Several dependable capacity metrics including the 80, 85, 90, 95, 99 and 100 percent exceedence values are calculated. Each of these measures is calculated for a summer marketing season (April through September) and a winter marketing season (October through March).

The results of the 90 percent nonparametric exceedence method are reported in the main body of this report. The results for other risk trade-off points may be found in Appendix 2. The 90 percent exceedence method used here is a simplified distribution-free version of the approach described in Western Area Power Administration (1986, 1993). To apply this method, the capacity data are categorized into the winter marketing season (October to March) and the summer marketing season (April to September). For each of these marketing seasons, the capacity value which corresponds to the X-percent empirical exceedence level is calculated. These capacity values are then reported as the X-percent exceedence dependable capacity for each marketing season.

Economic Value

The present economic value for each hydrologic trace is calculated using the monthly onpeak and offpeak generation, the forecast onpeak and offpeak price of electricity, and the discount and escalation rates identified for this analysis. This process results in 49 estimates of present economic value for each of the alternatives.

For each month in a trace, the monthly onpeak generation is evaluated using the forecast onpeak price and the monthly offpeak generation is evaluated using the forecast offpeak price. The monthly economic value is the sum of the onpeak value and the offpeak value for that month. Next, the annual economic value for each year in the trace is calculated from the monthly economic values.

In this application, the economic value of hydropower is estimated over the period CY 2012 to 2061 (50 years) for each of the alternatives. A procedure known as discounting is used to place the annual economic benefits, which occur at different points in time, on a commensurate dollar basis (see Appendix 1 for details). The approach used conforms to the procedures described in the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resource Council 1983).

Each observation of annual economic value occurring after 2012 is discounted by 4.125 percent, the applicable Federal discount rate for plan formulation and evaluation (Bureau of Reclamation, 2010). The 50 discounted annual values in the trace are then summed to compute the present economic value. This procedure is repeated for each trace, yielding 49 estimates of present economic value for each of the alternatives. Summary metrics including the mean, median, 90 percent exceedence and 10 percent exceedence values of the present economic value distribution are calculated. These summary results, measured in 2012 dollar terms, are reported in the narrative and tables which follow.

NO ACTION ALTERNATIVE

In this analysis the No Action Alternative serves as the base case against which all action alternatives can be compared. As described previously in this document, the impact indicators for this analysis are; annual generation measured in MWh, present economic value measured in 2012$ and dependable capacity measured in

MW. Appendices 3 through 5 illustrate the results calculated for each of these indicators. Selected results for each indicator under the No Action Alternative are presented in table 5 below.

Table 5.—No Action Alternative

Indicator	Mean	90% Exceedence	10% Exceedence
Annual generation (MWh)	895,846.9	595,699.2	1,231,637.7
Economic value (2012$)	1,609,310,821	1,576,870,199	1,645,951,189
Summer capacity (MW)	na	55.9	na
Winter capacity (MW)	na	66.6	na

This analysis is based on 49 hydrologic sequences or traces of monthly hydrology, each of which is 50 years in length. Under the No Action Alternative, the mean annual generation is approximately 895,847 MWh. At the 90% exceedence level, which corresponds to a year in which there is relatively limited inflow, the mean annual generation is approximately 595,699 MWh. At the 10% exceedence level, corresponding to a year with plentiful inflow, the mean annual generation is approximately 1,231,638 MWh.

The mean present economic value over the 49 hydrologic traces examined is 1,609,310,821 (2012$), over the 50-year analysis period. At the 90% exceedence level, the mean present economic value is approximately 1,576,870,199 measured in 2012$. At the 10% exceedence level, the mean present economic value is approximately 1,645,951,189 also measured in 2012$.

The total installed capacity at the four Klamath River hydropower plants is approximately 163 MW. This level of output is rarely achieved and this measure of maximum generation capacity is largely uninformative. Dependable capacity is a measure of the generation capability available on a reliable or probabilistic basis. As described in Appendix 2, the summer and winter dependable capacity is calculated for a range of reliability levels. Table 5 presents the results at the 90 percent exceedence level. The dependable capacity estimates shown in this table indicate the generation capability equaled, or exceeded, 90% of the time.

As shown, the summer capacity is approximately 55.9 MW and the winter season dependable capacity is approximately 66.6 MW, at the 90 percent exceedence level.

FULL FACILITIES DAM REMOVAL ALTERNATIVE

Under the Full Facilities Dam Removal Alternative, the four Klamath River hydropower plants will operate normally from 2012 through 2019. At midnight on January 1, 2020 they will instantaneously be decommissioned. Removal of the four dams will cause the production of hydropower to cease and all generation and capacity will be reduced to zero from January 1, 2020 through the end of 2061. As shown in table 6, the Full Facilities Dam Removal Alternative results in drastically reduced values for each of the indicators of hydropower benefits.

Table 6.—Full Facilities Dam Removal Alternative

Indicator	Mean	90% Exceedence	10% Exceedence
Annual generation (MWh)	106,072.9[12]	0.0	609,381.5
Economic value (2012$)	289,223,758	235,012,732	329,217,398
Summer capacity (MW)	na	0.0	na
Winter capacity (MW)	na	0.0	na

This analysis of the Full Facilities Dam Removal Alternative is based on 49 hydrologic sequences or traces of monthly hydrology, each of which is 50 years in length. Under the Full Facilities Dam Removal Alternative, generation is identical to the No Action Alternative for the first 8 years and then reduced to zero for the final 42 years. Across the 49 traces, the mean annual generation is approximately 106,073 MWh. At the 90% exceedence level, the mean annual generation is approximately 0.0 MWh. At the 10% exceedence level, the mean annual generation is approximately 609,381 MWh.

Under the Full Facilities Dam Removal Alternative illustrated in table 6, generation and thus economic benefits occur during the first 8 years and cease in 2020. The mean present economic value over the 49 hydrologic traces examined

[12] Average annual generation for the period 2012 through 2019 is 662,956 MWh. The average annual generation thereafter is 0.0 MWh.

is 289,223,758 (2012$). At the 90% exceedence level, the mean present economic value is approximately 235,012,732 measured in 2012$. At the 10% exceedence level, the mean present economic value is approximately 329,217,398, measured in 2012$ over the 50-year analysis period.

Under the Full Facilities Dam Removal Alternative, dependable capacity is unaffected for the first 8 years and is then reduced to zero for the remaining 42 years. As described in Appendix 2, the summer and winter dependable capacity is calculated for a range of reliability levels. Table 6 presents the results at the 90 percent exceedence level. As shown in table 6, for the Full Facilities Dam Removal Alternative the summer marketing season capacity is approximately 0.0 MW at the 90 percent exceedence level and the winter season dependable capacity is approximately 0.0 MW at the 90 percent exceedence level.

Table 7 illustrates the absolute change in these indicators, relative to the No Action Alternative. As might be expected, there are substantive reductions in the values of all of the hydropower benefit indicators under the Full Facilities Dam Removal Alternative. As shown in table 7, the mean annual generation is reduced by 789,774 MWh under this alternative. The mean present economic value under the Full Facilities Dam Removal Alternative is reduced by 1,320,087,063 (2012$), relative to the No Action Alternative. Measured at the 90% exceedence level, all summer and winter dependable capacity is lost.

Table 7.—Change from No Action Alternative

Indicator	Mean	90% Exceedence	10% Exceedence
Annual generation (MWh)	-789,774.0	-595,699.2	-622,253.2
Economic value (2012$)	-1,320,087,063	-1,341,857,467	-1,316,733,791
Summer capacity (MW)	na	-55.9	na
Winter capacity (MW)	na	-66.6	na

Table 8 illustrates the percentage change in the hydropower indicators, relative to the No Action Alternative. As might be expected, there are large reductions in the values of all of the hydropower benefit indicators when viewed on a percentage basis. As shown in table 8, the mean annual generation is reduced by approximately 88 percent under the Full Facilities Dam Removal Alternative. Similarly, the mean present economic value under the Full Facilities Dam

Table 8.—Percentage change from no action

Indicator	Mean	90% Exceedence	10% Exceedence
Annual generation (MWh)	-88.16%	-100.00%	-50.52%
Economic value (2012$)	-82.03%	-85.10%	-80.00%
Summer capacity (MW)	na	-100.00%	na
Winter capacity (MW)	na	-100.00%	na

Removal Alternative is reduced by 82 percent, relative to the No Action Alternative. Measured at the 90% exceedence level, both the summer and winter dependable capacities are reduced by 100%.

The empirical distributions of generation for each alternative are based on 2,450 observations of annual generation, measured in MWh. The empirical distributions of present value for each alternative are based on 49 observations of present value, measured in 2012 dollars. As described in Appendix 1, the present value calculation is sensitive to the timing of hydropower benefits. In the Full Facilities Dam Removal Alternative, benefits are zero from 2020 through 2061. The empirical distributions for the annual generation and present value differ considerably from one another. These differences are particularly evident in the tails of the distributions (for example, the 10% exceedence level shown in tables 5, 6, and 7). Consequently, the differences between the distributions of present value reported in table 8 are larger than might be inferred from the empirical distributions of annual generation.

PARTIAL FACILITIES DAM REMOVAL ALTERNATIVE

Under the Partial Facilities Dam Removal Alternative, the four Klamath River hydropower plants will operate normally from 2012 through 2019. At midnight on January 1, 2020 they will instantaneously be decommissioned. Removal of the four dams will cause the production of hydropower to cease and all generation and capacity will be zero from January 2020 through the end of 2061. The former dam sites will be only partially restored, which has no bearing on the present analysis.

The effects of the Partial Facilities Dam Removal Alternative on hydropower benefits are expected to be identical to the Full Facilities Dam Removal Alternative described previously.

CONCLUSIONS

This document estimates the generation, capacity and economic benefits provided by four PacifiCorp Klamath River hydropower plants for the No Action Alternative and the Full Facilities Dam Removal Alternative. The major features of the Full Facilities Dam Removal Alternative are the complete removal of the four Klamath River dams, full restoration of the dam sites and implementation of the Klamath Basin Restoration Act. These two alternatives are compared over the 50-year period, 2012 through 2061. The effects of hydrologic variability on hydropower generation are explicitly characterized. In the No Action Alternative, these four powerplants have a dependable capacity of 55.9 MW in the summer and 66.6 MW in the winter, measured using the 90 percent exceedence approach. Their mean annual generation is approximately 895,847 MWh. The mean present value of the benefits from these hydropower plants is approximately 1,609,310,821 (2012$), measured over the 50-year period. Under the Full Facilities Dam Removal Alternative, the four hydropower plants are expected to operate normally over the period 2012 through 2020, with decommissioning assumed to occur instantaneously at midnight on January 1, 2020. Generation, capacity and economic value at these four sites are all reduced to zero from January 1, 2020, through the end of the analysis period. Relative to the No Action Alternative, the Full Facilities Dam Removal Alternative is expected to have a relatively substantial effect on hydropower economic benefits, measured in discounted 2012 dollars. Relative to no action, the Full Facilities Dam Removal Alternative is projected to cause the average economic value of the hydropower produced to decrease by about $1,320,087,063 (present value in 2012 dollars), over the 50-year analysis period. This represents a benefit decrease of about 82 percent. The hydropower impacts of the Partial Facilities Dam Removal Alternative are expected to be identical to the Full Facilities Dam Removal Alternative. It should be noted this assessment represents only the effects on gross hydropower benefits afforded by these plants—not the net benefits. An assessment of the costs of operating and maintaining these four hydropower plants is found in a separate document.

REFERENCES

Auslam, David C. Jr., Robert B. Hamilton, William J. Friers, and Gina Veronese. 2011. "Estimation of Klamath Dams Hydroelectric Production Costs--Analysis for Klamath Dams Economic Sub-Team Task A.7 Subject Matter Expert Support." Transmittal Memo from Camp, Dresser and McKee (CDM) Hydropower Evaluation Team to Cynthia J. Thomson and Benjamin M. Simon, Secretarial Determination Overview Report (SDOR) Economics Team Co-Chairs. April 8, 2011.

Bureau of Economic Analysis. 2010. Gross Domestic Product: Implicit Price Deflator. Series ID: GDPDEF. U.S. Department of Commerce, Bureau of Economic Analysis. Last updated August 27, 2010. www.bea.gov/national/pdf/nipafuid.pdf . Accessed on October 28, 2010.

Bureau of Reclamation. 2010a. "Change in Discount Rate for Water Resources Planning." *Federal Register* Vol. 75 No. 249. Wednesday, December 29, 2010a. p. 82066.

______. 2010b. Memorandum from Roseann Gonzales, Director, Policy and Administration. Control No. 84-55000 PRJ-1.10. Subject: Interest Rates for Fiscal Year 2011. November 22, 2010b.

______. 2009 a. Glossary. Bureau of Reclamation. U.S. Department of the Interior, October 16, 2009. Accessed on July 9, 2010 at: http://www.usbr.gov/library/glossary/index.html#C

Edwards, Brian K., Silvio J. Flaim, and Richard E. Howitt. 1999. "Optimal Provision of Hydroelectric Power Under Environmental and Regulatory Constraints." Land Economics. Vol. 75 No. 2 (May 1999):267-283.

Environmental Protection Agency. 2000. Guidelines for Preparing Economic Analyses. EPA240-R-00-003. September 2000. Environmental Protection Agency, Office of the Administrator: Washington, D.C.

Energy Information Administration. *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use.* SR/OIAF/2000-02. Washington, D.C.: U.S. Department of Energy, Energy Information Administration. May 2000.

Energy Information Administration. *The Changing Structure of the Electric Power Industry: An Update.* DOE/EIA-D562 (96). Washington, D.C.: U.S. Department of Energy, Energy Information Administration. December 1996.

Electric Power Information Solutions, Inc. 2010. AURORA^{XMP}—Software for Forecasting Electric Market Price and Value. West Linn, Oregon: EPIS, Inc. http://www.epis.com.

Energy Information Administration (EIA). 2010. *Electric Power Annual 2009* DOE/EIA-0348(2009). U.S. Energy Information Administration. Washington, D.C. December 2010. 108 pp.

Federal Energy Regulatory Commission (FERC). 1995. "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities." Docket RM95-8-000, Washington, DC, March 29, 1995.

______. 2006. Draft Environmental Impact Statement for relicensing of the Klamath Hydroelectric Project No. 2082-027. Table 4-1. Staff assumptions for economic analysis of the Klamath Hydroelectric Project. September 25, 2006 Accessed on: June 7, 2010 at: http://www.klamathbasincrisis.org/ferc/drafteis092606.htm.

______. 2007. Final Environmental Impact Statement for Relicensing of the Klamath Hydroelectric Project No. 2082-027. FERC: Hydropower Relicensing of the Klamath Hydroelectric Project FESIS. Federal Energy Regulatory Commission, Washington, D.C. 20426, November 16, 2007. Accessed on May 22, 2010 at: http://www.ferc.gov/industries/hydropower/enviro/eis/2007/11-16-07.asp

Fish and Wildlife Service. 2008. *Biological/Conference Opinion Regarding the Effects of the U.S. Bureau of Reclamation's Proposed 10-Year Operation Plan (April 1, 2008 – March 31, 2018) for the Klamath Project and its Effects on the Endangered Lost River and Shortnose Suckers*. U.S. Fish and Wildlife Service. Klamath Falls, Oregon Office and Yreka California Office. April 2, 2008.

Fish and Wildlife Service, 2009. Description of PacifiCorp's Klamath Hydroelectric Project Facilities within the Klamath Hydroelectric Project (text and photos). Yreka Fish and Wildlife Office, Pacific Southwest Region. September 3, 2009. Accessed on July 15, 2010 at: http://www.bing.com/images/search?q=J.c.+boyle+dam&FORM=IGRE&qpvt=J.c.+boyle+dam&adlt=strict#focal=75ae5a75634ebbbc4647b51751124e9a&furl=http%3A%2F%2Fwww.fws.gov%2Fyreka%2FHydroProjectDescription_clip_image016.jpg.

Field, Barry C. Natural Resource Economics—An Introduction. 2nd Edition. 2008. Long Grove, Illinois: Waveland Press, Inc. 2008.

Governor of California, Office of the. 2008. Gov. Schwarzenegger Applauds Agreement in Principle that Marks First Critical Step on Presumptive Path to Remove Four Klamath River Dams. Office of the Governor of California. November 13, 2008. Accessed on July 28, 2010 at: http://gov.ca.gov/press-release/11009/.

Harpman, David A. 1999. "Assessing the Short-Run Economic Cost of Environmental Constraints on Hydropower Operations at Glen Canyon Dam." Land Economics 75 No. 3 (August 1999): 390-401.

______. 2002. Understanding Hourly Operations at Glen Canyon Dam, Colorado River Storage Project, AZ-GCPSPE95 version 2.0 U.S. Department of the Interior, Bureau of Reclamation Report #EC-2002-01. September 2002. Springfield, Virginia: National Technical Information Service. NTIS# PB2003-101395. 50 pp. Also available from: www.du.edu/~dharpman/glenpage.

______. 2006. *Exploring the Economic Value of Hydropower in the Interconnected Electricity System*. U.S. Department of the Interior, Bureau of Reclamation Report #EC-2006-03. December 2006. Springfield, Virginia: National Technical Information Service. NTIS# PB2007-109609. 140 pp.

Hemstreet, Tim. 2010. Personal communication. Klamath Project Manager for PacifiCorp an electric generation company. Telephone conversation with Richard Lichtkoppler, Economist, Bureau of Reclamation, Denver, Colorado. July 22, 2010.

Hirst, Eric and Brenden Kirby. 1996. “Ancillary Services,” Oak Ridge National Laboratory, Technical Report ORNL/CON 310, February 1996. http://www.ornl.gov/sci/btc/apps/Restructuring/Ancillary_Services.pdf.

King, David L. 2011. Hydraulic Engineer, Water Resources Planning and Support. Bureau of Reclamation. Denver Technical Service Center, Denver, Colorado. Personal communication with David A. Harpman, Natural Resource Economist. 20 April 2011.

King, David L. and Nancy L. Parker. 2011. “Klamath Dam Removal—Hydrologic Operations.” Appendix E in, *DRAFT Hydrology, Hydraulics and Sediment Transport Studies for the Secretary’s Determination on Klamath River Dam Removal and Basin Restoration.* Technical Report No. SRH-2011-02. Sedimentation and River Hydraulics Group. Bureau of Reclamation. Denver Technical Service Center, Denver, Colorado. April 2011.

Klamath Settlement Parties. 2010. Klamath Basin Restoration Agreement for the Sustainability of Public and Trust Resources and Affected Communities. February 18, 2010. Accessed on July 28, 2010 at: http://67.199.95.80/Klamath/Klamath%20Basin%20Restoration%20Agreement%202-18-10signed.pdf.

Mayer, Timothy D. 2008. "Analysis of Trends and Changes in Upper Klamath Lake Hydroclimatology." Unpublished Report. U.S. Fish and Wildlife Service, Water Resources Branch. Portland, Oregon.

M. Cubed. 2007. Economic Modeling of Relicensing and Decommissioning Options for the Klamath Basin Hydroelectric Project Addendum A Response to PacifiCorp's Comments on the Klamath Project Alternatives Analysis Model. April 2007. Accessed on July 27, 2010 at: http://www.friendsoftheriver.org/site/DocServer/CEC-700-2007-004-REV1.pdf?docID=1721.

National Academies. 2007. Fishes, Hydrology, and Ecology of the Klamath River Basin. The National Academy of Sciences. Washington, D.C.: National Research Council, 2007. 4 pp.

National Marine Fisheries Service, Southwest Region. 2010. *Operation of the Klamath Project between 2010 and 2018.* Biological Opinion completed for the U.S. Bureau of Reclamation. File No. 151422SWR2008AR00148. March 15, 2010.

North Carolina State University 2011. Renewables Portfolio Standards. April 2011. Accessed on 5/17/2011. http://www.dsireusa.org/

Northwest Power and Conservation Council. 2010. Sixth Northwest Conservation and Electric Power Plan. Council Document 2010-09. February 2010.

Ouarda, Taka B.M.J., John W. Labadie, and Darrell G. Fontane. 1997 a. "Indexed Sequential Hydrologic Modeling for Hydropower Capacity." Water Resource Bulletin. 33 No. 6 (December 1997):1337-1349.

______ 1997 b., "Validation of Indexed Sequential Hydrological Modeling for the Colorado River Basin," Journal of the American Water Resources Association, Vol. 33, No. 6 (December 1997):1-13.

PacifiCorp. 2004 a. Klamath Hydroelectric Project (FERC Project No. 2082). Exhibit A and Exhibit B – Project Operation and Resource Utilization. Portland, Oregon : PacifiCorp, February, 2004. 108 pp.

______.2007. Final Environmental Impact Statement for Relicensing of the Klamath Hydroelectric Project No.2082-027. Hydropower - Environmental Impact Statements. PacifiCorp, November 16, 2007. Accessed on June 7, 2010 at: http://www.klamathbasincrisis.org/Poweranddamstoc/ferc/finalKlamathDamsEIS111607.htm.

______. 2009. 2008 Integrated Resource Plan Volume I. PacifiCorp, May 28, 2009, Page 74. Table 5.6 . , pp. 78-79. Table 5.14. Accessed on June 10, 2010 at: http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_3.pdf.

______. 2010 a. 2008 Update Integrated Resource Plan. PacifiCorp, March 31, 2010. Accessed on June 11, 2010 at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf.

______. 2010 b. PacifiCorp Company Quick Facts. PacifiCorp, June 11, 2010. Accessed on June 8, 2010 at: http://www.pacificorp.com/about/co.html.

Powers, Kyna, Pamela Baldwin, Eugene H. Buck, and Betsy A. Cody. 2005. Klamath River Basin Issues and Activities: An Overview. CRS Report for Congress. The Library of Congress Congressional Research Service, September 22, 2005. Accessed on June 8, 2010 at: http://www.energy.ca.gov/klamath/documents/CRS_REPORT_RL33098.PDF. RL33098.

Tietenberg, Tom and Lynn Lewis. 2009. Environmental and Natural Resource Economics 8th Edition. Boston, Massachusetts: Pearson, Addison-Wesley Inc. 2008.

U.S. Department of the Interior, National Marine Fisheries Service, PacifiCorp, California Natural Resources Agency, and the State of Oregon. 2010. Klamath Hydroelectric Settlement Agreement. February 18, 2010. Accessed on July 28, 2010 at: http://67.199.95.80/Klamath/Klamath%20Hydroelectric%20Settlement%20Agreement2-18-10.pdf.

U.S. Department of the Interior, U.S. Department of Agriculture, U.S. Department of Commerce, and the California Department of Fish and Game. Undated. Klamath Water Basin Issues Background. Klamath Restoration.gov. Accessed on July 27, 2010 at: http://klamathrestoration.gov/about-us/background.

U.S. Fish and Wildlife Service. 2009. Description of PacifiCorp's Klamath Hydroelectric Project Facilities within the Klamath Hydroelectric Project (text and photos). Yreka Fish and Wildlife Office. U.S. Fish and Wildlife Service, September 3, 2009. Accessed on July 15, 2010 at: http://www.bing.com/images/search?q=J.c.+boyle+dam&FORM=IGRE&qpvt=J.c.+boyle+dam&adlt=strict#focal=75ae5a75634ebbbc4647b51751124e9a&furl=http%3A%2F%2Fwww.fws.gov%2Fyreka%2FHydroProjectDescription_clip_image016.jpg.

U.S. Water Resources Council. 1983. Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies. Washington, D.C.: U.S. Government Printing Office.

Western Area Power Administration. 1986. "Post-1989 General Power Marketing and Allocation Criteria: Pick-Sloan Missouri Basin Program—Western Division." Federal Register Vol. 51 No. 21 (21 January, 1986):4012-4027.

______. 1993. "Loveland Area Projects—Amounts of Energy with Capacity Under Contract and Reserved for Project and Special Use in Post-1989 Period." Federal Register Vol. 58 No. 211 (3 November 1993):58690-58696.

Zagona, Edith A., Terrance J. Fulp, Richard Shane, Timothy Magee and H. Morgan Goranflo. 2001. "RiverWare: A Generalized Tool for Complex Reservoir System Modeling." Journal of the American Water Resources Association. Vol. 37 No. 4 (August 2001): 913-929.

Appendices

1 Discounting Procedures
2 Dependable Capacity
3 Generation Results
4 Economic Results
5 Capacity Results
6 Data Dictionary
7 No Action Capacity

Appendix 1

Discounting Procedures

The costs and benefits of most environmental policies are incurred at different times over what are frequently long time horizons. A fundamental concept in finance and economics is that the timing of benefits and costs makes a difference in the attractiveness of an investment. All other things being equal, one would prefer to receive the benefits of an investment as soon as possible and to pay the costs as far out in the future as possible. Given the choice between receiving $100 today or $100 a year from now, most people would prefer $100 today. Alternatively, if given the choice between paying out $50 today or 1 year from now, most of us would prefer the latter.

Because the timing of these costs and benefits differs across alternatives, responsible policy choice requires the use of appropriate techniques to allow for commensurate comparisons. Typically, the present value of the future stream of costs and benefits for each alternative is computed and the results arrayed for decision-makers.

Discounting is the methodology used for identifying the present value of a cost or benefit that occurs at some time in the future. The process of "discounting" is used to make costs or benefits which occur at different points in time commensurate with each other.

Although the mechanics of the discounting process are very straightforward, the magnitude of the discount rate greatly influences the degree to which future costs and benefits "count" in the decision. As a result, the choice of discount rate is the subject of much controversy. The literature on discounting and the choice of a discount rate is rather vast. Many modern economics texts contain synopses of this literature (e.g., Field 2008, Tietenberg and Lewis, 2009). A more lengthy assessment can be found in the Environmental Protection Agency, *Guidelines for Preparing Economic Analyses* (2000).

Federal water resource agencies, such as the U.S. Bureau of Reclamation, are required to follow the procedures described in the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resource Council 1983) when undertaking a cost benefit analysis. This document is often fondly referred to as, the "P&Gs."

As proscribed in the P&Gs, the Federal water resource agencies must use an administratively determined discount rate for cost benefit analysis. This rate is known as the Federal discount rate for plan formulation and evaluation. The plan formulation and evaluation rate is calculated annually by the Secretary of the Treasury, pursuant to 42 United States Code 1962d-1 (See the electronic code of Federal Regulations (http://ecfr.gpoaccess.gov) for a description of the methodology) and then officially transmitted to the water resource agencies. The plan formulation and evaluation rate for 2011 is 4.125 percent (Bureau of Reclamation 2010a, 2010b).

Table 1 summarizes the inflation, escalation and discounting procedures used in this analysis. As illustrated, the base year chosen for this analysis is 2012. All economic value estimates reported in this document are measured in 2012 dollars. The forecast electricity prices used in this analysis were reported in constant 2006 dollars (NWPCC 2010). These 2006 prices were inflated from 2006 to 2010 dollars using the GDP implicit price deflator (Bureau of Economic Analysis 2010). The equivalent annual GDP inflation rate during the 2006 to 2010 period was calculated to be 1.8768 percent (rounded to 4 decimal places). Inflation between 2010 and 2012 was assumed to be the same as it was for 2006 to 2010 period. This 1.8768 annual percentage rate was then used to escalate the price of electricity from 2010 to 2012 dollars.

Table 1.—Discounting procedures

Base year for analysis	2012
Electricity price reporting year	2006
Electricity price annual inflation rate (2006 to 2010)[1]	1.8768%
Electricity price annual escalation rate (2010 to 2012)[2]	1.8768%
Electricity price annual escalation rate (2012 to 2060)	0.0%
Annual discount rate[3]	4.125%

[1] Annual equivalent GDP implicit price deflator.
[2] Assumed to be the same as the 2006 through 2010 period.
[3] Federal Water Resource plan formulation and evaluation rate for FY 2011.

Consistent with the procedures described in the *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (U.S. Water Resource Council 1983), all costs and benefits which occur after 2012 are reported in constant 2012 dollars (they are not escalated). Costs and benefits which occur in 2012 are not discounted. All costs and benefits which occur after 2012 are then discounted back to the 2012 base year using the 2011 Federal discount rate for plan formulation and evaluation (4.125 percent).

In summary, the discounting process employed in this analysis conforms to the procedures described in U.S. Water Resource Council (1983). The selected base year for this project is 2012 and the estimated costs and benefits occurring in 2012 are not discounted. All subsequent annual costs and benefits are discounted back to the 2012 base year using a discount rate of 4.125 percent.

Appendix 2

Dependable Capacity

Capacity is defined as the maximum generation capability of a powerplant. In the case of hydroelectric powerplants, capacity varies greatly from one period to the next, primarily because it is a function of reservoir elevation (and hence the head) and the amount of water available for release. Figure 1 illustrates the relationship between generation and release at three different reservoir elevations for a representative hydropower plant. This plant has an installed capacity of approximately 250 MW when the reservoir is full (elevation 2008.2 feet). This maximum generation is achieved when around 12,000 cfs are released through the turbines. Releases above 12,000 cfs must be made through the outlet works which increases the elevation of the tailrace, decreasing head and therefore maximum generation capability.

As shown in figure 1, the maximum generation capability varies considerably depending on how much water is released and the elevation of the storage reservoir. If the reservoir is less than full and/or if the amount of available water is insufficient to sustain a 12,000 cfs release, the maximum generation at this hydropower plant will be considerably below 250 MW.

The reservoir elevation and the amount of water available for release vary dramatically on both a seasonal and year-to-year basis. For this reason, installed capacity does not provide a very informative measure of how much electricity can be generated at a hydropower plant.

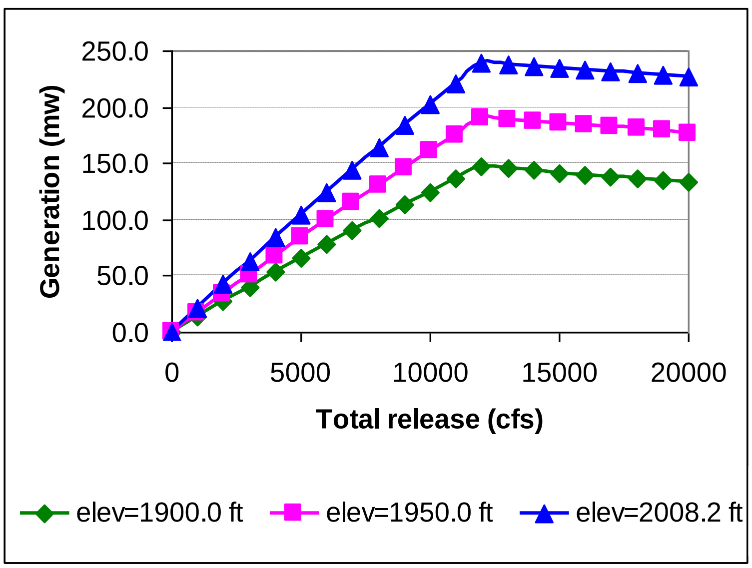

Figure 1.—Maximum generation at a hydropower plant.

Hydropower owner/operators often use a metric known as dependable or marketable capacity for planning purposes, for making marketing decisions and for making meaningful comparisons with thermal power plants. A dependable capacity value takes into account the hydrologic conditions (reservoir elevation and amount of water available for release) and represents a measure of the maximum generation capability which can be achieved at some given reliability level. It is desirable to have a high dependable capacity with a very high level of reliability. Unfortunately, the dependably capacity at a hydropower plant typically falls as the level of reliability increases. Consequently, hydropower owner/operators must assume some level of risk in order to market higher levels of the resource.

For example, assume a hydropower plant has 200 MW of installed capacity and a dependable capacity of 50 MW has been calculated using the 90 percent exceedence approach. This means the hydropower plant is capable of generating 50 MW or more, about 90 percent of the time. The converse is also true—approximately 10 percent of the time the hydropower plant will only be able to generate an amount less than 50 MW. There is an explicit tradeoff between the amount of hydropower generation which can be marketed on a "firm" basis and the amount of risk assumed by the owner/operator. The owner operator can, for example choose to market a very low amount of capacity which is available all, or virtually all, of the time, or they can market a higher amount of capacity, by assuming some probability of a generation shortfall, and taking appropriate measures to mitigate that risk.

Output from the KDRM model formed the basis for the calculations of dependable capacity displayed in this report. The model was employed to estimate onpeak (and offpeak) electrical generation at the four Klamath River hydropower plants for each day and trace (King and Parker 2011). These daily outputs were then aggregated to a monthly time-step for the capacity analysis. The average monthly onpeak generation is employed to approximate the maximum generation capability of the four Klamath River hydropower plants.

All dependable capacity calculations are based on 2012 (existing) installed capacities at the 4 Klamath River hydropower plants (approximately 163 MW). Under the Full Facilities Dam Removal Alternative, no equipment replacements and no increases in generation capabilities are envisioned (Auslam, et al., 2011). Estimates of 2012 dependable capacity provide the most appropriate measure of the capacity which would be lost, should these facilities be decommissioned.

For this analysis, estimates of dependable capacity are calculated using a nonparametric (distribution-free) empirical exceedence approach. To reiterate, no assumptions are made about the underlying statistical distribution which generated the monthly capacity values. Instead, exceedence values are computed for the empirical distribution of capacity values produced by the KDRM model. For purposes of this analysis, the 80, 85, 90, 95, 99 and 100 percent exceedence values are calculated for a summer marketing season (April through September) and a winter marketing season (October through March). All of these measures are reported in Appendix 5 and conveniently summarized in table 1.

Table 1.—Dependable capacity

	No Action		Dam Removal	
Percent exceedence	Summer season capacity (MW)	Winter season capacity (MW)	Summer season capacity (MW)	Winter season capacity (MW)
80	59.8	74.0	0	0
85	61.4	75.9	0	0
90	55.9	66.6	0	0
95	52.5	60.1	0	0
99	48.8	50.8	0	0
100	40.6	43.1	0	0

As shown in table 1 dependable or marketable capacity falls as the percent exceedence increases. The dependable capacity calculated using the 90 percent empirical exceedence approach is 55.9 MW in the summer and 66.6 MW in the winter. Estimates of dependable capacity at other exceedence levels are also shown in this table. For example, at the 99 percent exceedence level, the dependable capacity is 48.8 MW in the summer and 50.8 MW in the winter.

Appendix 3

Generation Results

The raw output from the KLAMGEN utility program is reported in this appendix. This output contains the generation results described in the narrative, as well as additional information.

```
KLAMGEN.PAS            GENERATION ANALYSIS               VER_2.2.1  06/29/2011

Base Onpeak gen.  file = noactionONpeak12-30-2010.dat        run date = 7/7/2011
Base Offpeak gen.  file = noactionOFFpeak12-30-2010.dat       run time = 9:15:28
AM
Alt.  Onpeak gen.  file = damremovalONpeak12-30-2010.dat
Alt.  Offpeak gen.  file = damremovalOFFpeak12-30-2010.dat
Capacity growth file = KlamathTotCap.txt                     Cap growth = ON

analysis scope = Klamath Basin                               nyears =   50
Power project = PacCorp Plants                               ntraces =   49
sim inflow years 2012-2061

Title: Revised (corrected) COB real price set with 1% real inflation in extension
period


                          Kolmogorov-Smirnov Test

                    n          min          max           mean
                 ------    ----------   -----------    ----------
  Change case     2450          0.00    1012443.40     106072.92
    Base case     2450     474478.20    1355884.80     895846.92
                 ------    ----------   -----------    ----------

                        KS statistic  = 0.8820408
                   P-value (D<=d) = 0.0000E+000  (2-tailed)


Mean Annual Generation
---------------------------------
Change case (MWh) =     106072.9
Base case   (MWh) =     895846.9
---------------------------------
Difference  (MWh) =    -789774.0  (-88.16%)


Median Annual Generation
---------------------------------
Change case (MWh) =          0.0
Base case   (MWh) =     887359.2
---------------------------------
Difference  (MWh) =    -887359.2  (-100.00%)


90% Exceedence Annual Generation
---------------------------------
Change case (MWh) =          0.0
Base case   (MWh) =     595699.2
---------------------------------
Difference  (MWh) =    -595699.2  (-100.00%)


10% Exceedence Annual Generation
---------------------------------
Change case (MWh) =     609381.5
Base case   (MWh) =    1231634.7
---------------------------------
Difference  (MWh) =    -622253.2  (-50.52%)



Notes...
   (a) Capacity growth algorithm enabled
   (a) Base case capacity growth ONLY

            <<<<<<<<<<<< end of output >>>>>>>>>>>>
```

Appendix 4

Economic Results

The raw output from the KLAMGEN utility program is reported in this appendix. This output contains the economic results described in the narrative, as well as additional information.

```
KLAMGEN.PAS             ECONOMIC ANALYSIS                   VER_2.2.1  06/29/2011

Base Onpeak gen.  file = noactionONpeak12-30-2010.dat        run date = 7/7/2011
Base Offpeak gen.  file = noactionOFFpeak12-30-2010.dat       run time = 9:15:28
AM
Alt.  Onpeak gen.  file = damremovalONpeak12-30-2010.dat
Alt.  Offpeak gen.  file = damremovalOFFpeak12-30-2010.dat
Capacity growth file = KlamathTotCap.txt                     Cap growth = ON
Onpeak  price file = COB_real_ONpeak.txt                     prealr =  1.0000
Offpeak price file = COB_real_OFFpeak.txt

analysis scope = Klamath Basin                               erate (%) =  0.0000
Power project = PacCorp Plants                               drate (%) =  4.1250
sim inflow years 2012-2061                                   prate (%) =  1.8768

Title: Revised (corrected) COB real price set with 1% real inflation in extension
period


                           Kolmogorov-Smirnov Test

                 n         min            max            mean
              ------   -----------    -----------    ----------
Change case      49    213011352.38    343859309.97   289223758.21
  Base case      49   1559591642.63   1654745129.50  1609310821.36
              ------   -----------    -----------    ----------

                         KS statistic  = 1.0000000
                  P-value (D<=d) = 1.0486E-021  (2-tailed)


Mean PV (all traces)
---------------------------------
Change case (2012$) =   289223758.21
Base case   (2012$) =  1609310821.36
---------------------------------
Difference  (2012$) = -1320087063.15  (-82.03%)


Median PV (all traces)
---------------------------------
Change case (2012$) =   298196280.05
Base case   (2012$) =  1605804396.11
---------------------------------
Difference  (2012$) = -1307608116.07  (-81.43%)


90% PV Exceedence (all traces)
---------------------------------
Change case (2012$) =   235012732.45
Base case   (2012$) =  1576870199.28
---------------------------------
Difference  (2012$) = -1341857466.83  (-85.10%)


10% PV Exceedence (all traces)
---------------------------------
Change case (2012$) =   329217397.75
Base case   (2012$) =  1645951189.22
---------------------------------
Difference  (2012$) = -1316733791.47  (-80.00%)


Evaluation notes...
   (a) Using NWPCC 6th Power Plan base forecast prices
   (b) COB price node used
   (c) On/off peak real prices 2012-2030
   (d) Real price growth 2031-2061 using prealr


Discounting notes...
   (a) Prices reported in real 2006$
   (b) Prices escalated to 2012 using prate
   (c) 2012 is the base year for analysis
   (d) 2012 is not discounted
   (e) Prices escalated from 2012 forward using erate

            <<<<<<<<<<<< end of output >>>>>>>>>>>>
```

Appendix 5

Capacity Results

The raw output from the KLAMCAP utility program is reported in this appendix. This output contains the summer and winter dependable capacity results described in the narrative, as well as additional information.

```
KLAMCAP.PAS            SUMMER MARKETING SEASON             VER_1.3.0  11/06/2010

base case = noactionONpeak12-30-2010.dat                   run date = 5/23/2011
alt.  case = damremovalONpeak12-30-2010.dat                 run time = 8:52:48 AM

analysis period = 2012-2061 (50 yrs)
ntraces = 49


title: Analysis of 12-30-2010 Klamath Hydrology


                            Kolmogorov-Smirnov Test

                     n          min            max           mean
                   ------     ----------     -----------     ----------
  Change case      14700           0.00         144.95          14.67
    Base case      14700          40.65         163.12          92.57
                   ------     ----------     -----------     ----------

                          KS statistic  = 0.8462585
                   P-value (D<=d) = 0.0000E+000  (2-tailed)


Median Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         74.4
---------------------------------
Difference  (MW) =        -74.4  (-100.00%)


80% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         59.8
---------------------------------
Difference  (MW) =        -59.8  (-100.00%)


85% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         61.4
---------------------------------
Difference  (MW) =        -61.4  (-100.00%)


90% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         55.9
---------------------------------
Difference  (MW) =        -55.9  (-100.00%)


95% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         52.5
---------------------------------
Difference  (MW) =        -52.5  (-100.00%)

99% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         48.8
---------------------------------
Difference  (MW) =        -48.8  (-100.00%)

Notes...
   (a) mean monthly capacity units: MW
   (b) capacity computed from RiverWare model runs

             <<<<<<<<<<<< end of output >>>>>>>>>>>>
```

```
KLAMCAP.PAS           WINTER MARKETING SEASON            VER_1.3.0  11/06/2010

base case = noactionONpeak12-30-2010.dat                 run date = 5/23/2011
alt.  case = damremovalONpeak12-30-2010.dat               run time = 8:52:48 AM

analysis period = 2012-2061 (50 yrs)
ntraces = 49


title: Analysis of 12-30-2010 Klamath Hydrology

                            Kolmogorov-Smirnov Test

                     n          min           max          mean
                  ------     ----------    -----------    ----------
  Change case     14700          0.00         150.27         13.38
    Base case     14700         43.12         170.44        108.72
                  ------     ----------    -----------    ----------

                          KS statistic  = 0.8808844
                   P-value (D<=d) = 0.0000E+000  (2-tailed)

Median Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         85.6
---------------------------------
Difference  (MW) =        -85.6  (-100.00%)


80% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         74.0
---------------------------------
Difference  (MW) =        -74.0  (-100.00%)


85% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         75.9
---------------------------------
Difference  (MW) =        -75.9  (-100.00%)


90% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         66.6
---------------------------------
Difference  (MW) =        -66.6  (-100.00%)


95% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         60.1
---------------------------------
Difference  (MW) =        -60.1  (-100.00%)



99% Exceedence Capacity Value
---------------------------------
Change case (MW) =          0.0
Base case   (MW) =         50.8
---------------------------------
Difference  (MW) =        -50.8  (-100.00%)


Notes...
   (a) mean monthly capacity units: MW
   (b) capacity computed from RiverWare model runs

            <<<<<<<<<<<< end of output >>>>>>>>>>>>
```

Appendix 6

Data Dictionary

Table 1 below contains the names of the data files used in this analysis and a description of their contents. This data dictionary will help facilitate replication of this analysis at a later date.

Table 1.—Data files employed

Analysis	Filename	Description
Generation/economic/ capacity	noactionONpeak12-30-2010.dat	No action monthly onpeak generation
Generation/economic	noactionOFFpeak12-30-2010.dat	No action monthly offpeak generation
Generation/economic/ capacity	damremovalONpeak12-30-2010.dat	Dam removal alternative monthly onpeak generation
Generation/economic	damremovalOFFpeak12-30-2010.dat	Dam removal alternative monthly offpeak generation
Generation/economic	KlamathTotCap.txt	No action capacity over analysis period
Economic	COB_real_ONpeak.txt	COB monthly onpeak prices
Economic	COB_real_OFFpeak.txt	COB monthly offpeak prices

Appendix 7

No Action Capacity

This appendix summarizes the installed capacity for the No Action Alternative over the 50-year analysis period (2012 through 2061) as described by Auslam, et al. (2011).

	J.C. Boyle		Copco Plant 1		Copco Plant 2		Iron Gate	
Year	**unit 1**	**unit 2**	**unit 1**	**unit 2**	**unit 1**	**unit 2**	**Unit 1**	**Total**
2012	50.35	47.63	10.00	10.00	13.50	13.50	18.00	162.98
2013	50.35	47.63	10.00	10.00	13.50	13.50	18.00	162.98
2014	50.35	47.63	10.00	10.00	13.50	13.50	18.00	162.98
2015	50.35	47.63	10.00	10.00	13.50	13.50	21.40	166.38
2016	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2017	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2018	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2019	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2020	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2021	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2022	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2023	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2024	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2025	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2026	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2027	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2028	50.35	47.63	15.00	15.00	19.60	20.00	21.40	188.98
2029	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2030	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2031	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2032	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2033	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2034	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2035	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2036	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2037	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2038	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2039	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2040	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2041	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2042	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2043	56.40	47.63	15.00	15.00	19.60	20.00	21.40	195.03
2044	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2045	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2046	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2047	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2048	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2049	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2050	57.00	47.63	15.00	15.00	19.60	20.00	21.40	195.63
2051	57.00	47.63	15.00	15.00	20.00	20.00	21.40	196.03
2052	57.00	47.63	15.00	15.00	20.00	20.00	21.40	196.03
2053	57.00	47.63	15.00	15.00	20.00	20.00	21.40	196.03
2054	57.00	47.63	15.00	15.00	20.00	20.00	21.40	196.03
2055	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2056	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2057	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2058	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2059	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2060	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10
2061	57.00	50.70	15.00	15.00	20.00	20.00	21.40	199.10