Chapter 10

Status and Trends of Hydropower Production at Glen Canyon Dam

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Introduction

Approximately 7% of the electricity in the United States is generated by hydroelectric powerplants (Energy Information Administration, 2004, p. 2). These plants are an invaluable component of the Nation's interconnected electric power system in which generation resources consist of thermal, nuclear, solar, wind, and other sources. Hydroelectric powerplants are characterized by 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 ensure the reliability and electrical integrity of the system.

Although they play an important role in the electric power system, hydroelectric powerplants, such as the one at Glen Canyon Dam, have some widely recognized environmental effects. Large hydro facilities have blocked the spawning of anadromous and migratory aquatic species, eliminated the downstream transport of sediment, fundamentally altered the seasonal hydrograph, affected water chemistry, and changed the downstream temperature regime (Collier and others, 1996; Poff and others, 1997; Van Steeter and Pitlick, 1998 a, b). Furthermore, the operation of these plants, particularly those used to produce peaking, or variable, power, causes hourly variations in stream flow and elevation, thereby adversely affecting downstream aquatic and riparian communities (Nilsson and others, 1997; Parasiewicz and others, 1998) and recreation (Bishop and others, 1987; Kearsley and others, 1994; Welsh and Poe, 1998). The unveiling of plans to construct Glen Canyon Dam spurred a nationwide protest (Bradley, 1964; Martin, 1989). Construction of the dam started a public environmental discourse which continues to this day (McPhee, 1971; Elfring, 1990; Brower, 1997; Long and Essick, 1997; Jacobs and Wescoat, 2002).

Glen Canyon Dam

Glen Canyon Dam, shown in figure 1, is a 710-ft-high (216 m) concrete thick arch dam. It is the second highest dam in the United States (Hoover Dam is 16 ft (5 m) higher). Construction of Glen Canyon Dam began on October 1, 1956; Lake Powell started filling on March

Figure 1. Aerial view of Glen Canyon Dam (photograph courtesy of the Bureau of Reclamation).

13, 1963; and the first electric power was generated on September 4, 1964.

The outlet works at Glen Canyon Dam are composed of four hollow “jet tubes” and two spillways. These outlet works are used only under special conditions, primarily to accommodate releases from the dam that exceed the amount of water which can be released through the powerplant. Such releases may occur when the reservoir is full and tributary inflows exceed the capacity of the powerplant or they may be ordered for environmental purposes such as the 1996 beach/habitat-building flow.

The hollow jet tubes consist of four 96-inch-diameter (244 cm) pipes. The combined release capacity of the four hollow jet tubes is 15,000 cubic feet per second (cfs). The intake elevation of the jet tubes is approximately 3,374 ft (1,028 m), or 326 ft (99 m) below the surface when the reservoir is full. These elevations are illustrated in figure 2.

Each of the two spillways consists of an intake structure with two 40- by 52.5-ft (12- by 16-m) radial gates and a concrete-lined spillway tunnel. These spillways are located on both sides of the dam, each of which is capable of releasing 104,000 cfs when the reservoir is full (3,700 ft (1,128 m)). The elevation of the spillway crest is 3,648 ft (1,112 m). The spillways cannot be used to release water from the reservoir when the lake elevation falls below 3,648 ft (1,112 m).

Powerplant

The powerplant at Glen Canyon Dam is made up of eight hydroelectric generation units. Since 1964, these units have been uprated and rewound several times. As of August 2003, the combined generation capability of the powerplant (at unity power factor) is 1,320.0 megawatts (MW) (Seitz, 2004). A separate penstock feeds each of the eight Francis type turbines, which each produce approximately 155,000 horsepower. Current operating rules require at least 40 ft (12 m) of submergence to prevent the entrainment of air into the penstocks, which would cause damage to the turbines. As a result, the powerplant cannot be operated at lake elevations below 3,490 ft (1,064 m). Each turbine has a release capacity of approximately 4,150 cfs when the reservoir is full. The nominal powerplant release capacity is approximately 33,200 cfs.

Electricity Background

Electricity cannot be efficiently stored on a large scale by using currently available technology. It must be produced as needed. Consequently, when a change in demand occurs—such as when an irrigation pump or a central air conditioner is turned on—somewhere in the interconnected power system, the production of electricity must be increased to satisfy this demand. In the language of the utility industry, the demand for electricity is known as “load.” Load varies on a monthly, weekly, daily, hourly, and even second-by-second basis. During the year, the aggregate demand for electricity is highest when heating and cooling needs are greatest. During a given week, the demand for electricity is typically higher on weekdays and lower on weekends, particularly holiday weekends.

The maximum amount of electricity which can be produced by a powerplant is called its capacity. Capacity is typically measured in megawatts. The capacity of thermal powerplants is determined by their design, their location, and the ambient temperature. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, the amount of water available for release, and the design of the facility. Because the capacity at hydroelectric powerplants is highly variable, the amount of dependable or marketable capacity is of particular significance. The amount of dependable or marketable capacity is determined by using various probabilistic methods (e.g., Ouarda and others, 1997).

The large variation in loads has important implications for the electrical generation system. In particular, it greatly influences the amount of generation capacity required and, therefore, the capital cost of the system. The implications of large variation in loads can be

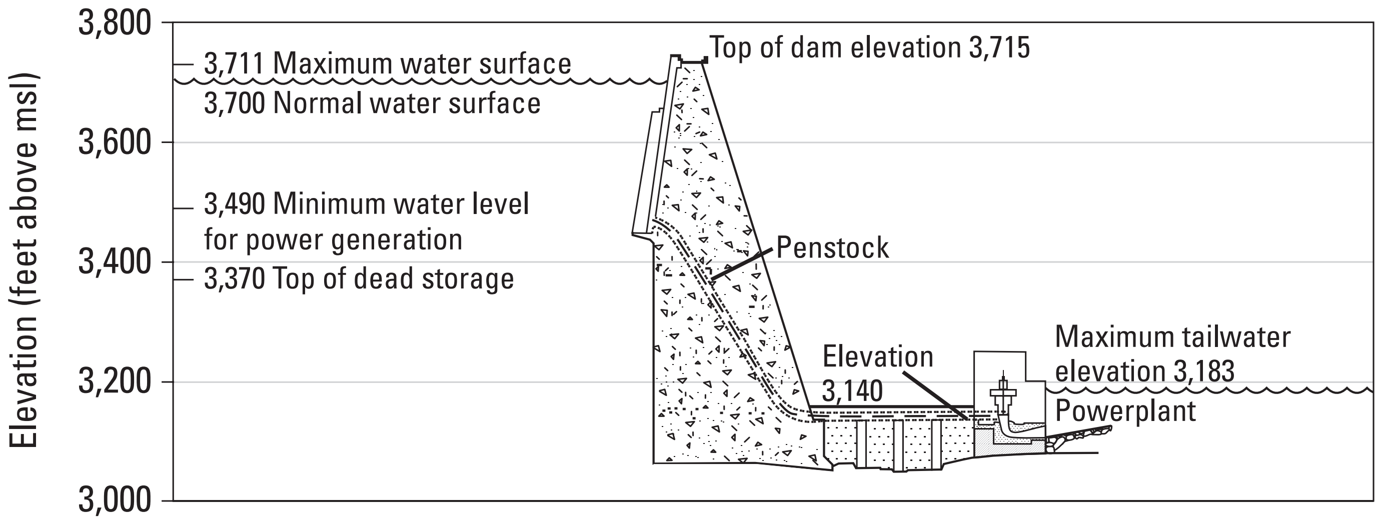

Figure 2. Important operating elevations of Glen Canyon Dam and Lake Powell in feet above mean sea level (msl).

readily illustrated by two extreme cases. First, assume the demand for electricity is constant and is 1.0 MW at all times. This assumed demand would imply (ignoring security and reliability concerns) that a utility supplier could supply this demand by building a 1.0-MW powerplant and operating it continuously. For a month (30 d), this situation would imply generation of 1.0 MW for 720 h, which would generate 720 megawatthours (MWh) of electricity. Now assume that the demand for electricity is more variable: assume that it is 1 MW for 1 h of the month and 0.5 MW for the rest of the hours in the month. In this case, the costs of constructing a 1-MW powerplant must also be incurred, but the plant generates only 360.5 MWh of energy (1 MW * 1 h + 0.5 MW * 719 h), or approximately 50% of its potential output. The highly variable nature of the demand for electricity results in the following observable characteristics of the electrical power system: (1) some powerplants are idle for part, or all, of the day or season, and (2) the capital costs of electricity production are quite high relative to operational costs.

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 7 a.m. to 11 p.m., Monday through Saturday. All other hours are considered to be offpeak.

Hydroelectric Power and the Interconnected Power System

The two most commonly encountered types of hydroelectric powerplants 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, resulting in little variation in electrical output during the day. Peaking hydroelectric powerplants, such as Glen Canyon Dam, often have significant water storage capability and are designed to rapidly change output levels to satisfy changes in the demand for electricity. Peaking hydroelectric powerplants are particularly valuable because they can be used to generate power during onpeak periods, thereby avoiding the cost of operating more expensive thermal plants such as gas turbine units.

In addition to furnishing capacity and energy, hydroelectric powerplants play an important role in the interconnected electric power system by supplying ancillary services. They contribute to system reliability by furnishing reactive power, voltage support, and system regulation services. These facilities also fulfill part of the regional reserve requirements and provide backup generation in the event of unexpected outages. In addition, they provide extra energy during extremely hot or cold weather periods and help maintain transmission stability during system disturbances.

The Economic Value of Hydropower

The economic value of operating an existing hydroelectric powerplant is measured by the avoided cost of doing so. In this context, avoided cost is the difference between the total power system cost of satisfying the demand for electricity "with" and "without" operating the hydroelectric powerplant. Conceptually, avoided cost is the savings realized by supplying electricity from a low-cost hydroelectric power source rather than from a higher cost thermal source. These savings arise, in part, because the cost of operating a hydroelectric powerplant is relatively low in comparison to thermal units. For example, the average operating expense for a typical hydroelectric powerplant in 2003 was $7.51/MWh. In contrast, the average cost of operating a typical fossil-fuel steam plant was $22.59/MWh, and the average cost of operating a typical gas turbine unit was approximately $48.93/MWh (Energy Information Administration, 2004, p. 49, table 8.2).

The economic value of operating an existing hydroelectric powerplant 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 gas 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.

If the cost of purchasing an additional megawatthour of electricity from a least cost source were observable in the market, then the economic value of producing hydroelectricity could be readily determined. For example, assume that in a particular hour the cost of purchasing a megawatthour of electricity from the least cost source was $30 and that the cost of producing a megawatt of hydroelectricity was $6. The avoided cost, or economic value, of producing an additional megawatthour of hydroelectric power at that time would be $24 ($30 - $6).

In addition to operating costs, the fixed investment (or capital) costs of alternative sources of electricity supply may contribute to the economic value or avoided cost of an existing hydroelectric powerplant. If a hydroelectric powerplant were decommissioned or its operations were restricted, the generation capacity in the system would be reduced. A new powerplant, probably a thermal plant, would need to be constructed to replace this lost capacity. If there were initially excess capacity in the system, the construction of a new powerplant could be deferred until a future date but would be constructed sooner than would otherwise be the case. If there were little or no excess capacity in the system, the need would be more immediate. All other factors being the same, the time of the required replacement capacity has a significant effect on the present worth of these additional costs. The sooner the replacement capacity is required, the higher the present worth of the costs incurred. The further out in the future these construction expenditures occur, the smaller the present worth of the costs incurred.

Federal Power

There is a long history of Federal involvement in the provision, operation, and regulation of the electric power system. The foundations for this involvement are based on three factors: first, the electric power industry is a natural monopoly (produces a product most efficiently supplied by one supplier in a given area) and hence is subject to regulation under the Sherman Antitrust Act of 1890, the Interstate Commerce Act of 1887, and other applicable statutes; second, the Federal Government owns most of the Nation's large-scale hydroelectric resources; and third, Federal economic development programs facilitated the provision of electricity to large areas of the rural United States (Energy Information Administration, 1996).

During the Great Depression and the Dust Bowl years (ca. 1930s), the Federal Government became much more active in the provision and regulation of electricity. This involvement was consistent with the widespread belief that electricity should be inexpensive and readily available to the public. Federal power- and water-development projects were also promulgated for purposes of creating employment, resettling the landless, improving agricultural production, and fostering business and industry. A number of large public works projects were begun during this period; among these were the construction of Hoover Dam and the construction of Grand Coulee Dam, which remains the Nation's largest hydroelectric facility. A hallmark of the era was creation of the Rural Electrification Administration (REA). The Rural Electrification Act of 1936 (Public Law 74-605) established the REA to provide loans and assistance to organizations providing electricity to rural areas and towns with populations under 2,500. REA-backed cooperatives were instrumental in tripling the proportion of rural homes and farms served by electricity between 1932 and the entry of the United States into the Second World War in 1941 (Energy Information Administration, 1996).

The Bureau of Reclamation constructed and operates Glen Canyon Dam. The Western Area Power Administration (hereafter Western), an entity established by the Department of Energy Organization Act of 1977, now markets and transmits the electricity produced by the dam.

In compliance with the Colorado River Storage Project (CRSP) Act of 1956, power generated at Glen Canyon Dam and other CRSP facilities is first provided to CRSP-participating projects. These are typically Bureau of Reclamation irrigation projects, and generation is used to meet their pumping needs. Generation that is surplus to these "project uses" is then marketed by Western to about 200 wholesale power customers entitled to preference allocations. These preference customers are generally municipal and county utilities, rural electric cooperatives, Federal reservations, Indian Tribes, and certain other authorized entities (see General Accounting Office, 2001, for further details on preference). A list of current preference customers and their allocations can be found in Western Area Power Administration (2004a). These preference customers, in turn, sell electricity to approximately 1.7 million residential, commercial, industrial, and agricultural users located predominantly in a six-State region comprising Nevada, Utah, Arizona, Wyoming, Colorado, and New Mexico.

Each of the preference customers is allocated an amount of energy and capacity based on Western's determination of the marketable power resource. The most recent such determination, the "Post-2004 Determination of Marketable Resource," is described in Western Area Power Administration (2004b). If these preference customers require additional energy and there is additional energy available, Western may sell additional power to them on a short-term basis. If energy is available beyond the needs of the preference customers, Western may exchange energy with other suppliers or make sales on the spot market. If generation is insufficient to meet the allocations of preference customers, Western must exchange energy with another supplier or purchase additional energy on the market.

Western's rate-setting procedure for power differs from that of a non-Federal utility (General Accounting Office, 2000). By statute, power must be marketed at the lowest possible rates that are consistent with sound business practice. Administratively, Glen Canyon Dam is located in Western's Salt Lake City Area/Integrated Projects (SLCA/IP) region. The preferred customer rate is known as the SLCA/IP rate. The SLCA/IP rate is set to ensure that revenues are sufficient to repay all assigned costs within a prescribed period. These costs include annual power operation and maintenance costs, power facility construction costs including interest, certain environmental costs, and other nonpower-related costs that power users were assigned by Congress to repay (including irrigation costs that water users are unable to repay). The current SLCA/IP (F7) rate is $20.72/MWh.

The SLCA/IP rates charged by Western are designed to recover the taxpayer investment. They are lower than current wholesale market rates for electric power. Comparisons of the electric power rates are relatively difficult because of differences in contractual terms, commitment lengths, products provided, and fluctuations in electricity market conditions. Because of these complexities, the average revenue per megawatthour of wholesale electricity sold is widely used in the industry as a metric for comparison purposes. Two studies compared Western's average revenue received per megawatthour of wholesale electricity sold against those of other utilities. In a 1994 study, the General Accounting Office (1996b, p. 105, table V.1.) estimated Western's average revenue per megawatthour of wholesale power sold to be 47% of the revenue received by publicly owned utilities and 52% of the revenue received by investor-owned utilities. A 1999 assessment by the Energy Information Administration estimated Western's average revenue per megawatthour of wholesale power sold to be 42% of the average revenue received by utilities in the West (Energy Information Administration, 2000, p. 44, table 13).

Monitoring of the Hydropower Resource

The hydropower resource at Glen Canyon Dam is monitored rather intensively. Since the plant's supervisory control and data acquisition (SCADA) system was installed in the early 1980s, it has monitored and recorded a voluminous amount of information about power production and operations. At each of the eight units, these data include generation, release, reservoir afterbay water-surface elevations, voltage, frequency, circuit breaker status, gate positions, bearing temperatures, transformer settings, and the temperatures and operational status of a variety of appurtenant equipment.

These data are sampled at time increments ranging from 1 to 4 s. Selected data are recorded and archived at larger time intervals. This level of monitoring is standard business practice in the electric power industry.

The Effects of Environmental Constraints

The single most important determinant of hydropower production and economic value at Glen Canyon Dam is the amount of water released during the month. Based on projected hydrologic conditions, monthly and annual release volumes for Glen Canyon Dam and all major CRSP facilities are established by the annual operating plan (AOP) at the beginning of the water year (see www.usbr.gov/uc/water/rsvrs/ops/aop/aop05draft.pdf for an example). Monthly release volumes under the modified low fluctuating flow (MLFF) operating regime are identical to those under historical operations (1963–91) except for water years in which an experimental flow occurs. In years when experimental releases occur, monthly release volumes may vary substantially from the historical pattern, and there may be differences in monthly releases across the entire water year.

The environmental constraints that are part of the MLFF operating regime affect hydropower production at Glen Canyon Dam to varying degrees under different circumstances. Typically, these constraints are most limiting for moderate monthly release volumes and less constraining at either very high or very low release volumes. The maximum release constraint of 25,000 cfs is binding or constraining only when the reservoir elevations and monthly release volumes are sufficiently high to permit releases of 25,000 cfs or greater. The upramp rate of 4,000 cfs/h and the downramp rate of 1,500 cfs/h limit the hour-to-hour ability of the powerplant to respond to changes in load the majority of the time. At extreme high and low monthly release volumes, these ramp-rate restrictions have less effect. The maximum daily change in flow constraint limits the 24-h change in flow to 5,000; 6,000; or 8,000 cfs depending on the monthly release volume. This constraint greatly reduces the ability of the powerplant to respond to load changes within any given 24-h period. At very high and very low release volumes, the maximum daily change constraint has less of an effect on hydropower operations. Readers wishing to explore the effects of the MLFF constraints at Glen Canyon Dam in conjunction with different monthly release volumes and reservoir elevations can do so by using an interactive computer model developed by Harpman (2002). A rigorous mathematical exposition of hourly hydropower models is presented in Edwards and others (1999). A Microsoft Excel spreadsheet example of such a model is described in Edwards (2003).

The relative effects of the hourly constraints at Glen Canyon Dam and changes in monthly release volumes are illustrated in figure 3, which is constructed from Harpman (1997, 1999b) and from unpublished results. The interim low fluctuating flow (iLFF) operation regime (interim operating criteria elsewhere in this report) was a precursor to the MLFF. The iLFF maximum release constraint was 20,000 cfs, and the iLFF upramp rate was 2,500 cfs. Otherwise, these two operational regimes are identical. Figure 3 compares the monthly economic value of hydroelectricity produced at Glen Canyon Dam in water year 1996 under three conditions: historical operations of Glen Canyon Dam, operation under the iLFF, and operation under the iLFF with the beach/habitat-building flow (BHBF) of 1996. Although the 1996 BHBF experiment started on March 22 and ended on April 8, to facilitate this 7-d high-release experiment, changes in water-release volumes were required over much of the water year. As shown in figure 3, the changes in monthly release volumes necessitated by the 1996 BHBF created a significant effect. Relative to historical operations, the economic effects of the iLFF hourly constraints are less pronounced.

The Costs of Environmental Constraints

Relative to historical operations, the MLFF hourly environmental constraints on hydropower operations (see Overview, this report) have both short-run and long-run effects. In the short run, the MLFF reduces the maximum generation ability of the powerplant to respond to changes in load. As a result, more of the load must be met by other generators in the system, typically thermal generators. Since operation of thermal powerplants is more expensive than hydropower, additional costs are incurred. In the long run, new or replacement powerplants are needed earlier than would otherwise be the case. Increased capital costs associated with the construction of new and replacement powerplants may be substantial.

A number of economic analyses of changes in the operation of Glen Canyon Dam have been undertaken. Only three of these contain analyses of the MLFF alternative. Of these, only one study contains an estimate of

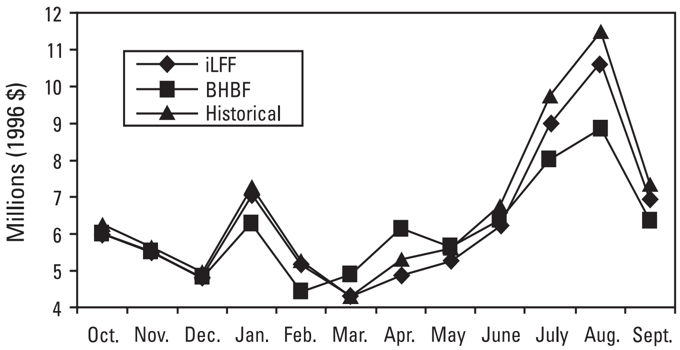

Figure 3. Comparison of the monthly economic value in water year 1996 of hydroelectricity produced at Glen Canyon Dam under different operating regimes (interim low fluctuating flows, iLFF; beach/habitat-building flow, BHBF; and historical operations, 1963–91).

both the short-run and long-run power system impacts of the MLFF. The Bureau of Reclamation Power Resources Committee (PRC) estimated the long-run cost of several alternative operating regimes at Glen Canyon Dam by using a production expansion model. Using regression analysis to interpolate between modeled alternatives, the PRC estimated that the annualized economic cost of changing from historical operations to the MLFF was $36.1 million (annualized value, 1996 dollars) per year. Because of excess capacity in the system, most of these costs were projected to be incurred late in the 50-yr analysis period (Power Resources Committee, 1995).

Two very detailed short-run studies of MLFF effects at Glen Canyon have been undertaken to date. These studies differ in conceptual approach and intended application. To correctly interpret their results, it is important to distinguish between the approaches they employ.

A study by Harpman (1999a) estimated the short-run economic effect of the MLFF relative to historical operations. This effect is conceptually equivalent to the difference between the historical line and the iLFF line in figure 3. The purpose of this study was to estimate the economic cost to all power users in the interconnected system. Using an hourly constrained nonlinear optimization model and spot market prices, Harpman estimated that the economic cost of the MLFF was $6.173 million (1996 dollars) for a representative 11.3 million acre-feet (maf) (13,933 million m^3) water year.

A short-run, ex post study of the 2000 low steady summer flow (LSSF) experiment was undertaken by Palmer and others (2004). Their approach was to estimate the difference in hydropower value between the MLFF and the 2000 LSSF relative to MLFF operations in the absence of the LSSF. The approach employed is conceptually equivalent to estimating the difference between the BHBF and the iLFF in figure 3. The goal of the Palmer and others (2004) study was to estimate the ex post financial cost of the LSSF to Federal power users, a subset of the power users in the interconnected system. Early in water year 2000, additional water was released from Lake Powell to create storage space in advance of expected spring inflows and to facilitate low steady flows during the summer experiment period. Because of the onset of the drought, approximately 605,000 acre-feet (af) (745,965,000 m^3) of this water was not replaced by inflows during water year 2000. Although some of the inflow deficit was subsequently recovered as of December 2004, a 228,000-af (281,124,000 m^3) storage deficit remains, and the reservoir elevation is 2.9 ft (0.9 m) lower than it would have been without the LSSF (Thomas Ryan, Bureau of Reclamation, written commun., 2005). Technically, the effects of the LSSF experiment are still ongoing. In order to complete their study, Palmer and others (2004) were forced to make several assumptions about when this inflow deficit would be recovered and the LSSF experiment would be concluded. Using these assumptions, observed prices, and an hourly linear programming model, Palmer and others (2004) estimated that the ex post cost of the LSSF experiment to Federal power users was approximately $32 million (2000 dollars).

Status and Trends in Hydropower Production

The average release at Glen Canyon Dam from water year 1978 through 1999 was approximately 10.93 maf (13,477 million m^3). Since the onset of the drought in 2000, releases have been much lower than average, and hydropower production has fallen annually. In water year 2000, the annual release was 9.38 maf (11,566 million m^3). The annual release from 2001 to 2004 has reflected the minimum objective release of approximately 8.23 maf (10,148 million m^3). As illustrated in figure 4, diminished inflows to Lake Powell combined with this nearly constant annual release have resulted in markedly lower reservoir elevation levels.

The average annual hydropower production from 1978 to 1999 was approximately 5,196,113 MWh. As shown in table 1, in recent years the production of hydropower at Glen Canyon Dam has been considerably below average. Generation has diminished since the onset of the drought in 2000. Although the annual

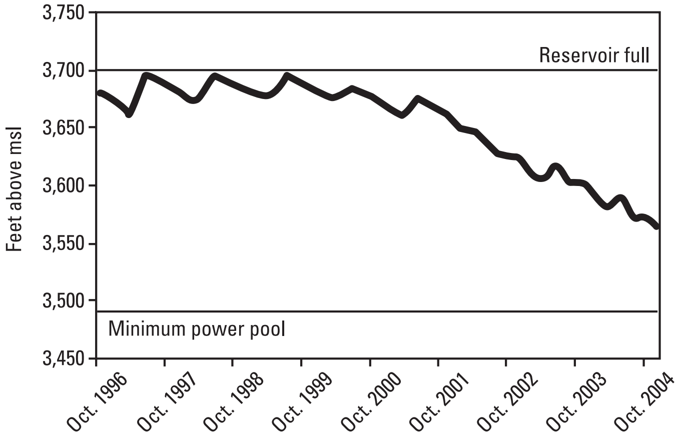

Figure 4. Lake Powell end of month (EOM) elevation in feet above mean sea level (msl).

release over the last 4 yr has been approximately the same (8.23 maf (10,148 million m^3)), decreasing head, or the distance water falls, has adversely affected annual generation. In 2001, approximately 3,940,247 MWh were generated. By water year 2004, only 3,320,196 MWh were generated.

Water year 2004 unregulated inflows to Lake Powell were approximately 51% of the 30-yr average (1971–2000). By the end of December 2004, the elevation of Lake Powell had fallen to 3,564.6 ft (1,086.5 m), and reservoir contents were approximately 8,678.0 thousand acre-feet (kaf) (10,699,974 thousand m^3), or 36% of capacity. This decrease in storage capacity is 135.4 ft (41.3 m) below full pool and 74.6 ft (22.7 m) above the minimum elevation necessary for power generation. These conditions last occurred in 1969 when the reservoir was being filled. Hydropower generation at Glen Canyon Dam is a function of both the amount of water released through the turbines and the head (for example, see Harpman, 2002, appendix 5).

As the reservoir elevation has fallen, the head available for hydropower production has declined, and this decrease has adversely affected generation capacity. When the reservoir is full (elevation 3,700 ft (1,128 m)), at a release level of 25,000 cfs the generation capability at Glen Canyon Dam is approximately 1,017 MW. At an elevation of 3,564.6 ft (1,086.5 m) and a release level of 25,000 cfs, the generation capacity at Glen Canyon Dam is approximately 749 MW, a reduction of 268 MW or approximately 26.4% (John Brooks, Bureau of Reclamation, written commun., 2005).

Table 1. Average and recent net hydropower production at Glen Canyon Dam.

Water year	Net generation (MWh)
1978–99 average	5,196,113
2000	4,600,453
2001	3,940,247
2002	3,772,544
2003	3,518,297
2004	3,320,196

The Basin Fund

The Colorado River Storage Project, authorized by the CRSP Act of 1956 (Public Law 84-485), is a program to develop, and make available for use, the water resources of the upper Colorado River Basin. The CRSP is composed of 4 multipurpose storage units—Flaming Gorge Dam, Wayne N. Aspinall Unit, Navajo Unit, and Glen Canyon Dam, often referred to as the "mainstem units"—and 21 authorized participating projects in the States of Colorado, New Mexico, Utah, and Wyoming.

Financial exchanges necessary to the operation of the CRSP are facilitated by the Upper Colorado River Basin Fund (Basin Fund). The Basin Fund was established by section 5 of the CRSP Act. The Basin Fund is a financial instrument that obviates the need for congressional actions to pay for project operation and maintenance. It is a dedicated Treasury account for the deposit of project revenues, which would otherwise be deposited in the general fund, and a source of funds for the payment of project expenses, which would otherwise need to be appropriated. Existence of the Basin Fund greatly streamlines the financial operations of CRSP and participating projects.

As described in the CRSP Act, all revenues collected in connection with the operation of the CRSP and participating projects are credited to the Basin Fund. Revenues are available, without further appropriation for defraying the cost of operation, maintenance, and replacements of and emergency expenditures for all CRSP facilities, with the exception that for participating projects, such costs are paid for with revenues generated from that project. Funds in excess of those needed for project operation and maintenance needs, certain environmental programs, and assigned costs of the salinity control program are paid annually to the general fund of the Treasury to repay CRSP investment costs with interest. Funds in excess of those requirements are then apportioned to each of the upper Colorado River Basin States to help defray investment costs associated with developing the irrigation components of the 21 authorized participating projects. There are a number of complex provisions, clauses, and details associated with the CRSP Act, the Basin Fund, and project repayment, but they are all outside the scope of this chapter. A description of these aspects of the CRSP Act and their implications for the recovery of the taxpayer investment can be found in General Accounting Office (1996a).

As dictated by prudent business practice, the SLCA/IP power rate is set at a level sufficient to meet operational and repayment needs while accommodating foreseeable variations in generation and resultant revenue. Sometimes unforeseen, adverse hydrologic conditions occur, necessitating greater than expected replacement power purchases. Purchases of replacement power, in excess of revenues, are made with funds from the Basin Fund. If adverse hydrologic conditions continue, the Basin Fund may be depleted and an increase in the SLCA/IP rate would be required. Conversely, favorable hydrologic conditions can result in greater than expected revenues from hydropower sales; these additional revenues are deposited into the Basin Fund. Funds in excess of those needed for project operations are treated as described in the CRSP Act. If favorable hydrologic conditions persist for a number of years, repayment on investment is accelerated, and a downward adjustment to the SLCA/IP rate may be initiated.

The status of the Basin Fund fluctuates monthly, thereby reflecting the timing of project revenues and expenditures. Exclusive of replacement power purchases, about $95 million is needed to fund CRSP project operational needs on an average annual basis. The vast majority of these revenues are derived from hydropower sales in the CRSP system. Since 2000, extensive and unplanned purchases of replacement power have been required because of the drought. These purchases have drawn down the cash reserve balance in the Basin Fund. In mid-January 2005, the Basin Fund held approximately $50 million (David Taylor, Western Area Power Administration, oral commun., 2005).

In addition to replacement power purchases, the Basin Fund is used to meet CRSP payroll and other operational and maintenance expenses. Certain environmentally related expenditures, including the costs of the Glen Canyon Dam Adaptive Management Program, are also made from the Basin Fund. To the extent that the Basin Fund is depleted during a period of adverse hydrologic conditions, funding for all of these purposes could be jeopardized. Western has taken two steps to bolster CRSP revenues and improve the status of the Basin Fund. First, Western has lowered their determination of marketable power resource (Western Area Power Administration, 2004b). The lower determination reduces the amount of replacement energy that they are required to purchase and shifts more of the risk of being energy-short in times of adverse hydrologic conditions to power users. Second, Western has initiated a substantial rate-increase action (Western Area Power Administration, 2005). As proposed, the new rate is $25.77/MWh, a 24.4% increase over the current rate. Western's rate proposal also includes a provision for cost recovery charge, which can be implemented when revenue shortfalls are projected. These steps will increase the amount of revenue derived from hydropower sales and bolster the position of the Basin Fund.

The Grand Canyon Protection Act of 1992 contains special provisions establishing and funding the Glen Canyon Dam Adaptive Management Program. Section 1805 of the act establishes the long-term monitoring program now carried out by the Glen Canyon Dam Adaptive Management Program, and section 1807 of the act declares expenditures for this program to be nonreimbursable. These provisions shift the burden of paying these costs from project beneficiaries, such as water and power users, to taxpayers in general. Expenditures by the Glen Canyon Dam Adaptive Management Program are drawn from the Basin Fund. These payments are then credited towards project repayment, thereby reducing the repayment obligation of all project beneficiaries. As a result, these environmentally related expenditures are indirectly paid for by all taxpayers in the United States.

Outlook for the Future

In the years to come, the amount of hydropower generated at Glen Canyon Dam is largely dependent on future hydrologic conditions. While future hydrologic conditions can never be known with certainty, probabilistic forecasts can provide some important insights. The Bureau of Reclamation uses the RiverWare™ modeling system (Zagona and others, 2001) for CRSP multiyear planning studies. These multiyear planning studies employ the indexed sequential method (described in Ouarda and others, 1997) for simulating future hydrologic conditions. RiverWare™ modeling runs completed in January 2005 use December 2004 CRSP end-of-month reservoir elevations as starting conditions and simulate monthly operations for 90 different monthly inflow sequences, each of which is 90 yr long. Statistical analysis of these simulations suggests that the median time required to refill Lake Powell (achieve an elevation of 3,695 ft (1,126 m) in July) is approximately 19 yr (Thomas Ryan, Bureau of Reclamation, written commun., 2005). This evidence suggests that several decades may pass before hydropower production at Glen Canyon returns to the level of the late 1990s.

The scheduled replacement of the turbine runners at Glen Canyon Dam will increase hydropower generation from 1% to 7% (John Brooks, Bureau of Reclamation, written commun., 2005). Turbine runners are the large fan-like blades turned by the force of water falling through the penstocks. The existing turbine runners at Glen Canyon Dam have reached the end of their design life and are now scheduled for replacement. Improvements in runner technology, design, and fabrication methods now allow for improvements in efficiency (more electricity produced for a given amount of water released), greater generation capacity (higher generation level for a given head and water release level), or both. Analysis of alternate turbine runner designs, their costs, and benefits is now underway. Installation of new turbine runners on two of the generation units at Glen Canyon Dam is expected to begin within 2 yr, and all of the turbine runners are expected to be replaced within the next 10 yr.

The potential installation of temperature control devices (TCDs) at Glen Canyon Dam is expected to reduce generation by less than 1% (Bureau of Reclamation, 1999). Thermal and chemical stratification develops in Lake Powell during the summer months. The penstock intakes are located at an elevation of 3,476 ft (1,059 m) and are typically within the cold, hypolimnetic strata (see chapter 4, this report). As a result, releases from Glen Canyon Dam remain at about 50ºF (10ºC) all year long. Native fish populations persist at these relatively low temperatures, but it is believed that their spawning and rearing success is drastically reduced (see chapter 2, this report). The Bureau of Reclamation is studying the feasibility of installing TCDs at Glen Canyon Dam (Bureau of Reclamation, 1999). The purpose of these TCDs is to allow for the management of downstream temperatures to benefit existing and remnant populations of native fish. Current plans call for installation of TCDs on two of the eight generation units at Glen Canyon Dam.

Given current drought conditions, the outlook for hydropower production at Glen Canyon Dam is somewhat bleak in the near term; however, conditions are expected to improve in the future. Easing of the current drought and subsequent gradual improvements in hydrologic conditions in the Colorado River Basin are expected to refill reservoirs and increase the amount of hydropower that can be generated at Glen Canyon Dam and other CRSP units. At any given reservoir elevation and release, the planned installation of new turbine runners will result in an increase in hydropower generation. Although the amount of CRSP generation has been reduced by the drought in recent years and CRSP rates are slated to increase, the hydroelectric energy produced at Glen Canyon Dam has been, and continues to be, one of the lowest cost sources of electric energy available in the West.

Acknowledgments

This effort was supported by the U.S. Geological Survey, Grand Canyon Monitoring and Research Center, interagency agreement DCN-5IA93953031. The assistance of Michael W. Loring, regional economist, Bureau of Reclamation, Salt Lake City, Utah, is gratefully acknowledged.

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